COST-BENEFIT & REGULATORY ANALYSIS
PURSUANT TO §24-4-103, C.R.S.
New Rules and Amendments to Current Rules of the Colorado Oil and Gas Conservation Commission, 2 CCR 404-1

Cause No. 1R Docket No. 151100667
Governor's Task Force Rulemaking

On November 16-17, 2015, the Colorado Oil and Gas Conservation Commission ("Commission") will consider new rules and amendments ("Governor's Task Force Rules" or "Task Force Rules") to the Commission's Rules of Practice and Procedure, 2 CCR 404-1 ("Rules").

The purpose of the Governor's Task Force Rulemaking is to implement Recommendation Nos. 17 and 20 of the Governor's Task Force on State and Local Regulation of Oil and Gas Operations. To implement these Recommendations, the Commission will consider a new definition in the 100-Series Rules and new Rules 302.c., 305A, and 604.c.(4), as well as amendments to Rules 303.b.(3)K, 303.c., 305.a.(1), 305.d., 306.d.(1), and 604.b.(1).

On October 7, 2015, the Commission submitted a Notice of Public Rulemaking Hearing, which was published in the Colorado Register on October 25, 2015. On October 26, 2015, the Colorado Oil & Gas Association, Colorado Petroleum Association, and Colorado Petroleum Council filed a timely request for a cost-benefit analysis of the proposed Task Force Rules, pursuant to the State Administrative Procedures Act, §24-4-103(2.5), C.R.S., and a regulatory analysis pursuant to §24-4-103(4.5), C.R.S.

On October 30, 2015, the Executive Director of the Department of Regulatory Agencies required the Commission to prepare a cost-benefit analysis of the proposed Task Force Rules.

On November 2, 2015, the National Association of Royalty Owners Colorado Chapter filed a timely request for a cost-benefit analysis and regulatory analysis of the proposed Task Force Rules.

I. APA Requirements for this Analysis

Pursuant to Section 24-4-103(2.5), C.R.S., a cost-benefit analysis must contain:

1) The reason for the rule or amendment;

2) The anticipated economic benefits of the rule or amendment, which shall include economic growth, the creation of new jobs, and increased economic competitiveness;

3) 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 agencies required to comply with the amendment;

4) Any adverse effects on the economy, consumers, private markets, small businesses, job creation, and economic competitiveness; and

5) A determination of whether there are less costly methods or less intrusive methods for achieving the rule's purpose; and

6) 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 cost and benefits of pursuing each of the alternatives identified.

Pursuant to Section 24-4-103(4.5), C.R.S., a regulatory analysis must contain:

1) A description of the classes of persons who will be affected by the proposed rule, including the benefits and costs to those persons;

2) A description of the probable quantitative and qualitative impacts on the affected classes of persons;

3) 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;

4) A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction;

5) A determination of whether there are less costly methods or less intrusive methods for achieving the rule's purpose; and

6) A description of any alternative methods of achieving the rule's purpose that were considered by the agency and rejected.

An analysis of each of the above required elements, including the quantification of the data to the extent practicable and consideration of short-term and long-term consequences, is provided below.

II. Reason for the Rules or Amendments

The Commission's reason for promulgating the Governor's Task Force Rules is to implement the Task Force's Recommendation Nos. 17 and 20. These Recommendations proposed that the Commission promulgate rules to encourage coordination and communication between operators and local governments, recognizing the need for additional regulatory tools to address issues arising from the proximity of large scale oil and gas operations to Colorado communities. The Task Force Rules are intended to increase operator coordination with local government decision-making processes and to facilitate local government engagement in the Commission's permitting processes.

A. *Executive Order B 2014-005*

On September 8, 2014, the Governor issued Executive Order B 2014-005, "Creating the Task Force on State and Local Regulation of Oil and Gas Operations" ("Executive Order"). This Executive Order identified a need for state and local jurisdictions, operators, and the public to discuss the complex issues surrounding increased oil and gas activity near communities. To facilitate the development of solutions to these issues, the Executive Order created the Task Force on State and Local Regulation of Oil and Gas Operations ("Task Force") comprised of representatives of various stakeholder groups.

The Task Force was directed to consider recommended policies, regulation, or legislation to "harmonize state and local regulatory structures" with the following objectives:

1) The benefit of oil and gas development on the state's economy;

2) Protecting public heath, water resources, the environment and wildlife;

3) Avoiding duplication and conflict between state and local regulations of oil and gas activities; and

4) Fostering a climate that encourages responsible oil and gas development.

On February 24, 2015, a majority of the Task Force voted to approve nine recommendations. Recommendations Nos. 17 and 20 were unanimously approved and contemplated the Commission implementing a rulemaking.

B. *Task Force Recommendation No. 17: Recommendation to Facilitate Collaboration of Local Governments, Colorado Oil and Gas Conservation Commission and Operators Relative to Oil and Gas locations and Urban Planning*

Recommendation No. 17, "Recommendation to Facilitate Collaboration of Local Governments, Colorado Oil and Gas Conservation Commission and Operators Relative to Oil and Gas locations and Urban Planning," proposed a Commission rulemaking to address local government collaboration with operators concerning locations for "Large Scale Oil and Gas Facilities" in "Urban Mitigation Areas" as defined in Commission Rules.

The Recommendation proposed that the Commission address three related issues through rulemaking: (1) "define and adopt a process for enhancing local government participation during the COGCC [permitting process] concerning location(s) of Large Scale Oil and Gas Facilities in Urban Mitigation Areas"; (2) "define what constitutes

'Large Scale Oil and Gas Facilities' taking into consideration scale, proximity, and intensity criteria"; and (3) address the authority of and procedures to be used by the Director to regulate the location of Large Scale Oil and Gas Facilities for the purpose of reducing impacts and conflicts with communities, including siting tools to locate facilities away from residential areas when feasible, and mitigation measures to lessen the impacts on neighboring communities.

Recommendation No. 17 was proposed and approved as a result of "concerns from numerous parties about the location of large multi-well production facilities in close proximity to urbanized areas" and "the scale and intensity of multi-well production facilities that are in close proximity to neighborhoods has led to an increased need for local governments to represent their constituents to a greater degree than in the past." It "provides a mechanism for local governments to influence locations prior to permitting at the COGCC and establishes a mechanism for collaboration among local governments, oil and gas Operators, and the COGCC."

C. Task Force Recommendation No. 20: Recommendation to Include Future Oil and Gas Drilling and Production Facilities in Existing Local Comprehensive Planning Processes

Recommendation No. 20, "Recommendation to Include Future Oil and Gas Drilling and Production Facilities in Existing Local Comprehensive Planning Processes," proposed a Commission rulemaking to address operator registration and information-sharing with municipal Local Government Designees ("LGDs") regarding "Future Oil and Gas Drilling and Production Facilities" for the purpose of incorporating those plans into "Existing Local Comprehensive Planning Processes."

This Recommendation was proposed and approved because "oil and gas development is within the purview of the State of Colorado, and long-term planning to the extent it is performed, is often disjointed and not coordinated with local governments, most acutely in municipalities."

III. Scope of the Task Force Rulemaking

The Task Force Rules will apply only to large Oil and Gas Facilities proposed to be located in Urban Mitigation Areas. Since August 2013, when "Urban Mitigation Area" was first defined in the Commission Rules, only one percent of new oil and gas locations have been sited within an Urban Mitigation Area. *See* Table 1. Consequently, the overall cost impact of the Task Force Rules on industry will be *de minimis*.

Table 1: Oil and Gas Locations within Urban Mitigation Areas since August 1, 2013

Where Proposed after August 1, 2013	Number Approved	% of Total Form 2As Submitted
Total Statewide Form 2As Approved	1,700	
Form 2As in Urban Mitigation Area	13	0.8%

Of the thirteen Form 2As that have been approved in an Urban Mitigation Area, twelve, or 92%, would be classified as a Large UMA Facility as defined in the draft proposed Rules based on the well or tank count at the proposed facility.

Even if the percentage of new oil and gas locations proposed to be within an Urban Mitigation Area grows by tenfold in coming years the overall cost impact still will be small. While preserving mineral owners' rights to access their minerals, an Urban Mitigation Area should be the last choice for siting a large oil and gas facility if an alternative location that is economically practicable can be identified.

Additionally, the proposed Task Force Rules will have no cost impact on the vast majority of operators in the state. "Large" oil and gas facilities include multiple wells – horizontal wells in most cases – and require tens of millions of dollars of capital investment. Presently, six of the seven operators with an Urban Mitigation Area location are among the top 30 operators in terms of oil production and number of active wells out of more than 500 operators in the state. Thus, only large operators in the state likely will be affected by the proposed Rules.

The Task Force Rules are substantially procedural in nature: operators proposing a Large UMA Facility may be obligated to notify and meet with local government representatives with land use jurisdiction over the site and with nearby local government representatives. Similarly, proposed Rules to implement Recommendation No. 20 require operators to provide certain information to local governments that request the information. These procedural requirements will impose transactional costs, but not capital expenditures. Quantifying these transactional costs is challenging. For example, costs will depend on the needs of the particular parties involved, the site-specific nature of proposed locations, and how groups decide to utilize the opportunities and information provided in the process. In this analysis, Commission Staff has endeavored to anticipate how these various elements may generally interact.

The Task Force Rules state, "Large UMA Facilities should be built and operated using the best available technology to avoid or minimize adverse impacts to adjoining land uses." Operators of Large UMA Facilities may incur increased capital costs to implement best management practices necessary to eliminate, minimize, or mitigate potential adverse impacts on public health, safety, and welfare, including the environment and wildlife resources at such locations. However, the precise best management practices to be required will vary from one Large UMA Facility to the next, depending on site-specific conditions. The variability in best management practices or mitigation measures that may be required makes quantifying these costs challenging.

IV. Affected Classes and Impacts to those Classes

This section describes the affected classes; anticipated economic and other types of benefits and costs, including direct and indirect costs, to the affected classes; and the probable qualitative and quantitative impacts to the affected classes.

A. Affected Classes of Persons

The Task Force Rules implementing Recommendation No. 17 will affect the following classes of persons: local governments with land use authority over a proposed Large UMA Facility; proximate local governments with land use authority within 1,000 feet of a proposed Large UMA Facility; large oil and gas operators, constituting less than 10% of all operators, who may develop a Large UMA Facility; surface owners; mineral owners; the citizens of Colorado; and Commission Staff.

The Task Force Rules implementing Recommendation No. 20 will affect the following classes of persons: local jurisdictions, defined as "a home rule or statutory city, town, territorial charter city, or city and county", and their growth management area, in which an operator has existing or planned oil and gas operations; oil and gas operators; the citizens of Colorado; and Commission Staff.

B. Anticipated Benefits

The anticipated benefits from the Executive Order, the Task Force Recommendations, and now the Task Force Rules, include improved planning, coordination, and collaboration between oil and gas operators, local governments, and the Commission regarding oil and gas development in more densely populated areas of the state.

Improved planning and coordination will reduce the potential for conflicts between mineral and surface owners seeking to develop their respective property rights and will create better opportunities for citizens living in close proximity to a proposed Large UMA Facility to participate in both local and state review of the location. It will also increase the certainty for local governments, operators, and the public regarding the timing and expectations through the Commission's permitting process. These benefits are difficult to quantify, but many resources have been expended in legal conflicts between local governments, operators, and the Commission over oil and gas development in recent years in Colorado.

1. <u>Task Force Rules Implementing Recommendation No. 17</u>

The local government with land use authority over a proposed Large UMA Facility will have several opportunities and rights regarding the siting and operational practices at the location. The required consultation with the operator will reduce conflict, allow local governments to more fully represent their citizens in oil and gas siting decisions, and provide established procedures if a resolution cannot be reached. ***See generally*** **Rule 305A.**

Proximate Local Governments, defined as local governments whose boundaries are within 1,000 feet of a proposed Large UMA Facility, will have the opportunity to meet with the operator and the Director regarding potential best management practices at the proposed location. These local governments will benefit from this opportunity to be heard and represent the interests of their citizens, which will include a written response from the Director regarding their proposed best management practices. **Rule 305A.d.(3).**

The Task Force Rules require an operator to provide a Notice of Intent to Construct a Large UMA Facility to the local government with land use authority over the proposed site before the operator has a final contract with the surface owner for a specific location. The consultation between the local government with land use authority and the operator must take into consideration the surface owner's siting requests and concerns. **Rule 305A.c.(2).** At the surface owner's request, the operator and the Director are also required to meet with the surface owner regarding the siting of the proposed facility. **Rule 305A.e.** Surface owners likely will also benefit from a reduction in the potential for conflict and the opportunity to have their concerns heard before a final location is chosen. Similarly, mineral owners will benefit from reducing the potential for conflict and the need for other lengthy resolution measures that would delay the development of the minerals.

The citizens of Colorado will benefit from their local governments' increased opportunities to represent their views in oil and gas siting and operational decisions. In addition, the Task Force Rules propose an extended comment period of 40 days for Large UMA Facilities, which the Director may extend for an additional 20 days. **Rule 305.d.** This extension will allow citizens to comment on the proposed location both when it is originally submitted and later in the process, in case the proposed location has significantly changed. Citizens will also benefit from a reduction in the potential for impacts from operations of extended duration, as a result of the duration limits on Large UMA Facilities for drilling, completion, and stimulation operations. **Rule 604.c.(4)B.ii.**

Operators may also benefit from the best management practices and mitigation measures set forth in Rule 604.c.(4). For example, the Task Force Rules require close loop drilling systems by incorporating the Designated Setback Zone mitigation measures. **Rule 604.c.(4)B.i.; Rule 604.c.(2)B.i.** The EPA has identified four case studies where operators saved between $1,320 to $12,700 per well by implementing a closed loop drilling system.[1] The Task Force Rules also incorporate the requirement for green completions at Large UMA Facilities. **Rule 604.c.(4)B(i); Rule 604.c.(2)C.** The EPA has estimated that green completions can pay back their costs in one year, allowing operators

[1] Environmental Protection Agency, *Compilation of Publicly Available Sources of Voluntary Management Practices for Oil and Gas Exploration & Production* (April 1, 2014), p. 74-76, available at http://www3.epa.gov/epawaste/nonhaz/industrial/special/oil/og_ep_vol_wste_mgt_%20prctcs_compilation_040114.pdf.

to only benefit from capturing otherwise flared or vented gas after that point.[2] Large UMA Facilities' Form 2As must also incorporate methods of fluid leak detection for all above and below ground on-site fluid handling, storage, and transportation equipment. **Rule 604.c.(4)A.ii.** Detecting leaks quickly or preventing them entirely will benefit operators by reducing or eliminating potential clean-up costs and on-site damage.

Although the Large UMA Facility consultation process applies to a limited number of facilities statewide, many of the principles regarding early communication and consideration of alternatives will ideally improve relationships regarding all types of locations. Additionally, these benefits will extend to the majority of locations proposed in Urban Mitigation Areas as described in Section III.

2. Task Force Rules Implementing Recommendation No. 20

At the jurisdictional LGD's request, the Task Force Rules require operators to share a good faith estimate of the number of wells they intend to drill in the next five years in the local jurisdiction and provide a map showing existing and planned locations. **Rule 302.c.(1)&(2).** This information must also cover the local jurisdiction's formally approved growth management area.

Local jurisdictions with which operators are required to register under proposed Rule 302.c. will benefit from information earlier in their land use planning process, especially in the growth management areas. Oil and gas operators will also benefit from earlier planning discussions with local governments and may identify and therefore avoid potential conflicts and issues with proposed development areas. Advanced planning and improved coordination between oil and gas operators and local governments will facilitate more harmonious development of oil and gas and other, competing land uses. Operators and citizens will benefit from starting these conversations regarding the intersection oil and gas and municipal development earlier.

C. Anticipated Costs

Again, the Task Force Rules implementing Recommendation No. 17 only apply to a proposed oil and gas location if it qualifies as a Large UMA Facility. They define a Large UMA Facility as an oil and gas location proposed to be located in an Urban Mitigation Area and on which: (1) the cumulative total depth of all new wells planned for the Location exceeds 90,000 feet; or (2) the cumulative new and existing on-site storage capacity for produced hydrocarbons exceeds 4,000 barrels. **100-Series Rules.** The costs to the affected classes must be viewed with the perspective of this limited scope.

[2] *Id.* at 78.

1. Task Force Rules Implementing Recommendation No. 17

Local governments with land use authority and operators may have costs associated with the staff time for preparing and attending the consultation meetings, as well as the mediation and hearing if necessary. The local government and operator will also share the costs of mediation, but can jointly choose the mediator and therefore a mediator's associated rate. **Rule 305A.c.(3)A&B.** The local government can always waive the consultation process, either globally or on a case-by-case basis, and not incur any costs. **Rule 305A.f.(1)B; 305A.f.(2)B.** The only costs to Proximate Local Governments may include staff time for preparing and attending the meetings. Similarly, the only costs surface owners will incur is the time to prepare for and attend the meetings with the Director and operator; however, the surface owner may always opt not to request a meeting and therefore not incur any costs. **Rule 305A.e.** Mineral owners may have a slight delay in the development of the minerals, and therefore their receipt of royalties, for under one percent of the proposed locations in the State; however, mineral owners may have been experiencing delays due to the controversial nature of these sites prior to the Task Force Rules.

The Commission will expend Staff time and resources participating in the consultation process and reviewing Form 2A, Oil and Gas Assessments, especially for Large UMA Facilities for which local governments and operators are not able to reach agreement. **Rule 305A.c.(1); 305A.d.; 305A.e.; 305A.f.** These burdens will fall largely on the Director, the Oil and Gas Assessment Unit, and possibly the Permitting Unit more generally. However, these types of facilities already require significant staff time and resources. Staff will also need to make adjustments to the Form 2A, Oil and Gas Assessment, to incorporate the Task Force Rule changes. Staff estimates that these changes will take 24 hours of development time and 80 hours of time to design, implement, and provide training. This will cost the Commission approximately $5,552 ($1,200 for developer time and $4,352 for Staff time). In cases where the local government and an operator cannot reach agreement, Staff will also spend time and resources preparing for Commission hearings on the operator's Form 2A, Oil and Gas Assessment, and the Commission will sit for the hearing. The costs to the Commission to implement these Task Force Rules are covered by current resources and will not require any additional appropriations.

The Rule 604.c.(4) required and site-specific best management practices and mitigation measures may impose costs on a small percentage of operators at fewer than ten percent of all new oil and gas locations in the state. **Rule 604.c.(4).** These additional costs, if any, will vary significantly depending on site-specific measures on the type of action required to eliminate, minimize, or mitigate potential adverse impacts at each Large UMA Facility.

In addition, under its current authority, the Commission can require operators to implement these best management practices and mitigation measures if necessary to protect public welfare and the environment. The Task Force Rules merely clarify what will likely be required on Form 2A, Oil and Gas Assessments, for proposed Large UMA Facilities. The Commission will always consider cost-effectiveness and technical feasibility in imposing mitigation measures. Since operators may already be subject to the mitigation measures or new BMPs to deal with issues identified in the Task Force Rules, new, additional costs to operators are minimal.

Many operators already implement the best management practices and mitigation measures that would be required under Rule 604.c.(4). For example, during the September 2013 floods, operators reported that the majority of the 2,657 wells that were shut-in as a result of the floods were shut-in remotely.[3] ***See* Rule 604.c.(4)A.iii.** The oil and gas industry is constantly developing new technologies and applications that reduce impacts cost-effectively. For example, Anadarko Petroleum Corporation has developed a completion transport system that recycles completion fluids from one staging site to another transported by temporary surface lines. This "reduces truck traffic, air emissions, fresh water utilization, and cost."[4]

Rule 604.c.(4) requires the same mitigation measures that were adopted for Exception Zone Setback locations for Large UMA Facilities. **Rule 604.c.(4)B.i.** During the 2012 Setback Rulemaking, Staff estimated that the implementation of all mitigation measures for locations in Buffer Zones would increase the cost of the location, on average, by $15,472.[5] These costs only reflected equipment costs and did not include continuing operation, maintenance, or third-party vendor costs.

One of the areas where the Director may require additional mitigation measures for Large UMA Facilities is to address noise impacts. **Rule 604.c.(4)A.i.** For example, an operator may be required to perform a baseline ambient sound survey or install continuous sound monitoring depending on the site-specific nature of the location. According to one industry representative, an ambient survey costs approximately $2,600 for a 72-hour time period with an additional $1,700 per sensor and a 24-hour noise monitoring station costs approximately $75/day with each additional monitoring station costing $50/day. A daily or weekly monitoring report costs an additional $100 to $250 per report.

[3] Staff Report to the Commissioners, *"Lessons Learned" in the Front Range Flood of September 2013*, p. 16 (March 14, 2014), available at http://cogcc.state.co.us/announcements/hot_topics/flood2013/finalstaffreportlessonslearned20140314.pdf.
[4] Anadarko Petroleum Corporation Presentation, ACTS: Anadarko Completion Transport System (2010), available at http://www.oilandgasbmps.org/workshops/vernal2010/ppt/Jeff_Dufresne_Anadarko_ACTS.pdf.
[5] 2012 Setback Rulemaking, Regulatory Analysis on the Setback Rules, available at http://cogcc.state.co.us/documents/reg/Rules/SetbackRulesRegulatoryAnalysis110912.pdf.

The Task Force Rules also provide that the Director, in consultation with the operator and others, will impose a reasonable time limit on the duration of drilling, completion, and stimulation operations for a Large UMA Facility. **Rule 604.c.(4)B.ii.** Limiting the duration of these operations may require an operator to develop a specific location in phases, which would impose additional costs. For example, phased development potentially would require de-mobilization and re-mobilization of a drilling rig and the completion and stimulation equipment for a site. Similarly, taking down and then reconstructing sound barriers might be necessary. A delay in bringing wells into production also delays revenues or may increase the cost of capital, which could reduce calculated rates of return.

Staff contacted two rig companies active in the DJ Basin which provided a range of $40,000 to $50,000 to move-in and rig-up prior to drilling a well and $40,000 to $50,000 to move-in the hydraulic fracturing crew. Because a phased development would require an operator to do this one additional time, it would cost operators an additional $80,000 to $100,000 for the second de-mobilization and re-mobilization. This cost does not incorporate any costs for lost operation time. According to another industry representative, a 24 foot sound wall on a 600 foot by 400 foot pad would cost $33,500 to set up and $25,000 to tear down. If phased development was required, an operator would incur an additional $58,500 cost for a second set-up and tear down.

Staff performed a pure cash flow analysis based on the impact to net present value (with a 10% discount rate) for identical wells in two scenarios: (1) continuous development and (2) a delay of half the wells on the pad for one year. This analysis is attached as **Exhibit A.** Staff used the following assumptions: $55/bbl oil and $3.00 MCF gas; 16-well pads; and all wells producing 690 Mboe. Staff calculated a $5.8 million reduction in net present value – from $106.5 million down to $100.4 million for the 16-well pad with delayed development over 10 years. This is a 5.5% reduction in the net present value compared to drilling all 16 wells in the first year.

Industry prepared an analysis that compared the continuous development of 12 wells at a proposed location and the development of the same pad with a 90-day duration limit, which is attached as **Exhibit B**.[6] The analysis with a 90-day duration limit used the following assumptions: 3 wells would be drilled per year, in the first calendar quarter; completing all 12 wells would take four years; previously drilled wells are shut-in for three months each year as new wells are drilled; the cost to drill and complete each well is $5.6 million; each well has two-mile lateral reach; and each well produced 700,000 barrels of oil equivalent over its lifetime. It appears a different oil price was used for each scenario ($55/bbl for the continuous development and $50/bbl for the intermittent development). It is unclear why a lower price for oil was chosen for the duration limit scenario. Under these assumptions, industry calculated an approximate 52% loss in

[6] Exhibit B, Bill Barrett Corporation's Prehearing Statement, Docket No. 151100667, available at http://cogcc.state.co.us/documents/reg/Rules/GtfRulemaking/Party%20Statements%20&%20Responses/Bill%20Barrett%20Corporation%20Prehearing%20Statement.pdf.

present value over ten years. The models or formulas resulting in the "economics damaged" were not provided.

The Commission believes the assumptions used by industry in the example above do not accurately reflect the duration limitations contemplated by the Task Force Rules for a variety of reasons.

The Task Force Rules' duration limits are necessary to address issues associated with 24/7, long-term operations that cannot be solved with best management practices or mitigation measures. Moreover, the duration of these operations has already been steadily decreasing over the last five years with the advancements in the industry. In the DJ Basin in 2015, it took operators an average of nine days to drill (spud, casing, and cement) a Niobrara or Codell formation well with a 4,500 foot lateral. This is almost a 50% reduction in time from the amount of time it took operators to drill a 3,915 foot lateral in 2010. As shown in Table 2 below, the total time for drilling and completion of 1-mile lateral wells in the DJ Basin has decreased from 17 to 12 days in five years. Operators have and will continue to benefit from reducing drilling and completion time.

Table 2: Time for Drilling and Completion of 1-mile Lateral DJ Basin Wells 2010-2015

Year	Measured Depth (feet)	Spud to Total Depth (days)	Casing and Cement (days)	Stimulation (days)	Total (days)
2010	3,915	13	3	2	17
2011	4,275	12	3	1	17
2012	4,413	10	2	2	14
2013	4,455	10	2	2	13
2014	4,524	9	2	3	14
2015	4,500	8	1	3	12

The data in the table above is based on time periods calculated from Form 5, Drilling Completion Report, and Form 5A, Completed Interval Report, submitted by operators during this period.

Furthermore, any additional costs imposed by the Task Force Rules on these limited locations will be a fraction of the total cost to drill and complete a well. For example, operators' recent filings with the Commission estimated the following costs for drilling wells in the Greater Wattenberg Area: $3.9 to $4.2 million for a 1 mile lateral, $4.6 million for a 1.5 mile lateral, and $5.6 to $7.8 million for a 2 mile lateral. Given that an average of five horizontal wells are being drilled from a single location in the Greater Wattenberg Area, the capital investment just for drilling and completions is likely to be between $20 and $40 million.[7]

[7] This average number of horizontal wells drilled per a single location was calculated based on information available in the COGIS database, does not include single well sites, and covers a total of 24,005 locations.

2. <u>Task Force Rules Implementing Recommendation No. 20</u>

Local jurisdictions can request a good faith estimate of an operator's planned wells and the map described in Rule 302.c.(3) through the existing Local Government Designee program, but may incur some cost in evaluating or integrating the new information into their planning process. Additionally, because this information will be provided at the LGD's request, it is within the local jurisdiction's discretion of whether and how to use this information.

Operators may incur costs to compile the good faith estimate of the number of wells it plans to drill. However, this likely is information that an operator has available for its internal planning purposes or, for publicly traded companies, already prepares for SEC reports. Similarly, operators may incur costs to develop a map of its existing well sites and related production facilities; sites for which the operator has approved, or has submitted applications for, drilling and spacing orders, Form 2s, and Form 2As; and, sites the operator has identified for development on its current drilling schedule for which it has not yet submitted applications for Commission permits. **Rule 302.c.(3)B.** This map is either based on information that an operator has already compiled or is planning to compile. The Task Force Rules acknowledge that all estimates are provided using reasonable business judgment based on information known to the operator at the time the estimates are submitted. **Rule 302.c.(3)C.**

Regarding the operator registration with local governments, the Commission's Local Government Liaison's ("LGLs") may become increasingly involved as operators provide good faith estimates and local governments begin incorporating oil and gas development into the local planning processes. **Rule 302.c.(3).** The Commission will also incur costs to develop a website tool for operator registration. **Rule 302.c.(2).** Staff anticipates 60 hours of developer time will be required to build and test the registration form and 80 hours of Staff time to design the form, test the form, and train operators on how to use the form. This will cost the Commission approximately $7,352 ($3,000 for development and $4,352 for implementation). The costs to the Commission to implement these Task Force Rules are covered by current resources and will not require any additional appropriations.

V. Adverse Effects and Anticipated Effect on State Revenues

The Governor's Task Force Rules will have minimal impacts on the economy, private markets, consumers, small businesses, job creation, and economic competitiveness. First and foremost, the Task Force Rules apply to a very limited number of proposed locations and therefore will not broadly affect the oil and gas market, consumers, or state revenues. The Task Force Rules will also not result in job creation unless the number of proposed locations qualifying as Large UMA Facilities significantly increases. Any economic impact from these Rules likely will be limited to large operators.

VI. Inaction, Alternative Methods, and Alternative Proposals

This section provides a determination of whether there are less costly methods or less intrusive methods for achieving the rule's purpose; a description of any alternative methods of achieving the rule's purpose that were considered by the agency and rejected; 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 cost and benefits of pursuing each of the alternatives identified.

A. Inaction and Alternative Methods for Achieving Purpose

The Executive Order directed the Task Force to consider "changes to existing laws or regulations" and "suggested new laws and regulations." The Task Force Recommendations were the result of an almost five month process that consisted of seven meetings across the State of Colorado. Recommendations that required new or amended legislation required a two-thirds majority for approval. Recommendation Nos. 17 and 20 were unanimously approved by the Task Force members, who consisted of representatives of the oil and gas industry, agricultural industry, homebuilding industry, local governments, conservation community, and citizens – the majority of the affected classes identified above.

The Commission cannot implement Task Force Recommendation Nos. 17 or 20 without adopting new or amended Rules. Both of these Recommendations specifically recommended the Commission conduct rulemaking to implement specific procedural and substantive requirements. The Commission could not consider inaction or alternative methods for achieving the purpose of this rulemaking, especially in light of the fact that these Recommendations were unanimously approved by representatives of many of the affected classes.

B. Alternative Proposals for the Task Force Rules

Two of the alternative proposals requested by stakeholder groups are addressed below. For an examination of other alternative proposals submitted by stakeholders groups, see the Governor's Task Force Rulemaking Statement of Basis, Specific Statutory Authority, and Purpose.

1. <u>Expanding the Definition of Large UMA Facility or Urban Mitigation Area</u>

Many stakeholders requested that the Commission consider expanding the definition of Large UMA Facility to include large facilities located beyond Urban Mitigation Areas or expand the definition of Urban Mitigation Areas to cover more of the State. This would require the Commission to go significantly beyond what Recommendation No. 17 proscribed, which reflected the agreement of all Task Force members.

This change would greatly increase the costs to oil and gas operators and local governments described above. If the proposed definition for Large UMA Facility was applied outside of Urban Mitigation Areas, it would apply to approximately 27 percent of the proposed locations in Colorado, regardless of proximity to an Urban Mitigation Area. This estimate was calculated for the number of locations with eight horizontal wells with a lateral length of 4,360 feet in the Greater Wattenberg Area with pending or approved permit applications in 2014. Staff did not believe a 26-fold increase in the anticipated costs under the parties was warranted, particularly because it was not agreed upon in the Recommendation.

The benefit of broadening the definition of Large UMA Facility or Urban Mitigation Area would be to enlarge the benefits described in Section II.B.1 to more proposed Oil and Gas Locations throughout the State. However, many of the notification and consultation principles from the Task Force Rules on Large UMA Facilities can be applied to other types of facilities at the option of the parties. Additionally, because the Commission has the authority to impose the Rule 604.c.(4) best management practices and mitigation measures on any location in the State, this expansion would not necessarily impact the requirements on the Form 2As that would be covered by the broader applicability of the Task Force Rules. ***See*** **Rule 604.c.(4)E.**

2. <u>Eliminating Proximate Local Government Involvement</u>

Some local governments and oil and gas operators requested that the Commission consider not including proximate local governments in the Task Force Rules. They articulated concern that Recommendation No. 17 did not expressly provide for notification to these local governments and it would result in creating more conflict.

These local governments will have the opportunity to meet with the operator, Commission Staff, and the local government with land use authority (at its option), but do not receive standing for the hearing procedures or the ability to override the local government with land use authority, which prevents costs associated with a hearing process driven by a Proximate Local Government. **Rule 305A.d.(4).**

Involving Proximate Local Governments at the initial meeting level does not significantly increase the costs on the impacted groups described above. It may also have the result of reducing costs by providing more information regarding community concerns that would not be apparent without the involvement of these types of local governments.

Exhibit A - Staff Analysis

Single well type curve

	Single well	Oil $	Annual Gas Prod. MCF	Gas $
2015	24740	$1,360,700.00	143,127	$429,381.00
2016	22134	$1,217,370.00	125,907	$377,721.00
2017	14843	$816,365.00	99,856	$299,568.00
2018	11131	$612,205.00	79,459	$238,377.00
2019	8982	$494,010.00	66,693	$200,079.00
2020	7568	$416,240.00	57,855	$173,565.00
2021	6561	$360,855.00	51,329	$153,987.00
2022	5806	$319,330.00	46,288	$138,864.00
2023	5217	$286,935.00	42,262	$126,786.00
2024	4743	$260,865.00	38,963	$116,889.00
2025	4354	$239,470.00	36,205	$108,615.00

16 Well pad

	Prod Oil Bbl	Oil $	Gas MCF	Gas $	NPV Oil	NPV Gas	NPV Gas+Oil
2015	395840	$21,771,200.00	2290032	$6,870,096.00	$21,771,200.00	$6,870,096.00	$28,641,296.00
2016	354144	$19,477,920.00	2014512	$6,043,536.00	$17,707,200.00	$5,494,123.64	$23,201,323.64
2017	237488	$13,061,840.00	1597696	$4,793,088.00	$10,794,909.09	$3,961,229.75	$14,756,138.84
2018	178096	$9,795,280.00	1271344	$3,814,032.00	$7,359,338.84	$2,865,538.69	$10,224,877.54
2019	143712	$7,904,160.00	1067088	$3,201,264.00	$5,398,647.63	$2,186,506.39	$7,585,154.02
2020	121088	$6,659,840.00	925680	$2,777,040.00	$4,135,236.66	$1,724,323.35	$5,859,560.02
2021	104976	$5,773,680.00	821264	$2,463,792.00	$3,259,091.84	$1,390,746.35	$4,649,838.19
2022	92896	$5,109,280.00	740608	$2,221,824.00	$2,621,868.51	$1,140,147.02	$3,762,015.53
2023	83472	$4,590,960.00	676192	$2,028,576.00	$2,141,716.72	$946,345.68	$3,088,062.40
2024	75888	$4,173,840.00	623408	$1,870,224.00	$1,770,115.60	$793,157.54	$2,563,273.15
2025	69664	$3,831,520.00	579280	$1,737,840.00	$1,477,216.82	$670,012.55	$2,147,229.37
					$78,436,541.73	$28,042,226.96	$106,478,768.70

$55/Bbl $3/MCF
10% disc. rate
D&C cost not included (cash flow only)
All wells are identical and produce ± 690k BOE (Type well)

8 wells in year one 16 wells in years 2-10

	Prod Oil Bbl	Oil $	Gas MCF	Gas $	NPV Oil	NPV Gas	NPV Gas+Oil
2015	197920	$10,885,600.00	1145016	$3,435,048.00	$10,885,600.00	$3,435,048.00	$14,320,648.00
2016	374992	$20,624,560.00	2152272	$6,456,816.00	$18,749,600.00	$5,869,832.73	$24,619,432.73
2017	295816	$16,269,880.00	1806104	$5,418,312.00	$13,446,181.82	$4,477,943.80	$17,924,125.62
2018	207792	$11,428,560.00	1434520	$4,303,560.00	$8,586,446.28	$3,233,328.32	$11,819,774.61
2019	160904	$8,849,720.00	1169216	$3,507,648.00	$6,044,477.84	$2,395,770.78	$8,440,248.62
2020	132400	$7,282,000.00	996384	$2,989,152.00	$4,521,549.07	$1,856,028.21	$6,377,577.29
2021	113032	$6,216,760.00	873472	$2,620,416.00	$3,509,198.95	$1,479,156.52	$4,988,355.47
2022	98936	$5,441,480.00	780936	$2,342,808.00	$2,792,339.64	$1,202,230.94	$3,994,570.58
2023	88184	$4,850,120.00	708400	$2,125,200.00	$2,262,616.77	$991,421.48	$3,254,038.26
2024	79680	$4,382,400.00	649800	$1,949,400.00	$1,858,565.40	$826,735.90	$2,685,301.30
2025	72776	$4,002,680.00	601344	$1,804,032.00	$1,543,206.41	$695,532.43	$2,238,738.85
							$100,662,811.31

EXHIBIT B[1]

Economic Impact of 90 Day Drilling and Completion (D&C) Limitation

Note: each 3 wells is considered a pad because returning to existing pad is difficult. That means one additional pad, more land disturbance and higher cost, raising estimated well cost (D&C) to $6.0mm.

Input:

Development of 12 wells DSU w/ continuous development

- D&C: 2016: $5.6mm per well
- Oil Price: 2016: $55/bo; $3.00/mcf flat
- 1st Spud: 1/1/16; full development in 2016
- 1st Sales: 10/1/16
- EUR per well: 700 Mboe
- Ownership: WI=100%; NRI=85.2%
- No well interference due to simultaneous development

Development of 12 wells DSU w/ 90 day restriction development

- 90 day activity = drill, complete & set facilities on 3 wells only
- Develop 3 wells in 1st quarter each year; delay activity for next 3 quarters
    - 3 wells developed per year; 4 years to complete development
- D&C: 2016: $6mm per well flat
- Oil Price: 2016: $50/bo; $3.00/mcf flat
    - Initial 1st Spud: 1/1/16; 2nd period 1st Spud: 1/1/17; 3rd period 1st Spud: 1/1/18; 4th period 1st Spud: 1/1/19
    - Initial 1st Sales: 4/1/16; 2nd period 1st Sales: 4/1/17; 3rd period 1st Sales: 4/1/18; 4th period 1st Sales: 4/1/19
- Previous wells shut-in during subsequent completion operations to protect wellbores
- EUR per well: 700 Mboe
- Ownership: WI=100%; NRI=85.2%
- NOTE: No assumptions made for wellbore integrity damage from three returning stimulation periods; No assumption made for well performance damage from repeated shut-in of wells

Conclusions:

Extends development period from 9 months to > 4 years

- Return to same DSU three times
- Lease remediation suspended for additional years

Economics Damaged @ $5.6mm D&C

- ~5% loss in Revenue
- ~52% loss on PV10 value
- ~20% (4.8 pts) reduction in IRR
- ~78% increase in undiscounted payout
- ~7% increase in project D&C cost
- 410 Mboe of shut-in volumes, ~70% of one net well

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[1] Information prepared by BBC's Reservoir and Planning Department.