Regulatory Impact Analysis for:

Revisions to 43 CFR 3100 (Onshore Oil and Gas Leasing) and 43 CFR 3600 (Onshore Oil and Gas Operations)

Additions of 43 CFR 3178 (Royalty-Free Use of Lease Production) and 43 CFR 3179 (Waste Prevention and Resource Conservation)

U.S. Bureau of Land Management

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Contents

Acronyms and Abbreviations

AFMSS	Automated Fluid Minerals Support System
AOFP	Absolute Open Flow Potential
APD	Application for Permit to Drill
API	American Petroleum Institute
AQCC	Colorado Air Quality Control Division
Bcf	Billion Cubic Feet
BLM	Bureau of Land Management
BTU	British Thermal Unit
CA	Communitized Agreement
CBM	Coalbed Methane
CFR	Code of Federal Regulations
CH_4	Methane
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CTG	EPA Control Technique Guidelines
DPHE	Colorado Department of Public Health and Environment
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FRFA	Final Regulatory Flexibility Analysis
GAO	Government Accountability Office
Gg	Giga gram (or 1,000 Mg or 1,000 metric tons)
GHG	Greenhouse Gas
IMDA	Indian Mineral Development Act
IPR	Inflow Performance Relationship
IRR	Internal Rate of Return
IRFA	Initial Regulatory Flexibility Analysis
LA	Lease Agreement
LDAR	Leak Detection and Repair
Mcf	Thousand Cubic Feet
Mcfd	Thousand Cubic Feet per Day
Mcfy	Thousand Cubic Feet per Year
MMbbl	Million Barrels
MMcf	Million Cubic Feet
NDIC	North Dakota Industrial Commission
NEMS	National Energy Modeling System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	Natural Gas Liquids
NPV	Net Present Value
NSPS	New Source Performance Standards
NTL-4A	Notice to Lessees 4A
OIRA	Office of Information and Regulatory Affairs
OMB	Office of Management and Budget
ONRR	Office of Natural Resources Revenue
Psia	Pounds per Square Inch Absolute
RFA	Regulatory Flexibility Act

SBREFA	Small Business Regulatory Enforcement Fairness Act
$SC\text{-}CH_4$	Social Cost of Methane
$SC\text{-}C0_2$	Social Cost of Carbon
scf	Standard Cubic Feet
scfd	Standard Cubic Feet per Day
scfh	Standard Cubic Feet per Hour
TSD	Technical Support Document
UGRB	Upper Green River Basin
VOC	Volatile Organic Compounds
VRU	Vapor Recovery Unit
2015 GHG Inventory	Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013
2016 GHG Inventory	Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014

1. Executive Summary

1.1 Summary of Final Rule

This analysis examines the regulatory impacts of the Bureau of Land Management's (BLM) final rule, which updates 43 CFR Part 3100 (Onshore Oil and Gas Leasing) and 43 CFR Part 3160 (Onshore Oil and Gas Operations) and creates new regulations 43 CFR Chapter II, Subpart 3178 (Royalty-Free Use of Lease Production) and Subpart 3179 (Waste Prevention and Resource Conservation). Subparts 3178 and 3179 update and replace the BLM's existing policy document Notice to Lessees-4A (or "NTL-4A").

The final rule revises 43 CFR 3103.3-1, which governs royalty rates applicable to onshore oil and gas leases, to make the rule text parallel to the BLM's statutory authority, which specifies that competitively-issued BLM-administered leases require "payment of a royalty at a rate of not less than 12.5 percent in amount or value of the production removed or sold from the lease." 30 U.S.C. § 226(b)(1)(A). The revised provision makes clear that for competitive leases issued after the effective date of this rule, the BLM has the flexibility to set rates at or above 12.5 percent, but the final rule does notset a new rate for competitive leases.

The final rule revises 43 CFR Part 3160 to require an operator, when submitting an Application for Permit to Drill (APD) for a development oil well, to also prepare and submit a Waste Minimization Plan. Preparation of a Waste Minimization Plan ensures that the operator carefully considers and plans for how it will capture the gas that will be produced, before the operator drills a well.

Subpart 3178 addresses the circumstances in which oil and gas produced from Federal and Indian leases may be used royalty-free. This subpart sets forth the general rule that royalty is not due on oil or gas that is produced from a lease or communitized area and used for operations and production purposes (including placing oil or gas in marketable condition) on the same lease or communitized area without being removed from the lease or communitized area (CA). The rule identifies uses of produced oil or gas that will and will not require prior written BLM approval for royalty-free treatment.

Subpart 3179 prohibits venting of natural gas, except under certain specified conditions, such as in an emergency or when flaring is technically infeasible. With respect to flaring, the rule requires operators of development oil wells to reduce wasteful flaring of gas by capturing for sale or using on the lease a percentage of their gas production. The rule provides for a base level of "allowable" flaring that ramps down over time, and it specifies a required capture percentage, which applies to the operator's volume of flaring adjusted to remove the allowable flaring, and which increases over time. The rule gives operators the option to meet their capture targets on a lease-by-lease basis, or on an average basis over all of their Federal or Indian production from development oil wells county-by-county or State-by-State.

Subpart 3179 also requires operators to conduct an instrument-based leak detection and repair (LDAR) program. The rule allows operators to use optical gas imaging equipment, portable analyzers deployed according to EPA's Method 21, or an alternative leak detection device approved by the BLM. The rule requires operators to conduct semi-annual inspections at well sites and quarterly inspections at compressor stations. Operators may also request BLM approval of an alternative instrument-based leak detection program. Operators must repair a leak within 30 days of discovery, absent good cause, and verify that the leak is fixed.

Subpart 3179 also includes requirements to update old, inefficient equipment and to follow best practices to minimize waste through venting. These provisions address gas losses from pneumatic controllers and pumps, storage vessels, liquids unloading, and well drilling and completions. As a practical matter, many of the requirements will impact only existing equipment or facilities that are not regulated by the Environmental Protection Agency's (EPA) New Source Performance Standards (NSPS) Subpart OOOO or Subpart OOOOa.

In addition, subpart 3179 includes provisions specifying when lost gas is considered unavoidably lost, and royalty-free, and when it is considered avoidably lost and subject to royalties. Other provisions of subpart 3179 include requirements for measuring volumes of flared gas and reporting gas losses to ONRR.

1.2 Need for Regulatory Action

Circular A-4, the Office of Management and Budget's (OMB) guidance on the development of regulatory analyses under Executive Order 12866, instructs Federal agencies to explain the need for the policy action, whether to correct a significant market failure, such as an externality, or to meet some other compelling public need, such as improving governmental processes.

A 2010 GAO investigation and our subsequent analysis show that a large amount of natural gas is being wasted through venting and flaring at oil and gas production sites on Federal and Indian lands, despite the fact that much of this gas could be economically captured and delivered to the market. The GAO estimated that, in 2008, about 128 billion cubic feet (Bcf) of natural gas was either vented or flared from Federal leases, about 50 Bcf of which was economically recoverable (about 40% of the total volume lost). The GAO estimated that the economically recoverable volume represents about $23 million in lost Federal royalties and 16.5 million metric tons of carbon dioxide equivalent (CO_2e) emissions.[1]

The GAO recommended that the BLM improve its data collection to ensure a complete and accurate picture of vented and flared gas, and revise its guidance to operators requiring the use of capture technologies when the capture of gas is economically viable. The GAO identified specific technologies and practices as being "generally considered technically and economically feasible," including reduced emissions completions during drilling and completion operations, plunger lift systems for wells requiring liquids unloading, vapor recovery units to capture gas from crude oil and condensate storage tanks, flash tank separators and glycol circulation optimization for dehydration units, and low-bleed pneumatic devices (GAO 2010, pp. 7-8).

When gas is wasted rather than captured and brought to market, society loses the opportunity to use the resource and social benefits are not maximized. In addition, when the wasted gas in question comes from the Federal or Tribal mineral estate, the public or Tribes often lose royalty revenues.

[1] The BLM's estimates smaller volumes of annual gas loss through venting and flaring, but we recognize that a substantial volume of gas is being lost despite being economically recoverable.

Additionally, State governments do not receive the compensation they are owed through royalty sharing from Federal production.

Wasting gas also produces air pollution, which imposes costs to society that are not reflected in the market price of the gas. Gas that is vented to the atmosphere or flared contributes greenhouse gas (GHG), volatile organic compound (VOC), and hazardous air pollutant emissions that have negative climate, health, and welfare impacts. These uncompensated costs to society are referred to as negative externalities.

Several market inefficiencies occur when society, rather than the producer, bears the costs of pollution damage. Since the damage is not borne by the producer, it is not reflected in the market price of the commodity, and uncontrolled markets produce an excessive amount of the commodity, dedicate an inadequate amount of resources to pollution control, and generate an inefficiently large amount of pollution. With stock pollutants, like methane and carbon dioxide, which build up in the environment and cause damage over time, the burden will be greater on future generations. Further, the fact that operators do not always bear the full costs of production introduces perverse incentives to the market. Operators that voluntarily make investments to limit or avoid the loss put themselves at a competitive disadvantage in relation to operators who do not make such investments.

1.3 Summary of Results

1.3.1 Baseline Natural Gas Loss Estimates

In 2014, we estimate that 111 Bcf of natural gas was vented and flared from Federal and Indian leases. At a $4/Mcf price of natural gas, this volume has a sales value of $444 million and a royalty value of $56 million. Of the 111 Bcf, we estimate that 30 Bcf was vented and 81 Bcf was flared. We estimate that 44 Bcf of the flared gas came from the Federal and Indian mineral estates with 37 Bcf coming from the estates of other mineral owners.[2] With this analysis, the BLM estimates the costs and benefits of the requirements to reduce these losses.

Table 1.3a: Estimated Flared Gas from Federal and Indian Leases in 2014, by Mineral Ownership, Volume in Bcf

Source	Mineral Ownership			Total
	Federal	Indian	Non-Federal, Non-Indian	
Flared oil-well gas (Bcf)	26.1	15.2	35.6	76.9
Flared gas-well gas (Bcf)	2.3	0.5	1.2	4.0
Total Flaring	**28.4**	**15.8**	**36.7**	**80.9**

[2] The volumes vented and flared represent all natural gas flared from Federal and Indian leases, but the ownership of those minerals is mixed between Federal, Indian, and non-Federal non-Indian owners. In the RIA for the proposed rule, we estimated natural gas losses for 2013 to be 98 Bcf, with 22 Bcf vented and 76 Bcf flared.

Table 1-3b: Estimated Vented Gas from Federal and Indian Leases in 2014, by Source, Volume in Bcf

Natural Gas Lost Through Venting	
Source	**Volume (Bcf)**
Well completions	1.12
Pneumatic controllers	14.93
Pneumatic pumps	2.32
Gas Engines	1.06
Compressors	0.52
Liquids Unloading	3.26
Storage Tanks	2.94
Other Production (Includes Leaks)	4.01
Total Venting	**30.15**

1.3.2 Monetized Costs

This rule will require operators to incur costs to reduce flaring, replace outdated equipment, implement or contract for leak detection and repair programs, install measurement equipment, and administer these programs. With respect to equipment replacement, we expect to see the highest levels of compliance activity during the first few, transitional years of the rule. The requirements to replace existing equipment would necessitate immediate expenditures. With respect to flaring reductions, we expect expenditures to be spread over the nine-year phase-in period, and with respect to leak detetection, operators could incur upfront capital costs and lower ongoing operations costs, or annual operations costs (through hiring contractors) throughout the life of the requirements. For the purpose of this analysis, we annualize the capital costs of equipment replacement over a reasonable estimate of the functional life of the equipment (generally 10 years).[3]

After reviewing the requirements, we estimate that the rule would pose costs of about $114 – 279 million per year (with capital costs annualized using a 7% discount rate) or $110 – 275 million per year (with capital costs annualized using a 3% discount rate), as shown in Table 1.3c. These costs include engineering compliance costs and the social cost of minor additions of carbon dioxide to the atmosphere.[4] The compliance costs presented do not include potential cost savings from the recovery and sale of natural gas or natural gas liquids (those savings are shown in the summary of benefits).

We believe that the estimated costs represent the likely upper bound of potential impacts. The estimated impacts account for activities that available data suggest some operators already undertake

[3] After the initial replacement of existing equipment that would be required by this proposal, any other replacement or modification of such equipment would be subject to EPA's requirements that apply to new or modified sources – the NSPS Subpart OOOO or Subpart OOOOa.

[4] Some gas that would have otherwise been vented would now be combusted on-site or presumably downstream to generate electricity. The estimated value of the carbon additions do not exceed $30,000 in any given year.

as a matter of practice or to comply with State or local regulations that we were not able to identify and account for in this analysis.[5] To the extent that operators are already in compliance with the requirements, the estimated impacts overstate the likely actual impacts of the rule.

Table 1-3c: Estimated Annual Costs, 2017 – 2026 ($ in millions)

Requirement	Capital Costs Annualized using a 7% Discount Rate	Capital Costs Annualized using a 3% Discount Rate
Capture Target Req.	$0 – 161	$0 – 161
Flare Measurement	$4 – 7	$3 – 6
Pneumatic Controllers	$2	$2
Pneumatic Pumps	$4	$4
Liquids Unloading	$6	$5 – 6
Storage Tanks	$8	$7
LDAR	$84	$83
Administrative Burden	$7	$7
Total	$114 – 279	$110 – 275

1.3.3 Monetized Benefits

We identify the benefits of the rule as the cost savings that the industry will receive from the recovery and sale of natural gas, and the environmental benefits of reducing the amount of greenhouse gases (GHG) and other air pollutants released into the atmosphere. As with the estimated costs, we expect benefits on an annual basis.

After reviewing the requirements, we estimate that the rule will result in benefits ranging from $209 – 403 million per year. Of that amount, we estimate cost savings to the industry of about $20 – 157 million per year. We estimate a reduction in methane emissions of 175,000 to 180,000 tons per year. The monetized value of the methane reductions to be $189 – 247 million per year.

Overall, we predict the rule will reduce methane emissions by 35% from the 2014 estimates and reduce the flaring of associated gas by 49%, when the capture requirements are fully phased in.

Estimated benefits are likely lower than actual benefits. Recent studies indicate that estimated gas losses are likely higher than estimated, and if so, measures to reduce such losses would have greater impact than we project here. Also, as discussed in section 7.12 of this document, the estimates for the benefits of the LDAR requirements are developed using data from EPA's recent Control Technique Guidelines, but due to a different scope of coverage under the EPA and BLM leak control requirements, some key sources of leaks that are covered by the BLM requirements are not represented in the EPA data. Hence, the benefits of applying an LDAR program to those sources are not included in our benefits estimates (we believe their inclusion would have little impact on costs, as operators would generally already be inspecting equipment on those sites). While the

[5] Where we are aware of State regulations that already require operators to take actions required by the rule, we have removed the associated costs and benefits of those actions by operators from this analysis.

benefits estimates may also be slightly overstated due to operator compliance activities that are already occurring voluntarily or due to other regulatory requirements for which we are unable to account, we believe that this effect is probably substantially outweighed by the factors discussed above that drive underestimated benefits.

Table 1-3d: Estimated Annual Benefits, 2017 – 2026 ($ in millions)

Requirement	Cost Savings	Social Benefits[1]	Range of Annual Benefits
Capture Target Req.	$0 – 124	$0	$0 – 124
Pneumatic Controllers	$1	$19 – 25	$20 – 26
Pneumatic Pumps	$2 – 3	$29 – 37	$31 – 40
Liquids Unloading	$5 – 8	$36 – 53	$41 – 60
Storage Tanks	$0	$8 – 10	$8 – 10
LDAR	$12 – 21	$96 – 123	$109 – 143
Total	$20 – 157	$189 – 247	$209 – 403

[1] Social benefits calculated using model averages of the social cost of methane with a 3% discount rate.

1.3.4 Non-monetized Costs and Benefits

The rule is expected to have additional impacts, both costs and benefits, that this analysis examines but does not include in the calculation of monetized costs and benefits. Although the analysis monetizes the benefits of reduced methane releases and the costs of carbon dioxide additions, the analysis does not monetize the benefits to public health and the environment of reducing VOC emissions by 250,000 – 267,000 tons per year and reducing emissions of hazardous air pollutants. The rule is expected to have additional minor environmental benefits associated with the productive use of the gas downstream instead of combusting the gas upstream (due to the generally higher efficiencies associated with downstream combustion).

1.3.5 Net Benefits

The following estimated net benefits are summarized from the sections that follow. The figures presented here are in 2012 dollars, with capital costs annualized using 7% and 3% discount rates and environmental costs and benefits monetized using the social cost of of carbon and social cost of methane – using model averages of the social cost of methane with a 3% discount rate (see section 7.2).

We estimate that the rule would result in net benefits of $46 – 199 million per year (capital costs annualized using a 7% discount rate) or $50 – 204 million per year (capital costs annualized using a 3% discount rate)[6], as follows:

[6] The highs and lows of the benefits and costs do not occur during the same years; therefore, the net benefit ranges presented here do not calculate simply as the range of benefits minus the range of costs presented previously.

Table 1-3e: Estimated Annual Net Benefits, 2017-2026 ($ in millions)

Requirement	Net Benefits (with Capital Costs Annualized using a 7% Discount Rate)	Net Benefits (with Capital Costs Annualized using a 3% Discount Rate)	Non-Monetized Benefits
Capture Target Req.	($88) – $39	($88) – $39	Health effects of $PM_{2.5}$ and ozone exposure from annual VOC reductions; Non-monetized climate benefits; Health effects of reduced HAP exposure; Minor secondary disbenefits; Incremental environmental benefits of combusting gas downstream.
Flare Measurement	($4 – 7)	($3 – 6)	
Pnumatic Controllers	$18 – 24	$19 – 25	
Pneumatic Pumps	$26 – 36	$27 – 36	
Liquids Unloading	$35 – 54	$36 – 55	
Storage Tanks	$0 – 2	$1 – 3	
LDAR	$25 – 60	$26 – 60	
Administrative Burden	($7)	($7)	
Total	$46 – 199	$50 – 204	

1.3.6 Distributional Impacts

Energy System: The rule has a number of requirements that are expected to influence the production of natural gas, natural gas liquids, and crude oil from onshore Federal and Indian oil and gas leases.

We estimate the following incremental changes in production, noting the representative share of the total U.S. production in 2015 for context:

- Additional natural gas production ranging from 9 – 41 Bcf per year (0.03 – 0.15% of the total U.S. production);
- A reduction in crude oil production ranging from 0.0 – 3.2 million barrels per year (0 – 0.07% of the total U.S. production).

Since the relative changes in production are expected to be small, we do not expect that the rule would significantly impact the price, supply, or distribution of energy.

Separate from the volumes listed above, we also expect 0.8 Bcf of gas to be combusted onsite that would have otherwise been vented.

Royalty: We estimate that the rule will result in annual incremental royalties of $3 – 13 million per year. Royalty payments are income to Federal or Tribal governments and costs to the operator or lessee. As such, they are transfer payments that do not affect the total resources available to society. An important, but sometimes difficult, problem in cost estimation is to distinguish between real costs and transfer payments. While transfers should not be included in the economic analysis estimates of the benefits and costs of a regulation, they may be important for describing the regulation's distributional effects.[7]

Small Businesses: The BLM reviewed the Small Business Administration (SBA) size standards for small businesses, and the number of affected entities fitting those size standards, as reported by the U.S. Census Bureau in the Economic Census. The BLM concludes that the vast majority of entities operating in the relevant sectors are small businesses as defined by the SBA. As such, the rule will likely affect a substantial number of small entities.

To examine the economic impact of the rule on small entities, the BLM performed a screening analysis for impacts on a sample of expected affected small entities by analyzing the potential impact on profit margins. For the 26 companies in the screening analysis, the rule's estimated compliance costs would reduce the entities' profit margin, on average, by about 0.15 percentage points.

Based on this information, we conclude that the rule will not have a significant impact on a substantial number of small entities and a Regulatory Flexibility Analysis is not required. Nevertheless, recognizing the potential for the rule to impact a large number of small entities, some significant data limitations and uncertainties that could affect the costs of some elements of the rule, and the potential for higher or lower costs depending on operators' compliance choices and variable commodity prices, the BLM decided to conduct an Initial Regulatory Flexibility Analysis with the proposed rule and includes a Final Regulatory Flexibility Analysis with this RIA (see Section 9).

Employment: We examined the requirements and the estimated compliance costs and determined that the rule is not expected to impact the investment decisions of firms or significantly adversely impact employment. The requirements would require the one-time installation or replacement of equipment, and the ongoing implementation of a LDAR program, both of which would require labor to comply. The administrative burden required to comply with the rule (including burdens to the industry and the BLM) are monetized and included in the costs estimates provided within this analysis. The Supporting Statement for the Paperwork Reduction Act discusses the administrative burdens posed by the rule's requirements in greater detail.

[7] OMB Circular A-4 "Regulatory Analysis." September 17, 2003. Available on the web at https://www.whitehouse.gov/omb/circulars_a004_a-4/.

2. Requirements for Analyzing the Impacts of a Regulatory Action

Executive Order 12866 requires agencies to assess the benefits and costs of regulatory actions, and for significant regulatory actions, submit a detailed report of the assessment to the OMB for review. A rule may be a significant regulatory action according to Executive Order 12866 if it would meet any of the following four criteria:

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities;
- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

The economic analysis is to provide information allowing decision makers to determine that:

- There is adequate information indicating the need for and consequences of the action;
- The potential benefits to society justify the potential costs, recognizing that not all benefits and costs can be described in monetary or even in quantitative terms, unless a statute requires another regulatory approach;
- The action will maximize net benefits to society (including potential economic, environmental, public health and safety, and other advantages; distributional impacts; and equity), unless a statute requires another regulatory approach;
- Where a statute requires a specific regulatory approach, the action will be the most cost-effective implementation of that approach, and will rely on performance objectives to the extent feasible; and
- Agency decisions are based on the best reasonably obtainable scientific, technical, economic, and other information.

To provide this information, the economic analyses of economically significant rules will contain three elements[8]:

- A statement of the need for the action;
- An examination of alternative approaches; and
- An analysis of benefits and costs.

The Regulatory Flexibility Act (RFA) and the Small Business Regulatory Enforcement Fairness Act (SBREFA) require agencies to analyze the economic impact of regulations to determine whether there would be a significant economic impact on a substantial number of small entities.

Unless the head of the agency certifies that the rule, when promulgated, would not have a significant economic impact on a substantial number of small entities, the agency must conduct an initial

[8] OMB Circular A-4.

regulatory flexibility analysis with the proposed rule and a final regulatory flexibility analysis with the final rule.[9]

The United States Code also requires special considerations if the Office of Information and Regulatory Affairs (OIRA) of the OMB determines that the rule is "major."[10] A rule is major if it has resulted in or is likely to result in:

- An annual effect on the economy of $100 million or more;
- A major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions; or
- Significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States-based enterprises to compete with foreign-based enterprises in domestic and export markets.

If OIRA determines that a rule is major, then the rule may become effective 60 days after the agency promulgates it and submits it to Congress. A major rule is subject to congressional review during this time, and to other procedural requirements.[11] If OIRA determines that the rule is not major, then it becomes effective when the agency submits it to Congress.

Executive Order 13272 reinforces executive intent that agencies give serious attention to impacts on small entities and develop regulatory alternatives to reduce the regulatory burden on small entities. When the regulation will impose a significant economic impact on a substantial number of small entities, the agency must evaluate alternatives that would accomplish the objectives of the rule without unduly burdening small entities.

[9] 5 U.S.C. 603; 5 U.S.C. 604; 5 U.S.C. 605(b).
[10] 5 U.S.C. 804.
[11] 5 U.S.C. 801.

3. Background on Venting and Flaring from Oil and Gas Operations

Operators may vent natural gas during drilling and production activities (such as during well completions, liquids unloading, and emergency events where the gas cannot be flared,) or from production equipment. Some equipment uses the gas for production purposes (like pneumatic devices) while other equipment may passively vent gas either intentionally (like storage tanks) or unintentionally (if there are leaks). Depending on the circumstances, operators may also flare natural gas from onshore leases.

In this section, we describe the primary sources of vented and flared gas from oil and gas production operations, as identified by the GAO and other studies. In the sections that follow, we estimate the volumes currently vented and flared and the impacts of the rule.

A. Gas flaring from production operations, including associated gas

Associated gas (or casinghead gas) is the natural gas that is produced from an oil well during normal production operations and is either sold, re-injected, used for production purposes, vented (rarely) or flared, depending on whether the well is connected to a gathering line or other method of capture.

Production tests (or productivity tests) are "tests in an oil or gas well to determine its flow capacity at specific conditions of reservoir and flowing pressures. The absolute open flow potential (AOFP) can be obtained from these tests, and then the inflow performance relationship (IPR) can be generated."[12] The AOFP is "the calculated maximum flow rate that a system may provide in the absence of restrictions."[13] To determine an AOFP, the operator may need to flare gas (and sometimes vent) for a period of time; however, it is also possible to calculate the AOFP while capturing the gas in a sales line. For conventional oil and gas wells, well completions and production tests are separate processes temporally. For unconventional wells, however, operators may conduct production tests during flowback.

In addition, emergency flaring or venting may be necessary for safety reasons.

B. Well completions and workovers

Well completion is the process taken to transform a drilled well into a producing well. Hydraulic fracturing is a type of well completion. A well workover is "the repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons."[14] Refracturing is "an operation to restimulate a well after an initial period of production"[15] and is considered to be both a hydraulic fracturing completion and a workover.

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12 "Productivity test" as defined by the Schlumberger Oilfield Glossary.

13 "Open flow potential" as defined by the Schlumberger Oilfield Glossary.

14 "Workover" as defined by the Schlumberger Oilfield Glossary, http://www.glossary.oilfield.slb.com/en/.aspx.

15 "Refracturing" as defined by the Schlumberger Oilfield Glossary.

Releases may occur during any well completion and workover; however, greater releases are associated with "flowback" from a hydraulic fracturing completion. Flowback is "the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production."[16]

During flowback, an operator will generally return recovered fluids to a temporary 3-phase flowback separator. From the separator, the gas is diverted to a sales line or is either vented or flared, the flowback water is returned to a flowback tank (and then trucked or pumped out), and the hydrocarbon liquid is returned to a storage tank. If uncontrolled, natural gas releases may occur during any step of this process.

C. Pneumatic controllers

Pneumatic controllers are automated instruments used for maintaining a process condition, such as liquid level, pressure, pressure difference and temperature. Depending on the design, controllers are most often powered by pressurized natural gas, but they may also be solar-powered, powered by electricity from the grid, or powered by instrument air.

Natural gas-driven controllers come in a variety of designs for a variety of uses. Continuous bleed pneumatic controllers are those with a continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control). Continuous controllers are generally classified by their bleed rate – the rate at which they continuously release gas. Low bleed continuous controllers have a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh), while high bleed continuous controllers have a bleed rate exceeding 6 scfh.

Intermittent pneumatic controllers are actuated using pressurized gas but do not bleed continuously and can serve functionally different purposes than continuous bleed controllers.

Other controllers are limited by their functionality and feasibility. Non-natural gas-driven pneumatic controllers, such as instrument air devices, can be used depending on the application, but they require electricity sufficient to power an air compressor. Mechanical controllers can replace continuous bleed controllers and intermittent controllers in many applications, but require electricity as their power source.

D. Pneumatic pumps

Pneumatic pumps are devices that use gas pressure to move or compress liquids or gases, and they are generally used at oil and natural gas production sites where electricity is not readily available. The supply gas for these pumps is most often natural gas from the production stream, though they may also use compressed air. The gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas.

The majority of pneumatic pumps used in oil and natural gas production are used for chemical injection or glycol circulation. During chemical injection, piston pumps or diaphragm pumps will inject small amounts of chemicals to limit processing problems and protect equipment. Pneumatic

[16] "Flowback" as defined by the Schlumberger Oilfield Glossary.

pumps commonly referred to as "Kimray" pumps are used for glycol circulation and recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber.

E. Liquids unloading

In producing gas wells, fluids may accumulate in the wellbore and impede the flow of gas, sometimes halting production itself. Gas wells generally have sufficient pressure to produce both formation fluids and gas early on, but as production continues and reservoir pressure declines, the gas velocity in the production tubing may not be sufficient to lift the formation fluids. When this occurs, liquids (hydrocarbons and salinized water) may accumulate in the tubing, causing a further drop in pressure, slowed gas velocity, and raised pressure at the perforations. When the bottom-hole pressure becomes static, gas flow stops and all liquids accumulate at the bottom of the tubing.

When liquid accumulation occurs, there are a number of options available to operators to remove the liquids, including:[17]

- Installing an artificial lift system or other pumping unit;
- Installing smaller diameter tubing;
- Swabbing the well to remove the fluids;
- Using a surfactant to reduce the density of the fluid column; or
- Shutting-in the well to increase bottom-hole pressure and then venting the well to the atmosphere (well purging).

We note that venting may occur during all of these interventions. Generally, lift systems reduce the volume of venting and facilitate the capture and production of gas that would otherwise be vented during purging. However, certain plunger lifts may not be connected to a gas flow line and may vent some gas in the process of unloading.

Liquid accumulation may become a recurring problem depending on the intervention that an operator uses. Lift systems, pumping units, or smaller diameter tubing, are longer lasting solutions, while swabbing, surfactants, and well purging are only temporary solutions.

F. Oil and condensate storage tanks

Crude oil and condensate tanks or vessels are used on-site to store produced hydrocarbons and other fluids. In most cases, an operator will direct recovered fluids from the well to a separator, with the hydrocarbons then directed to the storage tanks.

During storage, light hydrocarbons dissolved in the crude oil or condensate vaporize and collect in the space between the tank liquids and the tank roof. These vapors are often vented to the atmosphere when the liquid level in the tank subsequently fluctuates. Losses of gas vapors generally occur when oil is dumped into the tank, the fluids within the tank are circulated or agitated, or when

[17] An EPA document, *Lessons learned from natural gas STAR partners: Options for removing accumulated fluid and improving flow in gas wells*, describes the problem of liquid accumulation and options for removing the fluids.

the temperature changes. Lighter crude oil, with API gravity greater than 36°, typically vaporize more easily.

Rather than release these vapors to the atmosphere, an operator may install a combustion device to combust the vapors or it may install a vapor recovery unit (VRU) to capture gas vapors for sale. Capturing the gas with a VRU requires that a well be connected to a gas gathering line. VRUs have been shown to reduce VOC emissions from storage vessels by approximately 95 percent. Recovered vapors have a British Thermal Unit (Btu) content that is higher than pipeline quality natural gas. The vapors may range between 950 to 1,100 Btu per standard cubic foot, and can reach as high as 2,000 Btu/scf.

G. Leaks

Production sites with the potential for natural gas leaks include natural gas well pads, oil wells that co-produce natural gas, gathering and boosting stations, gas processing plants, and transmission and storage infrastructure. Potential sources of leaks include seals, connectors, flanges, hatches, and valves, among others. Leaked gases, or evaporated liquids, are lost to the atmosphere. The leaked natural gas is lost production, and results in the release of methane, VOCs, and other air pollutants into the air.

4. Estimated Venting and Flaring on Federal and Indian Leases

4.1 GAO Investigations – Initial Estimated Losses for 2008

In 2010, the GAO released a report entitled *Federal oil and gas leases: Opportunities exist to capture vented and flared natural gas, which would increase royalty payments and reduce greenhouse gases.*[18] In this report, the GAO estimated that 126 Bcf of natural gas was vented and flared from onshore Federal leases in 2008. The sources of the lost gas accounting for that volume included: flaring from a variety of sources (28 Bcf); pneumatic devices (16 Bcf); gas well liquids unloading (17 Bcf); well completions (30 Bcf); oil and condensate storage tanks (18 Bcf); glycol dehydrators (7 Bcf); and other (10 Bcf).[19]

The GAO further concluded that about 50 Bcf of that gas could be economically captured using currently available technology, including low bleed pneumatic devices, smart automated plunger lifts, reduced emissions completions, and vapor recovery devices.[20] It estimated that 40% of the gas was economically recoverable, representing $23 million in annual Federal royalties, and 16.5 million metric tons of CO_2 equivalent emissions.[21]

Table 4-1: GAO Estimated Venting and Flaring from Federal Leases in 2008, Reduction Technologies, and Potential Reductions

Sources	Vented/ Flared Volume (Bcf)	Reduction Technology	Potential Reduction (Bcf)	Percent of Total Volume Vented/ Flared
Flared (variety of sources)	28			
Pneumatic devices	16	Use low bleed devices	9.7	7.7%
Gas well liquids unloading	17	Expanded use of smart automated plungers	7.2	5.7%
Well completions	30	Expanded use of reduced emissions completions	14.7	11.7%
Oil and condensate tanks	18	Install vapor recovery units	12.9	10.2%
Glycol dehydrators	7	Install vapor recovery devices	5.7	4.5%
Other	10			
Total	**126**		**50.2**	**39.8%**

Source: GAO 2010, pp. 12 and 20.

[18] Government Accountability Office (2010). Federal oil and gas leases: Opportunities exist to capture vented and flared natural gas, which would increase royalty payments and reduce greenhouse gases (GAO-11-34). October 2010. Available on the web at http://www.gao.gov/new.items/d1134.pdf.
[19] Ibid., p. 12.
[20] Ibid., p. 20.
[21] Ibid., highlights.

4.2 BLM Estimates for 2014

The BLM reviewed data from the Office of Natural Resources Revenue (ONRR) and 2016 GHG Inventory. Based on this review, we conclude that about 111 Bcf of natural gas was vented and flared from producing operations on Federal and Indian leases in 2014. Of that total, we estimate that 81 Bcf was flared and 30 Bcf was vented.

The ONRR flaring data further indicate that the gas flared from operations producing from Federal and Indian leases contains a mix of gas produced from various mineral estates, including Federal and Indian mineral estates and non-Federal and non-Indian mineral estates (i.e., state-owned and privately-owned minerals). Using data provided by ONRR, we estimate that, of the 81 Bcf of gas flared in 2014, about 77 Bcf of gas was flared from oil wells and 4 Bcf of gas was flared from gas wells. Further, about 44 Bcf of that total (or 55%) came from either the Federal or Indian mineral estates. The remaining 37 Bcf came from non-Federal and non-Indian mineral estates. We note that the GAO identified consistency issues with the data reported to ONRR, so the reported volume of flared gas is likely to underrepresent the actual volume flared.

Of the estimated 30 Bcf of venting, pneumatic contollers represent the bulk of the natural gas losses with fugitive emissions (including leaks), liquids unloading, and storage tanks being the sources of next highest losses. Table 4-2 shows the estimated volumes of gas loss for each source and the relative share in the context of total venting/flaring and venting alone. The sources of natural gas venting (and leaks) ranked by the percent of total vented volumes are: pneumatic controllers (49.5%), fugitives (13.3%), liquids unloading (10.8%), storage tanks (9.8%), pneumatic pumps (7.7%), well completions and workovers (3.7%), gas engines (3.5%), and compressors (1.7%).[22]

[22] In addition to these source categories, the EPA GHG Inventory provides estimates for emissions coming from natural gas gathering and boosting stations. We estimate that, while up to 13 Bcf of natural gas might potentially be emitted from these gathering and boosting stations on Federal and Indian leases, units, or communitization agreements, these sources are unlikely to be located on Federal surface lands. If located on lease, they are located after the natural gas measurement point under a rights-of-way authorization and owned by an entity other than the Federal or Indian lessee. As such, we note the potential emissions from that source but do not include it in Table 4-2.

Table 4-2: Estimated Venting and Flaring from Federal and Indian Leases in 2014

Source	Natural Gas Releases from Natural Gas Production Segment (Bcf)	Natural Gas Releases from Petroleum Production Segment (Bcf)	Vented/ Flared Total (Bcf)	Percent of Total Vented/ Flared	Percent of Total Vented
Flared Gas	3.98	76.94	80.91	72.9%	NA
Well Completions and Workovers	0.57	0.55	1.12	1.0%	3.7%
Pneumatic Controllers	7.64	7.29	14.93	13.4%	49.5%
Pneumatic Pumps	1.42	0.90	2.32	2.1%	7.7%
Gas Engines	0.75	0.31	1.06	1.0%	3.5%
Compressors	0.51	0.01	0.52	0.5%	1.7%
Liquids Unloading	3.26	0.00	3.26	2.9%	10.8%
Storage Tanks	1.54	1.40	2.94	2.6%	9.8%
Fugitives	3.39	0.62	4.01	3.6%	13.3%
Total	23.05	88.01	111.06	100.0%	

In the RIA for the proposed rule, we estimated natural gas venting of 22 Bcf in 2013. For most of the source categories, our natural gas release estimates remained relatively constant from 2013 to 2014 with two exceptions. Estimated releases from well completions were almost cut in half from 2013 to 2014. This change reflects updated GHG Inventory data on well completion emissions and tracks to EPA regulations of all well completions using hydraulic fracturing. Also, estimated releases from pneumatic controllers increased threefold from 2013 to 2014. This change reflects updated GHG Inventory data showing that intermittent controllers accounted for a much larger share of the total controllers (with continuous bleed controllers accounting for a smaller share).

In calculating the estimates for vented gas, for most of the sources, we adjusted the EPA's national emissions estimates in the 2016 GHG Inventory downward based on the share of U.S. natural gas production in 2014 that came from Federal and Indian lands (about 10.49%) and the share of U.S. crude production in 2014 that came from Federal and Indian lands (about 7.06%).[23] This top-down approach is appropriate when we expect the national emissions level to be generally representative of what we would expect on Federal and Indian lands.

We deviated from this methodology when estimating emissions for liquids unloading, opting for a bottom-up approach and basing our estimates on the regional activity data and emission factors in

[23] Data from the EPA indicate that about 448 Bcf of natural gas was vented from all U.S. onshore oil and gas production operations in 2014. Of that amount, about 291 Bcf was vented from the natural gas production segment and 157 Bcf was vented from the petroleum production segment. The breakdown of these releases, by source, is shown in the Appendix.

the 2015 and 2016 GHG Inventory.[24] For this source of losses, in particular, the GHG Inventory data suggest a high degree of variability across regions, and also within regions relevant to natural gas production on Federal and Indian lands.

The Appendix to this report contains the following related tables:

- U.S. Methane Emissions from U.S. Oil and Gas Production Segments in 2014, Estimates from the 2016 GHG Inventory;
- U.S. Onshore Dry Natural Gas and Crude Oil Production and Natural Gas and Crude Oil Production on Federal and Indian Lands, in 2014, by State Jurisdiction and National Energy Modeling System (NEMS) Region;
- Methane Emission Factors for the Natural Gas Production Stage, by Region, Data from the 2016 GHG Inventory; and
- Methane Emission Factors for the Petroleum Production Stage, Data from the 2016 GHG Inventory.

The BLM's estimates differ markedly from GAO's estimates for 2008 (shown in Section 4.1). There are several possible explanations for these discrepancies.

First, since 2010, the regulatory landscape has changed, with action on the federal and state levels. In 2012, the EPA finalized its Oil and Natural Gas Sector: New Source Performance Standards (NSPS), which established standards for EPA's regulation of volatile organic compound (VOC) emissions from "new" or "modified" sources in the oil and natural gas sectors.[25] In 2016, the EPA finalized NSPS Subpart OOOOa which addresses additional sources of emissions from new and modified sources in the oil and natural gas sectors. The NSPS regulations apply to operations nationwide, including those on Federal and Indian lands, and have a co-benefit of reducing the loss of natural gas from certain sources.

Further, several states have published regulations and policies that have impacted Federal leases in those jurisdictions. In 2014, the Colorado Department of Public Health and the Environment, Air Quality Control Division (AQCC), finalized a rule addressing venting and leaks from new and existing sources. Also in 2014, the North Dakota Industrial Commission (NDIC) approved policies aimed at reducing the flaring of natural gas from oil wells.

Second, the amount of flared oil-well gas has increased dramatically since 2008. Increased oil production from tight oil and other unconventional formations without commensurate increases to the gas transportation and processing infrastructure has led to the flaring of large volumes of associated gas.

Third, the GAO based most of its estimates for vented gas on emission factors from the EPA. However, we note that since 2010, the EPA revised its emission factors for gas well liquids

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[24] In the RIA for the proposed rule, we also used a bottom-up estimation approach for well completion emissions. Since the EPA now regulates all well completions that use hydraulic fracturing, we believe that a top-down estimation is now appropriate.

[25] The EPA also finalized its National Emission Standards for Hazardous Air Pollutants (NESHAP) Review, which places certain control requirements on pneumatic pumps.

unloading and well completions. In addition to the EPA's work, additional research has focused on the loss of gas from oil and gas wells and production sites.

Lastly, regarding volumes of flared gas reported to ONRR, the GAO report identified that not all flared volumes were reported by operators. The data show that since 2008, the reported volumes of flared gas have increased quite dramatically. While these increases likely reflect the increased oil production over that period, they may also reflect the increased reporting of flared volumes. Interviews with BLM field personnel indicate that some field offices are requiring, as a condition of approval to flare, that the operator report the flared volumes to ONRR.

We note that while gas losses from oil and gas operations may have changed on an absolute or relative basis between 2008 and 2014, the GAO's conclusions about the need to expand the use of technologies to realize potential gas savings remain relevant.

5. Current Regulatory Framework

The development and production of oil and gas are regulated under a framework of Federal and State laws and regulations. Several Federal agencies implement Federal laws and requirements, while each State in which oil and gas is produced has one or more regulatory agencies that administer State laws and regulations.

State laws apply on federal lands except when they are preempted by Federal law. Accordingly, the drilling, completion, and production operations of oil and gas wells on Federal lands are subject both to Federal and to State regulation. If the requirements of a State regulation are more stringent than those of a federal regulation, for example, the operator will comply with both the State and the Federal regulation by meeting the more stringent State requirement.

Tribal and Federal laws apply to oil and gas drilling, completion, and production operations on tribal lands. Operators on tribal lands will comply with both tribal and Federal regulations by assuring that they are in compliance with the stricter of those rules.

Regardless of any difference in operational regulations, operators on Federal lands must comply with all Federal, State, and local permitting and reporting requirements. On Indian lands, they must comply with all Federal and tribal permitting and reporting requirements.

Since 2010, the regulatory landscape has changed, with action on the Federal and State levels. In 2012, the Environmental Protection Agency (EPA) finalized its Oil and Natural Gas Sector: New Source Performance Standards (NSPS) Subpart OOOO, which established standards for EPA's regulation of volatile organic compound (VOC) emissions from new, modified, and reconstructed sources in the oil and natural gas sectors. It does not address sources in existence prior to the date the NSPS was proposed, unless those sources are modified or replaced at some future time. NSPS Subpart OOOO addresses emissions from hydraulically fractured gas well completion operations, storage vessels emitting more than 6 tons per year of uncontrolled VOC, continuous bleed pneumatic controllers, and other sources. It applies to operations nationwide, including those on Federal and Indian lands, and it has a co-benefit of reducing the loss of natural gas from certain sources.

In addition, in 2016, the EPA finalized NSPS Subpart OOOOa, which addresses emissions from hydraulically fractured oil well completions, pneumatic diaphragm pumps, leaks, and other sources. Like the NSPS Subpart OOOO, this regulation addresses new, modified, and reconstructed sources in the oil and natural gas sectors, but not existing sources. It also applies to operations nationwide, including those on Federal and Indian lands, and would have a co-benefit of reducing the loss of gas from certain sources.

In October 2016, the EPA issued Control Techniques Guidelines (CTGs) to help States reduce VOCs from existing sources in certain nonattainment areas. These CTGs identify many of the same types of measures required by the OOOOa standards, but the guidelines are not a legal requirement to avoid or reduce emissions. Rather, the CTGs are a set of recommendations that State and local air pollution control agencies must consider when evaluating what they will identify as Reasonably Available Control Technology (RACT) for existing sources covered under State plans to implement

Clean Air Act requirements, known as State Implementation Plans (SIPs). States are only required to include RACT measures in their SIPs for areas whose air quality falls significantly below Clean Air Act standards for so-called criteria pollutants, such as ozone.[26]

Several States have published regulations and policies that have impacted Federal leases in those jurisdictions. Below is a summary of selected State regulations and policies that have the effect of limiting the waste of gas from production operations in the States where the production of oil and gas from Federal and Indian leases is most prevalent. Additionally, at least two States have recently expressed an intent to further reduce methane emissions through regulatory action. On February 1, 2016, California's Air Resources Board proposed new rules to reduce emissions of methane through venting and leaks during oil and gas production, processing, and storage.[27] These proposed rules would require the use of vapor collection systems and the control of vapors with 95 percent efficiency. The rules would limit the use of combustion; however, if a combustion control device must be used, the rules would require the use of a low-emissions incinerator. In January 2016, the Pennsylvania Department of Environmental Protection also announced that it would pursue an enhanced strategy for reducing methane emissions.[28]

Alaska: Historically, the State of Alaska had high rates of flaring, but the State adopted regulations in the 1970s to address the problem.[29] Since then, the State of Alaska has prohibited venting or flaring of gas except in narrowly defined circumstances: Testing a well before regular production; fuel that maintains a continuous flare; *de minimis* venting of gas incidental to normal oil field operations; and flaring or venting gas for no more than 1 hour during an emergency or operational upset. The practical effect is to drive widespread reinjection of associated gas into the field for conservation and oil recovery purposes. Alaska estimates that roughly 0.4 percent of gas production is flared, which is far lower than in most other States.

Colorado: The State has reduced venting through air quality regulations of emissions of hydrocarbons and other VOCs from the oil and natural gas industry.[30] The Colorado Department of Public Health and Environment, Air Quality Control Commission has instituted regulations similar in many ways to the EPA's existing new source performance standards (NSPS) for new and modified hydraulically fractured gas wells and gas processing facilities. The Colorado regulation incorporates some aspects of EPA's NSPS Subpart OOOO by reference, and expands upon the EPA standards in other areas. For example, the Colorado rule requires operators to control emissions from well operations (completions and recompletions) for all hydraulically fractured oil and gas wells. It extends the requirements for pneumatic controllers and storage tanks to cover existing, rather than just new, devices and facilities. It also requires operators to implement a

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[26] *I.e.*, nonattainment areas designated "moderate" or above.

[27] State of California Air Resources Board Staff Report: Statement of Reasons, available at: http://www.arb.ca.gov/cc/oil-gas/Oil%20and%20Gas%20ISOR.pdf.

[28] Pennsylvania Department of Environmental Protection, A Pennsylvania Framework of Actions for Methane Reductions from the Oil and Gas Sector, available at: http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Methane/DEP%20Methane%20Strategy%201-19-2016%20PDF.pdf.

[29] Alaska Regs is Alaska Administrative Code Title 20 - Chapter 25 235. Gas Disposition.

[30] Colorado Air Quality Control Commission Regulations, Regulation 7, Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions (Emissions of Volatile Organic Compounds and Nitrogen Oxides).

comprehensive instrument-based LDAR program, sets standards for liquids unloading similar to that which the BLM is proposing, and includes other measures.

Montana: The State has had some limits on venting and flaring in place for some years.[31] Produced gas vented to the atmosphere at a rate exceeding 20 Mcf per day that continues for more than 72 hours must be burned. After completion of a gas well, no gas may be permitted to escape, except gas required for periodic testing or cleaning of the well bore. If, after well completion, the operator intends to flare gas production in excess of 100 Mcf per day, the operator must obtain a variance from the oil and gas board. The operator must submit a production test and a statement justifying the need for a variance, including information such as potential human exposure; relative isolation of location; measures to restrict public access to location; low gas volume; and low Btu content. The board may elect to restrict production until the gas is marketed or otherwise beneficially used.

North Dakota: In March 2013, the Industrial Commission of North Dakota adopted a policy to reduce flaring, and it followed this with an enforceable order adopted in July 2014.[32] The policy and order require well operators to meet flaring reduction targets according to a prescribed timeline. The gas capture targets for each operator start with a target of capturing at least 74 percent of production by October 2014 and then rise over time, culminating with a target of capturing at least 91 percent of production by October 2020.[33] The operator may show compliance with the target by well, field, county, or statewide. The policy provides for oil production to be restricted from wells where the operator does not meet the flaring reduction targets. Production is restricted to no more than 200 barrels of oil per day for those wells capturing more than 60 percent of the gas production, but less than the applicable target percentage. Production is restricted to no more than 100 barrels of oil per day from those wells capturing less than 60 percent of produced gas.

Utah: Utah approved a "General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery" on June 5, 2014.[34] This GAO requires LDAR for equipment (e.g. – valves, pumps, etc.) at varying frequencies. The monitoring can be performed using Method 21 (leak definition of 500 ppm), a tunable diode laser absorption spectroscopy (leak definition of 500 ppm) or an IR camera (OGI – visible emissions indicate leak). Utah requires annual monitoring for the initial year. After the initial monitoring year, the frequencies begin to vary based on performance and vary from quarterly inspections to annual inspections. It also requires the use of low-bleed pneumatic controllers and the control or combustion of emissions from pneumatic pumps and storage tanks.

Wyoming: The Wyoming Department of Environmental Quality adopted regulations on May 19, 2015, to reduce emissions of VOCs in the Upper Green River Basin nonattainment area, which does not meet the air quality standards for ozone pollution.[35] The regulations require operators to control emissions from new and existing storage tanks with uncontrolled emissions of 4 or more tons per year, by 2017, and to control emissions from existing pneumatic pumps (as of January 1, 2014) by

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[31] Administrative Rules of Montana, Title 17-Chapter 8-Subchapter 16 Emission Control Requirements for Oil and Gas Well Facilities Operating Prior to Issuance of a Montana Air Quality Permit.
[32] https://www.dmr.nd.gov/oilgas/or24665.pdf
[33] Specifically, the targets for gas capture are: 74 percent of the gas by October 1, 2014; 77 percent by January 1, 2015; 85 percent by January 1, 2016; and 90 percent by October 1, 2020, with potential for 95 percent capture.
[34] http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf
[35] The BLM received an advanced copy of the final rule but do not have a citation with which the public can access the regulation.

2017. The regulations also require existing pneumatic controllers (as of January 1, 2014) to be low-bleed or zero-bleed by 2017, and they require operators to implement an instrument-based LDAR program with quarterly inspections, by 2017. Further, the regulations establish requirements on additional emissions sources.

6. Regulatory Action and Alternatives Considered

The section discusses specific elements of the regulation and identifies and discusses alternative policy approaches that the BLM considered. See Table 6-1 for a summary of the regulatory action and alternatives considered and Table 6-2 for a side-by-side comparison of the rule's requirements and the EPA's final NSPS regulations.

Royalty Rate: The rule will conform the regulations governing royalty rates for new competitive oil and gas leases on Federal lands to the corresponding statutory provisions. The language does not specify a royalty rate increase, but provides the BLM discretion to change the rate in the future. The royalty rate on existing Federal leases will remain unchanged. The royalty rate for Federal leases obtained non-competitively after the effective date of the final rule will also remain unchanged from its current level of 12.5%, as this level is specified by statute. Tribal leases will be unaffected by these revisions or any potential future changes to the royalty rate on Federal leases.

Flaring of oil-well gas: To reduce the amount of oil-well gas flaring, this rule requires the operator to:

- For planned oil wells, submit information about the anticipated gas production and planned gas disposition with the Application for Permit to Drill (APD);
- Limit flaring from development oil wells by meeting the following gas capture targets:
  - Year 1: No requirements;
  - Year 2: 85% capture target with 5,400 Mcf/month/well of flaring allowed;
  - Year 3: 85% capture target with 3,600 Mcf/month/well of flaring allowed;
  - Year 4: 90% capture target with 1,800 Mcf/month/well of flaring allowed;
  - Year 5: 90% capture target with 1,500 Mcf/month/well of flaring allowed;
  - Year 6: 90% capture target with 1,200 Mcf/month/well of flaring allowed;
  - Year 7: 95% capture target with 1,200 Mcf/month/well of flaring allowed;
  - Year 8: 95% capture target with 900 Mcf/month/well of flaring allowed;
  - Year 9: 95% capture target with 750 Mcf/month/well of flaring allowed;
  - Year 10: 98% capture target with 750 Mcf/month/well of flaring allowed;
- Operators may calculate capture percentages across the flaring wells it administers on a lease-by-lease basis or across a county or State;
- The BLM may approve an alternative capture target if the operator demonstrates that the specified targets would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease;
- Operators must measure rather than estimate flared volumes when the operator is flaring 50 Mcf or more of gas per day from a high pressure flare stack or manifold, based on estimated volumes from the previous 12 months, or the life of the flare, whichever is shorter; and
- Operators must pay royalty on flared gas in excess of the allowable volume. Operators would face penalties for non-compliance consistent with BLM's civil penalties procedures.

Several States have regulations specifying flaring limits. Wyoming and Utah limit flaring to 60 Mcf/well/day and 1,800 Mcf/well/month, respectively, unless the operator obtains State approval of a higher limit.[36] North Dakota has a more comprehensive policy to limit flaring within the State. It has established escalating gas capture targets, which the operator may meet on a well, field, or State-wide basis for the wells under its control. If the operator does not meet the targets, then the State imposes production limits on the operator's crude oil production.

In the proposed rule, the BLM proposed a flaring limit to be applied on a well basis, meaning that the operator would not be able to exceed a set flaring amount (proposed as 60 Mcf/day). The approach carried forward in the final rule instead allows operators to comply with the capture targets across their flaring development oil wells in a county or State; thus allowing them to prioritize flaring reductions to locations and operations where the marginal control costs are lowest.

In developing the rule, the BLM also considered whether it should assess royalty on all flared associated gas. It did not carry forward this option after determining that an across-the-board application of royalties was not consistent with past practice and precedent. Also, the BLM considered whether to identify zones that would potentially support capture based on information provided by the operator. Under this approach, the BLM envisioned ordering the capture of 100% of the associated gas in specified capture zones if the internal rate of return (IRR) for gas projects within the zone exceeded 7%. The BLM envisioned that it would determine a timeframe for capturing gas from the area on a case-by-case basis (not to exceed 3 years). The BLM did not move forward with this alternative, due to concerns about the complexity of identifying gas capture zones and making capture determinations. Further, analysis suggested that adding this requirement in addition to the flaring limit would add significantly to the costs of the rule without significantly reducing gas waste.

<u>Flaring of gas during well testing:</u> To reduce the amount of gas flared during well testing, this rule reduces the allowed amount of gas flared royalty-free from 50 MMcf to 20 MMcf. Generally, we believe that the operator is properly incentivized and will minimize the amount of gas flared during well testing. In addition, the BLM added a provision in the final rule which allows the BLM to increase the 20 MMcf royalty-free flaring limit by up to an additional 30 MMcf of gas for exploratory wells in remote locations where additional testing is needed in advance of development of pipeline infrastructure. We did not consider alternatives to limit the flaring further.

<u>Gas loss during well drilling, completion, and workover:</u> To reduce the amount of gas lost during well drilling, this rule requires that, unless technically infeasible, the gas from drilling operations be either captured and routed to a sales line, combusted, re-injected, or used for production purposes on site. It is common industry practice to control gas during drilling operations and route the gas either to a flare or, in some cases, to a sales line. Controlling gas produced during drilling is important for safety.

To reduce the amount of gas lost during well completions, this rule requires that, unless technically infeasible, the gas from well completions be either captured and routed to a sales line, combusted, re-injected, or used for production purposes on site. This is consistent with, although less detailed

[36] Wyoming Operational Rules, Drilling Rules Section Ch. 3, Section 39(b), available at http://soswy.state.wy.us/Rules/RULES/9584.pdf; Utah R649-3-20, Gas Flaring or Venting Section 1.1, available at (http://www.rules.utah.gov/publicat/code/r649/r649-003.htm#T20. We note that the state limits trigger a review by a state review board, which then determines whether the operator must capture the gas.

than the EPA requirements in NSPS Subpart OOOO and Subpart OOOOa, which regulate gas and oil well completions using hydraulic fracturing. Those requirements already apply to operations on Federal and Indian lands. As a result, we do not expect the BLM requirements to require any additional action from an operator in compliance with subparts OOOO and OOOOa. The BLM also considered placing requirements on conventional oil and gas well completions. We did not carry that option forward, because the loss of gas from conventional well completions is very small and regulating conventional well completions is not a particularly cost-effective way to reduce waste.

Gas loss from pneumatic controllers: To reduce the amount of gas lost from pneumatic controllers, this rule requires that operators replace all high-bleed continuous controllers with low-bleed continuous controllers. Exceptions to the requirement are available to the operator under certain conditions.

Gas loss from pneumatic diaphragm pumps: To reduce the amount of gas lost from pneumatic pumps, the rule requires that operators must either replace diaphragm pumps with zero-emission pumps or route the gas releases from the pumps to processing equipment for capture and sale. Alternatively, an operator may route the exhaust to a flare or low pressure combustion device if the operator makes a determination that replacing the pneumatic diaphragm pump with a zero-emissions pump or capturing the pump exhaust is not viable because (1) a pneumatic pump is necessary to perform the function required and (2) capturing the exhaust is technically infeasible or unduly costly. If an operator makes this determination and has no flare or low pressure combustor on-site or flaring to such a device would be technically infeasible, the operator is not required to route the exhaust to a flare or low pressure combustion device. A pump is exempted from this requirement if: it is temporarily on site; the pump does not vent exhaust gas to the atmosphere, or the operator demonstrates, and the BLM concurs, the installation of controls would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves. The BLM proposed to regulate pneumatic piston pumps, but did not carry that option forward, because gas releases from piston pumps are reported to be a fraction of those from diaphragm pumps, according to the 2016 GHG Inventory.

Gas loss during liquids unloading: To reduce the amount of gas lost during liquids unloading, the rule requires that the operator use practices for liquids unloading operations that minimize vented gas and the need for well venting, unless the practices are necessary for safety. The rule also requires that for wells equipped with a plunger lift system or an automated well control system, the operator must optimize the operation of the system to minimize gas losses. For all wells, before the operator manually purges a well for the first time after the effective date of rule, the operator must document in a Sundry Notice that other methods for liquids unloading are technically infeasible or unduly costly. In addition, during any liquids unloading by manual well purging, the person conducting the well purging is required to be present on site to minimize to the maximum extent practicable any venting to the atmosphere. In developing the rule, the BLM considered whether it would be appropriate to require the installation of plunger lifts, but determined that such a requirement would not be technically feasible in all cases. The BLM also considered prohibiting well purging from any wells drilled after the rule's effective date but did not carry that requirement forward in the final rule due to concerns about the technical feasibility for all potential operations and scenarios.

Gas loss from oil and condensate storage tanks: To reduce the amount of gas vapors vented or lost from storage tanks, the rule requires that if the potential VOC emissions from a tank exceed 6 tpy, operators must route the gas vapor to a sales line. Alternatively, the operator may route the vapor to a combustion device after determining that routing the vapor to a sales line is technically infeasible or unduly costly. The operator also may submit a Sundry Notice to the BLM that demonstrates that compliance with the above options would cause the operator to cease production on the lease due to the cost of compliance. The operator may remove the controls if VOC emissions fall below 4 tpy per tank. The EPA already imposes the same requirements on new or modified storage tanks. In developing the proposal, the BLM considered a range of thresholds.

Gas loss from leaks: To reduce the amount of gas lost from leaks, the rule requires that the operator conduct semi-annual instrument-based inspections of sites and equipment on a lease, unit, or communitized area (and quarterly inspections for compressor stations). Sites with only a wellhead or wellheads and no other equipment are exempt from the LDAR requirements.

In the RIA for the proposed rule, the BLM considered using different inspection frequencies based on the level of production from the site, e.g., sites with less gas production might require less frequent inspections (e.g., annual) while sites with greater gas production might require more frequent inspections (e.g., quarterly). In this RIA, we present alternatives that would apply annual inspections to all sites, quarterly inspections to all sites, and more specific alternatives centering around the semi-annual and annual inspection frequencies and well productivity for oil well sites.

The BLM also considered alternatives related to which leaks would require repair. The BLM considered whether to require the operator to repair only those leaks where the sales of the recovered gas would pay for the cost of the repair. The BLM also considered requiring the operator to repair leaks above a certain volume. Ultimately, the BLM proposed and carried forward with the final rule the requirement that the operator repair all detectable leaks, since the available data indicate that the vast majority of leaks can be repaired with a payback period of less than one year. We discuss the available data in detail in the examination of the alternatives.

Table 6-1: Final Requirements and Alternative Considered

Source	Distinction Within Source	Final Requirements	Alternatives Considered to the Final Requirements or Maintaining the Status Quo
Flared (variety of sources)	Oil-well gas (associated gas)	Requires operators to submit information with its APD for a development oil well about anticipated gas volumes and planned disposition of any associated gas. Requires operators to meet gas capture targets for oil wells that flare gas. The capture targets take effect in the second year of the rule and increase incrementally over time. Requires operators to measure flared associated gas from a flare stack or manifold if greater than 50 Mcf/day, monthly average. Royalty is specified on excess gas flared during production operations. Subject to the provisions in the final rule, royalty is not specified for well completion gas, well testing gas, gas used for production purposes, gas released during emergencies, gas released during liquids unloading, gas vapors emitted from storage tanks, or gas lost from leaks.	Specifying royalty on all lost gas; Flaring limits; Identifying gas capture zones and ordering the capture of gas under certain conditions.
	Well testing	Reduces maximum royalty-free volume limit to 20 MMcf, with an option for the BLM to increase the 20 MMcf royalty-free flaring limit by up to an additional 30 MMcf of gas for exploratory wells in remote locations where additional testing is needed in advance of development of pipeline infrastructure.	Increasing royalty-free flaring limit to 20 MMcf without the option to increase the limit.
Well drilling, completions, and well maintenance	Oil and gas well completions with hydraulic fracturing (no practical effect)	Requires gas from well completions to be captured and routed to a sales line, combusted, re-injected, or used for production purposes on site.	Regulating conventional well completions
Pneumatic controllers	Continuous, high bleed (practically affects existing controllers)	Requires operators to replace high-bleed continuous controllers with low-bleed controllers, with some exceptions.	None

Table 6-1: Final Requirements and Alternative Considered

Source	Distinction Within Source	Final Requirements	Alternatives Considered to the Final Requirements or Maintaining the Status Quo
Pneumatic pumps	Diaphragm chemical injection pumps (practically affects existing diaphragm pumps)	Requires operators to either replace pneumatic diaphragm pumps with zero-emission pumps or route the gas releases from the pumps to processing equipment for capture and sale, with exceptions.	Requiring replacement of piston pneumatic pumps in addition to diaphragm pneumatic pumps
Gas well liquids unloading	None	Requires various operational and reporting requirements when conducting liquids unloading.	Placing plunger lift requirements; Prohibiting well purging from new wells.
Oil and condensate storage vessels	None (practically affects existing uncontrolled tanks)	If VOC emissions exceed 6 tpy per storage vessel, requires operators to route gas vapor to a sales line. Alternatively, operators may route the vapor to a combustion device after determining that routing the vapor to a sales line is technically infeasible or unduly costly, with some exceptions.	Requiring combustion (at a minimum) at different VOC threshold; Placing VRU requirements on higher volume tanks.
Leaks	None (practically affects existing wellsite facilities)	Requires operators to implement a semi-annual LDAR program for well sites and quarterly LDAR for compressor stations. Operators must use an infrared camera, portable analyzer, or other method approved by the BLM. Operators must repair all identified leaks. Operators may request BLM approval of an alternative instrument-based leak detection program, which the BLM may approve if it finds that the program would reduce leaked volumes by at least as much as the BLM program.	Alternative inspection frequencies and mechanisms for adjusting the frequencies, including different frequencies for marginal wells.

Table 6-2: Final Requirements and Interaction with EPA's Regulations

Source	EPA Subpart OOOO	EPA Subpart OOOOa	Practical Impact of BLM's Rule
Flaring during normal production operations	None	None	Regulates operations.
Well drilling	None	None	Regulates well drilling
Well completions and workovers	Regulates hydraulically fractured gas well completions	Regulates hydraulically fractured oil well completions	None, since all well completions are "new" and compliance with Subpart OOOO and Subpart OOOOa satisfies BLM requirements.
Pneumatic controllers	Regulates new pneumatic controllers	None	Regulates pneumatic controllers installed before Subpart OOOO's implementation that are high-bleed and continuous-bleed.
Pneumatic Pumps	None	Regulates new diaphragm pneumatic pumps	Regulates diaphragm pneumatic pumps installed before Subpart OOOOa's implementation.
Gas well liquids unloading	None	None	Regulates operations.
Oil and condensate storage tanks	Regulates new or modified tanks	None	Regulates tanks existing before Subpart OOOO's implementation that have VOC emissions above 6 tpy.
Leaks	None	Regulates new and modified well sites	Regulates well sites in existence prior to Subpart OOOOa's implementation.

7. Examination of the Requirements and Alternatives

This section estimates the impacts of the requirements and the alternative approaches, where appropriate. For each requirement, we estimate the number of affected facilities and the incremental costs, production, and emissions reduction, as well as administrative costs to industry and the BLM. Those administrative costs are presented in the summary of results, in Section 9 of this analysis, and in more detail in the Supporting Statement for the Paperwork Reduction Act.

7.1 Estimating Costs, Benefits, and Net Benefits

The costs, benefits, and net benefits are estimated for each of the requirements. The costs include direct compliance costs and the social cost of additional carbon dioxide generated from the combustion of gas produced (in lieu of venting that gas). The benefits include the direct cost savings from recovered gas and the social benefit of methane reductions (from reduced venting). Net benefits are calculated as the benefits minus the costs.

All quantified reductions in emissions expressed in tons or tons per year mean short tons or short tons per year. The value of the emissions reductions, meaning the value of methane reduced or the value of carbon dioxide reduced, is calculated after converting the short ton volume to an equivalent metric ton volume (using a conversion factor of 1 short ton to 0.907185 metric ton), since the social cost of methane and carbon dioxide are expressed in dollars per metric ton (described in Section 7.2 below).

7.2 Climate Effects and Evaluation

As part of the analysis of costs and benefits, we considered the social costs and benefits of the estimated climate impacts. We estimated the quantity of methane emission reductions and monetized the social benefits of those reductions using estimates for the social cost of methane.[37] We also estimated changes in the quantity of carbon dioxide emission and monetized the social costs of those using estimates for the social cost of carbon.

We estimated the quantity of methane reductions using emissions factors and reductions data made available by the EPA. We then estimated the global value of these methane emisson reductions by applying the U.S. government's estimates of the social cost of methane, which are presented in the Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866 ("IWG non-CO2 Addendum").[38] These social cost of

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[37] Further, we expect that the reduction in the on-site flaring of associated gas will have small incremental environmental benefits in that large volumes of natural gas are expected to be combusted with greater efficiency in plants rather than in on-site flares. We did not measure this incremental benefit.

[38] Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866, Interagency Working Group on Social Cost of Greenhouse Gases, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Interior, Department of Transportation, Department of the Treasury,

methane estimates are taken from the Marten *et al.* (2014) and are the same estimates used by the EPA in its analysis of its Subpart OOOOa final regulation (*Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources*) and its final rule for *New Source Standards of Performance for Municipal Solid Waste Landfills*.[39] We estimated the quantity of carbon dioxide emissions by estimating the expected gas capture or gas flaring in lieu of gas venting and assuming a factor of 34 tons of carbon dioxide per Bcf of gas captured/flared.[40] We estimate the global social disbenefits (i.e., costs) of CO2 emissions expected from this final rulemaking using the SC-CO2 estimates presented in the Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised August 2016) ("current TSD").[41]

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that once emitted into the atmosphere absorbs terrestrial infrared radiation that contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere, which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

According to the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5, 2013), changes in methane concentrations since 1750 contributed 0.48 W/m^2 of forcing, which is about 17 percent of all global forcing due to increases in anthropogenic GHG concentrations, and which makes methane the second leading long-lived climate forcer after CO_2. However, after accounting for changes in other greenhouse substances such as ozone and stratospheric water vapor due to chemical reactions of methane in the atmosphere, historical methane emissions are estimated to have contributed to 0.97 W/m^2 of forcing today, which is about 30 percent of the contemporaneous forcing due to historical greenhouse gas emissions(EPA 2016 RIA, pp. 4-6.)

We calculated the global social benefits of methane emissions reductions expected from this rule using estimates of the social cost of methane (SC-CH_4), a metric that estimates the monetary value of impacts associated with marginal changes in methane emissions in a given year. It includes a wide

Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy (August 2016). Available at: < https://www.whitehouse.gov/sites/default/files/omb/inforeg/august_2016_sc_ch4_sc_n2o_addendum_final_8_26_16.pdf> Accessed 10/20/2016.

[39] Documents related to these rulemaking are available on the EPA websites at: http://www3.epa.gov/airtoxics/landfill/landflpg.html and https://www3.epa.gov/airquality/oilandgas/actions.html

[40] Emission factor derived from API 2009, p. 4-42.

[41] Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Greenhouse Gases, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Interior, Department of Transportation, Department of the Treasury, Environmental Protection Agency, National Economic Council, Office of Management and Budget, and Office of Science and Technology Policy, (May 2013, Revised August 2016). Available at: < https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf> Accessed 10/20/2016

range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. The SC-CH_4 estimates applied in this analysis were presented in the Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866 ("IWG non-CO2 Addendum"). These estimates were taken from Marten *et al.* (2014) and are discussed in greater detail below.

A similar metric, the social cost of CO_2 (SC-CO_2), provides important context for understanding the SC-CH_4 estimates. Estimates of the SC-CO_2 have been used by DOE, EPA and other federal agencies to value the impacts of CO_2 emissions changes in benefit cost analysis for GHG-related rulemakings since 2008. The SC-CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. Similar to the SC-CH_4, it includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is used to quantify the benefits of reducing CO_2 emissions, or the disbenefit from increasing emissions, in regulatory impact analyses.

The SC-CO_2 estimates were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG), that included several executive branch agencies, as well as White House offices (e.g. OMB, CEA) used three integrated assessment models (IAMs) to develop the SC-CO_2 estimates and recommended four global values for use in regulatory analyses. The SC-CO_2 estimates were first released in February 2010, and they were updated in 2013 using new versions of each IAM. The 2013 update did not revisit the 2010 modeling decisions with regards to the discount rate, reference case socioeconomic and emission scenarios, and equilibrium climate sensitivity distribution. Rather, improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves and published in the peer-reviewed literature. The 2010 SC-CO_2 Technical Support Document (2010 SC-CO_2 TSD) provides a complete discussion of the methods used to develop these estimates and the current SC-CO_2 TSD presents and discusses the 2013 update (including recent minor technical corrections to the estimates).[42]

The 2010 SC-CO_2 TSD noted a number of limitations to the SC-CO_2 analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently IAMs do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 reductions to inform benefit-cost analysis.

[42] The 2010 SC-CO_2 TSD, as well as the additional (2013, 2015 and 2016) technical updates are all available at: https://www.whitehouse.gov/omb/oira/social-cost-of-carbon.

Federal agencies have continued to consider feedback on the SC-CO2 estimates from stakeholders through a range of channels, including public comments rulemakings that use the SC-CO2 in supporting analyses and through regular interactions with stakeholders and research analysts implementing the SC-CO2 methodology used by the interagency working group. Commenters have provided constructive recommendations for potential opportunities to improve the SC-CO2 estimates in future updates. In addition, OMB sought public comment on the approach used to develop the SC-CO2 estimates through a separate comment period and published a response to those comments in 2015.[43]

After careful evaluation of the full range of comments submitted to OMB, the IWG continues to recommend the use of the SC-CO2 estimates in regulatory impact analysis while also continuing to engage in research on modeling and valuation of climate impacts. Currently, the IWG is seeking advice from the National Academies of Sciences, Engineering and Medicine on how to approach future updates to ensure that the estimates continue to reflect the best available scientific and economic information on climate change.[44] An Academies committee, "Assessing Approaches to Updating the Social Cost of Carbon," (Committee) will provide expert, independent advice on the merits of different technical approaches for modeling and highlight research priorities going forward. BLM will evaluate its approach based upon any feedback received from the Academies' panel.

To date, the Committee has released an interim report, which recommended against doing a near term update of the SC-CO2 estimates. For future revisions, the Committee recommended the IWG move efforts towards a broader update of the climate system module consistent with the most recent, best available science, and also offered recommendations for how to enhance the discussion and presentation of uncertainty in the SC-CO2 estimates. Specifically, the Committee recommended that "the IWG provide guidance in their technical support documents about how [SC-CO2] uncertainty should be represented and discussed in individual regulatory impact analyses that use the [SC-CO2]" and that the technical support document for each update of the estimates present a section discussing the uncertainty in the overall approach, in the models used, and uncertainty that may not be included in the estimates.[45] In August 2016, the IWG issued revisions to the SC-CO_2 Technical Support Document that responded to interim recommendations from the Academies regarding the presentation and discussion of uncertainty. The revision did not modify methodological decisions or change the SC-CO_2 estimates themselves. The Committee will release a final report in early 2017 with longer-term recommendations for updating the estimates.

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43 See https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf.

44 The Academies' review will be informed by public comments and focus on the technical merits and challenges of potential approaches to improving the SC-CO2 estimates in future updates. See https://www.whitehouse.gov/blog/2015/07/02/estimating-benefits-carbon-dioxide-emissions-reductions.

45 National Academies of Sciences, Engineering, and Medicine. (2016). Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on a Near-Term Update. Committee on Assessing Approaches to Updating the Social Cost of Carbon, Board on Environmental Change and Society. Washington, DC: The National Academies Press. doi: 10.17226/21898. See Executive Summary, page 1, for quoted text.

The four $SC-CO_2$ estimates are: $13, $45, $67, and $133 per metric ton of CO_2 emissions in the year 2020 (2012 dollars).[46] The first three values are based on the average $SC-CO_2$ from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. Estimates of the $SC-CO_2$ for several discount rates are included because the literature shows that the $SC-CO_2$ is sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the $SC-CO_2$ across all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the $SC-CO_2$ distribution, and while less likely than those reflected by the average SC- CO_2 estimates, would be much more harmful to society and therefore, are relevant to policy makers. The $SC-CO_2$ increases over time because future emissions are expected to produce larger incremental damages as economies grow and physical and economic systems become more stressed in response to greater climate change.

In August 2016, the IWG issued an Addendum to the current TSD that presents estimates of the SC-CH4 for use in regulatory impact analysis ("IWG non-CO2 Addendum").[47] As the Director of the Office of Information and Regulatory Affairs in OMB noted, "the methodology for valuing these damages and its application to regulatory cost-benefit analysis have been subject to rigorous independent peer review and public comment."[48] The IWG's SC-CH4 estimates are taken from a paper by Marten et al. (2014), which provided the first set of published SC-CH4 estimates that are consistent with the modeling assumptions underlying the SC-CO2.[49] Specifically, the estimation approach of Marten et al. used the same set of three IAMs, five socioeconomic and emissions scenarios, equilibrium climate sensitivity distribution, three constant discount rates, and aggregation approach used by the IWG to develop the SC-CO2 estimates. The aggregation method involved distilling the 45 distributions of the SC-CH4 produced for each emissions year into four estimates: the mean across all models and scenarios using a 2.5 percent, 3 percent, and 5 percent discount rate, and the 95th percentile of the pooled estimates from all models and scenarios using a 3 percent discount rate. Marten et al. also used the same rationale as the IWG to develop global estimates of the SC-CH4, given that methane is a global pollutant.

In addition, the atmospheric lifetime and radiative efficacy of methane used by Marten et al. is based on the estimates reported by the IPCC in their Fourth Assessment Report (AR4, 2007), including an adjustment in the radiative efficacy of methane to account for its role as a precursor for tropospheric ozone and stratospheric water. These values represent the same ones used by the IPCC in AR4 for calculating GWPs. At the time Marten et al. developed their estimates of the SC-CH4, AR4 was the latest assessment report by the IPCC. The IPCC updates GWP estimates with each new assessment, and in the most recent assessment, AR5, the latest estimate of the methane GWP ranged from 28-

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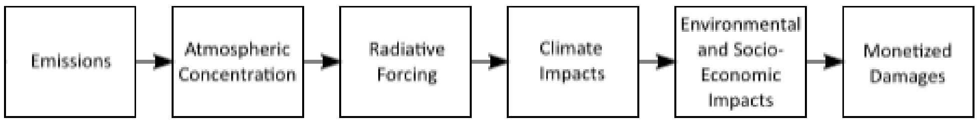
[46] Based on the current IWG Technical Support Document (AUGUST 2016), available at: https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf_The TSD presents $SC-CO_2$ in $2007. The estimates were adjusted to 2012$ using the GDP Implicit Price Deflator, from U.S. Bureau of Economic Analysis available at: http://www.bea.gov/national/index.htm#gdp.

[47] The IWG also published estimates of the SC-N2O, which were taken from the Marten et al paper.

[48] Howard Shelanski, Jay Shambaugh, *Strengthening Tools to Account for Damages from Greenhouse Gas Emissions in Regulatory Analysis* (Aug. 26, 2016) (https://www.whitehouse.gov/blog/2016/08/26/strengthening-tools-account-damages-greenhouse-gas-emissions-regulatory-analysis).

[49] Marten *et al.* (2015) also provided the first set of $SC-N_20$ estimates that are consistent with the assumptions underlying the $SC-CO_2$ estimates.

36, compared to a GWP of 25 in AR4. The updated values reflect a number of changes: changes in the lifetime and radiative efficiency estimates for CO2, changes in the lifetime estimate for methane, and changes in the correction factor applied to methane's GWP to reflect the effect of methane emissions on other climatically important substances such as tropospheric ozone and stratospheric water vapor. In addition, the range presented in the latest IPCC report reflects different choices regarding whether to account for climate feedbacks on the carbon cycle for both methane and CO2 (rather than just for CO2 as was done in AR4).



Source: Marten *et al.* 2014

Figure 7-2a Path from GHG Emissions to Monetized Damages

The IWG non-CO2 Addendum discusses the SC-CH4 estimates, and compares them with other recent estimates in the literature. A direct comparison of the estimates with all of the other published estimates is difficult, given the differences in the models and socioeconomic and emissions scenarios, but results from three relatively recent studies offer a better basis for comparison (see Hope (2006), Marten and Newbold (2012), Waldhoff *et al.* (2014)). Marten *et al.* found that in general the SC-CH_4 estimates from their 2014 paper are higher than previous estimates. The higher SC-CH_4 estimates are partially driven by the higher effective radiative forcing due to the inclusion of indirect effects from methane emissions in their modeling. Marten *et al.*, similar to other recent studies, also find that their directly modeled SC-CH_4 estimates are higher than the GWP-weighted estimates. More detailed discussion of the SC-CH_4 estimation methodology, results and a comparison to other published estimates can be found in Marten *et al.*

Table 7-2b: Social Cost of Methane (SC-CH_4), 2012 – 2050 [in 2012$ per metric ton]
(Source: IWG 2016[a])

Year	SC-CH_4			
	5 Percent Average	**3 Percent Average**	**2.5 Percent Average**	**3 Percent 95th percentile**
2012	$432	$1,016	$1,405	$2,810
2015	$486	$1,081	$1,513	$3,027
2020	$584	$1,300	$1,700	$3,500
2025	$703	$1,513	$1,946	$3,999
2030	$822	$1,729	$2,162	$4,540
2035	$973	$1,946	$2,486	$5,297
2040	$1,081	$2,162	$2,810	$5,945
2045	$1,297	$2,486	$3,027	$6,594
2050	$1,405	$2,702	$3,351	$7,242

[a] The IWG (2016) estimates are presented in 2007 dollars. These estimates were adjusted for inflation using Implicit Price Deflators for Gross Domestic Product (US Department of Commerce, Bureau of Economic Analysis), http://www.bea.gov/iTable/index_nipa.cfm

The application of the IWG's directly modeled SC-CH4 estimates to benefit-cost analysis of a regulatory action is analogous to the use of the SC-CO_2 estimates. Specifically, the SC-CH_4 estimates in Table 7-2b are used to monetize the benefits of reductions in methane emissions expected as a result of the rulemaking. Forecast changes in methane emissions in a given year, expected as a result of the regulatory action, are multiplied by the SC-CH_4 estimate for that year. To obtain a present value estimate, the monetized stream of future non-CO_2 benefits are discounted back to the analysis year using the same discount rate used to estimate the social cost of the non-CO_2 GHG emission changes. In addition, the limitations for the SC-CO_2 estimates discussed above likewise apply to the SC-CH_4 estimates, given the consistency in the methodology. See the IWG non-CO_2 Addendum for additional details about the peer review conducted of the application of Marten et al. (2014) non-CO_2 social cost estimates in regulatory analysis.

Thus, the BLM is incorporating the 2016 IWG Technical Update for the SC-CH_4 estimates in this RIA. As previously noted, the National Academies' Committee will release a final report on opportunities to improve the SC-CO2 estimates in early 2017.While the Committee's review focuses on the SC-CO_2 methodology, recommendations on how to update many of the underlying modeling assumptions will also likely pertain to the SC-CH_4 estimates. The IWG will evaluate its approach based upon any feedback received from the Academies' panel.

7.3 Discount Rate

OMB Circular A-94 (Revised) "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs"[50] provides guidance to Federal agencies when conducting analyses, including regulatory impacts analyses. It discusses the importance of discounting future benefits and costs when computing the net present value – "discounting reflects the time value of money. Benefits and costs are worth more if they are experienced sooner. All future benefits and costs, including nonmonetized benefits and costs, should be discounted. The higher the discount rate, the lower is the present value of future cash flows. For typical investments, with costs concentrated in early periods and benefits following in later periods, raising the discount rate tends to reduce the net present value."

Circular A-94 directs agencies to use a discount rate of 7% for baseline analyses. It states, "this rate approximates the marginal pretax rate of return on an average investment in the private sector in recent years." It also recommends that agencies show sensitivity of the discounted net present value and other outcomes using additional discount rates. Literature suggests that there is a divergence between the private (considered by firms or industry) and social (considered by society) discount rates, with the private rates exceeding the social rates. This difference is considered to result from a difference in risk premiums; meaning the cost of capital is higher as the risk increases. From society's perspective, the risk may be lower or there may be no-risk, in which case a lower discount rate would be appropriate. It is common for regulatory impact analyses to analyze outcomes using a 3% discount rate, particularly for regulations with expected environmental benefits. As such, for the purposes of this analysis, we use discount rates of 7% and 3% to annualize the costs of capital investments or to present the present value of cash savings occurring in the future.

With respect to monetized benefits, we use social cost of methane estimates from IWG (2016), which provides social cost of methane estimates using model averages using a 2.5%, 3%, and 5% discount rate, and the 95th percentile of the pooled estimates from all models and scenarios using a 3% discount rate. For purposes of this analysis, we used the values for methane using the estimate

[50] Signed October 29, 1992. Available on the web at https://www.whitehouse.gov/omb/circulars_a094/.

deemed to be central by the IWG, i.e., the model average at 3 percent discount rate. Similarly, we used the social cost of carbon estimates provided by the Interagency Working Group on Social Cost of Carbon "3% Average." The Interagency Working Group recommends considering all four SC-CO_2estimates in the analyses, and the BLM calculated these benefits and net benefits accordingly (see Section 8.3). We note that using the other SC-CO_2estimates would result in varying benefits and net benefits. Using the 2.5% SC-CO_2discount rate would result in lower levels of monetized benefits and net benefits, while using the 5% and 95th percentil rates would result in higher levels of monetized benefits and net benefits.

7.4 Period of Analysis

The rule's requirements would impose annual costs and produce annual benefits, and we measure the impacts over a 10-year period. As discussed above, however, we do not expect the annual costs, or annual benefits, to be uniform over the life of the requirements. Rather, the first few, transitional years that these requirements are in place are expected to see the highest levels of compliance activity with respect to equipment replacement and the implementation of leak detection programs.

Beyond the initial 10-year period, we expect the provisions of the rule to have less of an impact, although the capture requirements will continue to limit flaring. For many other provisions, as existing wells and equipment are shut in or retired, new, modified and reconstructed wells and equipment would be subject to Subpart OOOO and Subpart OOOOa.

7.5 Uncertainty

The estimated costs and benefits rely on the best data that we have available to us, and modeling assumptions that we believe are reasonable, but it is important to recognize that both the inputs to the estimates and the results are subject to substantial uncertainty. Below we describe several key sources of uncertainty.

A. Commodity Price Assumptions

Different assumptions about future commodity prices produce substantially different estimates of costs and benefits. Commodity prices will affect how operators will respond to the requirements. Future commodity prices are subject to substantial uncertainty; however, we believe it is reasonable to examine the costs and benefits of this rule by using the Energy Information Administration's (EIA) future price projections and discounting those prices to account for processing and transportation costs.

With respect to the appropriate crude oil price to consider, we note that current prices are low and EIA projected prices are modestly higher. Crude oil prices in 2016 have been among the lowest in recent history, ranging from \$27/bbl to \$51/bbl.[51] At the time we prepared this analysis, the crude oil price was about \$44/bbl. The EIA's long-term price projections are \$48/bbl in 2017, \$71/bbl in

[51] Bloomberg. Cited prices are for West Texas Intermediate (WTI) Crude Oil (NYMEX). Data available at http://www.bloomberg.com/energy

2020, \$85/bbl in 2025, \$97/bbl in 2030, \$112/bbl in 2035, and \$129/bbl in 2040 with an annual growth rate from 2015 to 2040 of 4.0%.[52]

Natural gas prices in 2016 have been among the lowest in recent years, ranging from \$1.64/Mcf to \$2.99/Mcf.[53] At the time we prepared this analysis, the natural gas price was about \$2.85/Mcf. The EIA's long-term price projections are \$3.19/Mcf in 2017, \$4.58/Mcf in 2020, \$5.29/Mcf in 2025, \$5.22/Mcf in 2030, \$5.07/Mcf in 2035, and \$5.02/Mcf in 2040, with an annual growth rate from 2015 to 2040 of 2.5%.[54]

Commenters on the proposed rule asserted that operators do not receive the indexed commodity prices, but rather lower prices, particularly for natural gas. Using ONRR data for 2015, we determined that it is reasonable to assume that an operator might receive prices for natural gas and crude oil that are about 75% and 98%, respectively, of the published index prices. We measured the discount to be the royalty revenues reported by ONRR divided by the royalty at 12.5% of the sales value. For processed gas and crude oil produced from Federal leases in 2015, the calculation returned 82% and 98%, respectively. Further, we compared the average sales value of unprocessed gas versus processed gas and found that price for unprocessed gas was 76% that of processed gas. Given additional feedback that the price received for natural gas could be even lower, we determined it was appropriate to assume a natural gas price that was 75% of the EIA's projections. Table 7-5, shows the projected commodity prices used in this analysis.

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52 EIA. Annual Energy Outlook, Table 12. WTI spot price. Release date May 2016. Data available at http://www.eia.gov/forecasts/aeo/tables_ref.cfm

53 Bloomberg. Cited prices are for Natural Gas (NYMEX). Data available at http://www.bloomberg.com/energy

54 EIA. Annual Energy Outlook, Table 13. Natural gas spot price at Henry Hub. Release date May 2016. Prices converted from MMbtu to Mcf using a factor of 1.032. Data available at http://www.eia.gov/forecasts/aeo/tables_ref.cfm

Table 7-5: Crude Oil and Natural Gas Price Forecasts, 2017 – 2026

Year	EIA Forecast – Crude Oil – West Texas Intermediate Spot ($/bbl)	Crude Oil Price Used in this Analysis ($/bbl)	EIA Forecast – Natural Gas – Spot Price at Henry Hub ($/Mcf)	Natural Gas Price Used in this Analysis ($/Mcf)
2017	48.08	47.12	3.19	2.39
2018	51.53	50.50	3.73	2.80
2019	64.24	62.96	4.14	3.11
2020	71.12	69.70	4.58	3.43
2021	75.37	73.86	4.47	3.35
2022	78.71	77.14	4.49	3.37
2023	81.06	79.44	4.89	3.67
2024	82.93	81.27	5.16	3.87
2025	85.41	83.70	5.29	3.97
2026	88.40	86.63	5.15	3.86
2027	92.96	91.10	4.95	3.83
2028	95.33	93.42	5.00	3.87
2029	97.06	95.12	5.05	3.91
2030	100.28	98.28	5.06	3.91
2031	103.50	101.43	5.01	3.88
2032	106.81	104.68	5.03	3.90
2033	110.31	108.11	4.98	3.85
2034	112.45	110.20	4.96	3.84
2035	116.14	113.81	4.91	3.80
2036	118.35	115.98	4.90	3.79
2037	122.09	119.64	4.84	3.74
2038	124.95	122.45	4.78	3.70
2039	129.11	126.52	4.85	3.75
2040	92.96	91.10	4.86	3.76

Source for index prices: EIA, Annual Energy Outlook 2016, Tables 12 and 13. Henry Hub natural gas prices converted from MMbtu to Mcf using a factor of 1.032.

B. Level of Voluntary Compliance

Due to the lack of available data, the analysis may not account for voluntary actions already undertaken by operators that comply with certain of the requirements. To the extent that operators are already in compliance with the requirements, the estimated impacts will overstate the actual impacts of the rule. The estimated costs and benefits of the LDAR requirements are particularly uncertain, since while many operators reportedly have some type of LDAR programs in place, we do not have data on the prevalence of these programs or on the relative costs of these existing programs compared to programs that would meet the BLM's specifications.

C. Site-Specific Characteristics

The impacts presented in this analysis are based on general emissions data and mitigation costs and may not reflect site-specific circumstances that could create significant differences in costs or benefits. We noted in the RIA for the proposed rule, that an operator's response to a requirement that restricts flaring is expected to depend on the individual characteristics of the well, and the readiness of the operator to deliver the gas to the market or bolster existing infrastructure to meet levels of production, the availability and viability of alternative capture technologies, among other factors. We believe that the approach carried forward in the final rule reduces the uncertainty about an operator's ability to meet the capture targets, because it allows the operator to prioritize the most cost-effective mitigation measure while not being confined by site-specific limitations.

D. Current Losses from Venting and Leaks

Our estimates for gas losses from venting and leaks are derived from data from the GHG Inventory. As discussed in detail in the preambles to the proposed and final rules, there is uncertainty regarding the accuracy of these estimates. In particular, several recent peer-reviewed studies suggest that these estimates underestimate, and potentially significantly underestimate, the volume of current losses from venting and leaks.

7.6 Flared Associated Gas

The final rule has several requirements to limit the flaring of associated gas from development oil wells. As presented in Section 4, according to ONRR data, operators flared roughly 81 Bcf of natural gas from BLM-administered leases in 2014. Of that amount, 77 Bcf was flared from oil wells and 4 Bcf was flared from gas wells. Further, we estimate that roughly 44 Bcf of the flared natural gas came from the Federal and Indian mineral estates and the remaining 37 Bcf came from non-Federal and non-Indian mineral estates.

This rule contains several requirements that would reduce the waste of associated gas through flaring. It establishes capture targets for natural gas coming from oil wells that operators must meet, on a lease basis or up to a statewide basis. The capture percentages apply to a volume of gas above an allowed amount of flaring, also specified by the rule. The rule establishes a schedule whereby the amount of natural gas allowed to be flared decreases over time and the natural gas capture target increases over time.

A. Flaring Allowable Volumes and Gas Capture Targets

The final rule requires operators to meet the following gas capture targets from development oil wells producing Federal or Indian minerals, either on a lease-by-lease basis or with flaring averaged across the operator's wells in a county or state.

Table 7-6a: Schedule for Flaring Allowable and Natural Gas Capture Targets

Year	Flaring Allowable (Mcf/ Well/ Month)	Capture Target - Percent (%)
2017	--	--
2018	5400	85%
2019	3600	85%
2020	1800	90%
2021	1500	90%
2022	1200	90%
2023	1200	95%
2024	900	95%
2025	750	95%
2026	750	98%

1. Background

The primary means to avoid flaring of associated gas from oil wells is to capture, transport, and process that gas for sale, using the same technologies that are used for natural gas wells. While industry continues to reduce the cost and improve the reliability of this technology, it is long-established and well understood. The capture and sale of associated gas can pay for itself where there is sufficient gas production relative to costs of connecting to or expanding existing infrastructure. Installing equipment and pipelines for capture and transport reportedly costs about $90,000 per inch-mile,[55] and therefore could cost upwards of $260,000 per mile (for a 2 and 5/8 inch diameter pipeline) or $360,000 per mile (for a 4-inch diameter pipeline).

In addition, the recent increase in flaring has encouraged entrepreneurs to develop new technologies and applications designed to capture smaller amounts of gas and put them to productive uses. Companies are beginning to experiment with and deploy several technologies as potential alternatives to the traditional pipeline systems that capture associated gas. These include: separating out natural gas liquids (NGL), which are often quite valuable, and trucking them off location; using the gas to run micro-turbines to generate power; and using small integrated gas compressors to convert the gas into compressed natural gas (CNG) that can be used on-site or trucked off location for use as transportation fuel or conversion to chemicals. In addition, there are other promising and innovative approaches that are either in development or in the earlier stages of deployment.[56]

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[55] Letter from INGAA to the California Energy Association, September 2011. Slide 46. Available at http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-27_workshop/comments/INGAA_Natural_Gas_Market_Assessment_Reference_Case_and_Scena_TN-62246.pdf. See also, Pipeline and Gas Journal, "Billions needed to meet long-term natural gas infrastructure supply, demands," April 2009. Figure 24. Available at http://pipelineandgasjournal.com/billions-needed-meet-long-term-natural-gas-infrastructure-supply-demands?page=4

[56] *See* Carbon Limits, *Improving utilization of associated gas in US tight oil fields* (April 2015) (providing detailed evaluation of new and emerging gas utilization technologies).

Natural gas contains hydrocarbons that can exist in liquid phase without being in a high pressure or low temperature environment. These are referred to as natural gas liquids (NGLs). Higher NGL concentrations in a gas stream reflect higher heating British thermal unit (Btu) value and a higher combined commodity value when the NGLs are separated from the remaining gas stream. Although NGLs are typically stripped and fractionated into their various components (e.g., propane, butane, etc.) at a gas processing plant, well-site equipment capable of stripping NGLs into a mixed liquid is available. This technology is particularly applicable in situations where high Btu associated natural gas is being flared due to lack of gas capture infrastructure. The NGLs can be stripped from the gas stream in the field, stored in tanks at the well site, and then transported by truck to a gas processing plant for sale. The remaining lower Btu gas would continue to be flared, but typically with a higher combustion efficiency than mixed gas. Conservation of the NGLs from a gas stream would reduce waste, add energy to the domestic supply, and increase royalty payments to the Federal Government and Tribal Governments.

Facilities to condense natural gas into liquefied natural gas (LNG) are more cost-effective at locations with large amounts of flaring, as relatively larger quantities of captured gas are needed to offset the cost of the LNG equipment. The surface area of well sites may need to be expanded to accommodate truck traffic and product storage needs. Also, because associated gas production drops off quickly at hydraulically fractured oil wells, LNG recovery is more likely to be cost-effective if it is implemented when production starts than if operators wait to install LNG capture equipment later in the life of the well.

Some commenters asserted that NGL recovery can only reduce 6% of flared gas volume and that it is not adequate on its own to meet the flaring limit. The commenters also estimated compliance costs based on pairing NGL with additional CNG trucking. While BLM agrees that NGL recovery only partially reduces the volume of gas left to be flared, the BLM does not agree that operators would always need to pair the technologies. As discussed above, a source could use CNG trucking without adopting NGL technologies, and given that the final rule allows operators to average flaring across multiple leases, even relatively small reductions in flaring volumes through NGL recovery may contribute to compliance with the capture targets.

On-site micro-turbines that generate electricity typically require preprocessing of the associated gas to minimize equipment maintenance issues. Generating electricity can work well if it is paired with NGL recovery, as the NGL residue gas stream is well suited as fuel for the generators. However, scaling the generators to the electricity demand that could be used locally on the well pad complicates their use. The generators may produce more electricity than is needed on site, but it may be too costly to connect to the electric grid from a remote location, as would be necessary to put the excess electricity to productive use. The cost of connecting to the electric grid depends, among other things, on the distance of the operation from the nearest electrical distribution lines. Moreover, if the electricity is used on site for production purposes, the gas used to generate the electricity would be royalty free. If the electricity produced by a micro-turbine is sold to the grid, however, the gas used to generate the electricity would incur royalties.

The CNG alternative technologies show considerable promise in effectively transporting associated gas to a centrally located processing plant while removing the higher value NGLs for other productive uses. However, limitations on the amount and rate of natural gas capture/compression on-site can limit applicability of this technology. Breakthroughs in compression technology are increasing the range of viable sites where CNG would be the preferred alternative technology. This technology could become sufficiently attractive to reduce flaring to near zero rates, according to companies offering these services.

Carbon Limits provides an in depth comparison of these capture approaches and technologies, which we summarize here.

For pipeline infrastructure, Carbon Limits shows capital costs of $100,000 – 700,000 per mile and operating costs of $0.05 – 1.00 per Mcf. It also suggests revenues of about $2 per Mcf and a payback period of less than 1 year, depending on the situation. Procurement and installation can take months and it is not a mobile technology.[57]

For CNG, Carbon Limits shows capital costs of $400 – 2,000 per Mcf of flowrate (expressed as Mcf/day) and operating costs of $0.24 – 1.30 per Mcf produced. It also suggests revenues $5 – 6 per Mcf and a payback period of about 1 year. However, the analysis below uses substantially lower revenues from gas sales stemming from CNG trucking. Equipment can be procured within weeks and deployed to or mobilized among operations in 1 day.[58]

For NGL recovery, Carbon Limits shows low to medium capital costs of $800 – 2,500 per Mcf per day and operating costs of $0 – 0.22 per Mcf, or high costs with capital costs of $2,500 or more per Mcf per day and operating costs of $0.22 – 0.68 per Mcf. It also suggests revenues $8 – 12 per Mcf and a payback period of less than 1 year. Equipment may be procured in 15 – 24 weeks and deployed to or mobilized among operations in 1 day to 2 weeks.[59]

For gas to power, Carbon Limits shows capital costs if $1,500 – 8,000 per Mcf per day and operating costs of $0.55 – 1.68 per Mcf. It also suggests revenues $3.60 – 6.70 per Mcf and a payback period of less than 1 year. Equipment can be procured in 15 – 36 weeks and deployed to or mobilized among operations in 1 day.[60]

While these newer on-site technologies may not be suitable in all situations, in many cases they could provide a profitable alternative to using traditional pipelines for capture and sale as a way to reduce waste, and operators should consider these approaches in assessing the opportunities to reduce waste from venting and flaring.

We expect that each operator will manage the flaring oil wells in its portfolio in manner such that it will meet the gas capture targets established in this rule. If an operator expects to fall short of the gas capture target, its response is likely to vary depending on the amount of the excess flaring, the duration of the excess flaring, and its readiness to avoid the excess. For short-term excess flaring, the operator might pay royalty on the excess flared volume and take corrective action to come into compliance the next month. It might also curtail production from any of the flaring wells in its portfolio to reduce the amount of gas co-produced and flared or use alternative capture technologies like CNG or NGL stripping. We note that any curtailed production is not lost. Rather, it is deferred from the present to the future.

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[57] Carbon Limits 2015a, Appendix p. 3.
[58] Ibid, p. 4.
[59] Ibid, p. 6.
[60] Ibid, p. 7-8.

2. Modeling the Impact

To analyze the impacts of potentially limiting flaring on Federal and Indian lands, the BLM requested oil and gas disposition data for all onshore activity reported to ONRR during FY 2015. This resulted in 816,231 observations with the unit of analysis being an operator's monthly volume of gas for each relevant disposition code. The data allowed for various extractions of data by date, operator, lease/unit, county, state, land class, and disposition code.

The various disposition codes describe the volumes of oil and gas that are sold, vented, flared, and used on lease among other actions. We modified the analysis over time, as early results revealed different aspects of flaring behavior on the lands of interest. One limitation of the data is in the land class. The land class types are Federal, Indian, State, Fee and Mixed. While we would like to focus on only Federal and Indian flared volumes for the purpose of this analysis, a record falls into the "mixed" category if any of the pervious varieties are in the unit/lease reported. Nearly 78 percent of the records are mixed. However; according to ONRR, about 50 percent of gas and 27 percent of oil production belongs to Federal and about 4 percent of the gas and 10 percent of the oil belongs to Indian lands.

A change from the proposed rule to the final rule includes allowing operators to group their production (at their option) across a State or county (as well as a unit/lease). As averaging the production across the State is seemingly the most advantageous to the operator, all further analysis was completed at the State level. To that end, spreadsheets were created to analyze the data state-by-state.

From the 800,000 plus records, each State specific set of records were extracted to the State spreadsheet template. For example, the North Dakota (ND) spreadsheet contains 84,604 records while the New Mexico (NM) spreadsheet has 297,268 records. Next the unique state and operator combinations were determined. For example, ND had 76 unique operators and NM had 354. To calculate a capture target percent for each operator in a State, relevant records had to be combined and then appropriately added or subtracted. We performed the calculations for each of the top flaring States: ND, NM, Wyoming (WY), Montana (MT), Colorado (CO), Utah (UT), California (CA), and South Dakota (SD). According to ONRR records, these eight States represented about 99.7 percent of the flaring reported from oil wells on Federal and Indian lands (including the mixed volumes).

We used the operator data in each state to determine the volume of flaring that would be allowed by the rule and the volume of excess flaring that would have occurred in FY 2015, for each of the specified flaring allowable volumes and capture targets shown in Table 7-6a. We then calculated the volume of excess flaring that would have occurred in FY 2015 with and without this rule in each of the eight top flaring states listed above.

In the analysis for the proposed rule, the BLM constructed several scenarios which represented likely responses of reasonable operators to the proposed flaring limits. This approach used geo-located data to group operators into response categories. These categories included the use of onsite capture (via NGL recovery), curtailment and exemptions in certain situations.

Since this final rule allows operators to average across all their oil operations, even as broadly as statewide, it becomes much more difficult to predict how operators will respond to meet the requirements for flaring reductions. Without this location information or cost data on each individual oil operator and operation, it is difficult to ascertain on which locations operators might focus to reduce flaring. Thus, in order to generate an estimate of the likely costs of reducing these flared volumes in each state, it was necessary to make certain assumptions regarding how operators could respond to the requirements to meet these capture targets.

Table 7-6b below illustrates how the percentage of the flaring controlled in each year is allocated between three avenues. These include Capacity buildout, Curtailment and CNG Trucking. First, we totaled Energy Information Administration data for pipeline outflow capacity for the Southwest and Western region over 2005 to 2015 and did a regression analysis. During this time period, the pipeline outflow capacity increased 2% per year. This growth was used to model projections going forward as the baseline for pipeline capacity.. For this RIA, capacity buildout does not carry with it any costs or benefits from this rule, as it effectively reduces the baseline of the yearly amount of flaring reduction required to be achieved by these requirements. Table 7-6c shows the amount of flaring that will be reduced by this rule as a total volume, incremental volume and an incremental increase in flaring prevented.

Table 7-6b: Percentage of Yearly Flaring Reductions Allocated to each Approach

Year	Flaring Allowable (Mcf/ month) [1]	Capture Target[2]	Capt Tar Vol Flared (Bcf)	Capacity Buildout	Curtailment	CNG Trucking
2017	n/a	0	0	0	0	0
2018	5400	85%	7.80	2%	5%	93%
2019	3600	85%	10.70	4%	10%	86%
2020	1800	90%	17.50	6%	15%	79%
2021	1500	90%	21.30	8%	20%	72%
2022	1200	90%	25.50	10%	15%	75%
2023	1200	95%	27.80	12%	10%	78%
2024	900	95%	34.40	14%	5%	81%
2025	750	95%	39.50	16%	5%	79%
2026	750	98%	40.50	18%	5%	77%

[1] Per well (averaged over all wells in a state by operator)

[2] Percent reduction required of an operators total flaring ABOVE the allowable limit

Curtailment is the first flaring reduction strategy we model for operators to meet each year's requirement for flaring reductions. The schedule for the amount of flaring reduced each year via curtailment is essentially a BLM assumption based on prices and likely operator responses. The cost of curtailment is calculated as the difference between the present value of selling oil and gas in each year versus 10 years later. A rate of 7% is used for the "opportunity cost" of oil and gas deferred. In this circumstance, operators are basically slowing their rate of production by the volume of gas necessary to meet a percentage of the flaring requirements. The associated amount of oil that would need to be deferred as a result of gas curtailment is estimated using the average Gas to Oil Ratio (GOR) for each state individually before the totals are summed together.

The analysis uses the 2016 EIA, Annual Energy Outlook for the projected prices for the modeled years 2017-2026, as well as the 10 future year's prices 2027-2036 for both oil and gas deferred. Oil and gas are valued using the West Texas Intermediate Spot Price and the Spot Price at Henry Hub for oil and gas respectively. The price operators receive for their oil was adjusted by at a rate of 98% to better reflect transportation costs. Additionally, the price operators receive for gas was adjusted by 75% to account for processing costs. Please reference section 7.5 in this RIA for an explanation of the rationale and derivation of these adjustments.

Furthermore, the BLM responded to a public commenter's suggestion that we apply an adder equivalent to 10% of the price of oil in the year of curtailment to the total cost of curtailment, to account for additional costs associated with deferring production. These additional costs could include: (1) fixed costs associated with servicing debt and other capital expenses, (2) potential penalties associated with term contracts that require providing a set volume of oil at set points in time, (3) well productivity decline from deferred production, leading to potential reduction in total recovery over the life of the well, and (4) permanent well shut-ins for wells that would need to defer significant production in order to comply with the rule.

Onsite capture is the second strategy we model for operators to reduce flaring. However, in response to public comments regarding the capacity of NGL recovery to deal with large volumes of flaring, that method of onsite capture is no longer modeled as a means by which operators would likely reduce excess flaring. We model the use of CNG trucking, as it is a low cost method of onsite capture. This analysis assumes that all reduction in excess flaring that is not addressed by the declining baseline due to capacity buildout or reduced by operators curtailing production will be achieved by CNG trucking. The costs for CNG trucking are derived from Carbon Limits (2015) which present operating costs between $0.24 and $1.30 per Mcf produced and capital costs between $400 and $2,000 per Mcf of flowrate (expressed as Mcf/day)[61].

Some commenters suggested that offload points and demand would not be sufficient to absorb increased CNG production resulting from the rule. According to the latest 2016 Annual Energy Outlook, significant growth is projected for natural gas fuel use, such as CNG and LNGs, in the transportation sector. In the 2016 AEO reference case, natural gas use in the transportation sector grows nearly 800% from current levels of 66 tBtus to 591 tBtus in 2040. Moreover, this significant growth in demand is projected to ramp up in the mid 2020s when the full flaring limits of this rulemaking are taking full effect. Therefore, the potential increase in supply of CNG from the rule is complemented by a corresponding uptick in market demand. For comparison, the incremental levels of CNG anticipated in this rulemaking, and demonstrated in RIA table 7-6b, is approximately 31 Bcf (~32 tBtus) relative to the growth of nearly 525 tBtus anticipated for natural gas use in the transportation sector. These CNG levels reflect the RIA assumptions that are illustrative compliance scenarios used in BLM's cost analysis. There is no regulatory requirement that flaring limits be met with this particular technology or at this particular level.

Since gas is captured and sold with CNG trucking[62], operators have cost savings from the sale of this gas, which can offset the cost of the onsite capture.

[61] Carbon Limits (April 2015) *Improving utilization of associated gas in US tight oil fields Appendix* page 4.
[62] The Environmental Assessment that BLM prepared for the final rule also measured the potential number of truck miles travelled and the associated carbon dioxide emissions. These estimated secondary effect impacts of about 5,700 tons per year of CO_2 emissions could pose social costs of up to $300,000 per year, depending on the year, using the model average at the 3% discount rate.

Table 7-6c: Summary of Excess Natural Gas Flared Addressed by the Rule

Year	Flaring Allowable (Mcf/ Well/ Month)	Capture Target - Percent	Flared Volumes from Operations Not Achieving the Capture Target (Bcf)	Total Flaring Prevented (%)[1]	Incre-mental Flared Volumes Addressed (Bcf)	Incre-mental Increase in Flaring Prevented (%)
2017	--	--				
2018	5400	85%	7.8	9.4%	7.8	9.4%
2019	3600	85%	10.7	13.0%	2.9	3.5%
2020	1800	90%	17.5	21.3%	6.8	8.3%
2021	1500	90%	21.3	25.8%	3.8	4.6%
2022	1200	90%	25.5	31.0%	4.2	5.1%
2023	1200	95%	27.8	33.7%	2.2	2.7%
2024	900	95%	34.4	41.7%	6.6	8.0%
2025	750	95%	39.5	48.0%	5.1	6.2%
2026	750	98%	40.5	49.1%	0.9	1.1%

[1] Based on Total Flaring in FY 2015. Data Reported to ONRR of 82.4 Bcf.

3. Results

Table 7-6d presents the total costs of the flaring reductions, cost savings from gas sales in the CNG trucking portion of reductions, as well as the net benefits of the flaring reductions when these cost savings are taken into account.

<u>Final Capture Requirements:</u>

Estimated annual impacts:

- Pose costs of about $0 to $110 million per year (low CNG costs assumed) or $0 to $162 million per year (high CNG costs assumed);
- Pose cost savings of about $0 to $124 million per year;
- Increase natural gas production by 0 – 31 Bcf per year.
- Result in net benefits ranging from -$46 to $39 million per year (low CNG costs assumed) or -$88 to $0 million per year (high CNG costs assumed).

Estimated total impacts over the 10-year evaluation period:

- Pose total costs of about $371 to $615 million (NPV using a 7% discount rate) or $483 to $798 million (NPV using a 3% discount rate);
- Pose total cost savings of about $398 million (NPV using a 7% discount rate) or $520 million (NPV using a 3% discount rate);
- Increase natural gas production by 176 Bcf between 2018 and 2026.
- Result in net benefits ranging from -$217 to $26 million per year (NPV using a 7% discount rate) or -$278 to $37 million per year (NPV using a 3% discount rate).

Table 7-6d: Estimated Annual Costs, Cost Savings and Net Benefits, 2017 – 2026 ($ in millions)

Year	Annual										2017 - 2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Flaring Allowable [1]	n/a	5400	3600	1800	1500	1200	1200	900	750	750		
Capture Target [2]	0	85%	85%	90%	90%	90%	95%	95%	95%	98%		
Estimated Costs ($ in million)												
(Low)	$0.0	$3.9	$8.4	$43.3	$92.4	$110.4	$84.4	$69.2	$89.2	$92.9	$371	$483
(High)	$0.0	$19.8	$28.6	$73.8	$126.1	$152.5	$132.1	$130.5	$157.9	$161.5	$615	$798
Cost Savings from Gas Sales	$0.0	$20.2	$28.6	$47.6	$51.4	$64.5	$79.5	$107.8	$123.9	$120.4	$398	$520
Estimated Net Benefits ($ in million)												
(Low)	$0.0	$16.4	$20.2	$4.2	-$41.0	-$45.9	-$5.0	$38.6	$34.7	$27.4	$26	$37
(High)	$0.0	$0.5	-$0.1	-$26.2	-$74.7	-$88.0	-$52.6	-$22.6	-$33.9	-$41.1	-$217	-$278

[1] Per well (averaged over all wells in a state by operator)

[2] Percent reduction required of an operators total flaring above the allowable limit

B. Flare Measurement Requirements

The rule requires the measurement of flared volumes when gas flaring meets or exceeds 50 Mcf/day for a flare stack or manifold. Operators may comply with this requirement using either a meter or measuring the GOR as specified by the rule.

According to BLM field engineers, a "thermal mass meter" would be sufficient to meet the measurment requirement using a meter and that the cost of a thermal mass meter ranges between $4,000 and $6,000. We received comments that we should also take into account the installation costs of the meter, which one commenter (referencing an EPA manual) suggested to be 1.92 times the cost of the device. If we consider the midpoint of the metering equipment to cost $5,000, then the additional 1.92 surcharge for installation and setup would take the total capital investment to about $9,600.[63] Given the $9,600 capital investment and an estimated $500 per year in operating costs,[64] assuming an equipment life of 10 years, the cost per meter is about $1,867 per year when we annualize the capital costs using a 7% interest rate or $1,625 per year when we annualize the capital costs using a 3% interest rate.

In addition, operators may comply by measuring the GOR using permanent equipment on lease. The costs of these equipment are generally considered to be less than that of the meter, but for the purpose of this analysis, we use the meter costs listed above for calculating costs of the rule.

Many operations are already set up to measure GOR. For example, according to BLM engineers in North Dakota, operations within the state should be set up to measure GOR in order to comply with the state's accounting requirements. For such operations, the operator would be able to comply with the BLM measurement requirements without making any adjustments to their site.

We estimated that operators will need to install meters on about 1,840 existing flare stacks or manifolds and about 184 new flare stacks or manifolds per year. From the total number of leases with oil-well gas flaring where we had well count data (removing ND leases since we understand that operations should already be equipped to measure GOR), we made assumptions about the number of flares required based on the number of wells on a lease. We then scaled the total up to account for the leases where we did not have well count data. The result of this process is an estimated 1,840 required meters for leases with existing flares. For the number new meters required, we assumed 10% of that number would be required in out years.[65]

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[63] We note that the commenter also suggested that an "ultrasonic time-of-flight" meter would be more expensive, costing $20,000 for the device and about $38,000 for the device plus installation. However, as stated, the BLM engineers believe that a less expensive thermal mass meter is more than sufficient.

[64] We note that the same commenter suggested that this operating cost figure was low. However, the commenter did not provide a different cost estimate and, indeed, used the $500 operating cost figure in its cost formulation.

[65] We made a similar assumption in the RIA for the proposed rule and believe that it is still valid.

Table 7-6d: Estimated Number of Flare Measurement Required for Existing Leases

Lease Size Category	Assumed Flare(s) Per Lease	Number of Flare Measurement Equipment Required for Existing Leases	Number of Flare Measurement Equipment Required for Existing Leases (excluding ND)
Single well leases	1	1,036	258
2-4 well leases	1	461	141
5-10 well leases	1.5	255	94
11-20 well leases	2	112	88
21-30 well leases	3	60	51
31-40 well leases	4	92	88
41-50 well leases	5	35	35
51-100 well leases	7.5	120	118
101-200 well leases	15	150	146
201-300 well leases	25	125	125
301-400 well leases	35	-	-
401-500 well leases	45	45	45
Total for matched leases		2,491	1,189
Total adjusted for unmatched lease/units		3,586	1,840

We estimate the following impacts for the flare measurement requirements.

Estimated annual impacts:

- Impact about 1,840 operations in 2017 with that number increasing on an annual basis to an estimated 3,680 operations in 2026;
- Pose compliance costs ranging from $4 – 7 million per year (capital costs annualized with a 7% discount rate) or $3 – 6 million per year (capital costs annualized with a 3% discount rate).

Estimated total impacts over the 10-year evaluation period:

- Pose total costs of $34 – 39 million (NPV using a 7% discount rate) or $40 – 46 million (NPV using a 3% discount rate).

Table 7-6e: Estimated Impacts of Flare Measurement Requirements

	Annual Costs										2017-2026	
YEAR	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Impacted operations												
Existing	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840		
New	184	368	552	736	920	1,104	1,288	1,472	1,656	1,840		
Total operations	2,024	2,208	2,392	2,576	2,760	2,944	3,128	3,312	3,496	3,680		
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)												
Existing	$3.44	$3.44	$3.44	$3.44	$3.44	$3.44	$3.44	$3.44	$3.44	$3.44	$25.8	$30.2
New	$0.34	$0.69	$1.03	$1.37	$1.72	$2.06	$2.40	$2.75	$3.09	$3.44	$12.8	$15.9
Total operations	$3.78	$4.12	$4.47	$4.81	$5.2	$5.5	$5.8	$6.2	$6.5	$6.9	$38.6	$46.0
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)												
Existing	$2.99	$2.99	$2.99	$2.99	$2.99	$2.99	$2.99	$2.99	$2.99	$2.99	$22.5	$26.3
New	$0.30	$0.60	$0.90	$1.20	$1.50	$1.79	$2.09	$2.39	$2.69	$2.99	$11.1	$13.8
Total operations	$3.29	$3.59	$3.89	$4.19	$4.49	$4.78	$5.08	$5.4	$5.7	$6.0	$33.6	$40.1

C. Royalty Provisions

Royalty payments are income to Federal or Tribal governments and costs to the operator or lessee. As such, they are transfer payments that do not affect the total resources available to society. An important, but sometimes difficult, problem in cost estimation is to distinguish between real costs and transfer payments. While transfer payments should not be included in the economic analysis estimates of the benefits and costs of a regulation, they may be important for describing the distributional effects of a regulation.[66]

The rule specifies that gas flared when the operator's capture percentage is below the capture target is royalty-bearing.

The royalty provisions only apply to gas originating from the Federal and Tribal mineral estates, and not to gas originating from non-Federal and non-Indian mineral owners. Therefore, any incremental royalty resulting from this rule would be applied only to natural gas from Federal and Indian leases, and for the Federal and Indian portion of gas produced from leases with mixed owndership.

The royalty implications of this rule should be viewed in concert with the gas capture targets. We expect that operators will manage their portfolios such that they comply with the gas capture requirements and do not conduct excessive flaring.

In section 7A of this analysis, we examine the implications of the gas capture requirements assuming full compliance. Meaning, we examine how operators will respond to those requirements and avoid excessive flaring. Therefore, we do not examine the implications of the royalty provisions here, since that would result in a double-counting of impacts. However, if operators do not fully operate in compliance with the gas capture requirements, then the rule would result in additional royalty payments to Federal and Tribal governments.

7.7 Well Drilling, Completions, and Maintenance

A. Well Drilling

The rule operators to capture, flare, inject or use gas generated during drilling operations.. The operator is allowed to vent the drilling gas if each of the other options are technically infeasible. Operators already control gas from drilling operations as a general matter of safety and operating practice. As such, any costs associated with this requirement are expected to be *de minimis*.

B. Well Completions and Other Well Maintenance (Workovers)

The rule operators to capture, flare, inject or use gas generated during well completions of hydraulically fractured wells, and it deems an operator that is complying with the NSPS Subparts OOOO and OOOOa to be in compliance with the BLM requirements. Subparts OOOO or OOOOa apply to all new hydraulically fractured wells and refractured wells, we do not expect this

[66] OMB Circular A-4 "Regulatory Analysis." September 17, 2003. Available on the web at https://www.whitehouse.gov/omb/circulars_a004_a-4/.

rule to have an additional practical impact and no costs, benefits, or distributional impacts are associated with this requirement.

The final rule does not cover conventional well completions. According to the GHG Inventory, the emissions factors for these activities are very small. In addition, the drilling and completion of conventional wells are now relatively infrequent, with unconventional wells the norm.

7.8 Pneumatic Controllers

The final rule requires operators to replace exisiting high-bleed continuous pneumatic controllers with a controllers whith a bleed rate of 6 standard cubic feet per hour or less. NSPS Subpart OOOO has required that all continuous pneumatic controllers newly installed or modified since August 23, 2011, not be high bleed. . Also, Colorado requires operators to replace high bleed controllers, and Wyoming requires all controllers in the Upper Green River Basin (UGRB) to be low bleed by January 2017.

We estimated the number of impacted controllers by scaling down the EPA's nationwide estimate for the number of continuous high bleed pneumatic controllers (listed in the 2016 GHG Inventory, Annex 3) according to the share of oil and gas production (7.06% and 10.49%, respectively) coming from Federal and Indian lands in 2014. We then removed the potentially impacted controllers in the states of Colorado and Wyoming (Upper Green River Basin wells only).

The average capital cost of a low bleed pneumatic controller is estimated to be $2,594, or $369 per year when the capital costs are annualized with a 7% discount rate over a 10-year period and $304 per year when the capital costs are annualized with a 3% discount rate over a 10-year period (costs escalated to 2012 dollars).[67] A controller in either the petroleum production segment or natural gas production segment is expected to pay for itself on an annual basis over the life of the equipment when the proceeds from additional gas capture are considered.

Savings due to fuel sales were calculated using the differential of whole gas emission factors from high bleed (37.30 scfh) to low bleed (1.39 scfh) as indicated in EPA Subpart W for controllers in the natural gas production segment (40 CFR, Table W-1A), and the differential of whole gas emission factors from high bleed (17.46 scfh) to low bleed (2.75 scfh) as indicated in the 2015 GHG Inventory for controllers in the petroleum production segment.[68] Methane reductions were calculated using the conversion factors: 82.8% methane by volume of natural gas; and 1 Mcf of methane = 0.0208 ton of methane. VOC reductions were calculated using a conversion factor, 1 tpy VOC = 0.278 tpy methane.[69]

[67] Controller costs come from EPA (2011b), p. 5-15. Costs are escalated to 2012 dollars using the CE Indices for 2008 (575.4) and 2012 (584.6). The average controller cost is $2,594 with a range of $532-$8,994.
[68] We note that the CTG analysis assumes the same level of reductions for low bleed pneumatic control replacements in the natural gas and petroleum production sectors. We decided to make the distinction due to reported differences in the reference materials.
[69] Assumptions used in the CTG analysis; values drawn from an EPA 2011 Gas Composition Memorandum.

Requirements

Estimated annual impacts:

- Impact up to about 5,040 existing high-bleed pneumatic controllers;
- Costs of about $2 million per year (capital costs annualized using 7% and 3% discount rates);
- Cost savings of about $3 – 4 million per year;
- Monetized benefits of the reduced methane emissions of $19 – 25 million per year in 2017 – 2026 (using the model average at the 3% discount rate);
- Net benefits of $20 – 27 million per year in 2017 – 2026 (capital costs annualized using 7% and 3% discount rates);
- Increase gas production by 1.05 Bcf per year;
- Reduce methane emissions by about 18,000 tons per year; and
- Reduce VOC emissions by about 65,000 tons per year.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $12 – 14 million (NPV using a 7% discount rate) or $14 – 16 million (NPV using a 3% discount rate);
- Total cost savings of about $26 million (NPV using a 7% discount rate) or $31 million (NPV using a 3% discount rate);
- Total monetized social benefit from the reduction of methane emissions of $165 million (NPV using a 7% discount rate) or $195 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $177 – 179 million (NPV using a 7% discount rate) or $209 – 212 million (NPV using a 3% discount rate).

Table 7-8: Estimated Impacts of Pneumatic Controller Requirements

YEAR	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Impacted Pneumatic Controllers												
Existing controllers - petroleum sector	2,890	2,890	2,890	2,890	2,890	2,890	2,890	2,890	2,890	2,890		
Existing controllers - natural gas sector	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150		
Total controllers	5,040	5,040	5,040	5,040	5,040	5,040	5,040	5,040	5,040	5,040		
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)												
Existing controllers - petroleum sector	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$8.02	$9.37
Existing controllers - natural gas sector	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$5.95	$6.96
Total controllers	$1.86	$1.86	$1.86	$1.86	$1.86	$1.86	$1.86	$1.86	$1.86	$1.86	$14.0	$16.3
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)												
Existing controllers - petroleum sector	$0.88	$0.88	$0.88	$0.88	$0.88	$0.88	$0.88	$0.88	$0.88	$0.88	$6.61	$7.72
Existing controllers - natural gas sector	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$4.91	$5.73
Total controllers	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$11.5	$13.5
Estimated Costs - CO2 Emissions Additions (tons)												
Existing controllers - petroleum sector	14	14	14	14	14	14	14	14	14	14		
Existing controllers - natural gas sector	26	26	26	26	26	26	26	26	26	26		
Total controllers	40	40	40	40	40	40	40	40	40	40		
Value of CO2 Additions ($MM)	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.01	$0.01
Estimated Benefits Cost Savings ($ in million)												
Existing controllers in the petroleum production sector	$0.89	$1.04	$1.16	$1.28	$1.25	$1.25	$1.37	$1.44	$1.48	$1.44	$9.22	$10.9
Existing controllers in the natural gas production sector	$1.62	$1.89	$2.10	$2.32	$2.27	$2.28	$2.48	$2.62	$2.68	$2.61	$16.7	$19.8
Total controllers	$2.51	$2.93	$3.26	$3.60	$3.51	$3.53	$3.85	$4.06	$4.16	$4.05	$25.9	$30.8
Estimated Benefits Incremental Production (Bcf)												
Existing controllers - petroleum sector	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37		
Existing controllers - natural gas sector	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68		
Total controllers	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05		
Estimated Methane Emissions Reductions (tons)												
Existing controllers - petroleum sector	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400		
Existing controllers - natural gas sector	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600		
Total CH4 reductions	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000		
Value of CH4 reductions ($MM)	$19.47	$19.47	$21.24	$21.24	$21.24	$23.01	$23.01	$24.78	$24.78	$24.78	$165	$195
Estimated VOC Emissions Reductions												
Existing controllers - petroleum sector	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100		
Existing controllers - natural gas sector	41,800	41,800	41,800	41,800	41,800	41,800	41,800	41,800	41,800	41,800		
Total VOC reductions	64,900	64,900	64,900	64,900	64,900	64,900	64,900	64,900	64,900	64,900		

YEAR	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Net Benefits												
Net Benefits (Capital Costs Annualized at 7%) ($ MM)	$20	$21	$23	$23	$23	$25	$25	$27	$27	$27	$177	$209
Net Benefits (Capital Costs Annualized at 3%) ($ MM)	$20	$21	$23	$23	$23	$25	$25	$27	$27	$27	$179	$212

7.9 Pneumatic Pumps

The final rule requires the operator to replace a pneumatic diaphragm pump with a zero-emissions pump or route the exhaust gas to capture. Alternatively, if the operator determines that replacing the pump with a zero-emissions pump is not viable because a pneumatic pump is necessary to perform the function, and routing to capture is technically infeasible or unduly costly, the operator may route the exhaust gas to an existing flare or combustor on site, or if there is no flare or combustor on site, the operator may take no further action. The final rule's requirements do not apply to pneumatic piston pumps or to pneumatic pumps that would be subject to NSPS OOOOa if they were a new, modified or reconstructed source.

Commenters asserted that the BLM's own data regarding gas recovery from piston pumps demonstrated that replacing chemical injection pumps is not cost effective. The BLM has further considered coverage of piston pumps and concluded that it does not make sense to require their replacement in this rule given their very small volumes of gas releases. However, some chemical injection pumps are diaphragm pumps rather than piston pumps, and the BLM notes that diaphragm pumps release much larger volumes of gas. Thus, the BLM has limited the provisions on pneumatic pumps to diaphragm pumps used for any purpose.

The NSPS Subpart OOOOa requires operators to control the emissions from new, modified and reconstructed pneumatic diaphragm pumps. Therefore, the BLM's requirements would apply only to pumps that were in use prior to the publication date of the Subpart OOOOa proposal. In addition, Wyoming will regulate pneumatic pumps in the UGRB (Upper Green River Basin) beginning in January 2017. Therefore, we removed these facilities from those impacted by the BLM's rule.

To determine the number of impacted existing pumps, we scaled down the EPA's nationwide estimate for the number of pneumatic pumps (listed in the 2016 GHG Inventory, Annex 3) according to the share of oil and gas production coming from Federal and Indian lands in 2014. We then reduced the number of impacted pumps by 3.29% and 17.46%, or the share of producing oil and gas wells in Wyoming's UGRB, respectively, since those pumps should already be in compliance with the BLM's rule by the time it would be effective. In addition, we made the assumption that half of the remaining pumps are diaphragm pumps (covered by the rule) and the other half are piston pumps (not covered by the rule). This 50/50 split was the same assumption that the EPA made in its analysis of the Subpart OOOOa rule (see TSD at p. 149).

The replacement of gas-assisted pumps may vary in cost and feasibility. We describe the costs and considerations presented in the EPA's CTG (pp. 7-7 – 7-16):

- <u>Converting to a solar powered pump:</u> Total capital cost of $2,227 (in 2012 dollars) and no special operating costs; meaning, a calculated annualized cost of $317 per year using a 7% discount rate. When replacing a diaphragm pump, the EPA estimates emissions reductions of 3.46 tpy of CH_4 and 0.96 tpy of VOC and gas recovery of 197 Mcf/year per device.
- <u>Converting to an electric pump:</u> Total capital cost of $4,647 (in 2012 dollars) to replace a diaphragm pump with annual operating costs estimated to be $293. Therefore, the EPA calculates, using a 7% discount rate, annualized costs of $954 for a diaphragm pump and emissions reductions of 3.46 tpy of CH_4 and 0.96 tpy of VOC and gas recovery of 197 Mcf/year per device.

- Converting to an instrument air system: The cost varies, depending on the size of the compressor, power supply, labor, and equipment. The total capital costs range from about \$6,000 - \$53,000 and operating costs range from about 9,000 - \$65,000. The estimated annualized costs, using a 7% discount rate and an equipment life of 10 years, ranges from about \$10,000 to \$72,000. When replacing a diaphragm pump, the EPA estimates emissions reductions of 3.46 tpy of CH_4 and 0.96 tpy of VOC and gas recovery of 197 Mcf/year per device.
- Routing emissions to an existing combustion device: Total cost of \$5,433 (in 2012 dollars); meaning, a calculated annualized cost of \$774 using a 7% discount rate. Since the gas is combusted, there is no gas savings; however, it would reduce VOC emissions by an estimated 0.91 tpy per diaphragm pump.
- Routing emissions to a new combustion device: Total capital cost of \$34,250 and annual operating costs of \$17,001 (in 2012 dollars); meaning, a calculated annualized cost of \$21,877 using a 7% discount rate. Since the gas is combusted, there is no gas savings; however, it would reduce VOC emissions by an estimated 0.91 tpy per diaphragm pump.
- Routing emissions to an existing vapor recovery unit (VRU): Total cost of \$5,433 (in 2012 dollars); meaning, a calculated annualized cost of \$774 using a 7% discount rate. When routing to a VRU from a diaphragm pump, the EPA estimates emissions reductions of 3.29 tpy of CH_4 and 0.91 tpy of VOC and gas recovery of 187 Mcf/year per device.
- Routing emissions to a new VRU: Total capital cost of \$104,000 and annual operating costs of \$9,932 (in 2012 dollars); meaning, a calculated annualized cost of \$24,755 using a 7% discount rate. When routing to a VRU from a diaphragm pump, the EPA estimates emissions reductions of 3.29 tpy of CH_4 and 0.91 tpy of VOC and gas recovery of 187 Mcf/year per device.

We estimate the engineering costs and emissions reductions for the pneumatic pump requirements using the following data points:

Metric	Value	Explanation
Percent of compliance through replacement pumps	50%	BLM assumption
Annualized cost of compliance through replacement pumps (\$/pump) (using 7% discount rate) (in 2012 dollars)	\$317	EPA's CTG presents costs using a 7% discount rate only, explaining that the difference in costs among the discount rates is minor.
Annualized cost of compliance through replacement pumps (\$/pump) (using 3% discount rate) (in 2012 dollars)	\$261	Calculated using the capital costs in the CTG and its assume 10 year life of equipment.
Methane emissions reductions with replacement pump (tpy/pump)	3.46	EPA's CTG
VOC emissions reductions with replacement pump (tpy/pump)	0.96	EPA's CTG
Gas savings for compliance through replacement pumps (Mcf/yr)	197	EPA's CTG
Percent of compliance through routing to existing combustion device	50%	BLM assumption
Annualized cost of compliance through existing combustion device (\$/pump) (using 7% discount rate) (in 2012 dollars)	\$774	EPA's CTG presents costs using a 7% discount rate only, explaining that the difference in costs among the discount

		rates is minor.
Annualized cost of compliance through existing combustion device ($/pump) (using 3% discount rate) (in 2012 dollars)	$637	Calculated using the capital costs in the CTG and its assume 10 year life of equipment.
Methane emissions reductions with replacement pump (tpy/pump)	3.29	EPA's CTG
VOC emissions reductions with replacement pump (tpy/pump)	0.91	EPA's CTG

Requirements

Estimated annual impacts:

- Impact up to about 7,950 existing diaphragm pumps;
- Costs of about $4 million per year (capital costs annualized using 7% and 3% discount rates);
- Cost savings of about $2 – 3 million per year;
- Monetized benefits of the reduced methane emissions of $29 – 37 million per year in 2017 – 2026 (using the model average at the 3% discount rate);
- Net benefits of $26 – 36 million per year in 2017 – 2026 (capital costs annualized using 7% and 3% discount rates);
- Increase gas production by 0.78 Bcf per year;
- Reduce methane emissions by about 27,000 tons per year; and
- Reduce VOC emissions by about 7,000 tons per year.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $27 – 33 million (NPV using a 7% discount rate) or $31 – 38 million (NPV using a 3% discount rate);
- Total cost savings of about $19 million (NPV using a 7% discount rate) or $23 million (NPV using a 3% discount rate);
- Total monetized social benefit from the reduction of methane emissions of $245 million (NPV using a 7% discount rate) or $289 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $232 – 238 million (NPV using a 7% discount rate) or $274 – 281 million (NPV using a 3% discount rate).

While we estimate that the final rule would impact about 7,950 pneumatic pumps, it is also likely that a portion of these pumps would not be impacted by the rule at all, given that the final rule does not cover temporary pumps, those sites where there is no existing flare device on-site or routing to an existing flare device is technically infeasible, or if compliance would impose costs on the operator such that the operator would cease production and abandon significant oil reserves.

Table 7-9: Estimated Impacts of Pneumatic Pump Requirements

YEAR	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
<u>Impacted Pneumatic Pumps</u>												
Total pumps	7,954	7,954	7,954	7,954	7,954	7,954	7,954	7,954	7,954	7,954		
<u>Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)</u>												
Total pumps	$4.34	$4.34	$4.34	$4.34	$4.34	$4.34	$4.34	$4.34	$4.34	$4.34	$32.6	$38.1
<u>Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)</u>												
Total pumps	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$26.8	$31.4
<u>Estimated Costs - CO2 Emissions Additions (tons)</u>												
Total pumps	60	60	60	60	60	60	60	60	60	60		
Value of CO2 Additions ($MM)	$0.002	$0.002	$0.002	$0.002	$0.002	$0.003	$0.003	$0.003	$0.003	$0.003	$0.02	$0.02
<u>Estimated Benefits Cost Savings ($ in million)</u>												
Total pumps	$1.87	$2.19	$2.43	$2.69	$2.62	$2.64	$2.88	$3.03	$3.11	$3.02	$19.4	$23.0
<u>Estimated Benefits Incremental Production (Bcf)</u>												
Total pumps	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78		
<u>Estimated Methane Emissions Reductions (tons)</u>												
Total CH4 reductions	26,800	26,800	26,800	26,800	26,800	26,800	26,800	26,800	26,800	26,800		
Value of CH4 reductions ($MM)	$29.0	$29.0	$31.6	$31.6	$31.6	$34.2	$34.2	$36.9	$36.9	$36.9	$245	$289
<u>Estimated VOC Emissions Reductions (tons)</u>												
Total VOC reductions	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000		
<u>Net Benefits</u>												
Net Benefits (Capital Costs Annualized at 7%) ($ MM)	$26	$27	$30	$30	$30	$33	$33	$36	$36	$36	$232	$274
Net Benefits (Capital Costs Annualized at 3%) ($ MM)	$27	$28	$30	$31	$31	$33	$34	$36	$36	$36	$238	$281

7.10 Liquids Unloading

The rule requires operators to "minimize vented gas and the need for well venting associated with downhole well maintenance and liquids unloading, consistent with safe operations." For wells equipped with a plunger lift system and/or an automated well control system, minimizing gas venting includes optimizing the system to minimize gas losses to the extent possible consistent with removing liquids. For operators that intend to unload liquids by manual purging, the rule requires that prior to manually purging a well for the first time after the effective date of the rule, the operator must consider other methods for liquids unloading and determine that they are technically infeasible or unduly costly. The operator must use specified best practices when manually purging a well, including staying on site during the event and keeping records, and must notify the BLM when the duration or volume of manual purging exceeds specified thresholds.

We estimate that there are about 8,500 operating gas wells where gas is vented during liquids unloading. Of those wells, we estimate that about 6,950 wells (or 82%) are equipped with plunger lifts, while 1,550 wells (or 18%) are not equipped with plunger lifts. The wells impacted by the best practices requirements would be those 1,550 wells that are not equipped with plunger lifts. In addition to those wells, there is the likelihood that some number of currently producing gas wells will develop liquids accumulation issues in the future, and depending on how the operator removes the liquids from the wellbore, those wells could potentially be impacted by the requirements.

We do not expect that these requirements will have much effect on operators' choice between installing equipment to remove liquids and manual purging. As indicated by the estimate that 82% of wells with venting during liquids unloading already have plunger lifts, many operators already find plunger lifts the most cost-effective way to unload liquids. Nor do we anticipate that the best practices requirement for manual purging will impose any significant additional burden on operators. First, we expect that a prudent operator will remain onsite for the duration of the liquids unloading activity to minimize the unnecessary loss of gas, even in the absence of the requirement. It is in the best interest of the operator to limit the venting of gas to only that amount which is necessary to remove liquids from the wellbore and return the well to production. Second, the available data show that average vent times are relatively short in duration, further supporting the idea that the operator would remain onsite. Data from Shires & Lev-on analysis of API/ANGA (American Petroleum Institute /America's Natural Gas Alliance) survey data, for wells in the Rocky Mountain region, indicate that the average vent times for wells equipped with plunger lifts and wells not equipped with plunger lifts were 0.93 and 1.89 hours per event, respectively. Allen et al. (2013) found, for wells in the Rocky Mountain region, that average vent times for wells not equipped with plunger lifts were 0.73 hours per event.

Nevertheless, we recognize that the requirement to determine the need for manual purging in the first instance and keep records on each manual purging event may tip the balance for some operators towards installing equipment to remove liquids. For purposes of this analysis, we estimate that roughly 25 gas wells per year might develop liquids loading problems and have plunger lifts installed, where the operators would not have installed plunger lifts absent this rule (See Table 7-10a). We developed these estimates assuming about 900 gas well completions per year in the future on Federal and Indian lands[70] and a regional distribution of new wells consistent with the distribution of currently producing gas wells.[71] The estimated number of wells without plunger lifts, by region, are based on data from the 2015 GHG Inventory and 2016 GHG Inventory, Annex 3.

Table 7-10a: Estimated Existing Gas Wells Impacted by the Rule and Calculated Difference in Venting

NEMS REGION	Estimated number of existing wells that would be impacted	Gas venting without plunger lifts (Mcfy/well)	Gas venting with plunger lifts (Mcfy/well)	Difference (Mcfy/well)
Northeast	81	315	166	-149
Midcontinent	54	1380	230	-1150
Rocky Mountain	799	154	2578	2424
Southwest	565	4	97	93
West Coast	4	345	304	-41
Gulf Coast	44	70	301	231
Total	1,547		Weighted Average	1,244

Table 7-10b: Estimated Annual New Gas Wells Completions and Wells that Would Not Have Been Equipped with Plunger Lifts Absent This Rule

Region	Federal Lands		Indian Lands	
	Estimated gas well completions	Estimated wells that would develop liquids loading problems and not have used plunger lifts	Estimated gas well completions	Estimated wells that would develop liquids loading problems and not have used plunger lifts
Northeast	11	1	0	0
Midcontinent	14	1	6	0
Rocky Mtn	722	11	93	1
Southwest	44	9	0	0
West Coast	1	0	0	0
Gulf Coast	10	1	0	0
Total	801	**22**	**99**	**2**

[70] Or that about 30% of future well completions, numbering 3,000 per year, would be on gas wells. These assumptions are consistent with recent trends in completions on Federal and Indian lands.
[71] As of January 1, 2015.

Since the gas wells that encounter liquids accumulation problems generally do so after the well starts going into decline, the timing of any future impacts of this rule is also uncertain. It seems reasonable to conclude that the potentially impacted new wells would develop liquids loading problems many years after the effective date of the rule.

The EPA's Gas Star Program has shown that interventions taken (where plunger lift or other) at the start of a well's decline have been more successful than interventions taken at a later time. The cost of various alternatives uncontrolled liquids unloading are shown in Table 7-10c (in 2012 dollars), but these costs do not include the sale of recovered gas nor the benefits to well productivity. The annualized cost of a plunger lift is estimated to be $1,845 - $2,816 using a 7% discount rate. The annualized cost of a "smart" (or automated) plunger lift is estimated to be $2,471 - $4,520 using a 7% discount rate. Both estimates are based on an equipment life of 10 years.

The costs presented in the table do not include sales from the recovered gas. The Gas STAR Program information indicates that operators installing plunger lifts may experience increases in production from two effects – gas that was vented is now captured and the well's production decline may slow improving productivity. The gains are well specific but it was the experience of the Gas Star partners that the sales of gas from these two effects paid for the plunger lift.

Overall, as was demonstrated by the experiences of the Gas STAR Program partners, we would expect that the boost in well productivity and the sale of recovered gas would pay for the capital costs of the production equipment and installation

Table 7-10c: Annualized Cost of Methods to Unload Liquids

Cost Category	Plunger Lift	"Smart" Plunger Lift	Traditional Beam Lift	Remedial Treatment
Capital and Startup Costs (2012)	$2,274 - $9,094	$6,670 - $21,062	$30,315 - $60,628	$0
Maintenance (2012)($/yr)	$1,521	$1,521	$1,521 - $22,818	$0
Well Treatment (2012)	$0	$0	$15,446+	$15,446+
Electrical (2012)($/yr)	$0	$0	$1,170 - $8,542	$0
Salvage (2012)	$0	$0	($14,042 - $48,561)	$0
Annualized costs (using 3% interest, 10 year equipment life)	$1,788 - 2,587	$2,303 - $3,990	$6,410 - $34,585	$1,811
Annualized costs (using 7% interest, 10 year equipment life)	$1,845 - $2,816	$2,471 - $4,520	$7,207 - $35,277	$2,199

Source: Plunger lift, traditional beam lift, and remedial treatment cost data come from EPA (2006), p. 7. Smart plunger lift cost data come from EPA (2011b), p.11, except for maintenance costs which are assumed to be the same as for a plunger lift. Costs are escalated to 2012 dollars using the CE Indices for 2006 (499.6), 2011 (585.7), and 2012 (584.6). Remedial treatment includes soaping, swabbing, and blowing down. For traditional beam lift, maintenance costs include workovers and assume 1 to 15 workovers per year. The table does not include savings due to fuel sales, although these are possible with with plunger lifts, smart plunger lifts, and beam lifts.

For the purposes of this analysis, we estimate impacts of the liquids unloading requirements, assuming that operators would install smart or automated plunger lifts on the impacted wells, since plunger lifts appear to be the most effective and widely-used method of liquids removal. Our assumptions for this analysis are as follows:

- Impacted wells include 1,550 existing wells and 25 new wells per year;
- Plunger lift costs of about \$3,500 (capital costs annualized using a 7% discount rate) or \$3,150 (capital costs annualized using a 3% discount rate). These amounts are generally the midpoints of the cost ranges for smart plunger lifts listed in the above table;
- Gas savings of 1,244 Mcf per year per well. This volume is the weighted average of the differences in gas venting for wells not equipped with lifts and wells equipped with lifts estimated to be on Federal and Indian lands, by region. The emissions data, by region, come from the GHG Inventory, Annex 3.
- Methane reductions were calculated using the conversion factors: 82.8% methane by volume of natural gas; and 1 Mcf of methane = 0.0208 tons of methane.
- VOC reductions were calculated using a conversion factor, 1 tpy VOC = 0.278 tpy methane.

Estimated annual impacts:

- Impact up to about 1,550 existing wells and about 25 new wells per year;
- Costs of about \$6 million per year (capital costs annualized using a 7% discount rate) or \$5 – 6 million per year (capital costs annualized using a 3% discount rate);
- Cost savings of about \$5 – 9 million per year;
- Monetized benefits of the reduced methane emissions of \$36 – 53 million per year in 2017 – 2026 (using the model average at the 3% discount rate);
- Net benefits of \$36 – 56 million per year in 2017 – 2026 (capital costs annualized using 7% and 3% discount rates);
- Increase gas production by roughly 2 Bcf per year;
- Reduce methane emissions by 34,000 – 39,000 tons per year; and
- Reduce VOC emissions by about 121,000 – 138,000 tons per year.

Estimated total impacts over the 10-year evaluation period:

- Total costs of \$40 – 44 million (NPV using a 7% discount rate) or \$47 – 52 million (NPV using a 3% discount rate);
- Total cost savings of about \$52 million (NPV using a 7% discount rate) or \$62 million (NPV using a 3% discount rate);
- Total monetized social benefit from the reduction of methane emissions of \$329 million (NPV using a 7% discount rate) or \$390 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from \$336 – 341 million (NPV using a 7% discount rate) or \$400 – 405 million (NPV using a 3% discount rate).

The estimates provided likely overestimate the impacts of the rule, because the liquids unloading requirements do not require the operator to install a plunger lift. Also, since the use of plunger lifts is reportedly common among operators, it is possible that operators have already installed lift systems on wells where the installations are feasible and that the remaining wells are those where such installations are infeasible. Accordingly, the operators might not install any additional plunger lifts or realize the amount of gas savings assumed in conducting this analysis.

Table 7-10c: Estimated Impacts of Liquids Unloading Requirements

	Annual										2017-2026	
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Impacted Wells with Liquids Unloading												
Existing wells	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550		
New wells	25	50	75	100	125	150	175	200	225	250		
Total wells	1,575	1,600	1,625	1,650	1,675	1,700	1,725	1,750	1,775	1,800		
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)												
Existing wells	$5.43	$5.43	$5.43	$5.43	$5.43	$5.43	$5.43	$5.43	$5.43	$5.43	$40.8	$47.7
New wells	$0.09	$0.18	$0.26	$0.35	$0.44	$0.53	$0.61	$0.70	$0.79	$0.88	$3.25	$4.04
Total wells	$5.51	$5.60	$5.69	$5.78	$5.86	$5.95	$6.04	$6.13	$6.21	$6.30	$44.0	$51.7
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)												
Existing wells	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$36.7	$42.9
New wells	$0.08	$0.16	$0.24	$0.32	$0.39	$0.47	$0.55	$0.63	$0.71	$0.79	$2.93	$3.64
Total wells	$4.96	$5.04	$5.12	$5.20	$5.28	$5.36	$5.43	$5.51	$5.59	$5.67	$39.6	$46.5
Estimated Costs - CO2 Emissions Additions (tons)												
Existing wells	73	73	73	73	73	73	73	73	73	73		
New wells	1	2	4	5	6	7	8	9	11	12		
Total wells	74	76	77	78	79	80	82	83	84	85		
Value of CO2 Additions ($MM)	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.004	$0.004	$0.004	$0.004	$0.02	$0.03
Estimated Benefits Cost Savings ($ in million)												
Existing controllers in the petroleum production sector	$4.61	$5.40	$5.99	$6.62	$6.46	$6.49	$7.08	$7.46	$7.65	$7.44	$47.7	$56.6
Existing controllers in the natural gas production sector	$0.07	$0.17	$0.29	$0.43	$0.52	$0.63	$0.80	$0.96	$1.11	$1.20	$4.11	$5.16
Total controllers	$4.68	$5.57	$6.28	$7.04	$6.98	$7.12	$7.88	$8.42	$8.76	$8.64	$51.8	$61.8
Estimated Benefits Incremental Production (Bcf)												
Existing wells	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93		
New wells	0.03	0.06	0.09	0.12	0.16	0.19	0.22	0.25	0.28	0.31		
Total wells	1.96	1.99	2.02	2.05	2.08	2.11	2.15	2.18	2.21	2.24		
Estimated Methane Emissions Reductions (tons)												
Existing wells	33,200	33,200	33,200	33,200	33,200	33,200	33,200	33,200	33,200	33,200		
New wells	500	1,100	1,600	2,100	2,700	3,200	3,700	4,300	4,800	5,400		
Total CH4 reductions	33,700	34,300	34,800	35,400	35,900	36,400	37,000	37,500	38,000	38,600		
Value of CH4 reductions ($MM)	$36.4	$37.0	$41.0	$41.6	$42.2	$46.4	$47.1	$51.5	$52.2	$52.9	$329	$390
Estimated VOC Emissions Reductions												
Existing wells	119,000	119,000	119,000	119,000	119,000	119,000	119,000	119,000	119,000	119,000		
New wells	2,000	4,000	6,000	8,000	10,000	12,000	13,000	15,000	17,000	19,000		
Total VOC reductions	121,000	123,000	125,000	127,000	129,000	131,000	132,000	134,000	136,000	138,000		
Net Benefits												
Net Benefits (Capital Costs Annualized at 7%) ($ MM)	$36	$37	$42	$43	$43	$48	$49	$54	$55	$55	$336	$400
Net Benefits (Capital Costs Annualized at 3%) ($ MM)	$36	$38	$42	$43	$44	$48	$50	$54	$55	$56	$341	$405

7.11 Storage Vessels

The rule requires operators either to capture or combust releases from storage vessels with the potential to emit at or above 6 tpy of VOC per vessel (with exceptions to this requirement). We estimate that this would impact 292 storage tanks on Federal and Indian lands.

The EPA's NSPS currently regulates new, modified or reconstructed storage vessels above a 6 tpy of VOC threshold, and the rule would not affect those vessels. Similarly, Colorado regulates new and existing storage tanks above a 6 tpy of VOC threshold, Utah requires the control of tank emissions, and Wyoming regulates new and existing storage tanks in the UGRB beginning in January 2017. As a practical matter, the rule would not require any additional controls on storage vessels in these jurisdictions. In analyzing the impact of the requirements for storage vessels, we used data from the EPA's analysis for the NSPS Subpart OOOO, which considered existing operator activity to comply with state requirements. Although it appear unlikely that the EPA's analysis accounted for Wyoming's regulations concerning the UGRB, we did not remove any additional facilities from this impacts analysis since the number of impacted facilities is already very low.

For cost data, we used data from EPA's analysis supporting the Control Techniques Guidelines for the Oil and Natural Gas Industry, which evaluates controls on existing sources. During the public comment period for the proposed rule, we received comments stating that some existing storage tanks would need to be retrofitted or replaced in order to handle increased pressures driven by the connection to a VRU or combustor. The CTG analysis includes these retrofit costs.

In addition, we received comment that the RIA for the proposed rule underestimated the number of tanks that would be subject to the requirements. In light of the comments, the BLM has clarified that in cases in which multiple storage tanks comprise a tank battery, the VOC threshold applies to the average VOC emissions of each tank within the battery.

We estimated the number of impacted tanks using a similar methodology as used in the EPA's Regulatory Impact Analysis for the NSPS Subpart OOOO. In its analysis, the EPA analyzed a sample of tanks for production volumes and emissions. It categorized each into model tank batteries (some of the data from the EPA's Background Supplemental Technical Support Document for the NSPS is in Table 7-11a). We determined the number of crude oil vessels on Federal and Indian lands as of January 1, 2014 (or the end of 2013), assuming that each well site has one storage vessel. We determined the number of condensate storage vessels on Federal and Indian Lands by multiplying the number of nationwide storage tanks, as indicated by the EPA's Background Supplemental Technical Support Document, by 12%. According to EIA data and BLM's AFMSS data, gas wells on Federal and Indian lands account for about 12% of the nationwide onshore gas wells.

Of that tank population, we determined the number of uncontrolled storage vessels using the EPA's assumption in its Background Supplemental Technical Support Document that 36% of storage vessels (irrespective of model category) would be uncontrolled without the NSPS regulation. We also used the EPA's data for uncontrolled VOC emissions per storage vessel within each model tank battery. See Table 7-11b

Table 7-11a: Baseline Activity Data for Crude Oil and Condensate Storage Vessels

Parameter	Model Crude Oil Tank Batteries			
	A	B	C	D
Percent of vessels in model size range[1]	94.7%	3.95%	0.789%	0.552%
Number of storage vessels[2]	30,765	1,283	256	179
Percent of throughput across tank batteries[1]	26%	7%	15%	51%
Crude oil throughput per storage vessel (bbl/day)[1]	1.96	13.0	130	652
Parameter	**Model Condensate Tank Batteries**			
	E	**F**	**G**	**H**
Percent of vessels in model size range[1]	94.7%	3.95%	0.789%	0.552%
Number of storage vessels[3]	6,729	280	56	39
Percent of throughput across tank batteries[1]	26%	7%	15%	51%
Condensate throughput per storage vessel (bbl/day)[1]	1.6	10.7	106.8	534

[1] EPA (2012). Background Supplemental Technical Support Document for the Final New Source Performance Standards, p. 7-2.
[2] Assumes one storage vessel per well site. Calculated by multiplying the number of producing oil wells on Federal and Indian lands on January 1, 2014 by the percent of the number of vessels in the model size range.
[3] Assumes that about 12% of the condensate storage vessels identified by the EPA in its Background Technical Support Document are on Federal and Indian Lands. We derived the 12% figure by dividing the the number of producing gas wells on Federal and Indian lands on January 1, 2014 (or 58,226 wells) by the number of gas wellsnationwide (less Gulf of Mexico wells) in 2013 (or 485,886 wells) as reported by the EIA (data are available at http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm).

Table 7-11b: Uncontrolled Crude Oil and Condensate Storage Vessels, and Uncontrolled Emissions

Parameter	Model Crude Oil Tank Batteries				
	A	B	C	D	Total
Total number of existing storage vessels	30,765	1,283	256	179	32,484
Number of uncontrolled storage vessels in absence of the rule[1]	11,075	462	92	65	11,694
Uncontrolled VOC emissions from storage vessel at model tank battery (tpy)[2]	0.4	2.8	28	140	171
Total uncontrolled VOC emissions (tpy)	4,430	1,294	2,584	9,038	17,346
Parameter	**Model Condensate Tank Batteries**				
	E	**F**	**G**	**H**	**Total**
Total number of existing storage vessels	6,729	280	56	39	7,105
Number of uncontrolled storage vessels in absence of the rule[1]	2,422	101	20	14	2,558
Uncontrolled VOC emissions from storage vessel at model tank battery (tpy)[2]	3.35	22.3	223	1,117	1,366
Total uncontrolled VOC emissions (tpy)	8,115	2,251	4,502	15,806	30,674

[1] Based on the assumption that 36% of vessels are uncontrolled. This assumption was used in the Background Supplemental Technical Support Document for the Final New Source Performance Standards, p. 7-2.
[2] EPA (2012). Background Supplemental Technical Support Document for the Final New Source Performance Standards, p. 7-2.

Regarding compliance for the affected tanks, the rule requires that with some exceptions, the operator either capture or combust the gas vapors coming from an affected tank. An operator may capture and produce the vapors using a VRU or combust the vapors using a combustor. We believe that when selecting from the compliance options, the operator will consider the availability of equipment, operational feasibility of the control method on the production site, and the availability of infrastructure to produce the gas that would be captured by a VRU. Engineering costs for each option are presented on an annualized basis in Table 7-11c and Table 7-11d.

In cases where the operator choses a combustor, there will be no additional resource recovery to help offset the engineering costs. In cases where the operator installs a VRU to capture the gas, we would expect the additional resource recovery to help offset the engineering costs. For this analysis, we assume that a VRU would return about 296 Mcf per year in additional production (derived from EPA reported annual cost savings of about $1,183 per year at $4 per Mcf). For its analysis of the NSPS Subpart OOOO tank requirements, the EPA assumed that half of the affected facilities would comply by installing a VRU and half would comply by installing a combustor. We used the same assumption in this analysis.

We estimated the potential methane and VOC emissions for the final rule threshold and alternative thresholds, above which a tank would be subject to the control requirements. The reductions were calculated as 95% of the uncontrolled emissions (shown in Table 7-11b).

Table 7-11c: EPA Costs for a Combustor on an Existing Source (Available in CTG at pp. 4-14 – 4-15)

Cost Item[a]	Cost ($2012)
Capital Cost Items	
Combustor[a]	$18,169
Freight and Design[a]	$1,648
Auto Ignitor[a]	$1,648
Surveillance System[b,c,d]	$3,805
Combustor Installation[a]	$6,980
Storage Vessel Retrofit[e]	$68,736
Total Capital Investment	$100,986
Annual Cost Items	
Operating Labor[f]	$5,155
Maintenance Labor[f]	$4,160
Non-Labor Maintenance[a]	$2,197
Pilot Fuel	$1,537
Data Management[c]	$1,057
Capital Recovery (7 percent interest, 15 year equipment life) ($/yr)	$11,088
Total Annual Cost ($/yr)	$25,194

a. Cost data from Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.
b. Surveillance system identifies when pilot is not lit and attempts to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.
c. U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards.* April 2012. EPA Docket ID No.EPA-HQ-OAR-2010-0505-4550.
d. Cost obtained from 2012 NSPS TSD and escalated using the change in GDP: Implicit Price Deflator from 2008 to 2012 (percent)(which was 5.69 percent). Source: FRED GDP: Implicit Price Deflator from Jan 2008 to Jan 2012 (http://research.stlouisfed.org/fred2/series/GDPDEF/#).
e. Retrofit cost obtained from Storage Vessel Retrofit in Table 4-3 (assumed to include vent system and piping to route emissions to the control device).
f. Operating labor consists of labor resources for technical operation of device (130 hr/yr) and supervisory labor (15 percent of technical labor hours). Maintenance labor hours are assumed to be the same as operating labor (130 hr/yr). Labor rates are $32.00/hr (for technical and maintenance labor) and $51.03 (supervisory labor) and were obtained from the U.S. Department of Labor, Bureau of Labor Statistics, Employer Costs for Employee Compensation, December 2012. Labor rates account for total compensation (wages/salaries, insurance, paid leave, retirement and savings, supplemental pay and legally required benefits).

Table 7-11d: EPA Costs for a VRU on an Existing Source (Available in CTG at p. 4-10)

Cost Item[a]	Cost ($2012)
Capital Cost Items	
VRU[a]	$90,000
Freight and Design[a]	$1,648
VRU Installation[a]	$11,154
Storage Vessel Retrofit[b]	$68,736
Total Capital Investment	$171,538
Annual Cost Items	
Maintenance	$9,396
Capital Recovery (7 percent interest, 15 year equipment life) ($/yr)	$18,834
Total Annual Costs w/o Savings ($/yr)	***$28,230***

[a.] Cost data from Initial Economic Impact Analysis (EIA) for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.
[b.] Assumes the storage vessel retrofit cost is 75 percent of the purchased equipment price (assumed to include vent system and piping to route emissions to the control device). Retrofit assumption from Exhibit 6 of the EPA Natural Gas Star Lessons Learned, Installing Vapor Recovery Units on Storage Tanks, October 2006.

For the analysis of compliance costs, we assumed that operators would meet the requirements by using half combustors and half VRUs. Using a 7% discount rate to annualize the capital investment, we assumed per-unit annualized cost of $26,712 (average of $28,230 for a VRU and $25,194 for a combustor). Using a 3% discount rate to annualize the capital investment, we assumed per-unit annualized cost of $23,165 (average of $23,765 for a VRU and $22,565 for a combustor).

In addition to the threshold in the rule of 6 tons per year VOCs, we analyzed two alternative thresholds – 3 tons per year VOCs and 30 tons per year VOCs. While industry commenters recommended increasing the threshold to 10-15 tons per year of VOCs, the BLM did not have data allowing analysis of this alternative. The EPA analysis did include data for a 30 tons per year VOC threshold, so we analyzed that threshold. We can extrapolate that the costs and benefits of a 10-15 ton per year threshold would fall somewhere between the results of the 6 ton per year VOC threshold and the 30 ton per year VOC threshold. A summary of the estimated impacts of the requirements and the alternatives considered are shown in Table 7-11g and with more detail in Tables 7-11h-j.

Tank Requirements – 6 tpy VOC Threshold

Estimated annual impacts:

- Impact about 300 existing storage tanks;
- Costs of about $7 – 8 million per year (capital costs annualized using 7% and 3% discount rates);
- Cost savings of about $0.1 – 0.2 million per year;
- Monetized benefits of the reduced methane emissions of $8 – 10 million per year in 2017 – 2026 (using the model average at the 3% discount rate);
- Net benefits of $0 – 3 million per year in 2017 – 2026 (capital costs annualized using 7% and 3% discount rates);
- Increase gas production by 0.04 Bcf per year;
- Reduce methane emissions by 7,100 tons per year; and
- Reduce VOC emissions by 32,500 tons per year.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $51 – 59 million (NPV using a 7% discount rate) or $60 – 69 million (NPV using a 3% discount rate);
- Total cost savings of about $1 million (NPV using 7% and 3% discount rates);
- Total monetized social benefit from the reduction of methane emissions of $65 million (NPV using a 7% discount rate) or $77 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $7 – 15 million (NPV using a 7% discount rate) or $9 – 18 million (NPV using a 3% discount rate).

Alternative Tank Requirements – 3 tpy VOC Threshold

We estimate the following impacts for the alternative tank requirement (3 tpy VOC threshold).

Estimated annual impacts:

- Impact about 3,200 existing storage tanks;
- Costs of about $74 – 85 million per year (capital costs annualized using 7% and 3% discount rates);
- Cost savings of about $1 – 2 million per year;
- Monetized benefits of the reduced methane emissions of $10 – 12 million per year in 2017 – 2026 (using the model average at the 3% discount rate);
- Net costs of $71 – 74 million per year (capital costs annualized using a 7% discount rate) or $59 – 63 million per year (capital costs annualized using a 3% discount rate);
- Increase gas production by 0.5 Bcf per year;
- Reduce methane emissions by 9,100 tons per year; and
- Reduce VOC emissions by 41,400 tons per year.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $553 – 638 million (NPV using a 7% discount rate) or $647 – 746 million (NPV using a 3% discount rate);
- Total cost savings of about $12 million (NPV using a 7% discount rate) or $14 million (NPV using a 3% discount rate);
- Total monetized social benefit from the reduction of methane emissions of $83 million (NPV using a 7% discount rate) or $98 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net costs ranging from $459 – 543 million (NPV using a 7% discount rate) or $535 – 634 million (NPV using a 3% discount rate).

<u>Alternative Tank Requirements – 30 tpy VOC Threshold</u>

We estimate the following impacts for the alternative tank requirement (30 tpy VOC threshold).

Estimated annual impacts:

- Impact about 100 existing storage tanks;
- Costs of about $2 – 3 million per year (capital costs annualized using 7% and 3% discount rates);
- Cost savings of up to $0.06 million per year;
- Monetized benefits of the reduced methane emissions of $7 – 8 million per year in 2017 – 2026 (using the model average at the 3% discount rate);
- Net benefits of $4 – 6 million per year (capital costs annualized using 7% and 3% discount rates);
- Increase gas production by 0.01 Bcf per year;
- Reduce methane emissions by 6,100 tons per year; and
- Reduce VOC emissions by 27,900 tons per year.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $17 – 20 million (NPV using a 7% discount rate) or $20 – 23 million (NPV using a 3% discount rate);
- Total cost savings of about $0.4 million (NPV using 7% and 3% discount rates);
- Total monetized social benefit from the reduction of methane emissions of $56 million (NPV using a 7% discount rate) or $66 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net costs ranging from $36 – 39 million (NPV using a 7% discount rate) or $43 – 46 million (NPV using a 3% discount rate).

<u>Comparison of Storage Vessel Threshold and Alternatives</u>

The results of this analysis, illustrated in Table 7-11g below, show that among the alternatives examined, both the VOC thresholds of 6 tpy and 30 tpy produce net benefits, and the VOC threshold of 30 tpy has somewhat higher net benefits compared to the VOC threshold of 6 tpy. The BLM selected the threshold of 6 tpy in the final rule rather than 10, 15 or 30 tpy VOC in large part because this threshold is consistent with the Colorado standards for new and existing storage vessels and the EPA OOOO standards for new, modified and reconstructed storage vessels, as well as being less stringent than the Wyoming standards for new and existing storage vessels in the Upper Green River Basin. In addition, the BLM notes that this threshold is exceeded only by the storage vessels with among the highest volumes of releases, and it covers only a very small number of storage vessels compared to the overall inventory. This suggests that this requirement, even with the 6 tpy threshold, is tightly targeted on storage vessels that are outliers in terms of their volumes of lost gas, which supports the BLM's conclusion that gas losses above the 6 tpy VOC threshold is unreasonable and wasteful.

Table 7-11g: Summary of Annual Impacts for Storage Tank Options

Metric	VOC Threshold		
	3 tpy	6 tpy (Final)	30 tpy
Annual Impacts			
Impacted tanks	3,176	292	99
Annual Costs – Engineering Costs ($ in million)	$74 – 85	$7 – 8	$2 – 3
Annual Benefits – Cost Savings ($ in million)	$1 – 2	$0.1 – 0.2	$0.03 – 0.06
Methane Reductions (tons)	9,100	7,100	6,100
Value of Methane Reductions ($ in million)	$10 – 12	$8 – 10	$7 – 8
Incremental Production (Bcf)	0.5	0.04	0.01
VOC Reductions (tons)	41,400	32,500	27,900
Annual Net Benefits ($ in million)	($59 – 74)	$0 – 3	$4 – 6

Table 7-11h: Impacts of a the Requirement to Control Storage Tanks Exceeding 6 tpy of VOC

	Annual										2017-2026	
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Impacted tanks												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	92	92	92	92	92	92	92	92	92	92		
Crude - model D	65	65	65	65	65	65	65	65	65	65		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	101	101	101	101	101	101	101	101	101	101		
Condensate - model G	20	20	20	20	20	20	20	20	20	20		
Condensate - model H	14	14	14	14	14	14	14	14	14	14		
Total tanks	292	292	292	292	292	292	292	292	292	292		
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)												
Crude - model B	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model C	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$18.5	$21.7
Crude - model D	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$13.0	$15.2
Condensate - model E	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model F	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$20.3	$23.7
Condensate - model G	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$4.05	$4.74
Condensate - model H	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$2.84	$3.32
Total costs	$7.80	$7.80	$7.80	$7.80	$7.80	$7.80	$7.80	$7.80	$7.80	$7.80	$58.6	$68.6
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)												
Crude - model B	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model C	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$16.1	$18.8
Crude - model D	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$11.2	$13.1
Condensate - model E	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model F	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$17.6	$20.5
Condensate - model G	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$3.51	$4.11
Condensate - model H	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$2.46	$2.88
Total costs	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$50.9	$59.5
Estimated Costs - CO2 Emissions Additions (tons)												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	1	1	1	1	1	1	1	1	1	1		
Crude - model D	1	1	1	1	1	1	1	1	1	1		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	1	1	1	1	1	1	1	1	1	1		
Condensate - model G	0	0	0	0	0	0	0	0	0	0		
Condensate - model H	0	0	0	0	0	0	0	0	0	0		
Total CO2 Additions	3	3	3	3	3	3	3	3	3	3		
Value of CO2 Additions ($MM)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.001	$0.001
Estimated Benefits Cost Savings ($ in million)												
Crude - model B	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model C	$0.03	$0.04	$0.04	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.34	$0.40
Crude - model D	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.04	$0.04	$0.04	$0.04	$0.24	$0.28

YEAR	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Condensate - model E	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model F	$0.04	$0.04	$0.05	$0.05	$0.05	$0.05	$0.05	$0.06	$0.06	$0.06	$0.37	$0.44
Condensate - model G	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.07	$0.09
Condensate - model H	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.05	$0.06
Total cost savings	$0.10	$0.12	$0.13	$0.15	$0.14	$0.15	$0.16	$0.17	$0.17	$0.17	$1.07	$1.27
Estimated Benefits Incremental Production (Bcf)												
Crude - model B	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Crude - model C	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Crude - model D	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Condensate - model E	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Condensate - model F	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Condensate - model G	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Condensate - model H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Total incremental production	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04		
Estimated Benefits - Methane Emissions Reductions (tons)												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	500	500	500	500	500	500	500	500	500	500		
Crude - model D	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	500	500	500	500	500	500	500	500	500	500		
Condensate - model G	900	900	900	900	900	900	900	900	900	900		
Condensate - model H	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300		
Total CH4 reductions	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100		
Value of CH4 reductions ($MM)	$7.67	$7.67	$8.37	$8.37	$8.37	$9.06	$9.06	$9.76	$9.76	$9.76	$64.9	$76.6
Estimated VOC Emissions Reductions												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500		
Crude - model D	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100		
Condensate - model G	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300		
Condensate - model H	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000		
Total VOC reductions	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500		
Net Benefits												
Net Benefits (Capital Costs Annualized at 7%) ($ MM)	$0	$0	$1	$1	$1	$1	$1	$2	$2	$2	$7	$9
Net Benefits (Capital Costs Annualized at 3%) ($ MM)	$1	$1	$2	$2	$2	$2	$2	$3	$3	$3	$15	$18

Table 7-11i: Impacts of a the Alternative Requirement to Control Storage Tanks Exceeding 3 tpy of VOC

	Annual										2017-2026	
YEAR	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Impacted tanks												
Crude - model B	462	462	462	462	462	462	462	462	462	462		
Crude - model C	92	92	92	92	92	92	92	92	92	92		
Crude - model D	65	65	65	65	65	65	65	65	65	65		
Condensate - model E	2,422	2,422	2,422	2,422	2,422	2,422	2,422	2,422	2,422	2,422		
Condensate - model F	101	101	101	101	101	101	101	101	101	101		
Condensate - model G	20	20	20	20	20	20	20	20	20	20		
Condensate - model H	14	14	14	14	14	14	14	14	14	14		
Total tanks	3,176	3,176	3,176	3,176	3,176	3,176	3,176	3,176	3,176	3,176		
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)												
Crude - model B	$12.3	$12.3	$12.3	$12.3	$12.3	$12.3	$12.3	$12.3	$12.3	$12.3	$92.7	$108
Crude - model C	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$18.5	$21.7
Crude - model D	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$13.0	$15.2
Condensate - model E	$64.7	$64.7	$64.7	$64.7	$64.7	$64.7	$64.7	$64.7	$64.7	$64.7	$486	$569
Condensate - model F	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$20.3	$23.7
Condensate - model G	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$4.05	$4.74
Condensate - model H	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$2.84	$3.32
Total costs	$84.8	$84.8	$84.8	$84.8	$84.8	$84.8	$84.8	$84.8	$84.8	$84.8	$638	$746
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)												
Crude - model B	$10.7	$10.7	$10.7	$10.7	$10.7	$10.7	$10.7	$10.7	$10.7	$10.7	$80.4	$94.0
Crude - model C	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$16.1	$18.8
Crude - model D	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$11.2	$13.1
Condensate - model E	$56.1	$56.1	$56.1	$56.1	$56.1	$56.1	$56.1	$56.1	$56.1	$56.1	$422	$493
Condensate - model F	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$17.6	$20.5
Condensate - model G	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$3.51	$4.11
Condensate - model H	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$2.46	$2.88
Total costs	$73.6	$73.6	$73.6	$73.6	$73.6	$73.6	$73.6	$73.6	$73.6	$73.6	$553	$647
Estimated Costs - CO2 Emissions Additions (tons)												
Crude - model B	5	5	5	5	5	5	5	5	5	5		
Crude - model C	1	1	1	1	1	1	1	1	1	1		
Crude - model D	1	1	1	1	1	1	1	1	1	1		
Condensate - model E	27	27	27	27	27	27	27	27	27	27		
Condensate - model F	1	1	1	1	1	1	1	1	1	1		
Condensate - model G	0	0	0	0	0	0	0	0	0	0		
Condensate - model H	0	0	0	0	0	0	0	0	0	0		
Total CO2 Additions	36	36	36	36	36	36	36	36	36	36		
Value of CO2 Additions ($MM)	$0.001	$0.001	$0.001	$0.001	$0.001	$0.002	$0.002	$0.002	$0.002	$0.002	$0.011	$0.013
Estimated Benefits Cost Savings ($ in million)												
Crude - model B	$0.16	$0.19	$0.21	$0.23	$0.23	$0.23	$0.25	$0.26	$0.27	$0.26	$1.69	$2.01
Crude - model C	$0.03	$0.04	$0.04	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.34	$0.40

YEAR	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Crude - model D	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.04	$0.04	$0.04	$0.04	$0.24	$0.28
Condensate - model E	$0.86	$1.00	$1.11	$1.23	$1.20	$1.21	$1.32	$1.39	$1.42	$1.38	$8.87	$10.5
Condensate - model F	$0.04	$0.04	$0.05	$0.05	$0.05	$0.05	$0.05	$0.06	$0.06	$0.06	$0.37	$0.44
Condensate - model G	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.07	$0.09
Condensate - model H	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.05	$0.06
Total cost savings	$1.12	$1.32	$1.46	$1.61	$1.57	$1.58	$1.73	$1.82	$1.86	$1.81	$11.6	$13.8
Estimated Benefits Incremental Production (Bcf)												
Crude - model B	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07		
Crude - model C	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Crude - model D	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Condensate - model E	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36		
Condensate - model F	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Condensate - model G	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Condensate - model H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Total incremental production	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47		
Estimated Benefits - Methane Emissions Reductions (tons)												
Crude - model B	300	300	300	300	300	300	300	300	300	300		
Crude - model C	500	500	500	500	500	500	500	500	500	500		
Crude - model D	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900		
Condensate - model E	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700		
Condensate - model F	500	500	500	500	500	500	500	500	500	500		
Condensate - model G	900	900	900	900	900	900	900	900	900	900		
Condensate - model H	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300		
Total CH4 reductions	9,100	9,100	9,100	9,100	9,100	9,100	9,100	9,100	9,100	9,100		
Value of CH4 reductions ($MM)	$9.78	$9.78	$10.7	$10.7	$10.7	$11.6	$11.6	$12.4	$12.4	$12.4	$82.8	$97.7
Estimated VOC Emissions Reductions												
Crude - model B	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200		
Crude - model C	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500		
Crude - model D	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600		
Condensate - model E	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700		
Condensate - model F	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100		
Condensate - model G	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300		
Condensate - model H	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000		
Total VOC reductions	41,400	41,400	41,400	41,400	41,400	41,400	41,400	41,400	41,400	41,400		
Net Benefits												
Net Benefits (Capital Costs Annualized at 7%) ($ MM)	-$74	-$74	-$73	-$73	-$73	-$72	-$72	-$71	-$71	-$71	-$543	-$634
Net Benefits (Capital Costs Annualized at 3%) ($ MM)	-$63	-$62	-$61	-$61	-$61	-$60	-$60	-$59	-$59	-$59	-$459	-$535

Table 7-11j: Impacts of a the Alternative Requirement to Control Storage Tanks Exceeding 30 tpy of VOC

	Annual										2017-2026	
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Impacted tanks												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	0	0	0	0	0	0	0	0	0	0		
Crude - model D	65	65	65	65	65	65	65	65	65	65		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	0	0	0	0	0	0	0	0	0	0		
Condensate - model G	20	20	20	20	20	20	20	20	20	20		
Condensate - model H	14	14	14	14	14	14	14	14	14	14		
Total tanks	99	99	99	99	99	99	99	99	99	99		
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)												
Crude - model B	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model C	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model D	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$13.0	$15.2
Condensate - model E	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model F	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model G	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$4.05	$4.74
Condensate - model H	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$2.84	$3.32
Total costs	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$19.9	$23.2
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)												
Crude - model B	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model C	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model D	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$11.2	$13.1
Condensate - model E	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model F	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model G	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$3.51	$4.11
Condensate - model H	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$2.46	$2.88
Total costs	$2.29	$2.29	$2.29	$2.29	$2.29	$2.29	$2.29	$2.29	$2.29	$2.29	$17.2	$20.1
Estimated Costs - CO2 Emissions Additions (tons)												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	0	0	0	0	0	0	0	0	0	0		
Crude - model D	1	1	1	1	1	1	1	1	1	1		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	0	0	0	0	0	0	0	0	0	0		
Condensate - model G	0	0	0	0	0	0	0	0	0	0		
Condensate - model H	0	0	0	0	0	0	0	0	0	0		
Total CO2 Additions	1	1	1	1	1	1	1	1	1	1		
Value of CO2 Additions ($MM)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Estimated Benefits Cost Savings ($ in million)												
Crude - model B	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model C	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

YEAR	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Crude - model D	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.04	$0.04	$0.04	$0.04	$0.24	$0.28
Condensate - model E	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model F	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model G	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.07	$0.09
Condensate - model H	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.05	$0.06
Total cost savings	$0.03	$0.04	$0.05	$0.05	$0.05	$0.05	$0.05	$0.06	$0.06	$0.06	$0.36	$0.43
Estimated Benefits Incremental Production (Bcf)												
Crude - model B	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Crude - model C	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Crude - model D	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Condensate - model E	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Condensate - model F	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Condensate - model G	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Condensate - model H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Total incremental production	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Estimated Benefits - Methane Emissions Reductions (tons)												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	0	0	0	0	0	0	0	0	0	0		
Crude - model D	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	0	0	0	0	0	0	0	0	0	0		
Condensate - model G	900	900	900	900	900	900	900	900	900	900		
Condensate - model H	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300		
Total CH4 reductions	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100		
Value of CH4 reductions ($MM)	$6.59	$6.59	$7.18	$7.18	$7.18	$7.78	$7.78	$8.38	$8.38	$8.38	$55.7	$65.8
Estimated VOC Emissions Reductions												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	0	0	0	0	0	0	0	0	0	0		
Crude - model D	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	0	0	0	0	0	0	0	0	0	0		
Condensate - model G	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300		
Condensate - model H	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000		
Total VOC reductions	27,900	27,900	27,900	27,900	27,900	27,900	27,900	27,900	27,900	27,900		
Net Benefits												
Net Benefits (Capital Costs Annualized at 7%) ($ MM)	$4	$4	$5	$5	$5	$5	$5	$6	$6	$6	$36	$43
Net Benefits (Capital Costs Annualized at 3%) ($ MM)	$4	$4	$5	$5	$5	$6	$6	$6	$6	$6	$39	$46

7.12 Leak Detection and Repair

Sections 3179.301 through 3179.305 require operators to inspect sites and equipment handling gas from a Federal or Indian lease, unit or communitized area, and sites and equipment handling produced water located on a Federal or Indian lease, except that sites containing only wellheads and no other equipment are exempt from these requirements. Operators must inspect using optical gas imaging (OGI) (such as an infra-red camera), a portable analyzer device, assisted by audio, visual, and olfactory (AVO) inspection, or another instrument-based monitoring device or method approved by the BLM. The operator must make the first inspection within one year of the effective date of the rule, and continue with semi-annual inspections (or quarterly for compressor stations), and must fix identified leaks within 30 days, unless there is good cause for a longer period.

Costs of Inspections

To meet these requirements, the operator is likely either to contract with a service provider to conduct the inspections or to conduct the inspections itself. Carbon Limits provides the following estimates of the costs of using a service provider, not including the costs to repair potential leaks or the cost savings from the gas recovered after leaks are repaired:[72]

- $400 per well site;
- $600 per single well batteries;
- $1,200 per multi-well batteries; and
- $2,300 per compressor station.

The Carbon Limits estimates are likely conservative. Rebellion Photonics indicates that its turn-key services are available for $250 per site.[73] One commenter cited a presentation by Jonah Energy at the WCCA 2015 Spring Meeting indicating that their total LDAR program costs were about $99 per inspection in the first year, decreasing to about $29 per inspection in the 5th year.[74] This commenter also cited an ICF model-based estimate of third-party contractor costs, which ranged between $491 - $793 per facility, depending on facility size, as well as a FLIR presentation with information from survey providers suggesting well-pad rates ranging from $300 - $800.[75]

If conducting the inspections itself, the operator would incur costs for any additional equipment and labor required (if the operator already has an LDAR program in place, then it may already have the adequate equipment and labor to meet the BLM LDAR requirements). Optical gas imaging equipment, such as infrared (IR) cameras, has been reported to cost between $85,000 - $124,000 per device (EPA 2014, p. 40).[76] Portable analyzers have been reported to cost $10,800 per device, plus

[72] Carbon Limits 2014, p. 32.

[73] Comments submitted to the BLM on Waste Prevention, Production Subject to Royalties, and Resource Conservation Proposed Rule (proposed February 8, 2016) by Environmental Defense Fund; April 22, 2016; p. 29.

[74] EDF comment, p. 30 citing WCCA Spring Meeting, Jonah Energy Presentation, May 8, 2015, delivered by Paul Ulrich.

[75] EDF Comment, citing ICF Leak Detection and Repair Cost-Effectiveness Analysis (Dec. 4, 2015), and FLIR, OGI Service Provider Survey (March 2016), at 2-3 (Attachment 2).

[76] Reported by Meister 2009 and ICF International 2014, respectively.

additional labor costs associated with the inspections (EPA 2014, p. 39).[77] While optical gas imaging equipment requires a larger capital investment, it can monitor more pieces of equipment per hour, with estimates ranging up to 2,100 components per hour. Portable analyzers require frequent calibration during the inspection, limiting inspection speed, and can inspect about 30-40 components per hour (EPA 2014, pp. 39-40). While the EPA references costs of $10,800 per device, the BLM identified portable detectors that cost as low as $1,000.[78]

Some commenters provided cost estimates for conducting an in-house LDAR program that were significantly higher than those used by BLM in the draft RIA for the proposed rule and also higher than the costs detailed in the CTG. These commenters' cost estimates for a third-party contractor to conduct LDAR inspections were more modest, however, although still somewhat higher than the BLM's estimates. In addition, these commenters suggested that the cost of administering an LDAR program would be slightly higher than the BLM's estimate in the proposed rule. In response to these comments and to new information available in the CTG, the BLM adjusted its cost estimates for conducting an LDAR program to match those in the CTG. We note that the CTG is specific to existing sources and provides a more direct comparison to the type of wellsites that will be covered by the BLM rule.

Costs of Repairs

Once leaks are identified, Carbon Limits finds that the average repair costs range from $56 to $189, depending on the component that is leaking. These repair cost estimates cover the equipment and replacement costs, and do not consider potential cost savings from the sale of the conserved gas.

Table 7-12a: Engineering Costs of Leak Detection Devices, Capital Costs and Annualized Costs Considering 5-year Equipment Life

Device	Capital Costs[1]	Annualized Capital Costs[1], Using Interest Rates of: 3%	7%
IR camera	$124,000	$27,076	$30,242
Portable analyzer	$11,000	$2,402	$2,683
Portable analyzer (midpoint)	$6,000	$1,310	$1,463
Portable detector	$1,000	$218	$244

[1] Capital costs include the equipment costs only, without potential offsets from the sale of recovered gas.

[77] Reported costs from RTI memorandum.
[78] For example, Honeywell PhD6, http://www.honeywellanalytics.com/en/products/PhD6

Table 7-12b: Total Average Leak Rate and Repair Costs by Components at Well Sites

Component	Average Leak Rate (scfm)	Repair Costs			
		Minimum	Average	Median	Maximum
Valve	0.12	$20	$90	$50	$5,500
Connector/ Connection	0.10	$15	$56	$50	$5,000
Regulator	0.12	$20	$189	$125	$1,000
Instrument Controller (Leak only)	0.14	$20	$129	$50	$2,000

Source: Carbon Limits 2014, p. 32

Given the value of the gas conserved by repairing a leak, Carbon Limits concludes that, once identified, the vast majority of leaks are economic to repair at a gas price of $3/Mcf (p. 16). It found that 90% of the leak volume could be repaired with a payback period of less than 1 year.

This finding is supported by experiences within the industry. In its comment letter[79] to the EPA concerning the EPA's white paper on Oil and Natural Gas Sector Leaks, Southwestern Energy indicated that through its LDAR program, the company has identified that leaking components represent less than 0.08% of the total components, and well sites with leaks represent about 20% of the total wells. Southwestern Energy carries out an inspection program that includes annual inspections of its roughly 4,660 wells and 1,730 well pads. It also indicated that 89% of the leaks are repaired upon discovery and 100% of leaks are repaired within 15 days of discovery. It has found that the majority of leaky components were connectors that were easily repairable at no replacement cost and no significant personnel cost. This generally supports the claim that most leaks are easy, and therefore cost effective, to repair.

<u>Uncertainties</u>

Potential leak reductions and volumes of gas conserved are expected to vary depending on the frequency of the inspection program, but the precise relationship between inspection frequency and the expected reduction in the volume of gas lost through leaks is uncertain. In its regulatory analysis for the Colorado AQCC regulations, the Colorado Department of Public Health and Environment used potential leak reduction rates of 40% for annual LDAR inspections, 60% for quarterly LDAR inspections, and 80% for monthly LDAR inspections (CO 2014, p. 49). ICF (2015) used an assumed a leak reduction rate of 60% for its analysis of quarterly LDAR. Carbon Limits (2014) examined potential emissions reductions scenarios for a single survey and determined that potential leak reductions of 94.5% are obtainable if the operator repairs all of the leaks that it identifies. In both the TSD for the NSPS Subpart OOOOa and later the Control Techniques Guidelines for the Oil and Natural Gas Industry, the EPA assumed a 40%, 60%, and 80% emissions reductions for annual, semi-annual, and quarterly inspection frequency programs, respectively. In this analysis, we have

[79] Southwestern Energy 2014, p. 9.

used the same assumptions as EPA and the Colorado Department of Public Health and Environment—a 40% reduction for annual surveys, 60% reduction for semi-annual surveys, and 80% reduction for quarterly surveys.

In addition, there are a number of other significant sources of uncertainty in estimating the benefits of LDAR requirements. First, as discussed in the preamble, recent studies continue to suggest that the GHG Inventory estimates (which the EPA and the BLM use for these analyses) of volumes of methane released through leaks are too low, and perhaps significantly too low. In particular, there is evidence that a substantial proportion of the gas lost through leaks is lost through low frequency high volume events (referred to as losses at "super-emitters"). If a substantially larger volume of gas is actually being lost through leaks than projected, the LDAR requirements will produce substantially larger benefits than estimated here in terms of the volumes of saved gas and avoided methane releases.

Second, we have reason to believe that many operators currently conduct some LDAR activities on oil and gas wells on Federal and Indian leases and would continue to do so absent this rule, although the extent to which they are using optical gas imaging or portable analyzers, and the frequency of their inspections, are unknown.[80] We would not expect incremental costs or benefits for any operators that currently administer an LDAR program that already meets the requirements of the rule.

Third, the final rule exempts sites that contain only a wellhead or wellheads, and no other equipment. We believe that these sites are less likely to lose significant volumes of gas through leaks, compared to other sites, and thus their exclusion should improve the cost-effectiveness of the final rule. We do not have any information, however, on how many sites fall into this category, and thus we do not know how much their exclusion will reduce costs and benefits.

Fourth, this analysis uses inputs developed by the EPA for the Control Technique Guidelines, but we have reason to believe that those inputs may substantially underestimate the benefits of the BLM LDAR requirements. While we have tried to align the BLM LDAR and EPA fugitive emissions programs as much as possible, the programs are different in one significant respect. The BLM LDAR requirements apply to all equipment at a site, while the EPA fugitive emissions requirements do not require inspections of most storage vessels, covers, and closed vent systems, as these are covered under separate comprehensive requirements to control emissions from those sources. Thus, the EPA analysis of the EPA fugitive emissions requirements does not include the reduction of leaks from those sources. The BLM does not apply separate standards to reduce gas losses from those sources, instead requiring that they be inspected under the LDAR requirements. Additionally, the sources not subject to the EPA fugitive emissions requirements but covered by the BLM LDAR requirements—storage vessels, in particular—appear to be a very significant source of lost gas, based on recent studies. As noted in the preamble, Section III., the Lyon et al. study, a helicopter survey of over 8,000 oil and gas wells, reported that over 90 percent of the detected emission incidences were from tanks. Moreover, the Lyon et al. study was only picking up the largest leaks, which could be detected from the air. Similarly, the Colorado State University studies found

[80] For example, EPA stated that it EPA "has found that owners and operators are voluntarily using [Optical Gas Imaging] systems to detect leaks. However, the EPA does not know the extent of these voluntary efforts within the industry on a national level" (EPA 2014, p. 42).

substantial venting at tanks, and the City of Fort Worth study found that thief hatches are the largest source of fugitive emissions.

Conversely, the BLM also received comments during the public comment period and during Executive Order 12866 meetings with OMB indicating that leak rates and leak emissions are lower than the estimates presented by the EPA in its analysis of the NSPS Subpart OOOOa and CTG (again, noting that the EPA figures do not include leaks from storage vessels) and which we used in this analysis. Lower leak rates and lower emissions associated with those leaks would result in lower benefits and net benefits than those estimated for the LDAR requirements.

<u>Analyses of Costs and Benefits</u>

The BLM is aware of several detailed analyses of the costs and gas savings attributable to leak detection requirements: the Carbon Limits study; ICF (2015); and the model plant analyses that EPA used in the OOOOa rulemaking and the development of the CTGs. Here, we review all three analyses, and use the EPA data to produce cost and benefit estimates for the final rule LDAR requirements and to conduct a sensitivity analysis of how those costs and benefits might be affected by requiring different inspection frequencies for certain sources. We note, however, that while the EPA data allows for the most detailed cost estimates and comparisons across different scenarios, the actual results likely understate the benefits of the BLM provisions, and may substantially understate them.

Carbon Limits considered the full costs of an LDAR program, including inspections, repairs, and value of the conserved gas. This study found an average NPV of -$35 per survey on well sites and batteries using a discount rate of 7% and an average NPV of $21 per survey on well sites using a discount rate of 3% (Carbon Limits 2015b). A negative NPV indicates that the average survey posed a net cost to the operator, while a positive NPV indicates that the average survey posed a net savings to the operator. The analysis included observations for 1,764 surveys on wellsites and well batteries that were generally conducted annually or bi-annually (i.e., once every two years).

Carbon Limits (2014) also examined the impacts of increased inspection frequencies using a subset of the data where multiple inspections were conducted on the facilities and for which it could ascertain reliable frequency information. Carbon Limits determined that increasing the LDAR survey frequencies would achieve greater emissions reductions, since leaks can be identified and repaired earlier. However, more frequent inspections would also increase the overall costs, with additional surveys being conducted, and the per-survey benefits would be expected to decline as surveys become more frequent and the number of undiscovered leaks declines.

Carbon Limits (2015b) estimated average NPVs of $2,435, $854, and -$2,401 for annual, semi-annual, and quarterly LDAR programs on well sites and batteries, respectively, using a discount rate of 7%. The researchers estimated average NPVs of $2,666, $1,051 and -$2,220 for annual, semi-annual, and quarterly LDAR programs on well sites and batteries, respectively, using a discount rate of 3%. Again, negative NPVs indicate that the average LDAR program for a well site or battery would pose a net cost to the operator, while a positive NPV indicates cost savings. These data, in Table 7-12c, show that the average costs of LDAR programs on well sites or batteries increases with the inspection frequency. The data also indicate that there could be a difference in the wellsites and well batteries in the full dataset (1,764 survey observations) and those in the subset (62 survey observations). Overall, Carbon Limits (2015b) finds that, requiring semi-annual LDAR inspections for wellsites and well batteries would produce net cost savings to the operator, while a quarterly inspection requirement would pose net costs to the operator.

Other research indicates that LDAR programs produce cost savings for operators at well pads, gathering and processing facilities, even with quarterly inspections. ICF (2015) estimates that an LDAR program with quarterly inspections would result in cost savings of $7,334, $36,768, and $12,214, for well pads, gathering facilities, and processing facilities, respectively. This analysis uses a sales value of $4/Mcf for natural gas. For well pads, ICF estimates annual inspection costs of $1,084 (for all 4 inspections), initial set-up costs of $108, and labor repair costs of $813, which are offset by a value of the recovered gas of $9,340 (p. 2).

Table 7-12c: Carbon Limits - Average NPV for LDAR Programs, by Inspection Frequency

	NPV using a 7% Discount Rate				
		Inspection Frequency[2]			
Site or Facility	**All Surveys[1]**	**Annual**	**Semi-Annual**	**Quarterly**	**Monthly**
Compressor station	$3,376	$2,890	($466)	($7,319)	($34,886)
Wellsite and well battery	($35)	$2,435	$854	($2,401)	($15,521)
	NPV using a 3% Discount Rate				
		Inspection Frequency[2]			
Site or Facility	**All Surveys[1]**	**Annual**	**Semi-Annual**	**Quarterly**	**Monthly**
Compressor station	$3,881	$3,349	($56)	($6,934)	($34,519)
Wellsite and well battery	$21	$2,666	$1,051	($2,220)	($15,351)

Source: Carbon Limits (2015b).
[1] Surveys numbered 1,915, 614, and 1,764 for the compressor station, gas plant, and wellsite and well battery categories, respectively.
[2] NPV should be considered as the cost to implement the LDAR program for the average well with the given inspection frequency (and not the cost per inspection). Surveys numbered 268, 87, and 61 for the compressor station, gas plant, and wellsite and well battery categories, respectively. These surveys were a subset of the larger dataset and included sites and facilities that Carbon Limts was able to ascertain frequency information.

The EPA's Control Techniques Guidelines for the Oil and Natural Gas Industry lists per-wellsite costs and emissions reductions of implementing an LDAR program with annual, semi-annual, and quarterly OGI inspections, as well as LDAR programs using Method 21 inspections of repair criteria. For the most part, the OGI programs, irrespective of frequency, are less costly than the Method 21 programs. Unlike the Carbon Limits and ICF cost estimates, the EPA estimates include not only capital and operations or third-party provider costs, but also additional costs that an operator might encounter when developing and implementing a comprehensive company-wide LDAR program, such as reading the EPA's requirements, developing the monitoring plan, and the costs of repairs, resurveys, documentation, etc. Note also, however, that the EPA emissions reduction and incremental production estimates are understated with respect to the BLM LDAR program, as discussed above.

Table 7-12d: Per Facility Annual Costs and Emissions Reductions for OGI Monitoring and Repair Programs at Wellsites

Frequency of OGI Monitoring and Repair	Well Site Type	Annualized Cost Per Facility ($)[1]		Emissions Reduction Per Facility (tpy)[2]		Incremental Production Per Facility (Mcf)[3]
		7% Discount rate	3% Discount rate	Methane	VOC	
Annual	Gas wellsite	$1,318	$1,299	2.19	0.61	127
	Oil wellsite <300 GOR	$1,318	$1,299	0.50	0.13	29
	Oil wellsite >300 GOR	$1,318	$1,299	1.10	0.30	64
Semi-annual	Gas wellsite	$2,285	$2,265	3.29	0.917	191
	Oil wellsite <300 GOR	$2,285	$2,265	0.74	0.199	43
	Oil wellsite >300 GOR	$2,285	$2,265	1.66	0.451	96
Quarterly	Gas wellsite	$4,220	$4,197	4.38	1.222	254
	Oil wellsite <300 GOR	$4,220	$4,197	0.98	0.265	57
	Oil wellsite >300 GOR	$4,220	$4,197	2.21	0.602	128

[1] Costs do not consider the value of the gas recovered. See CTG, pp. 9-25 – 9-27. The costs using a 3% discount rate are calculated using the EPA data.
[2] Methane Reductions calculated by converting the gas savings, see footnote 3; does not include emissions reductions from leak detection at certain sources covered by the BLM LDAR requirements.
[3] Inferred from the difference in per-facility costs with and without the value of the gas recovered, using a $4/Mcf natural gas price, the price used in the CTG; does not include emissions reductions from leak detection at certain sources covered by the BLM LDAR requirements.

To apply these EPA estimates to the BLM LDAR requirements, we estimated the number of existing wellsites that would be impacted by the rule. First, we identified the number of producing oil and gas wells on Federal and Indian leases. Next we removed the wells in Colorado and Wyoming (in the Upper Green River Basin). Colorado has existing LDAR requirements and Wyoming's new requirements will take effect on January 1, 2017. To calculate the number of impacted wellsites (as opposed to wells), we assumed 2 wells per wellsite, consistent with EPA's assumption based on analysis that it conducted. This yields a total of 36,690 existing wellsites (about 20,660 gas wellsites and 16,030 oil wellsites) that would be impacted by the final rule. The number of impacted wellsites will decline over time, however, as wells are plugged or recompleted , and recompleted and new wells will be covered by the Subpart OOOOa requirements.

Table 7-12e: Derivation of Impacted Well Sites

Metric	Federal		Indian	
	Gas	Oil	Gas	Oil
Number producing wells[1]	52,131	28,510	6,443	5,292
Number of wells in CO and WY (GRB)[1]	15,457	1,357	1,795	388
Number of impacted wells	36,674	27,153	4,648	4,904
Number of wells per site[2]	2	2	2	2
Number of wellsites impacted by the rule	18,337	13,577	2,324	2,452

[1] Data from AFMSS, as of January 1, 2015.

[2] Basis for assumption provided in the TSD for the NSPS Subpart OOOOa rule.

Based on these activity data and the per-facility cost, incremental production (or gas recovery) per wellsite, and emissions reductions data from the CTG, we estimate the impacts of the BLM's final LDAR requirements and alternative approaches that we evaluated. We used the EPA's CTG information, because we believe it represents an approximate picture of what a company would have to undertake to implement an LDAR program, and because it includes detailed data that allow us to conduct more detailed sensitivity analyses of different approaches. Specifically, the CTG data differentiates between potential natural gas releases and potential reductions (or gas savings) from oil wells with a GOR of less than 300 and a GOR of more than 300. The EPA's analysis for the NSPS Subpart OOOOa did not make that distinction. We recognize, however, that if we used per-facility or per-inspection cost data from other sources then that the result would show lower compliance costs. For example, if we used the Carbon Limits cost estimate of $35 per well inspection (7% discount rate), then the total cost of the rule's LDAR requirement would be estimated as $2.6 million per year. In addition, because the CTG emissions reductions data exclude some significant sources covered by the BLM program, as discussed earlier, we believe the benefits estimates presented here are underestimated, and may be significantly underestimated.

We present below the results for the final rule requirements and four alternative approaches: (1) the approach in the final rule of semi-annual inspections for all wells; (2) quarterly inspections for all wells; (3) semi-annual inspections for all wells and annual inspections for wells with a GOR of less than 300; (4) semi-annual inspections with an exemption for wells with a GOR of less than 300; and (5) annual inspections for all wells. We analyzed many other possible approaches, including approaches that reduced inspection frequency for low production wells, but only include here those alternative approaches that we selected as the most viable in reducing waste of gas and releases of methane at a reasonable cost. Thus, we include approaches that maintain most of the benefits produced by semi-annual inspections while reducing costs.

The summary results of the final rule and alternative approaches are shown in Tables 7-12f and 7-12g with the details of each approach provided in the appendix. The cost estimates are in 2012 dollars, and the cost savings estimates use projected natural gas prices, as described in Section 7.5. Estimates are presented as annual impacts from 2017 to 2026.

Final Rule: Semi-Annual Inspections:

Estimated annual impacts:

- Impact up to 36,700 wellsites per year;
- Costs of about $83 – 84 million per year;
- Cost savings of about $12 – 21 million per year*;
- Monetized benefits of the reduced methane emissions of $96 – 123 million per year* (using the model average at the 3% discount rate);
- Net benefits of $25 – 60 million per year* in 2017 – 2026;
- Increase gas production by 5.2 Bcf per year*;
- Reduce methane emissions by 89,500 tons per year*; and
- Reduce VOC emissions by 24,800 tons per year*.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $625 – 630 million (NPV using a 7% discount rate) or $730 – 737 million (NPV using a 3% discount rate);
- Total cost savings of of $128 million (NPV using a 7% discount rate) or $152 million (NPV using a 3% discount rate)*;
- Total monetized social benefit from the reduction of methane emissions of $96 million (NPV using a 7% discount rate) or $123 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $315 – 321 million (NPV using a 7% discount rate) or $380 – 386 million (NPV using a 3% discount rate)*.

Alternative 1.: Quarterly Inspections

Estimated annual impacts:

- Impact up to 36,700 wellsites per year;
- Costs of about $154 – 155 million per year;
- Cost savings of about $16 – 27 million per year*;
- Monetized benefits of the reduced methane emissions of $128 – 163 million per year* (using the model average at the 3% discount rate);
- Net benefits ranging from a net cost of $10 million to a net benefit of $36 million per year*;
- Increase gas production by 6.9 Bcf per year*;
- Reduce methane emissions by 119,000 tons per year*; and
- Reduce VOC emissions by 33,000 tons per year*.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $1.16 billion (NPV using a 7% discount rate) or $1.36 billion (NPV using a 3% discount rate);
- Total cost savings of of $171 million (NPV using a 7% discount rate) or $202 million (NPV using a 3% discount rate)*;

- Total monetized social benefit from the reduction of methane emissions of $128 million (NPV using a 7% discount rate) or $163 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $94 – 97 million (NPV using a 7% discount rate) or $125 – 129 million (NPV using a 3% discount rate)*.

Alternative 2.: Semi-Annual Inspections and Annual Inspections for Oil Wells <300 GOR

Estimated annual impacts:

- Impact up to 36,700 wellsites per year;
- Costs of about $78 million per year;
- Cost savings of about $12 – 20 million per year*;
- Monetized benefits of the reduced methane emissions of $95 – 121 million per year* (using the model average at the 3% discount rate);
- Net benefits of $29 – 64 million per year* in 2017 – 2026;
- Increase gas production by 5.1 Bcf per year*;
- Reduce methane emissions by 88,100 tons per year*; and
- Reduce VOC emissions by 24,400 tons per year*.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $584 – 589 million (NPV using a 7% discount rate) or $683 – 689 million (NPV using a 3% discount rate);
- Total cost savings of of $126 million (NPV using a 7% discount rate) or $150 million (NPV using a 3% discount rate)*;
- Total monetized social benefit from the reduction of methane emissions of $95 million (NPV using a 7% discount rate) or $121 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $342 – 347 million (NPV using a 7% discount rate) or $410 – 417 million (NPV using a 3% discount rate)*.

Alternative 3.: Semi-Annual Inspections and Exempt Oil Wells <300 GOR

Estimated annual impacts:

- Impact up to up to 31,100 wellsites per year;
- Costs of about $70 – 71 million per year;
- Cost savings of about $12 – 20 million per year*;
- Monetized benefits of the reduced methane emissions of $92 – 117 million per year* (using the model average at the 3% discount rate);
- Net benefits of $33 – 66 million per year* in 2017 – 2026;
- Increase gas production by 4.9 Bcf per year*;
- Reduce methane emissions by 85,300 tons per year*; and
- Reduce VOC emissions by 23,600 tons per year*.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $529 – 534 million (NPV using a 7% discount rate) or $618 – 624 million (NPV using a 3% discount rate);
- Total cost savings of of $122 million (NPV using a 7% discount rate) or $145 million (NPV using a 3% discount rate)*;
- Total monetized social benefit from the reduction of methane emissions of $92 million (NPV using a 7% discount rate) or $117 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $367 – 372 million (NPV using a 7% discount rate) or $440 – 446 million (NPV using a 3% discount rate)*.

<u>Alternative 4.: Annual Inspections</u>

Estimated annual impacts:

- Impact up to up to 36,700 wellsites per year;
- Costs of about $48 million per year;
- Cost savings of about $8 – 14 million per year*;
- Monetized benefits of the reduced methane emissions of $64 – 82 million per year* (using the model average at the 3% discount rate);
- Net benefits of $24 – 48 million per year* in 2017 – 2026;
- Increase gas production by 3.5 Bcf per year*;
- Reduce methane emissions by 59,500 tons per year*; and
- Reduce VOC emissions by 16,500 tons per year*.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $358 – 363 million (NPV using a 7% discount rate) or $419 – 425 million (NPV using a 3% discount rate);
- Total cost savings of of $85 million (NPV using a 7% discount rate) or $101 million (NPV using a 3% discount rate)*;
- Total monetized social benefit from the reduction of methane emissions of $64 million (NPV using a 7% discount rate) or $82 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $266 – 271 million (NPV using a 7% discount rate) or $318 – 324 million (NPV using a 3% discount rate)*.

* Including benefits from the full set of sources covered by the BLM LDAR requirements would produce additional cost savings, gas production, methane reductions, monetized benefits, VOC reductions, and net benefits.

Comparison of Final Rule LDAR Requirements and Alternatives

The results of this analysis, illustrated in Table 7-12f, show that, among the regulatory options examined for LDAR, some variation of the semi-annual LDAR inspection requirement would maximize net benefits when compared with alternatives for either quarterly or annual LDAR inspections. The regulatory options for semi-annual LDAR inspections would result in roughly the same general levels of annual net benefits, ranging roughly from $25 - $66 million per year. Given the very substantial uncertainties identified above, and especially the known underestimate of benefits, as well as the relatively small differences in net benefits between the analyzed approaches, we have no assurance that selecting one of the alternative approaches would actually increase net benefits. In addition, the selected approach is conservative with respect to waste reduction and aligns with the EPA requirements for LDAR at new, modified, and reconstructed facilities, reducing the potential for confusion. Finally, the options for approval of new LDAR technology and for operators to design their own alternative LDAR programs with approval from the BLM, should reduce operators' costs, possibly substantially, below those estimated here.

Quarterly Inspections of Compressor Stations

As defined in the rule, a compressor station is a permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station and would require semi-annual inspections and not quarterly inspections.

The rule includes LDAR requirements, including quarterly inspections, on compressor stations that are located on Federal and Indian leases and are at a site that is upstream of or contains the approved point of royalty measurement. Few compressor stations would meet these conditions. In the few instances of compressor stations that are subject to quarterly LDAR inspection under this rule, the operator is likely to incur compliance costs for conducting an LDAR program; however, the gas savings from correcting any potential leaks are likely to offset those costs. The Carbon Limits study referenced earlier describes positive net present values for inspections performed on compressor stations which considering their larger dataset (NPV of $3,376 using a 7% discount rate and $3,881 using a 3% discount rate). However, using a small subset of that data, Carbon Limits modeled net costs for a quarterly inspection requirement (NPV of -$7,319 using a 7% discount rate and -$6,934 using a 3% discount rate).

In its NSPS Subpart OOOOa regulations, the EPA requires quarterly LDAR requirements on compressor stations. With this rule, the BLM will extend a quarterly LDAR requirement to existing compressor stations, which as we previously stated are rare. We do not have data on the number of compressor stations that will be impacted, but we expect that number to be very small. While we do not estimate total costs associated with this provision, we note the potential for per-unit inspection costs on the rare occurrence that such compressor stations exist.

Table 7-12f: Summary of Annual Impacts for LDAR Options and Alternatives, 2017 - 2026 ($ in million)*

Regulatory Options	Annual Costs[1]		Annual Cost Savings		Annual Value of CH4 Reductions	
	Capital Costs Annualized at 7%	Capital Costs Annualized at 3%	Low	High	Low	High
Quarterly Inspections	$155	$154	$16	$27	$128	$163
Semi-Annual Inspections	$84	$83	$12	$21	$96	$123
Semi-Annual Inspections and Annual Inspections for Oil Wells <300 GOR	$78	$78	$12	$20	$95	$121
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$71	$70	$12	$20	$92	$117
Annual Inspections	$48	$48	$8	$14	$64	$82

Regulatory Options	Annual Net Benefits (with Capital Costs Annualized at 7%)		Annual Net Benefits (with Capital Costs Annualized at 3%)		Net Benefits over the 10 Year Period, 2017-2026 (with Capital Costs Annualized at 7%)		Net Benefits over the 10 Year Period, 2017-2026 (with Capital Costs Annualized at 3%)	
	Low	High	Low	High	NPV 7	NPV 3	NPV 7	NPV 3
Quarterly Inspections	-$10	$36	-$10	$36	$94	$125	$97	$129
Semi-Annual Inspections	$25	$60	$26	$60	$315	$380	$321	$386
Semi-Annual Inspections and Annual Inspections for Oil Wells <300 GOR	$29	$63	$30	$64	$342	$410	$347	$417
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$33	$66	$33	$66	$367	$440	$372	$446
Annual Inspections	$24	$47	$25	$48	$266	$318	$271	$324

Regulatory Options	Annual Prod. (Bcf)	Annual Royalty		CH4 Reduced (tpy)	VOC Reduced (tpy)	$/Ton CH4 Reduced	
		Low	High			Capital Costs Annualized at 7%	Capital Costs Annualized at 3%
Quarterly Inspections	6.9	$2.1	$3.4	118,999	33,006	$1,301	$1,297
Semi-Annual Inspections	5.2	$1.5	$2.6	89,452	24,761	$937	$929
Semi-Annual Inspections and Annual Inspections for Oil Wells <300 GOR	5.1	$1.5	$2.5	88,098	24,374	$890	$882
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	4.9	$1.5	$2.5	85,292	23,645	$833	$825
Annual Inspections	3.5	$1.0	$1.7	59,548	16,458	$812	$800

[1] Includes the value of the minor Carbon Dioxide Emissions.

* Including benefits from the full set of sources covered by the BLM LDAR requirements would produce additional cost savings, gas production, methane reductions, monetized benefits, VOC reductions, and net benefits.

7.13 Administrative Burden

The Supporting Statement for the Paperwork Reduction Act describes the administrative burden associated with the rule. In that document, the BLM estimates a net cost burden to the industry and the BLM associated with administrative requirements of the rule of about $5.5 million per year and $1.35 million per year, respectively, in nominal terms. That burden is expected to decrease slightly over time, since the burden associated with most of the exemption requests is for the near term only. That monetized administrative burden is included in the overall costs of the rule that this analysis presents in Section 8.1.

The estimated administrative burden[81] to industry is as follows:

Type of Response	Number of Responses	Hours per Response	Total Hours	Total Wage Cost (at $64.53/hour)
Plan to Minimize Waste of Natural Gas 43 CFR 3162.3-1 Form 3160-3	2,000	8	16,000	1,032,480
Request for Prior Approval for Royalty-Free Uses On-Lease or Off-Lease 43 CFR 3178.5, 3178.7, and 3178.9 Form 3160-5	50	4	200	12,906
Notification to use State- or County-wide Capture Target Calculation 43 CFR 3179.7(c)(ii)	200	1	200	12,906
Request for Approval of Alternative Capture Requirement 43 CFR 3179.7(b) Form 3160-5	50	16	800	51,624
Request for Exemption from Well Completion Requirements 43 CFR 3179.102(c) and (d) Form 3160-5[82]	0	0	0	0
Request for Extension of Royalty-Free Flaring During Initial Production Testing 43 CFR 3179.103 Form 3160-5	500	2	1000	64,530
Request for Extension of Royalty-Free Flaring During Subsequent Well Testing 43 CFR 3179.104 Form 3160-5	5	2	10	645

[81] Estimates for the number of responses and burden hours per response were provided by BLM program staff. In some instances, the estimates may have changed from the RIA for the proposed rule.
[82] We note that the estimated number of responses is zero, because operators already comply with the requirement when they comply with the EPA's NSPS Subpart OOOO and Subpart OOOOa. The line item is retained in this table for Paperwork Reduction Act purposes only.

Type of Response	**Number of Responses**	**Hours per Response**	**Total Hours**	**Total Wage Cost (at $64.53/hour)**
Reporting of Venting or Flaring 43 CFR 3179.105 Form 3160-5	250	2	500	32,265
Notification of Functional Needs for a Pneumatic Controller (43 CFR 3179.201(b)(1)) *Form 3160-5*	10	2	20	1,291
Showing that Cost of Compliance Replacement of Pneumatic Controller Would Cause Cessation of Production and Abandonment of Oil Reserves (43 CFR 3175.201(b)(4) and 3175.201(c)) *Form 3160-5*	50	4	200	12,906
Showing in Support of Replacement of Pneumatic Controller within 3 Years (43 CFR 3179.201(d)) *Form 3160-5*	100	1	100	6,453
Showing that a Pneumatic Diaphragm Pump was Operated on Fewer than 90 Individual Days in the Prior Calendar Year (43 CFR 3179.202(b)(2)) *Form 3160-5*	100	1	100	6,453
NotificationShowing of Functional Needs for a Pneumatic Diaphragm Pump (43 CFR 3179.202(d)) *Form 3160-5*	150	1	150	9,680
Showing that Cost of Compliance Replacement of Pneumatic Diaphragm Pump Would Cause Cessation of Production and Abandonment of Oil Reserves 43 CFR 3175.202(f) and (g) *Form 3160-5*	10	4	40	2,581
Showing in Support of Replacement of Pneumatic Diaphragm Pump within 3 Years 43 CFR 3179.202(h) Form 3160-5	100	1	100	6,453

Type of Response	**Number of Responses**	**Hours per Response**	**Total Hours**	**Total Wage Cost (at $64.53/hour)**
Storage Vessels 43 CFR 3179.203(c) Form 3160-5	50	4	200	12,906
Downhole Well Maintenance and Liquids Unloading — Documentation and Reporting 43 CFR 3179.204(c) and (e) Form 3160-5	5,000	1	5,000	322,650
Downhole Well Maintenance and Liquids Unloading — Notification of Excessive Duration or Volume 43 CFR 3179.204(f) *Form 3160-5*	250	1	250	16,133
Leak Detection — Compliance with EPA Regulations 43 CFR 3179.301(e) Form 3160-5	50	4	200	12,906
Leak Detection — Request to Use an Alternative Monitoring Device and Protocol 43 CFR 3179.302(c) Form 3160-5	5	40	200	12,906
Leak Detection — Operator Request to Use an Alternative Leak Detection Program 43 CFR 3179.303(b) Form 3160-5	20	40	800	51,624
Leak Detection — Operator Request for Exemption Allowing Use of an Alternative Leak-Detection Program that Does Not Meet Specified 43 CFR 3179.303(d) Form 3160-5	150	40	3,000	387,180
Leak Detection — Notification of Delay in Repairing Leaks 43 CFR 3179.304(a) Form 3160-5	100	1	100	6,453
Leak Detection — Inspection Recordkeeping 43 CFR 3179.305	52,000	.25	13,000	838,890
Leak Detection — Inspection Annual Reporting 43 CFR 3179.305(b) Form 3160-5	2,000	20	40,000	2,581,200

Type of Response	Number of Responses	Hours per Response	Total Hours	Total Wage Cost (at $64.53/hour)
Totals	**63,200**	**-**	**85,170**	**5,496,020**

The estimated administrative burden[83] to the BLM is as follows:

Type of Response	**Number of Responses**	**Hours per Response**	**Total Hours**	**Total Wage Cost (at $44.73/ hour)**
Plan to Minimize Waste of Natural Gas 43 CFR 3162.3-1 Form 3160-3	2,000	2	4,000	178,920
Request for Prior Approval for Royalty-Free Uses On-Lease or Off-Lease 43 CFR 3178.5, 3178.7, and 3178.9 Form 3160-5	50	4	200	8,946
Notification to use State- or County-wide Capture Target Calculation 43 CFR 3179.7(c)(ii)	200	0.25 (15 minutes)	50	2,237
Request for Approval of Alternative Capture Requirement 43 CFR 3179.7(b) Form 3160-5	50	8	400	17,892
Request for Exemption from Well Completion Requirements 43 CFR 3179.102(c) and (d) Form 3160-5	0	0	0	0
Request for Extension of Royalty-Free Flaring During Initial Production Testing 43 CFR 3179.103 Form 3160-5	500	1	500	22,365
Request for Extension of Royalty-Free Flaring During Subsequent Well Testing 43 CFR 3179.104 Form 3160-5	5	1	5	224

[83] Estimates for the number of responses and burden hours per response were provided by BLM program staff. In some instances, the estimates may have changed from the RIA for the proposed rule.

Reporting of Venting or Flaring 43 CFR 3179.105 Form 3160-5	250	2	500	22,365
Pneumatic Controllers – Notification of Functional Need 43 CFR 3179.201(b)(1) Form 3160-5	10	0.25 (15 minutes)	3	112
Pneumatic Controllers – Request for Exemption of Replacement Requirements 43 CFR 3179.201(b)(4) Form 3160-5	50	3	150	6,710
Pneumatic Controllers – Notification of Extension of Replacement Requirements 43 CFR 3179.201(d) Form 3160-5	100	0.25 (15 minutes)	25	1,118
Pneumatic Pump– Notification of Temporary Pump 43 CFR 3179.202(b)(2) Form 3160-5	100	0.25 (15 minutes)	25	1,118
Pneumatic Pump – Notification of Functional Need 43 CFR 3179.202(d) Form 3160-5	150	2	300	13,419
Pneumatic Pump – Request for Exemption of Replacement Requirements 43 CFR 3179.202(f) Form 3160-5	10	3	30	1,342
Showing in Support of Replacement of Pneumatic Diaphragm Pump within 3 Years 43 CFR 3179.202(h) Form 3160-5	100	0.25 (15 minutes)	25	1,118
Storage Vessels 43 CFR 3179.203(c) Form 3160-5	50	3	150	6,710
Downhole Well Maintenance and Liquids Unloading — Documentation and Reporting 43 CFR 3179.204(c) and (e) Form 3160-5	5,000	0.167 (10 minutes)	833	37,275
Downhole Well Maintenance and Liquids Unloading — Notification of Excessive Duration or Volume 43 CFR 3179.204(f) Form 3160-5	250	0.5 (30 minutes)	125	5,591

Leak Detection — Compliance with EPA Regulations 43 CFR 3179.301(i)(3) Form 3160-5	50	0.25 (15 minutes)	13	559
Leak Detection — Request to Use an Alternative Monitoring Device and Protocol 43 CFR 3179.302(c) Form 3160-5	5	160	800	35,784
Leak Detection — Operator Request to Use an Alternative Leak Detection Program 43 CFR 3179.303(b) Form 3160-5	20	80	1,600	71,568
Leak Detection — Operator Request for Exemption Allowing Use of an Alternative Leak-Detection Program that Does Not Meet Specified 43 CFR 3179.303(d) Form 3160-5	150	80	12,000	536,760
Leak Detection — Notification of Delay in Repairing Leaks 43 CFR 3179.304(a) Form 3160-5	100	0.5 (30 minutes)	50	2,237
Leak Detection — Inspection Recordkeeping 43 CFR 3179.305(a)	52,000	0.083 (5 minutes)	4,333	193,830
Leak Detection — Inspection Annual Reporting 43 CFR 3179.305(b) Form 3160-5	2,000	2	4,000	178,920
Totals	**63,200**	**-**	**30,117**	**1,347,119**

7.14 Royalty Free Use of Production

The requirements in 43 CFR 3168 would clarify the parameters for an operator to use production on lease without that production incurring royalty. The requirements would ensure that the royalty free use of production applies only to uses on the lease, unit, or CA. The changes do not prohibit the operator from using the production off the lease, unit, or CA; however, they would specify royalty on that production.

The requirements are consistent with current BLM policy, found in NTL-4A. While there may be a few instances where the BLM has approved the royalty free use of production off of the lease, unit, or CA, the vast majority of existing approvals are expected to be consistent with the requirements. As such, any impacts of the requirements are expected to be *de minimis*.

7.15 Change of Royalty Rate Language

The GAO originally expressed concerns about the adequacy of the BLM's onshore oil and gas fiscal system in 2007 and 2008, with two reports addressing the United States' Federal oil and gas fiscal system. The first report compared oil and gas revenues received by the United States Government to the revenues that foreign governments receive from the development of their public oil and gas resources.[84] That report concluded that the United States' oil and gas "government take" is among the lowest in the world.[85]

The second report, which focused on whether the Department of the Interior receives a fair return on the resources it manages, cited the "lack of price flexibility in royalty rates," and the "inability to change fiscal terms on existing leases," in support of a finding that the United States could be foregoing significant revenue from the production of onshore Federal oil and gas resources.[86] The GAO recommended that the U.S. Congress direct the Secretary of the Interior to convene an independent panel to review the Federal oil and gas fiscal system and establish procedures for periodic evaluation of the system going forward.

In response to the GAO's findings, the BLM and the Bureau of Ocean Energy Management (BOEM) contracted with the consulting firm Information Handling Services' Cambridge Energy Research Associates (IHS CERA) for a comparative assessment of the fiscal systems applicable to certain Federal, State, private, and foreign oil and gas resources ("IHS CERA Study").[87] The IHS CERA Study identified four factors amenable to comparison: government take, internal rate of return, profit-investment ratio, and progressivity.[88] The study also considered measures of revenue risk and fiscal system stability. Overall, the study found that, as of the time of the study, the Federal

[84] GAO, Oil and Gas Royalties: A Comparison of the Share of Revenue Received from Oil and Gas Production by the Federal Government and Other Resource Owners, GAO 07 676R, May 2007.
[85] GAO-07-676R at 2.
[86] GAO-08-691 at 6.
[87] Agalliu, I. (2011). Comparative Assessment of the Federal Oil and Gas Fiscal Systems. U.S. Department of the Interior, Bureau of Ocean Energy Management, OCS Study, available at http://www.blm.gov/wo/st/en/prog/energy/comparative_assessment.html
[88] A "progressive" royalty rate refers to a rate that increases with the quantity or price of the resource being sold.

Government's fiscal system and overall government take, in aggregate, were in the mainstream both nationally and internationally. Even within specific geographic regions, however, it estimated a wide range of government take, and its authors acknowledged that government take varies with a variety of factors, including commodity prices, reserve size, reservoir characteristics, resource location, and water depth. As a result, the study's authors favored a sliding-scale royalty system, because a sliding-scale royalty is more progressive than a fixed-rate royalty, and can also respond to changes in commodity market conditions.

In addition to the IHS CERA Study, the BLM also reviewed a separate private study conducted by the Van Meurs Corporation.[89] The study looked at a range of jurisdictions and regions across North America and provided a comparison of the oil and gas fiscal systems on Federal, State, and private lands throughout the United States and the provinces in Canada. It suggested that as of 2011, government take on Federal lands was generally lower than the corresponding take on State or private lands. The study also made several recommendations to State and Federal Governments in the United States and Canada, including that governments apply different fiscal terms to oil leases than to gas leases, based on the differing prices of oil and gas at the time the report was published.

In April 2015, the BLM published an Advanced Notice of Proposed Rulemaking (ANPR) to solicit public comments and suggestions that might be used to update the BLM's regulations related to royalty rates, annual rental payments, minimum acceptable bids, and other financial measures.[90] In preparing the ANPR, the BLM gathered information about royalty rates charged by States and private mineral holders for oil and gas activities on State and private lands, and compared those rates to rates charged for federal oil and gas resources. The data showed that the royalty rates charged on private and State lands range from 12.5 to 25 percent, and that the average rate assessed exceeds 16.67 percent.[91] The BLM received over 80,000 comments on the ANPR. The preamble of this rule discusses the content of those comments.

This rule would change 43 CFR 3100 to conform to the corresponding statutory text, which provides the BLM with flexibility to increase the royalty rate on Federal leases obtained competitively. However, the rule would not, in itself, change the royalty rate.

As stated in the preamble, the BLM does not currently anticipate increasing the base royalty rate for new competitively issued leases above 12.5 percent. Before making such a change, the BLM would announce the change at least 60 days prior to the effective date, and would provide at least 30 days for public comment. Any proposed change would be based on an assessment of comparable onshore State and private fiscal systems, and an assessment of the proposed impacts of the change on Federal revenue, on production from Federal lands, and on demand for Federal oil and gas leases relative to State and private leases. The BLM would make its assessments of these various factors available for public review during the comment period. Since the timing and the nature of any potential changes are both speculative, this analysis does not estimate the impacts of this change to the regulatory language.

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[89] PFC Energy, Van Meurs Corporation, and Rodgers Oil & Gas Consulting (2011). World Rating of Oil and Gas Terms: Volume 1—Rating of North American Terms for Oil and Gas Wells with a Special Report on Shale Plays.
[90] 80 FR 22148.
[91] 80 FR at 22151-52.

8. Summary Of Impacts

8.1 Costs Of The Rule

The estimated costs of the rule include: (1) private costs that would be assumed by the industry and (2) public costs to society from *de minimis* amounts of carbon dioxide additions (coming from the combustion of natural gas that would have otherwise been vented). The costs shown below do not include savings from the recovery of natural gas or natural gas liquids. Instead, those savings are included in the benefits section.

The estimated compliance costs are as follows (see Table 8-1).

Annual Impacts:

- Costs range from \$114 – \$279 million per year (using a 7% discount rate to annualize capital costs) or \$110 – \$275 million per year (using a 3% discount rate to annualize capital costs).

Impacts over the 10-year evaluation period:

- Total costs range from \$1.2 – 1.5 billion (NPV using a 7% discount rate) or \$1.5 – 1.8 billion (NPV using a 3% discount rate).

After reviewing the equirements, we estimate that the largest compliance costs are associated with the LDAR and capture target requirements. Since we are unable to account for existing LDAR programs, these costs are likely to overstate the true costs of the rule.

We have attempted to estimate the upper bound of potential costs, and seek comment on factors not fully accounted for that may warrant a higher estimate. Where data are available, the impacts account for activities already conducted by operators as a result of state or other federal regulations. Due to the lack of available data, these estimates may not account for voluntary actions already undertaken by operators. To the extent that operators are already in compliance with the requirements, the estimated impacts will overstate the actual impacts of the rule.

Table 8-1: Estimated Annual Total Costs ($ in million)

Estimated Costs* - Capital Costs Annualized Using a 7% Discount Rate												
	Annual										2017-2026	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$4 - 20	$8 - 29	$43 - 74	$92 - 126	$110 - 153	$84 - 132	$69 - 130	$89 - 158	$93 - 161	$371 - 615	$483 - 798
Flare Measurement	$4	$4	$4	$5	$5	$5	$6	$6	$7	$7	$39	$46
Pnumatic Controllers	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$14	$16
Pneumatic Pumps	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$33	$38
Liquids Unloading	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$44	$52
Storage Tanks	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$59	$69
LDAR	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$630	$737
Administrative Burden	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$51	$60
Total	$114	$118 - 134	$123 - 143	$159 - 189	$208 - 242	$227 - 269	$201 - 249	$186 - 247	$207 - 275	$211 - 279	$1,241 - 1,484	$1,500 - 1,816
Estimated Costs* - Capital Costs Annualized Using a 3% Discount Rate												
	Annual										2017-2026	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$4 - 20	$8 - 29	$43 - 74	$92 - 126	$110 - 153	$84 - 132	$69 - 130	$89 - 158	$93 - 161	$371 - 615	$483 - 798
Flare Measurement	$3	$4	$4	$4	$4	$5	$5	$5	$6	$6	$34	$40
Pnumatic Controllers	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$12	$13
Pneumatic Pumps	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$27	$31
Liquids Unloading	$5	$5	$5	$5	$5	$5	$5	$6	$6	$6	$40	$47
Storage Tanks	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$51	$59
LDAR	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$625	$730
Administrative Burden	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$51	$60
Total	$110	$114 - 130	$123 - 143	$155 - 185	$204 - 238	$222 - 264	$197 - 244	$182 - 243	$202 - 271	$206 - 275	$1,210 - 1,453	$1,464 - 1,780

* Includes the monetized value of the CO_2 additions which are relatively minor (less than $30,000 during any given year).

8.2 Benefits Of The Rule

The quantified benefits of the rule include: (1) private cost savings (from the sale of recovered natural gas and natural gas liquids) that would benefit the industry and (2) public benefits to society from reductions in methane emissions. Reductions in the venting and flaring of gas would have environmental benefits by reducing the amount of greenhouse gas released into the atmosphere. Methane is a greenhouse gas and the release of methane to the atmosphere has climate impacts, generally discussed in terms of its 100-year global warming potential. While methane has a shorter atmospheric lifetime than carbon dioxide, it is 25 times more efficient at trapping heat in the atmosphere relative to carbon dioxide.[92]

After reviewing the requirements, we estimate that the largest benefits are associated with the LDAR requirements. However, as mentioned in the summary of costs, since we are unable to account for existing LDAR programs, these benefits are likely to overstate the true benefits of the rule. We also estimate large relative benefits from the pneumatic controller and flaring requirements.

The estimated benefits are as follows (see Table 8.2a).

Annual Impacts:

- Benefits from costs savings range from \$20 – 157 million per year;
- Benefits from reduced methane emissions range from \$189 – 247 million per year, using model averages of the social cost of methane with a 3% discount rate.
- Total benefits range from \$209 – 403 million per year, using model averages of the social cost of methane with a 3% discount rate.

Impacts over the 10-year evaluation period:

- Total costs savings of \$603 million (NPV using a 7% discount rate) or \$764 million (NPV using a 3% discount rate);
- Total monetized social benefit from the reduction of methane emissions of \$1.6 billion (NPV using a 7% discount rate) or \$1.9 billion (NPV using a 3% discount rate), using model averages of the social cost of methane with a 3% discount rate;
- Total benefits \$2.2 billion (NPV using a 7% discount rate) or \$2.7 billion (NPV using a 3% discount rate);

We estimate that the rule would reduce methane emissions by 175,000 – 180,000 tons per year and 1.8 million tons over 10 years (see Table 8-2b). We monetized these reductions and included them in the monetized benefits. We estimate that the rule would reduce VOC emissions by 250,000 – 267,000 tons per year and 2.6 million tons over 10 years (see Table 8-2c). The VOC emissions reductions are not monetized.

Overall, we predict the rule will reduce methane emissions by 35% from the 2014 estimates and reduce the flaring of associated gas by 49%, when the capture requirements are fully phased in.

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[92] Shelanski, H. and Shambaugh, J. "Strengthening tools to account for damages from greenhouse gas emissions in regulatory analysis." Web blog post. *Blog.* The White House, August 26, 2016. Web. Accessed on November 4, 2016.

Again, we believe that the estimated benefits from cost savings represent the likely upper bound of potential benefits. Where data are available, the impacts account for activities already conducted by operators as a result of state or other federal regulations. Due to the lack of available data, it may not account for voluntary actions already undertaken by operators. To the extent that operators are already in compliance with the requirements, the estimated impacts will overstate the actual impacts of the rule.

Table 8-2a: Estimated Annual Total Benefits ($ in million)

	Requirement	Annual 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026 NPV 7	NPV 3
Estimated Benefits - Cost Savings ($ in million)	Capture Target Req.	$0	$20	$29	$48	$51	$64	$79	$108	$124	$120	$398	$520
	Pnumatic Controllers	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$9	$11
	Pneumatic Pumps	$2	$2	$2	$3	$3	$3	$3	$3	$3	$3	$19	$23
	Liquids Unloading	$5	$5	$6	$7	$6	$6	$7	$7	$8	$7	$48	$57
	Storage Tanks	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1
	LDAR	$12	$15	$16	$18	$17	$17	$19	$20	$21	$20	$128	$152
	Total	$20	$44	$54	$76	$79	$92	$110	$140	$157	$152	$603	$764

	Requirement	Annual 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026 NPV 7	NPV 3
Estimated Benefits - Value of Methane Reductions	Capture Target Req.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Flare Measurement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Pnumatic Controllers	$19	$19	$21	$21	$21	$23	$23	$25	$25	$25	$165	$195
	Pneumatic Pumps	$29	$29	$32	$32	$32	$34	$34	$37	$37	$37	$245	$289
	Liquids Unloading	$36	$37	$41	$42	$42	$46	$47	$51	$52	$53	$329	$390
	Storage Tanks	$8	$8	$8	$8	$8	$9	$9	$10	$10	$10	$65	$77
	LDAR	$96	$96	$105	$105	$105	$114	$114	$123	$123	$123	$817	$964
	Total	$189	$190	$207	$208	$209	$227	$227	$246	$246	$247	$1,620	$1,914

	Requirement	Annual 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026 NPV 7	NPV 3
Total Estimated Benefits	Capture Target Req.	$0	$20	$29	$48	$51	$64	$79	$108	$124	$120	$398	$520
	Flare Measurement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Pnumatic Controllers	$20	$21	$22	$23	$22	$24	$24	$26	$26	$26	$174	$205
	Pneumatic Pumps	$31	$31	$34	$34	$34	$37	$37	$40	$40	$40	$265	$312
	Liquids Unloading	$41	$42	$47	$48	$49	$53	$54	$59	$60	$60	$376	$446
	Storage Tanks	$8	$8	$9	$9	$9	$9	$9	$10	$10	$10	$66	$78
	LDAR	$109	$111	$121	$123	$123	$131	$133	$143	$143	$143	$945	$1,116
	Total	$209	$233	$262	$284	$288	$319	$337	$386	$403	$400	$2,224	$2,678

Table 8-2b: Estimated Annual Methane Reductions (tons)

Requirement	Annual										10-Years
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026
Capture Target Req.	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE
Pnumatic Controllers	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	180,000
Pneumatic Pumps	26,800	26,800	26,800	26,800	26,800	26,800	26,800	26,800	26,800	26,800	268,000
Liquids Unloading	33,700	34,300	34,800	35,400	35,900	36,400	37,000	37,500	38,000	38,600	361,600
Storage Tanks	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	71,000
LDAR	89,500	89,500	89,500	89,500	89,500	89,500	89,500	89,500	89,500	89,500	895,000
Total	175,000	176,000	176,000	177,000	177,000	178,000	178,000	179,000	179,000	180,000	1,775,000

Table 8-2c: Estimated VOC Reductions (tons)

Requirement	Annual										10-Years
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026
Capture Target Req.	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE
Pnumatic Controllers	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000	649,000
Pneumatic Pumps	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	70,000
Liquids Unloading	121,000	123,000	125,000	127,000	129,000	131,000	132,000	134,000	136,000	138,000	1,296,000
Storage Tanks	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	325,000
LDAR	24,800	24,800	24,800	24,800	24,800	24,800	24,800	24,800	24,800	24,800	248,000
Total	250,000	252,000	254,000	256,000	258,000	260,000	261,000	263,000	265,000	267,000	2,586,000

8.3 Net Benefits

The net benefits are calculated as the estimated benefits minus the estimated costs of the rule. After reviewing the requirements, we estimate that the largest net benefits are associated with the pneumatic controller, liquids unloading, and LDAR requirements.

The estimated net benefits are as follows[93] (see Table 8-3a).

Annual Impacts:

- Net benefits range from $46 – $199 million per year (with capital costs annualized using a 7% discount rate) or $50 – $204 million per year (with capital costs annualized using a 3% discount rate), using model averages of the social cost of methane with a 3% discount rate.

Impacts over the 10-year evaluation period:

- Total net benefits range from $740 million – $1 billion (NPV using a 7% discount rate) or $862 million – $1.2 billion (NPV using a 3% discount rate), using model averages of the social cost of methane with a 3% discount rate.

[93] The highs and lows of the benefits and costs do not occur during the same years; therefore, the net benefit ranges presented here do not calculate simply as the range of benefits minus the range of costs presented previously.

Table 8-3a: Estimated Net Benefits, using model averages of the social cost of methane with a 3% discount rate ($ in million)

Net Benefits (Capital Costs Annualized at 7%) ($ MM)												
	Annual										2017-2026	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$0 - 16	$0 - 20	($26) - $4	($41 - 75)	($46 - 88)	($5 - 53)	($23) - $39	($34) - $35	($41) - $27	($217) - $26	($278) - $37
Flare Measurement	($4)	($4)	($4)	($5)	($5)	($5)	($6)	($6)	($7)	($7)	($39)	($46)
Pnumatic Controllers	$18	$19	$21	$21	$21	$22	$23	$24	$24	$24	$160	$189
Pneumatic Pumps	$26	$27	$30	$30	$30	$33	$33	$36	$36	$36	$232	$274
Liquids Unloading	$35	$37	$41	$42	$43	$47	$48	$53	$54	$54	$332	$395
Storage Tanks	$0	$0	$1	$1	$1	$1	$1	$2	$2	$2	$7	$9
LDAR	$25	$27	$38	$39	$39	$48	$49	$59	$60	$59	$315	$380
Administrative Burden	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($51)	($60)
Total	$95	$99 - 115	$118 - 139	$95 - 126	$46 - 80	$51 - 93	$89 - 136	$138 - 199	$128 - 197	$120 - 189	$740 - 983	$862 - 1,178

Net Benefits (Capital Costs Annualized at 3%) ($ MM)												
	Annual										2017-2026	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$0 - 16	$0 - 20	($26) - $4	($41 - 75)	($46 - 88)	($5 - 53)	($23) - $39	($34) - $35	($41) - $27	($217) - $26	($278) - $37
Flare Measurement	($3)	($4)	($4)	($4)	($4)	($5)	($5)	($5)	($6)	($6)	($34)	($40)
Pnumatic Controllers	$19	$19	$21	$21	$21	$23	$23	$25	$25	$25	$163	$192
Pneumatic Pumps	$27	$28	$30	$31	$31	$33	$34	$36	$36	$36	$238	$281
Liquids Unloading	$36	$37	$42	$43	$43	$48	$49	$53	$54	$55	$337	$400
Storage Tanks	$1	$1	$2	$2	$2	$2	$2	$3	$3	$3	$15	$18
LDAR	$26	$28	$38	$40	$40	$48	$50	$60	$60	$60	$321	$386
Administrative Burden	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($51)	($60)
Total	$99	$103 - 119	$122 - 143	$99 - 130	$50 - 84	$55 - 97	$93 - 141	$142 - 204	$132 - 201	$125 - 193	$771 - 1,014	$889 - 1,214

Comparison of Benefits and Net Benefits using the Four SC-GHG Estimates

The IWG recommends calculating benefits and net benefits using all four SC-GHG estimates: 5% (average); 3% (average); 2.5% (average); and 3% (95th percentile). Table 8-3b and 8-3c present results consistent with the IWG TSD.

Table 8-3b shows the global benefit of the methane reductions estimated to result form this rule. Table 8-3c shows the estimated benefits (including costs savings and methane reductions) and the estimated net benefits (including costs, cost savigns, and methane reductions).

As stated previously, the monetized benefits and net benefits reported throughout this RIA include the "3% (average)" model values. The benefits and net benefits using other SC-GHG model estimates are shown in this section only.

Table 8-3b: Estimated Social Benefits of Methane Reductions[1] ($ in million, 2012$)

SC-GHG Model Estimate	Annual Value										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
5% (average)	$84	$88	$90	$94	$97	$103	$107	$111	$114	$118	$740	$875
3% (average)	$189	$190	$207	$208	$209	$227	$227	$246	$246	$247	$1,620	$1,914
2.5% (average)	$258	$258	$259	$277	$278	$297	$297	$316	$317	$335	$2,138	$2,523
3% (95th percentile)	$515	$517	$536	$555	$574	$593	$612	$632	$651	$671	$4,325	$5,106

[1] The SC-CH4 values are dollar-year and emissions-year specific. SC-CH4 values represent only a partial accounting of climate impacts.

Table 8-3c: Estimated Benefits and Net Benefits using the Four SC-GHG Estimates ($ in million, 2012$)

Estimated Benefits of the Rule[1, 2]			
SC-GHG Model Estimate	**Annual Range**	**10-Year Total, NPV 7**	**10-Year Total, NPV 3**
5% (average)	$104 – 271	$1,343	$1,640
3% (average)	$209 – 403	$2,224	$2,678
2.5% (average)	$278 – 488	$2,741	$3,287
3% (95th percentile)	$535 – 823	$4,929	$5,871
Estimated Net Benefits of the Rule (Capital costs annualized using 7% rate)[1, 3]			
SC-GHG Model Estimate	**Annual Range**	**10-Year Total, NPV 7**	**10-Year Total, NPV 3**
5% (average)	($73) – $65	($141) – $103	($176) – $139
3% (average)	$46 – 199	$740 – 983	$862 – 1,178
2.5% (average)	$116 – 277	$1,257 – 1,500	$1,471 – 1,787
3% (95th percentile)	$411 – 612	$3,445 – 3,688	$4,055 – 4,370
Estimated Net Benefits of the Rule (Capital costs annualized using 3% rate)[1, 3]			
SC-GHG Model Estimate	**Annual Range**	**10-Year Total, NPV 7**	**10-Year Total, NPV 3**
5% (average)	($69) – $69	($110) – $133	($140) – $176
3% (average)	$50 – 204	$771 – 1,014	$899 – 1,214
2.5% (average)	$120 – 281	$1,288 – 1,531	$1,508 – 1,823
3% (95th percentile)	$415 – 617	$3,476 – 3,719	$4,091 – 4,407

[1] The SC-CH4 values are dollar-year and emissions-year specific. SC-CH4 values represent only a partial accounting of climate impacts.

[2] Benefits include cost savings and the social benefit of methane reductions.

[3] Net benefits include costs, cost savings, and the social benefit of methane reductions.

8.4 Distributional Impacts

8.4.1 Energy Systems

The rule has a number of requirements that are expected to influence the production of natural gas, natural gas liquids, and crude oil from onshore Federal and Indian oil and gas leases.

We estimate the following incremental changes in production, noting the representative share of the total U.S. production in 2015 for context:

- Additional natural gas production ranging from 9 – 41 Bcf per year (0.03 – 0.15% of the total U.S. production);
- A reduction in crude oil production ranging from 0.0 – 3.2 million barrels per year (0 – 0.07% of the total U.S. production).

Separate from the volumes listed above, we also expect 0.8 Bcf of gas to be combusted onsite that would have otherwise been vented.

Since the relative changes in production are expected to be small, we do not expect that the rule would significantly impact the price, supply, or distribution of energy.

The requirements designed to conserve gas that would otherwise be flared are expected to result in some near term gas capture and temporary deferral of some crude oil production, with those volumes expected to be produced in the future. The deferment would slow the flaring of oil-well gas, such that we expect that a large portion of gas that would have otherwise been flared would be conserved and brought to the market. The impacts of the rule's flaring limits are quite uncertain due to several factors. Regulatory action to limit flaring was undertaken by the state of North Dakota, and those efforts should reduce the overall flaring in the state by the time this rule is final; the North Dakota requirements could also drive further deployment of and improvements in on-site capture technologies over that same time-frame. As discussed previously, there is also substantial uncertainty regarding how operators will choose to meet the flaring limits. Additionally, crude oil prices are currently very low, both reducing the opportunity cost of deferred oil receipts and slowing the pace of drilling activity and potential oil-well gas flaring.

Table 8-4a: Estimated Incremental Production

Requirement	Annual										10 Years
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026
Natural Gas (Bcf)											
Capture Target Req.	0.0	7.2	9.2	13.8	15.3	19.1	21.7	27.9	31.2	31.2	176.7
Pnumatic Controllers	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10.5
Pneumatic Pumps	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	7.8
Liquids Unloading	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.2	2.2	2.2	21.0
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
LDAR	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	51.9
Total Natural Gas	9.0	16.3	18.3	23.0	24.5	28.3	30.9	37.1	40.5	40.5	268.3
Requirement	**Annual**										**10 Years**
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Crude Oil (million bbl)											
Capture Target Req.	0.0	-0.1	-0.3	-1.5	-3.0	-3.2	-2.3	-1.7	-2.1	-2.2	-16.3
Total Crude	0.0	-0.1	-0.3	-1.5	-3.0	-3.2	-2.3	-1.7	-2.1	-2.2	-16.3

8.4.2 Royalty Impacts

The rule is expected to increase natural gas production from Federal and Indian leases, and likewise, is expected to increase annual royalties to the Federal Government, tribal governments, states and private landowners.

Royalty payments are recurring income to Federal or Tribal governments and costs to the operator or lessee. As such, they are transfer payments that do not affect the total resources available to society. An important but sometimes difficult problem in cost estimation is to distinguish between real costs and transfer payments. While transfers should not be included in the economic analysis estimates of the benefits and costs of a regulation, they may be important for describing the distributional effects of a regulation.[94]

For requirements that would result in incremental gas production, we calculate the additional royalties based on that production. When considering the deferment of production that could result from the rule's flaring limit, we calculate the incremental royalty as the difference in the present value of the royalty received ten years later and the value of the royalty that would have been received now or absent the deferment.[95]

We estimate additional royalties of \$3 – 10 million per year. Over the 10-year evaluation period, we estimate additional royalties of \$65 million (NPV using a 7% discount rate) or \$82 million (NPV using a 3% discount rate). See Table 8-4b.

[94] OMB Circular A-4 "Regulatory Analysis." September 17, 2003. Available on the web at https://www.whitehouse.gov/omb/circulars_a004_a-4/.

[95] For incremental gas production that would occur only due to estimated oil production deferment, the royalty of the value that would be received now is \$0, and so the difference is therefore the present value of the royalty received in the future.

Table 8-4b: Estimated Incremental Royalty ($ in millions)

Requirement	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Natural Gas (Bcf)												
Capture Target Req.	0.0	3.1	4.2	6.7	7.1	8.0	8.8	10.8	11.6	10.5	$69.6	$90.9
Pnumatic Controllers	0.3	0.3	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	$3.2	$3.8
Pneumatic Pumps	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	$2.4	$2.9
Liquids Unloading	0.6	0.7	0.7	0.7	0.7	0.6	0.7	0.7	0.6	0.6	$6.5	$7.7
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	$0.1	$0.2
LDAR	1.5	1.7	1.8	1.8	1.7	1.6	1.6	1.6	1.5	1.4	$16.0	$19.0
Total Natural Gas	2.7	6.0	7.3	9.9	10.0	10.8	11.6	13.6	14.2	13.0	$97.9	$124.5
Requirement	**Annual**										**2017-2026**	
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Crude Oil (Difference in Royalty Value of Deferred Production)												
Capture Target Req.	0.0	0.0	-0.4	-3.0	-6.3	-6.9	-4.7	-3.2	-4.0	-3.9	($32.5)	($42.2)
Total Crude	0.0	0.0	-0.4	-3.0	-6.3	-6.9	-4.7	-3.2	-4.0	-3.9	($32.5)	($42.2)
Total Net Royalty	**2.7**	**6.0**	**6.8**	**6.9**	**3.7**	**3.8**	**6.9**	**10.3**	**10.2**	**9.0**	**$65.4**	**$82.3**

8.4.3 Employment Impacts

Executive Order 13563 reaffirms the principles established in Executive Order 12866, but calls for additional consideration of the regulatory impact on employment. It states, "Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation." An analysis of employment impacts is a standalone analysis and the impacts should not be included in the estimation of benefits and costs.

The rule is not expected to impact the employment within the oil and gas extraction, drilling oil and gas wells, and support activities industries, in any material way. As noted previously, the anticipated additional gas production volumes represent only a small fraction of the U.S. natural gas production volumes. Additionally, the annualized compliance costs represent only a small fraction of the annual net incomes of companies likely to be impacted (See Section 9. Initial Regulatory Flexibility Analysis). For those operations which would be impacted to the extent that the compliance costs would force the operator to shut in production, the rule has provisions that would exempt these operations from compliance. Therefore, we believe that the rule would not alter the investment or employment decisions of firms or significantly adversely impact employment. The requirements would require the one-time installation or replacement of equipment and the ongoing implementation of a leak detection and repair program, both of which would require labor to comply.

8.4.4 Impacts on Tribal Lands

The rule would apply to oil and gas operations on both Federal and Indian leases. In this section of the analysis, we estimate the costs, benefits, net benefits, and incremental production associated with operations on Indian leases, as well as royalty implications for Tribal governments. We estimated these impacts by scaling down the total impacts by the share oil wells on Indian lands and the share of gas wells on Indian Lands. From 2013 to 2015, AFMSS data indicate that oil and gas wells on Indian leases accounted for roughly 15% and 11%, respectively, of the total wells on Federal and Indian Lands.

Costs associated with operations on Indian leases. We estimate the following costs associated with the rule's provisions for operators with leases on Indian lands.

Annual Impacts:

- Costs range from \$15 – \$39 million per year (using a 7% discount rate to annualize capital costs) or \$14 – \$39 million per year (using a 3% discount rate to annualize capital costs).

Impacts over the 10-year evaluation period:

- Total costs range from \$164 – 204 million (NPV using a 7% discount rate) or \$199 – 251 million (NPV using a 3% discount rate).

Benefits associated with operations on Indian leases. We estimate the following benefits associated with the rule's provisions with respect to leases on Indian lands.

Annual Impacts:

- Benefits from costs savings range from $3 – 23 million per year;
- Benefits from reduced methane emissions range from $23 – 30 million per year, using model averages of the social cost of methane with a 3% discount rate.
- Total benefits range from $26 – 53 million per year, using model averages of the social cost of methane with a 3% discount rate.

Impacts over the 10-year evaluation period:

- Total costs savings of $85 million (NPV using a 7% discount rate) or $108 million (NPV using a 3% discount rate);
- Total social benefits $199 million (NPV using a 7% discount rate) or $235 million (NPV using a 3% discount rate);
- Total benefits $284 million (NPV using a 7% discount rate) or $343 million (NPV using a 3% discount rate);

We estimate that the rule would reduce methane emissions by about 22,000 tons per year and 218,000 tons over 10 years. We monetized these reductions and included them in the monetized benefits. We estimate that the rule would reduce VOC emissions by 30,000 – 32,000 tons per year, and 310,000 tons over 10 years. The VOC emissions reductions are not monetized.

Net benefits associated with operations on Indian leases. We estimate the following net benefits associated with the rule's provisions with respect to leases on Indian lands[96]:

Annual Impacts:

- Net benefits range from $3 – $25 million per year (with capital costs annualized using 7% and 3% discount rates).

Impacts over the 10-year evaluation period:

- Total net benefits range from $80 – 120 million (NPV using a 7% discount rate) or $92 – 144 million (NPV using a 3% discount rate).

Incremental production associated with operations on Indian leases. We estimate the following incremental production associated with the rule's provisions with respect to leases on Indian lands:

- Additional natural gas production ranging from 1.1 – 5.8 Bcf per year; and
- A reduction in crude oil production ranging from 0 – 320,000 barrels per year.

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[96] The highs and lows of the benefits and costs do not occur during the same years; therefore, the net benefit ranges presented here do not calculate simply as the range of benefits minus the range of costs presented above.

Incremental royalty associated with operations on Indian leases.

We estimate additional royalties of $0.3 – 1.9 million per year. Over the 10-year evaluation period, we estimate additional royalties of $10 million (NPV using a 7% discount rate) or $12 million (NPV using a 3% discount rate).

8.4.5 Additional Considerations

In this section, we qualitatively discuss other potential impacts of the rule.

Potential impact on new drilling on Federal lands. The rule is expected to increase the costs of developing new oil and gas resources on Federal and Indian Lands. Since the EPA finalized Subpart OOOOa, then as a practical matter, this rule will only impact new liquids unloading operations, and new oil wells flaring associated gas. All of the other requirements would practically impact existing operations only.

Due to the potentially higher development costs for new operations on Federal and Indian Lands, there is the concern that these properties could become less desirable than non-Federal and non-Tribal properties. In response, operators might conceivably shift future activity away from Federal and Indian Lands to non-Federal and non-Tribal properties or, less conceivably, away from the affected areas or regions entirely.

In response to these concerns, we do not think that this rule would cause operators to shift new drilling away from Federal and Indian Lands in most, if not all, regions. However, we recognize that the requirements in this rule discourage developmental wells in regions lacking any means for capturing and transporting gas to market. We understand that, as a general industry practice, there is a strong preference to site development in areas with the capacity to transport all gas that is produced. BLM seeks comment on regions that may be disproportionately impacted by this rule. For liquids unloading, we estimate positive returns to the industry, meaning the cost savings exceed the compliance costs. The control technologies are currently available and widely used by the industry. With respect to the flaring of associated gas, given state regulations and industry activity to curb flaring, we expect that the continued build out of pipelines in the future will result in industry compliance to the rule without diminished desirability of the Federal and Indian mineral estates.

Impact on lease bids as a result of higher regulatory costs. Similar to the discussion above, there is a concern that any added and significant regulatory costs would reduce the level of bonus bids that the Federal Government would receive for new Federal leases or the upfront payments that a Tribal government would receive for its new leases. The BLM awards the rights to develop an oil and gas lease on Federal lands to the company that bids the highest amount at auction. Leases that do not receive bids may be acquired through a non-competitive process.

The concern would be that if the regulatory requirements reduce the desirability of leases on Federal lands, then as a consequence, there would be reduced demand for the leases, less competition at auction, and bonus bids would be reduced. Or similarly, that the additional compliance costs would reduce the amount that companies would be willing to pay for the Federal leases. For example, if the bonus bid for a particular lease were reduced by an amount commensurate to the compliance costs, then the operator would effectively pass on the compliance costs to the Federal Government, or the public.

The same concern would apply to Tribal leases. The BLM does not auction oil and gas leases on Indian Lands, rather the particular Tribe leases its own properties with companies making upfront payments to the Tribal government for the rights to develop the leases. The concern remains that in response to the additional compliance costs, companies would offer less in upfront payment (effectively passing on the compliance costs to the Tribal government) or there would be less demand for leases on Indian Lands and the upfront payments would be reduced.

While the potential for lower bonus bids is of general concern, again, we do not believe that the compliance costs of the rule are significant for new leases. Since the EPA finalized Subpart OOOOa, then as a practical matter, this rule would impact new liquids unloading operations, and new oil wells flaring associated gas. All of the other requirements would practically impact existing operations only. The only scenario we envision affecting bonus bids is where the leases are being offered in an area lacking any means for capturing and transporting gas to market. When conducting a review to offer new leases for oil and gas development, BLM considers factors affecting the ability of operators to capture and transport gas to market, and will continue to emphasize this aspect in future leasing decisions.

For most, if not all new leases, we do not believe that the compliance costs are significant enough to reduce bonus bids. For liquids unloading, we estimate positive returns to the industry, meaning the cost savings exceed the compliance costs. The control technologies are currently available and widely used by the industry. With respect to the flaring of associated gas, given state regulations and industry activity to curb flaring, we expect that the continued build out of pipelines in the future will result in industry compliance to the rule without diminished desirability of the Federal and Indian mineral estates.

Indirect economic impacts in regions where flaring is in excess of the limits. In general, economic impacts can be estimated at the direct, indirect and induced levels. Direct impacts result from expenditures associated with the operations (or compliance with the regulation) and include, for example, labor, equipment, and capital. Indirect impacts result from the suppliers of the purchased goods and services used in the operations and hiring workers to deliver those goods and services. These “2nd round” impacts would not occur if not for the operations themselves. Induced impacts result from the employees of the operations and suppliers at a household level.

While we might expect that the requirements of the rule would generate positive indirect or induced impacts through equipment purchases, infrastructure investments, or contracted services that would be provided by suppliers or service providers, we might also expect that the rule would generate negative indirect or induced impacts if operators choose to reduce investment and thereby reduce transactions made with suppliers or service providers.

Of particular interest is the operator or industry response in regions where oil-well gas flaring is the highest and where the operator might not achieve the gas capture targets. The BLM believes that the estimates of impacts in this analysis may be overstated to the extent current and pending state regulations require operators to capture more gas. Several aspects of the rule were designed to account for ongoing state efforts, including the flexibility to issue variances upon a determination by the BLM that a state or tribal government's regulation meets or exceeds the requirements of BLM's respective provision(s).

Concerns that changes required under this rule would trigger permitting requirements. Stakeholders have raised concerns that operators might need to obtain regulatory approvals, such as rights of way or Clean Air Act permits, for various actions required by the rule. We do not believe that actions to comply with the requirements would "modify" a source for purposes of triggering Clean Air Act and state permitting requirements applicable to new and modified sources. The definition of "modification" requires both a physical change and an increase in emissions. Actions to comply with the rule, such as replacing pneumatic controllers and pneumatic pumps, installing automatic lifts, and routing gas releases to a flare, would all reduce, rather than increase emissions.

The BLM recognizes that some options for complying with the flaring limits might require additional notification to BLM or regulatory approvals for rights of way. For example, if an operator chooses to comply with using on-site capture equipment, the operator will need to file a Sundry Notice with the BLM to convey changes to the well site including an updated site facility diagram. Many operators ensure that their initial NEPA analysis at the well or field development permitting stage is sufficiently broad to include the potential impacts from these sorts of changes to the site plan, but in some cases, an operator might need to supplement the pre-existing NEPA analysis to account for the additional environmental impacts from adding capture equipment to the site. Similarly, some operators may need to file for a use authorization to obtain approval for new rights of way for adding gathering lines to connect wells to gas pipelines.

Impact on exising wells and potential concerns over premature abandonment. Depending on the lease and the requirement, the rule might increase the costs for operators with existing leases on Federal and Indian Lands. One concern is whether the existing wells can economically support these additional costs or whether the operator would respond by prematurely abandoning the well. We generally believe that the cost savings available to operators would exceed the compliance costs or that the compliance costs would not be as significant as to force the operator to prematurely abandon the well. However, we recognize that some existing leases might not support the investments and therefore include exemption clauses for requirements if compliance would force the operator to prematurely abandon the well.

We note also that specific requirements are likely to impact existing wells that are classified as marginal (those with low production volumes making their economic viability "marginal") or stripper wells (generally classified as 15 barrels of oil equivalent per day). For example, these wells are may have existing production equipment, like high-bleed continuous pneumatic controllers or uncontrolled diaphragm pneumatic pumps, that might require replacement, or the wellsites are subject to the LDAR or liquids unloading requirements. However, these wells are highly unlikely to have uncontrolled storage tanks that would require control and would not have large enough oil-well gas flaring volumes to garner compliance.

We note that when the operator abandons a marginal well, it removes the surface equipment and forfeits the lease. Replacing the equipment in the future to recover marginal amounts of production is likely to be cost prohibitive. BLM does not anticipate this scenario occurring because of the ability to issue exemption clauses where appropriate, and therefore the cost of foregone hydrocarbon reserves are not included in the rule.

9. Final Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA) (5 U.S.C.§ 601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) (Public Law No. 104-121), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis (IRFA), unless it certifies that the proposed rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. § 605(b)). For final rules, the agency is required to publish a final regulatory flexibility analysis (FRFA).

Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impacts of this rule on small entities, a small entity is defined as: (1) A small business in the oil or natural gas industry whose parent company has no more than 1,250 employees (or revenues of less than $27.5 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.[97]

Based on the analysis below, the BLM believes that the rule will not have a significant economic impact on a substantial number of small entities. Although the rule will affect a substantial number of small entities, the BLM does not believe that these effects will be economically significant. As described in more detail below, the screening analysis conducted by the BLM estimates the average reduction in profit margin for small companies will be just a fraction of one percentage point, which is simply not a large enough impact to be considered significant.

Although it is not required, the BLM nevertheless chose to prepare an initial regulatory flexibility analysis with the proposed rule and this final regulatory flexibility analysis with the final rule. There are several factors driving this decision. First, although the projected costs are expected to be quite small, as a percentage of a typical firm's annual profits, there is significant uncertainty associated with these costs. There is a combination of factors contributing to the uncertainty associated with the costs of this rule. These factors include limited data, a wide range of possible variation in commodity prices over time, and a variety of possible compliance options, particularly with respect to the associated gas flaring requirements.

Thus, given the unique circumstances present in this rulemaking, the BLM believes it is prudent, and potentially helpful to small entities, to provide an IRFA and FRFA for this rulemaking. We do not believe this decision should be viewed as a precedent for other rulemakings.

Under Section 603 of the RFA, a Regulatory Flexibility Analysis must contain:

- A description of the reasons why action by the agency is being considered;

[97] Small Business Administration, Office of Advocacy. *A Guide for Government Agencies. How to Comply with the Regulatory Flexibility Act.* May 2012. Page 14.

- A succinct statement of the objectives of, and legal basis for, the rule;
- A description of and, where feasible, an estimate of the number of small entities to which the rule will apply;
- A description of the projected reporting, recordkeeping and other compliance requirements of the rule, including an estimate of the classes of small entities which will be subject to the requirement and the type of professional skills necessary for preparation of the report or record;
- An identification, to the extent practicable, of all relevant Federal rules which may duplicate, overlap or conflict with the rule; and,
- A description of any significant alternatives to the rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the rule on small entities.

9.1 Reasons why Action is Being Considered

As was described in Section 1.2 of this Regulatory Impact Analysis, OMB's Circular A-4 instructs Federal agencies to explain the need for regulatory action, such as market failure, compelling public need or social purpose. This regulatory action seeks to reduce the loss of gas from venting and flaring during operations on onshore Federal and Indian oil and gas leases. By doing so, the action aims to reduce waste in the petroleum markets and maximize revenue for taxpayers, as well as reduce the accompanying external costs imposed on society by gas which is released or flared. A 2010 GAO investigation and our subsequent analysis show that a considerable amount of natural gas is being wasted (through venting and flaring) at oil and gas production sites on Federal and Indian lands

When gas is wasted rather than captured and brought to market, society loses the ability to consume the resource. In addition, since the wasted gas in question comes from the Federal or Tribal mineral estate, the public or Tribes are often not compensated for the loss when royalty is not assessed. Additionally, state governments also lose the revenue they would ordinarily receive through royalty sharing from Federal production.

In addition to being wasted, lost gas also produces air pollution, which imposes costs to society that are not reflected in the market price of the goods. These uncompensated costs to society are referred to as negative externalities. Gas that is vented to the atmosphere or flared contributes greenhouse gases (GHG), volatile organic compounds (VOCs), and hazardous air pollutants that have negative climate, health, and welfare impacts.

Several market inefficiencies occur when society bears the costs of the damages instead of the producer. Since the damage is not borne by the producer, it is not reflected in the market price, and uncontrolled markets will produce an excessive amount of the commodity, dedicate an inadequate amount of resources to pollution control, and generate an inefficiently large amount of pollution. With stock pollutants, like methane and carbon dioxide, which build up in the atmosphere and cause damage over time, future generations bear greater a greater proportion of the burden. Further, the fact that operators do not always bear the full costs of production introduces perverse incentives to the market. Operators that voluntarily make investments to limit or avoid the loss put themselves at a competitive disadvantage in relation to operators who do not make investments.

9.2 Statement of Objectives and Legal Basis for Rule

This regulation aims to reduce the waste of natural gas from mineral leases administered by the BLM. This gas is lost during oil and gas production activities through flaring or venting of the gas, and equipment leaks. While oil and gas production technology has advanced dramatically in recent years, the BLM's requirements to minimize waste of gas have not been updated for over thirty years. The BLM believes there are economical, cost-effective, and reasonable measures that operators should take to minimize waste, which will enhance our nation's natural gas supplies, boost royalty receipts for federal taxpayers, tribes, and States, and reduce environmental damage from venting and flaring.

Flaring, venting, and leaks waste a valuable resource that could be put to productive use, and deprive American taxpayers, tribes, and States of royalty revenues. In addition, the wasted gas harms local communities and surrounding areas through visual and noise impacts from flaring, and regional and global air pollution problems of smog, particulate matter, toxic air pollution (such as benzene, a carcinogen) and climate change. The primary constituent of natural gas is methane, and gas that is wasted through venting is a major contributor to rising atmospheric methane levels.

The BLM oversees oil and gas activities under the authority of a variety of laws, including the Mineral Leasing Act of 1920 (MLA), the Mineral Leasing Act for Acquired Lands of 1947 (MLAAL), the Federal Oil and Gas Royalty Management Act (FOGRMA), the Federal Land Policy and Management Act of 1976 (FLPMA), the Indian Mineral Leasing Act of 1938 (IMLA), the Indian Mineral Development Act of 1982 (IMDA), and the Act of March 3, 1909[98].

In particular, the MLA requires the BLM to ensure that lessees "use all reasonable precautions to prevent waste of oil or gas developed in the land…." 30 U.S.C. 225. This rule would replace current requirements related to flaring, venting, and royalty-free use of production, which are contained in Notice to Lessees-4A (NTL-4A); amend the BLM's oil and gas regulations at 43 CFR Part 3160; and add new subparts 3178 and 3179. It would apply to all Federal and Indian (other than Osage Tribe) onshore oil and gas leases as well as leases and business agreements entered into by tribes (including IMDA agreements), as consistent with those agreements and with principles of Federal Indian law.

9.3 Description and Estimate of Affected Small Entities

The small entities affected by the regulatory action include small businesses in Oil and Gas Extraction, Drilling and Support. We identify the population of affected entities in accordance with the Small Business Administration (SBA) size standards developed to carry out the purposes of the

[98] Mineral Leasing Act, 30 U.S.C. 188–287; Mineral Leasing Act for Acquired Lands, 30 U.S.C. 351–360; Federal Oil and Gas Royalty Management Act, 30 U.S.C. 1701–1758; Federal Land Policy and Management Act of 1976, 43 U.S.C. 1701–1785; Indian Mineral Leasing Act of 1938, 25 U.S.C. 396a–g; Indian Mineral Development Act of 1982, 25 U.S.C. 2101–2108; Act of March 3, 1909, 25 U.S.C. 396.

Small Business Act.[99] Based on these standards (also described below) the vast majority of businesses in the Oil and Gas Extraction, Drilling and Support sectors are considered small entities.

Small entities for mining, including the extraction of crude oil and natural gas, are defined by the SBA as an individual, limited partnership, or small company considered being at "arm's length" from the control of any parent companies, with fewer than 1,250 employees. For firms drilling oil and gas wells, the threshold is 1,000 employees. For firms involved in support activities, the standard is annual receipts of less than $38.5 million.

To estimate a percentage for firms involved in oil and gas support activities we reference Tables 9-3a to 9-3b, which provide the NAICS information for firms involved in oil and gas support activities based on the size of receipts. As Table 9-3a illustrates, in 2012 the vast majority of establishments in the oil and gas sector were classified as small as defined by the SBA. Of the establishments involved in crude petroleum, natural gas, and NGL extraction, over 99% had fewer than 1,000 employees. Of the establishments involved in the drilling of oil and gas wells, over 99% had fewer than 1,000 employees.

Table 9-3a Oil and Gas Establishments by Employment Size – (2012)

NAICS	Industry	Employees	Number of Establishments	% <1000 Employees
211111	Crude Petroleum and Natural Gas Extraction	All	6398	
		< 1000	6380	99.7%
211112	Natural Gas Liquid Extraction	All	337	
		< 1000	337	100%
213111	Drilling Oil and Gas Wells	All	2179	
		< 1000	2166	99.4%
213112	Support Activities for Oil and Gas Operations	All	9659	
		< 1000	9640	99.8%

[1] The SBA size standard for the 211111 category is <1,250 employees, and <750 and <1000 for the catagories 211112 and 213111 respectively, but the 2012 Economic Census Data does not provide that level of granularity. Nonetheless, this tables provides a clear demonstration that the vast majority of Oil and Gas establishments are considered small by SBA's 2016 standards.

Source: U.S. Census Bureau, 2012 Economic Census. Mining: Industry Series: Detailed Statistics by Industry for the U.S. Query available at http://factfinder.census.gov/

[99] Code of Federal Regulations, Title 13, Chapter I, Part 121, Subpart A, Section 121.201.

Table 9-3b provides a snapshot of the oil and gas sector, including number of establishments and employees, as well as annual payroll and shipments and receipts.

Table 9-3b: Industry Statistics for the Affected Industries (2012)

NAICS	Description	Number of Establishments	Number of Employees	Annual Payroll ($1,000)	Total Value of Shipments and Receipts for Services ($1,000)
211111	Crude Petroleum and Natural Gas Extraction	6,398	161,685	13,917,174	271,148,770
211112	Natural Gas Liquid Extraction	337	14,537	1,220,786	39,811,595
213111	Drilling Oil and Gas	2,179	115,466	8,439,260	30,735,287
213112	Support Activities for Oil and Gas Operations	9,659	323,523	20,601,811	84,790,406

Source: U.S. Census Bureau, 2012 Economic Census. Mining: Industry Series: Detailed Statistics by Industry for the U.S. Query available at http://factfinder.census.gov/

Data from 2014 in Table 9-3c show that the industry is mostly "small" entities when split by number of employees; 500 and greater vs 500 and less. However, total employment and payroll are higher for the larger entities.

Table 9-3c Oil & Gas Extraction, Drilling and Support Activities by Employment Size (2014)

NAICS Code	NAICS Description	Enterprise Employment Size	Number of Firms	Number Establishments	Employment	Annual Payroll ($1,000)
211111	Crude Petroleum and Gas Extraction	<500	6,436	6,663	52,538	6,199,919
		500+	96	1,179	74,128	11,403,686
211112	Natural Gas Liquid Extraction	<500	109	118	1,859	158,597
		500+	40	296	9,314	1,094,161
213111	Drilling Oil and Gas Wells	<500	2,068	2,150	39,788	3,128,687
		500+	53	300	62,946	6,324,093
213112	Support Activities for Oil and Gas Operations	<500	9,577	9,992	138,224	10,234,463
		500+	158	1,896	169,553	16,474,022

Source: U.S. Census Bureau, Statistics of U.S. Businesses, *Number of Firms, Number of Establishments, Employment, and Annual Payroll by Employment Size of the Enterprise for the United States, All Industries 2014* – http://www.census.gov/programs-surveys/susb/technical-documentation/methodology.html

Older data in Table 9-3d for 2007, available from the U.S. Census Bureau for establishment/firm size based on receiptsshow that of the 5,880 firms in oil and gas support activities in 2007, 97 percent had annual receipts of less than $35 million.[100]

Table 9-3d: Oil and Gas Support Activities by Receipts - 2007

NAICS Code	Description	Data Type	Receipt Size		
			Total	<$35 million	>$35 million
213112	Support Activities	Firms	5,880	5,693	187
213112	Support Activities	Establishments	7,105	4,490	1,203
213112	Support Activities	Employment	247,839	86,376	161,463
213112	Support Activities	Annual Payroll ($1,000)	12,644,163	3,566,689	9,077,474

Source: U.S. Census Bureau, Special Tabulation - 2007 – (http://www.census.gov).

Based on this national data, the preponderance of entities involved in developing oil and gas resources are small entities as defined by the SBA. As such, it appears that a substantial number of small entities are potentially affected by the final rule.

9.4 Compliance Cost Impact Estimates

The BLM identified up to 1,828 entities that currently operate Federal and Indian leases and recognizes that the vast majority of these entities are small business, as defined by the SBA. We estimated a range of potential per-entity costs, based on different discount rates and scenarios considered when estimating costs to the industry. For example, using a 7% discount rate to estimate total costs, we estimate average per-entity compliance costs ranging from about $44,600 to $65,800 per-entity per year.

Table 9-4: Per-Entity Costs

Discount Rate used to Annualize Capital Costs	Capture Target Cost Scenario	Years 2017 – 2026		
		Low	High	Average
7%	Low	$24,500	$72,600	$44,600
	High	$48,000	$95,600	$65,800
3%	Low	$22,200	$70,300	$42,300
	High	$45,800	$93,400	$63,600

Recognizing that the SBA definition for a small business for oil and gas producers (21111) is one with fewer than 1,250 employees and that presents a wide range of possible oil and gas producers, the BLM looked at company data for 26 different small-sized entities that currently hold BLM-

[100] U.S. Census Bureau does not provide receipt data that allow a break at the $38.5 million threshold as defined by SBA. As such the 97 percent figure is a slight under estimate.

managed oil and gas leases. The BLM ascertained the following information from the companies' annual reports to the U.S. Securities and Exchange Commission (SEC) for 2012 to 2014.

From data in the companies' 10-K filings to the SEC, the BLM was able to calculate the companies' profit margins[101] for the years 2012, 2013 and 2014. We then calculated a profit margin figure for each company when subject to the average annual cost increase associated with this rule. For simplicity, we used the midpoint of the low and high average per-entity cost increase figures (shown above), or $55,200, recognizing this figure includes costs where the capital costs are annualized using a 7% discount rate.

For these 26 small companies, a per-entity compliance cost increase of $55,200 would result in an average reduction in profit margin of 0.15 percentage points (based on the 2014 company data).

The full detail of this calculation is available in the Appendix. As discussed above, the per-entity compliance cost figures are an average cost. Entities with higher activity levels would be subjected to a higher cost than the average. We assume small entities, as defined by SBA, would generally have lower activity levels and thus face a lower annual cost increase than the average. As such, the estimated profit margin reduction is likely to be over-estimated.

9.5 Projected Reporting, Recordkeeping and Other Compliance Requirements

The SBA has developed size standards to carry out the purposes of the Small Business Act that can be found at 13 CFR 121.201. Small entities for mining, including the extraction of crude oil and natural gas, are defined by the SBA as an individual, limited partnership, or small company considered to be at "arm's length" from the control of any parent companies, with fewer than 1,250 employees. For firms drilling oil and gas wells the threshold is 1,000 employees. For firms involved in support activities the standard is annual receipts of less than $38.5 million. As shown previously, of the vast majority of firms in these industries are small businesses as defined by the SBA.

Based on the available national data, the preponderance of firms involved in developing, producing, purchasing, and transporting oil and gas from Federal and Indian lands are small entities as defined by the SBA. As such, it appears a substantial number of small entities would be potentially affected by the rule, although not significantly.

The Regulatory Impact Analysis for the final rule identifies annual costs of the rule as being between $113 and $243 million depending on the discount rate used. Greater details of the regulatory provisions are provided in the rule preamble. This section primarily discusses the paperwork burden on operators.

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101 The profit margin was calculated by dividing the net income by the total revenue as reported in the companies' 10-K filings.

The Paperwork Reduction section of the rule identifies 85,170 hours of paperwork, reporting, and recordkeeping required annually by the regulations. Using the Bureau of Labor Statistics weighted hourly rate of $64.53 per hour, the estimated hour burden to industry for this rulemaking is about $5.5 million. This burden is expected to decrease over time as requests for many of the exemptions are only relevant in the first few years.

The estimated administrative burden to industry is as follows:

Type of Response	**Number of Responses**	**Hours per Response**	**Total Hours**	**Total Wage Cost (at $64.53/hour)**
Plan to Minimize Waste of Natural Gas 43 CFR 3162.3-1 Form 3160-3	2,000	8	16,000	1,032,480
Request for Prior Approval for Royalty-Free Uses On-Lease or Off-Lease 43 CFR 3178.5, 3178.7, and 3178.9 Form 3160-5	50	4	200	12,906
Notification to use State- or County-wide Capture Target Calculation 43 CFR 3179.7(c)(ii)	200	1	200	12,906
Request for Approval of Alternative Capture Requirement 43 CFR 3179.7(b) Form 3160-5	50	16	800	51,624
Request for Exemption from Well Completion Requirements 43 CFR 3179.102(c) and (d) Form 3160-5	0	0	0	0
Request for Extension of Royalty-Free Flaring During Initial Production Testing 43 CFR 3179.103 Form 3160-5	500	2	1000	64,530
Request for Extension of Royalty-Free Flaring During Subsequent Well Testing 43 CFR 3179.104 Form 3160-5	5	2	10	645

Reporting of Venting or Flaring 43 CFR 3179.105 Form 3160-5	250	2	500	32,265
Notification of Functional Needs for a Pneumatic Controller (43 CFR 3179.201(b)(1)) Form 3160-5	10	2	20	1,291
Showing that Cost of Compliance Replacement of Pneumatic Controller Would Cause Cessation of Production and Abandonment of Oil Reserves (43 CFR 3175.201(b)(4) and 3175.201(c)) Form 3160-5	50	4	200	12,906
Showing in Support of Replacement of Pneumatic Controller within 3 Years (43 CFR 3179.201(d)) Form 3160-5	100	1	100	6,453
Showing that a Pneumatic Diaphragm Pump was Operated on Fewer than 90 Individual Days in the Prior Calendar Year (43 CFR 3179.202(b)(2)) Form 3160-5	100	1	100	6,453
NotificationShowing of Functional Needs for a Pneumatic Diaphragm Pump (43 CFR 3179.202(d)) Form 3160-5	150	1	150	9,680
Showing that Cost of Compliance Replacement of Pneumatic Diaphragm Pump Would Cause Cessation of Production and Abandonment of Oil Reserves 43 CFR 3175.202(f) and (g) Form 3160-5	10	4	40	2,581

Showing in Support of Replacement of Pneumatic Diaphragm Pump within 3 Years 43 CFR 3179.202(h) Form 3160-5	100	1	100	6,453
Storage Vessels 43 CFR 3179.203(c) Form 3160-5	50	4	200	12,906
Downhole Well Maintenance and Liquids Unloading — Documentation and Reporting 43 CFR 3179.204(c) and (e) Form 3160-5	5,000	1	5,000	322,650
Downhole Well Maintenance and Liquids Unloading — Notification of Excessive Duration or Volume 43 CFR 3179.204(f) Form 3160-5	250	1	250	16,133
Leak Detection — Compliance with EPA Regulations 43 CFR 3179.301(e) Form 3160-5	50	4	200	12,906
Leak Detection — Request to Use an Alternative Monitoring Device and Protocol 43 CFR 3179.302(c) Form 3160-5	5	40	200	12,906
Leak Detection — Operator Request to Use an Alternative Leak Detection Program 43 CFR 3179.303(b) Form 3160-5	20	40	800	51,624
Leak Detection — Operator Request for Exemption Allowing Use of an Alternative Leak-Detection Program that Does Not Meet Specified 43 CFR 3179.303(d) Form 3160-5	150	40	3,000	387,180

Leak Detection — Notification of Delay in Repairing Leaks 43 CFR 3179.304(a) Form 3160-5	100	1	100	6,453
Leak Detection — Inspection Recordkeeping 43 CFR 3179.305	52,000	.25	13,000	838,890
Leak Detection — Inspection Annual Reporting 43 CFR 3179.305(b) Form 3160-5	2,000	20	40,000	2,581,200
Totals	63,200	-	85,170	5,496,020

9.6 Related Federal Rules

In 2012, the Environmental Protection Agency (EPA) adopted Clean Air Act new source performance standards (NSPS) for certain activities in the oil and gas production sector. These regulations target reductions of volatile organic compounds (VOCs) but have the effect of reducing venting and leaks. The EPA finalized regulations that amend the 2012 NSPS for the oil and natural gas source category by setting standards for both methane and VOCs for certain equipment, processes and activities across this source category (Subpart OOOOa Rulemaking). We have described those regulations in Section 5 of this RIA.

The ongoing EPA activities do not, however, obviate the need for the BLM, in its role as a public lands manager, to update its requirements governing flaring, venting, and leaks to ensure that the public's resources and assets are protected and developed in a manner that provides for long term productivity and sustainability. First, the BLM has an independent legal responsibility, and a proprietary interest as a land manager, to oversee oil and gas production activities on Federal and Indian leases. The BLM has requirements in place, but as independent reviews have pointed out, the existing requirements pre-date, and thus do not account for, significant technological developments. Updating and clarifying the regulations will make them more effective, more transparent, and easier to understand and administer, and will reduce operators' compliance burdens in some respects. The BLM must ensure that it has modern, effective requirements to govern oil and gas operations on BLM-administered leases. Second, as a practical matter, the EPA regulations do not adequately address the issue of waste of gas from BLM-administered leases. The EPA regulations are directed at air pollution reduction, not waste prevention; they focus largely on new sources; and they do not address all avenues for reducing waste (for example, they do not impose flaring limits for associated gas). It is wholly within the BLM's statutory authority to address flaring, venting, and leaks in its capacity as a land manager with a responsibility to ensure the longevity and long term productivity of public lands and resources.

9.7 Regulatory Flexibility Alternatives

The RFA requires BLM to identify and consider (but not necessarily adopt) alternatives that minimize this final regulatory action's economic impacts on small entities. The BLM recognizes that the vast majority of business entities affected by this rule are small. Therefore, throughout the drafting of this rule, the BLM looked for regulatory alternatives in order to provide flexibility where appropriate opportunities exist. This flexibility can lessen impacts to smaller operators as well as others. The decription of the final regulation and alternatives examined are described in Section 6 of this RIA. In this section, we also describe the flexibilities that we included in the rule to minimize significant economic impacts on the regulated sector, which is includes a large number of small entities.

9.7.1 Developmental Oil Wells

The final rule requires operators submitting certain Applications for Permit to Drill (APDs) to provide information, in the form of Waste Minimization Plans, in addition to that required under existing regulation. This additional information will ensure the operator has actively explored opportunities to capture and use or sell natural gas that is expected to be produced in association with oil production, before a well is drilled.

The additional information requirement is limited to only those APDs associated with developmental oil wells. In addition, this provision minimizes burdents on operators by requiring that operators develop a plan that will work for them, rather than specifying how the operator is to reduce waste. Also, the plan is not enforceable against operators, recognizing that circumstances may change from the time of the plan to the time of the development of the well and allowing operators to adjust their approach as needed.

9.7.2 Gas Capture Targets

The final rule will establish gas capture targets for operators to meet. Whereas the rule would have required the operator to take action to limit gas flaring from each individual lease, the final rule offers greater flexibility and economic efficiency by allowing the operator to direct resources to wells or operations where it might achieve flaring reductions at the lowest marginal cost across all of that operator's flaring wells in a county or a State.

9.7.2.1 Phasing in Gas Capture Targets

Gas capture targets will be phased in gradually over a nine year period. Particularly when paired with the the opportunity to average the operator's gas capture rates across all of the operator's wells in a given State, the gradual phase-in maximizes operator's opportunities to comply in the most cost-effective manner possible.

9.7.2.2 Alternate Targets

The final rule carries forward from the rule the ability of operators to seek alternative targets in certain instances. The operator of a lease that predates the final rule may demonstrate to the BLM with engineering and economic data that meeting the specified capture percentage would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. If an operator meets this criteria, the BLM may approve an alternate capture target at the highest level that the BLM determines will not cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

9.7.3 Requirements for Pneumatic Controllers

These final regulations require operators to replace all high-bleed continuous controllers with controllers that are not high-bleed controllers. The BLM included provisions in the final rule to reduce costs associated with compliance and allow for compliance flexibility, while still preventing waste. The operator is not required to replace an existing high bleed pneumatic controllers if (1) the high bleed controller is required to meet a functional need; (2) the pneumatic controller exhaust was, as of the date of the rule, and continues to be routed to a flare device or low pressure combustor; (3) the pneumatic controller exhaust is routed to processing equipment; or (4), the operator demonstrates that replacement) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

9.7.4 Requirements for Pneumatic Pneumatic Diaphragm Pumps

The final regulations require the operator to replace a pneumatic diaphragm pump with a zero-emissions pump or route the exhaust gas to capture. The BLM included provisions in the final rule to reduce costs associated with compliance and provide compliance flexibility to operators, while still preventing waste. If the operator determines that replacing the pump with a zero-emissions pump is not viable because a pneumatic pump is necessary to perform the function, and routing to capture is technically infeasible or unduly costly, the operator may route the exhaust gas to an existing flare or combustor on site, or if there is no flare or combustor on site, the operator may take no further action. The operator also need not replace existing pneumatic pump(s)if the operator demonstrates that the cost to replace the pump(s) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

9.7.5 Storage Vessels

The final regulations require operators either to capture or combust releases from storage vessels with the potential to emit at or above 6 tpy of VOC per vessel (with exceptions to this requirement). We estimate that this would impact less than 300 storage vessels on Federal and Indian lands. The BLM included a provision in the final rule to provide operators compliance flexibility and reduce costs associated with compliance. The operator may be exempted from these provisions if the operator submits an economic analysis to the BLM that demonstrates that compliance with this requirement would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. In addition, if the uncontrolled emissions drop below 4 tpy of VOC per vessel, then the operator may remove the controls.

9.7.6 Leak Detection and Repair (LDAR) Programs

The final regulations require the operator to inspect its well sites and equipment for leaksThe BLM included in the final rule provisions to provide operators compliance flexibility and reduce costs associated with compliance. While the final rule specifies the coverage and inspection frequency for an LDAR program, an operator may also request approval of an alternative instrument-based program if the BLM finds that the alternative program would achieve equal or greater reduction of gas lost through leaks compared with the approach specified in the regulations. In addition, the rule provides for the BLM to approve an alternative monitoring device to those specified in the rule, if the BLM finds that the alternative would achieve equal or greater reduction of gas lost through leaks compared to those specified in the rule.

10. Statutory And Executive Order Reviews

10.1 Executive Order 12866 Regulatory Planning and Review

Executive Order 12866 requires agencies to assess the benefits and costs of regulatory actions, and for significant regulatory actions, submit a detailed report of their assessment to the OMB for review. A rule may be significant under Executive Order 12866 if it meets any of four criteria. A significant regulatory action is any rule that may:

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities;
- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

After reviewing the requirements, we have determined that the rule is an economically significant regulatory action according to the criteria of Executive Order 12866 and have prepared this regulatory impact analysis.

10.2 Regulatory Flexibility Act and Small Business Regulatory Enforcement Fairness Act of 1996

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act, unless the head of the agency certifies that the rule would not have a significant economic impact on a substantial number of small entities. (see 5 U.S.C. 601 – 612). Congress enacted the RFA to ensure that government regulations do not unnecessarily or disproportionately burden small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

The BLM reviewed the Small Business Administration (SBA) size standards for small businesses and the number of entities fitting those size standards as reported by the U.S. Census Bureau in the Economic Census. The BLM concludes that the vast majority of entities operating in the relevant sectors are small businesses as defined by the SBA. As such, the rule would likely affect a substantial number of small entities. However, the BLM believes that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities. Although the rule will affect a substantial number of small entities, the BLM does not believe that these effects would be economically significant. The screening analysis conducted by BLM estimates the average reduction in profit margin for small companies will be just a fraction of one percentage point, which is not a large enough impact to be considered significant.

Although it is not required, the BLM nevertheless has chosen to prepare an Initial Regulatory Flexibility Analysis and Final Regulatory Flexibility Analysis. There are several factors driving this decision. First, although the projected costs are expected to be quite small, as a percentage of a typical firm's annual profits, there is significant uncertainty associated with these costs. There is a combination of factors contributing to the uncertainty associated with the costs of this rule. These factors include limited data, a wide range of possible variation in commodity prices over time, and a variety of possible compliance options, particularly with respect to the gas capture requirements.

Due to the fact that the rule is economically significant and impacts a substantial number of small entities, the BLM believes it is prudent, and potentially helpful to small entities, to provide an IRFA and FRFA for the rulemaking. We do not believe this decision should be viewed as a precedent for other rulemakings.

10.3 Unfunded Mandates Reform Act of 1995

Under the Unfunded Mandates Reform Act, agencies must prepare a written statement about benefits and costs prior to issuing a rule that is likely to result in aggregate expenditure by State, local, and tribal governments, or by the private sector, of $100 million or more in any one year, and prior to issuing any final rule for which a rule was published.

This rule does not contain a Federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any one year. Thus, the rule is also not subject to the requirements of section 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments, because it contains no requirements that apply to such governments, nor does it impose obligations upon them.

10.4 Executive Order 13211 Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use

Under Executive Order 13211, agencies are required to prepare and submit to OMB a Statement of Energy Effects for significant energy actions. This Statement is to include a detailed statement of "any adverse effects on energy supply, distribution, or use (including a shortfall in supply, price increases, and increase use of foreign supplies)" for the action and reasonable alternatives and their effects.

Section 4(b) of Executive Order 13211 defines a "significant energy action" as "any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of rulemaking, and notices of rulemaking: (1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of [OIRA] as a significant energy action."

The incremental production of gas estimated to result from the rule's enactment represent a small fraction of the total U.S. production. Since the compliance costs represent such a small fraction of company net incomes, we also believe that the rule is unlikely to impact the investment decisions of firms. Any potential and temporarily deferred production also represents a small fraction of the total U.S. production. Due to these reasons, we do not expect that this final rule will significantly impact the supply, distribution, or use of energy. As such, the rule is not a "significant energy action" as defined in Executive Order 13211.

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12. Appendix

Appendix A-1: U.S. Methane Emissions Estimates, Onshore Natural Gas and Crude Petroleum Production Sectors, 2016 GHG Inventory

Sector	Emissions Source	Methane (Metric tons)	Methane (Bcf)	Whole gas (Bcf)
Gas	Gathering and Boosting Stations	1,864,870.3	96.8	122.9
Gas	Pneumatic Devices-gas	1,105,119.0	57.4	72.8
Gas	Liquids unloading	260,643.9	13.5	17.2
Gas	Condensate tanks	222,405.0	11.5	14.7
Gas	Pipeline Leaks	169,701.4	8.8	11.2
Gas	Chemical Injection Pumps-gas	128,876.5	6.7	8.5
Gas	Gas Engines-gas	108,783.2	5.6	7.2
Gas	Separators-gas	90,558.0	4.7	6.0
Gas	Meters/Piping	81,839.1	4.2	5.4
Gas	HF Well Completions-gas	81,664.3	4.2	5.4
Gas	Kimray Pumps	77,016.1	4.0	5.1
Gas	Compressors	73,437.3	3.8	4.8
Gas	Prod Water from CBM - Powder River	36,368.9	1.9	2.4
Gas	Gas Wells with Hydraulic Fracturing	26,791.5	1.4	1.8
Gas	Dehydrator Vents	21,357.1	1.1	1.4
Gas	Heaters	18,291.1	0.9	1.2
Gas	Non-associated Gas Wells (less fractured wells)	13,557.6	0.7	0.9
Gas	Prod Water from CBM - Black Warrior	9,767.0	0.5	0.6
Gas	Compressor Starts	7,795.9	0.4	0.5
Gas	Dehydrators	6,427.8	0.3	0.4
Gas	Compressor BD	2,835.9	0.1	0.2
Gas	Pipeline BD	2,064.0	0.1	0.1
Gas	Mishaps	1,117.2	0.1	0.1
Gas	Well Drilling	741.9	0.0	0.0
Gas	Pressure Relief Valves	534.8	0.0	0.0
Gas	Vessel BD	510.5	0.0	0.0
Gas	Gas Well Workovers without Hydraulic Fracturing	340.4	0.0	0.0
Gas	Gas Well Completions without Hydraulic Fracturing	8.7	0.0	0.0

Sector	Emissions Source	Methane (Metric tons)	Methane (Bcf)	Whole gas (Bcf)
Oil	Oil tanks	302,142.7	15.7	19.9
Oil	Chemical Injection Pumps-oil	192,887.9	10.0	12.7
Oil	HF Well Completions-oil	118,768.7	6.2	7.8
Oil	Gas Engines-oil	65,886.1	3.4	4.3
Oil	Oil Wellheads (light crude)	47,275.4	2.5	3.1
Oil	Separators-oil	26,061.7	1.4	1.7
Oil	Heaters	24,328.1	1.3	1.6
Oil	Heater/Treaters (light crude)	11,693.4	0.6	0.8
Oil	Stripper wells	11,283.8	0.6	0.7
Oil	Headers (light crude)	6,430.2	0.3	0.4
Oil	Well Blowouts Onshore	2,175.0	0.1	0.1
Oil	Compressors	1,590.5	0.1	0.1
Oil	Sales Areas	1,577.3	0.1	0.1
Oil	Well Drilling	640.3	0.0	0.0
Oil	Vessel Blowdowns	576.0	0.0	0.0
Oil	Compressor Starts	367.9	0.0	0.0
Oil	Battery Pumps	346.7	0.0	0.0
Oil	Well Completion Venting	169.6	0.0	0.0
Oil	Compressor Blowdowns	164.5	0.0	0.0
Oil	Pressure Relief Valves	135.3	0.0	0.0
Oil	Flares	132.9	0.0	0.0
Oil	Floating Roof Tanks	121.5	0.0	0.0
Oil	Well Workovers	95.0	0.0	0.0
Oil	Oil Wellheads (heavy crude)	27.4	0.0	0.0
Oil	Headers (heavy crude)	14.6	0.0	0.0
Oil	Pneumatic Devices-oil	1,567,089.1	81.4	103.3

Appendix A-2: U.S. Onshore Dry Natural Gas and Crude Oil Production and Natural Gas and Crude Oil Production on Federal and Indian Lands, in 2014, by State Jurisdiction and NEMS Region

	U.S. Onshore	Federal/ Indian Lands		U.S. Onshore	Federal/ Indian Lands	
Jurisdiction	Gas Production (MMcf)	Gas Production (MMcf)	% of U.S. Gas Production	Oil Production (Mbbl)	Oil Production (Mbbl)	% of U.S. Oil Production
Alabama	106,903	1,016	0.95%	9,828	19	0.19%
Alaska	286,627	10,502	3.66%	362,350	616	0.17%
Arizona	106	19	17.52%	56	54	96.96%
Arkansas	1,123,096	11,534	1.03%	6,845	0	0.00%
California	205,320	6,983	3.40%	204,269	14,660	7.18%
Colorado	1,546,193	454,877	29.42%	95,192	5,119	5.38%
Florida	136	0	0.00%	2,227	0	0.00%
Illinois	2,579	0	0.00%	9,547	22	0.23%
Indiana	6,616	0	0.00%	2,507	0	0.00%
Kansas	269,564	4,051	1.50%	49,510	194	0.39%
Kentucky	72,266	73	0.10%	3,376	11	0.34%
Louisiana	1,884,566	16,809	0.89%	68,356	211	0.31%
Maryland	20	0	0.00%	0	0	NA
Michigan	113,024	1,353	1.20%	7,289	-10	-0.14%
Mississippi	53,945	237	0.44%	24,346	351	1.44%
Missouri	9	0	NA	196	0	0.00%
Montana	58,261	13,253	22.75%	29,880	3,054	10.22%
Nebraska	402	1	0.33%	3,050	25	0.81%
Nevada	3	0	0.00%	316	313	99.20%
New Mexico	1,091,914	673,570	61.69%	123,686	55,842	45.15%
New York	20,201	148	0.73%	341	0	0.00%
North Dakota	275,947	29,910	10.84%	396,866	56,832	14.32%
Ohio	485,434	402	0.08%	14,918	16	0.11%
Oklahoma	2,140,250	41,208	1.93%	127,047	1,776	1.40%
Oregon	950	0	0.00%	0	0	NA
Pennsylvania	4,174,655	12	0.00%	6,692	1	0.02%
South Dakota	15,286	114	0.75%	1,798	155	8.62%
Tennessee	4,912	0	0.00%	330	0	0.00%
Texas	7,135,326	48,092	0.67%	1,155,684	490	0.04%
Utah	434,555	260,350	59.91%	40,905	23,402	57.21%
Virginia	131,885	146	0.11%	14	0	0.05%
West Virginia	982,669	156	0.02%	7,524	0	0.00%

Wyoming	1,714,292	978,683	57.09%	76,078	36,605	48.12%
Total	**24,337,912**	**2,553,500**	**10.49%**	**2,831,023**	**199,758**	**7.06%**

	U.S. Onshore	**Federal/ Indian Lands**		**U.S. Onshore**	**Federal/ Indian Lands**	
NEMS Region	**Gas Production (MMcf)**	**Gas Production (MMcf)**	**% of U.S. Gas Production**	**Oil Production (Mbbl)**	**Oil Production (Mbbl)**	**% of U.S. Oil Production**
East Coast	5,309,566	463	0.01%	16,798	1	0.01%
Midwest	3,386,289	77,112	2.28%	616,434	59,020	9.57%
Gulf Coast	11,395,750	751,258	6.59%	1,388,745	56,913	4.10%
Rocky Mountain	3,753,301	1,707,163	45.48%	242,055	68,180	28.17%
West Coast	493,006	17,504	3.55%	566,991	15,643	2.76%
Total	**24,337,912**	**2,553,500**	**10.49%**	**2,831,023**	**199,758**	**7.06%**

Source: U.S. natural gas and crude oil production from the EIA. Federal and Indian natural gas and crude oil production from ONRR.

Appendix A-3: Methane Emission Factors for the Natural Gas Production Stage

Emission Source Category	Unit of Measurement	National Methane Emission Factor or Range of Regional Values (Potential emissions with some exceptions)
Gas Wells		
Associated Gas Wells	NA	NA
Non-associated Gas Wells (less fractured wells)	scfd/well	7.43-42.49
Gas Wells with Hydraulic Fracturing	scfd/well	7.59-42.49
Well Pad Equipment		
Heaters	scfd/heater	14.87-67.29
Separators	scfd/separator	0.94-142.27
Dehydrators	scfd/dehydrator	23.18-106.25
Meters/Piping	scfd/meter	9.43-61.68
Compressors	scfd/compressor	263.85-312.19
Gathering and Boosting		
Gathering And Boosting Stations	scfd/station	53,066.00
Pipeline Leaks	scfd/mile	52.38-61.97
Drilling, Well Completion, and Well Workover		
Gas Well Completions without Hydraulic Fracturing	scf/completion	707.23-854.65
Gas Well Workovers without Hydraulic Fracturing	scf/workover	2,367.7-2,861.3
Hydraulic Fracturing Completions and Workovers that vent	Mg/event	36.82
Flared Hydraulic Fracturing Completions and Workovers	Mg/event	4.91
Hydraulic Fracturing Completions and Workovers with RECs	Mg/event	3.24
Hydraulic Fracturing Completions and Workovers with RECs that flare	Mg/event	4.88
Well Drilling	scf/well	2,505.9-2,965.0
Produced Water from Coal Bed Methane		
Powder River	kt/gal	2.3E-09
Black Warrior	kt/well	0.0023
Normal Operations		
Pneumatic Device Vents	scfd/device	176.74-209.12
Pneumatic Device Vents - Low Bleed (LB)	scfd/device	22.52-26.64
Pneumatic Device Vents - High Bleed (HB)	scfd/device	612.66-724.91
Pneumatic Device Vents - Intermittent Bleed (IB)	scfd/device	215.13-254.55
Chemical Injection Pumps	scfd/pump	208.89-252.30
Kimray Pumps	scf/MMscf	977.5-1,156.6
Dehydrator Vents	scf/MMscf	271.58-321.34
Condensate Tank Vents		
Condensate Tanks without Control Devices	scf/bbl	21.87-302.75
Condensate Tanks with Control Devices	scf/bbl	4.37-60.55
Compressor Exhaust Vented		
Gas Engines	scf/HPhr	0.237-0.280
Well Clean Ups		
Liquids Unloading with Plunger Lifts	scfy/venting	2,856-1,137,406

Emission Source Category	Unit of	National Methane
	well	
Liquids Unloading without Plunger Lifts	scfy/venting well	77,891-2,002,960
Blowdowns		
Vessel BD	scfy/vessel	76.86-90.94
Pipeline BD	scfy/mile	304.49-360.28
Compressor BD	scfy/compressor	3,719-4,400
Compressor Starts	scfy/compressor	8,320-9,844
Upsets		
Pressure Relief Valves	scfy/PRV	33.50-39.64
Mishaps	scf/mile	659.24-780.03

Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014, Annex 3.

Appendix A-4: Methane Emission Factors for the Petroleum Production Stage

Emission Classification	Emission Source Category	Unit of Measurement	Emission Factor (CH4)
Vented	Oil Tanks	scf/bbl	7.40
	Pneumatic Devices, High Bleed	scfd/controller	622.00
	Pneumatic Devices, Low Bleed	scfd/controller	23.00
	Pneumatic Devices, Int Bleed		218.00
	Chemical Injection Pumps	scfd/pump	216.00
	Vessel Blowdowns	scfy/vessel	78.00
	Compressor Blowdowns	scfy/compressor	3,775.00
	Compressor Starts	scfy/compressor	8,443.00
	Stripper wells	scfy/stripper well	2,345.00
	Well Completion Venting	scf/completion	733.00
	Well Workovers	scf/workover	96.00
	HF Well Completions, Unconterolled	scf/completion	351,146.00
	HF Well Completions, Conterolled	scf/completion	17,557.00
	Pipeline Pigging	scfd/pig station	2.40
Fugitive	Oil Wellheads (heavy crude)	scfd/well	0.13
	Oil Wellheads (light crude)	scfd/well	17.00
	Separators (heavy crude)	scfd/separator	0.15
	Separators (light crude)	scfd/separator	14.00
	Heater/Treaters (light crude)	scfd/heater	19.00
	Headers (heavy crude)	scfd/header	0.08
	Headers (light crude)	scfd/header	11.00
	Floating Roof Tanks	scfy/floating roof	338,306.00
	Compressors	scfd/compressor	100.00
	Large Compressors	scfd/compressor	16,360.00
	Sales Areas	scf/loading	41.00
	Pipelines	scfd/mile or pipeline	NE
	Well Drilling	scfd/well drilled	NE
	Battery Pumps	scfd/pump	0.24
Combusted	Gas Engines	scf/HP-hr	0.24
	Heaters	scf/bbl	0.52
	Well Drilling	scf/well drilled	2,453.00
	Flares	scf/Mcf flared	20.00
Upset	Pressure Relief Valves	scfy/PR valve	35.00
	Well Blowouts Onshore	MMscf/blowout	2.50

Source: Methane emission factors are listed in the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014, Annex 3.

Appendix A-5: Social Cost of GHG Estimates

Year	SC - CO2 (2012$ per metric ton)[1]				SC - CH4 (2012$ per metric ton)[2]			
	5% Average	3% Average	2.5% Average	High Impact (95th Pct at 3%)	5% Average	3% Average	2.5% Average	High Impact (95th Pct at 3%)
2010	11	34	54	93	400	940	1,297	2,594
2011	12	35	55	97	411	984	1,297	2,702
2012	12	36	57	101	432	1,016	1,405	2,810
2013	12	37	58	105	454	1,048	1,405	2,918
2014	12	38	59	109	476	1,081	1,405	2,918
2015	12	39	61	113	486	1,081	1,513	3,027
2016	12	41	62	117	508	1,189	1,513	3,135
2017	12	42	64	121	530	1,189	1,621	3,243
2018	13	43	65	125	551	1,189	1,621	3,243
2019	13	44	66	130	562	1,297	1,621	3,351
2020	13	45	67	133	584	1,297	1,729	3,459
2021	13	45	68	136	605	1,297	1,729	3,567
2022	14	46	69	139	638	1,405	1,838	3,675
2023	14	48	70	143	659	1,405	1,838	3,783
2024	14	49	71	146	681	1,513	1,946	3,891
2025	15	50	74	149	703	1,513	1,946	3,999
2026	15	51	75	152	724	1,513	2,054	4,108
2027	16	52	76	155	757	1,621	2,054	4,216
2028	16	53	77	158	778	1,621	2,162	4,324
2029	16	53	78	161	800	1,729	2,162	4,432
2030	17	54	79	164	822	1,729	2,162	4,540
2031	17	55	80	168	854	1,729	2,270	4,648
2032	18	56	81	171	886	1,838	2,270	4,864
2033	18	57	82	174	919	1,838	2,378	4,972
2034	19	58	83	177	951	1,946	2,378	5,080
2035	19	59	84	182	973	1,946	2,486	5,297
2036	21	61	85	185	1,005	2,054	2,594	5,405
2037	21	62	88	188	1,038	2,054	2,594	5,513
2038	22	63	89	191	1,070	2,162	2,702	5,621
2039	22	64	90	195	1,081	2,162	2,702	5,837
2040	23	65	91	198	1,081	2,162	2,810	5,945
2041	23	66	92	201	1,189	2,270	2,810	6,053
2042	24	66	93	204	1,189	2,270	2,918	6,161
2043	24	67	94	208	1,189	2,378	2,918	6,269
2044	25	68	95	210	1,297	2,378	3,027	6,377
2045	25	69	96	213	1,297	2,486	3,027	6,594

2046	26	70	97	216	1,297	2,486	3,135	6,702
2047	26	71	99	219	1,405	2,594	3,135	6,810
2048	27	72	101	223	1,405	2,594	3,243	6,918
2049	27	74	102	226	1,405	2,702	3,243	7,026
2050	28	75	103	229	1,405	2,702	3,351	7,242

[1] Dollars adjusted from 2007 to 2012 based on the change in IDP-GDP. The SC-CO2 values are provided in 2007 dollars by OMB, Technical Support Document available on the web at https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf

[2] Dollars adjusted from 2007 to 2012 based on the change in IDP-GDP. The SC-CH4 values are provided in 2007 dollars by OMB, Technical Support Document available on the web at https://www.whitehouse.gov/sites/default/files/omb/inforeg/august_2016_sc_ch4_sc_n2o_addendum_final_8_26_16.pdf

Appendix A-6: Detail of LDAR Cost and Benefit Tables

Regulatory Options	Total Costs (Capital Costs Annualized at 7% Discount Rate)										NPV 7	NPV 3
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		
Quarterly Inspections	$155	$155	$155	$155	$155	$155	$155	$155	$155	$155	$1,164	$1,360
Semi-Annual Inspections	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$630	$737
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$78	$78	$78	$78	$78	$78	$78	$78	$78	$78	$589	$689
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$71	$71	$71	$71	$71	$71	$71	$71	$71	$71	$534	$624
Annual Inspections	$48	$48	$48	$48	$48	$48	$48	$48	$48	$48	$363	$425
Regulatory Options	Total Costs (Capital Costs Annualized at 3% Discount Rate)										NPV 7	NPV 3
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		
Quarterly Inspections	$154	$154	$154	$154	$154	$154	$154	$154	$154	$154	$1,160	$1,356
Semi-Annual Inspections	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$625	$730
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$78	$78	$78	$78	$78	$78	$78	$78	$78	$78	$584	$683
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$529	$618
Annual Inspections	$48	$48	$48	$48	$48	$48	$48	$48	$48	$48	$358	$419
Regulatory Options	Annual Benefits - Cost Savings										NPV 7	NPV 3
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		
Quarterly Inspections	$16	$19	$21	$24	$23	$23	$25	$27	$27	$27	$171	$203
Semi-Annual Inspections	$12	$15	$16	$18	$17	$17	$19	$20	$21	$20	$128	$152
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$12	$14	$16	$18	$17	$17	$19	$20	$20	$20	$126	$150
Semi-Annual Inspections (exempt oil wells <300 GOR)	$12	$14	$15	$17	$17	$17	$18	$19	$20	$19	$122	$145
Annual Inspections	$8	$10	$11	$12	$12	$12	$13	$13	$14	$13	$85	$101
Regulatory Options	Annual Cost of CO2 Additions										NPV 7	NPV 3
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		
Quarterly Inspections	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.09	$0.11
Semi-Annual Inspections	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.07	$0.08
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.07	$0.08
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.06	$0.08
Annual Inspections	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.05	$0.05
Regulatory Options	Annual Total Benefits - Value of CH4 Reductions										NPV 7	NPV 3
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		
Quarterly Inspections	$128	$128	$140	$140	$140	$152	$152	$163	$163	$163	$1,087	$1,282
Semi-Annual Inspections	$96	$96	$105	$105	$105	$114	$114	$123	$123	$123	$817	$964

Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$95	$95	$104	$104	$104	$112	$112	$121	$121	$121	$804	$949
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$92	$92	$100	$100	$100	$109	$109	$117	$117	$117	$779	$919
Annual Inspections	$64	$64	$70	$70	$70	$76	$76	$82	$82	$82	$544	$642
Regulatory Options	**Net Benefits (Capital Costs Annualized at 7%)**										**NPV 7**	**NPV 3**
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**		
Quarterly Inspections	-$10	-$7	$7	$9	$8	$20	$22	$35	$36	$35	$94	$125
Semi-Annual Inspections	$25	$27	$38	$39	$39	$48	$49	$59	$60	$59	$315	$380
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$29	$31	$41	$43	$42	$51	$53	$62	$63	$62	$342	$410
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$33	$35	$45	$46	$46	$54	$56	$65	$66	$65	$367	$440
Annual Inspections	$24	$26	$32	$34	$33	$39	$40	$47	$47	$47	$266	$318
Regulatory Options	**Net Benefits (Capital Costs Annualized at 3%)**										**NPV 7**	**NPV 3**
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**		
Quarterly Inspections	-$10	-$7	$7	$9	$9	$21	$23	$36	$36	$36	$97	$129
Semi-Annual Inspections	$26	$28	$38	$40	$40	$48	$50	$60	$60	$60	$321	$386
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$30	$32	$42	$44	$43	$52	$53	$63	$64	$63	$347	$417
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$33	$35	$45	$47	$47	$55	$56	$66	$66	$66	$372	$446
Annual Inspections	$25	$26	$33	$34	$34	$40	$41	$47	$48	$47	$271	$324
Regulatory Options	**Royalty**										**NPV 7**	**NPV 3**
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**		
Quarterly Inspections	$2	$2	$3	$3	$3	$3	$3	$3	$3	$3	$21	$25
Semi-Annual Inspections	$2	$2	$2	$2	$2	$2	$2	$3	$3	$3	$16	$19
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$2	$2	$2	$2	$2	$2	$2	$2	$3	$2	$16	$19
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$15	$18
Annual Inspections	$1	$1	$1	$1	$1	$1	$2	$2	$2	$2	$11	$13

Appendix A-7: Detail of Small Business Impacts Analysis

Company	Number of Employees	Reported Total Revenue ($ in 1000s)			Reported Net Income ($ in 1000s)			Difference in Profit Margin (%)		
		2014	2013	2012	2014	2013	2012	2014	2013	2012
A	444	$2,720,632	$1,313,134	$735,718	$673,587	-$18,930	-$285,069	0.002%	0.004%	0.008%
B	384	$795,542	$974,179	$951,489	-$189,543	$117,634	$149,426	0.007%	0.006%	0.006%
C	15	$1,558,758	$1,983,388	$1,934,642	$253,285	-$553,889	$141,571	0.004%	0.003%	0.003%
D	75	$793,885	$665,257	$583,894	$265,573	$118,000	$61,654	0.007%	0.008%	0.009%
E	293	$569,428	$561,562	$709,038	-$103,100	$161,618	-$2,352,606	0.010%	0.010%	0.008%
F	159	$298,204	$197,372	$231,315	-$139,907	-$277,979	-$150,602	0.019%	0.028%	0.024%
G	300	$532,299	$485,489	$346,460	-$283,645	-$35,272	$68,637	0.010%	0.011%	0.016%
H	225	$616,207	$355,792	$319,299	$99,200	-$153,715	-$95,875	0.009%	0.016%	0.017%
I	158	$224,209	$317,502	$356,516	$120,437	$14,319	-$46,587	0.025%	0.017%	0.015%
J	247	$710,187	$520,182	$368,180	$226,343	$43,683	$55,487	0.008%	0.011%	0.015%
K	202	$472,291	$568,093	$700,195	$15,081	-$192,733	$582	0.012%	0.010%	0.008%
L	123	$133,776	$92,324	$65,664	$63,269	$38,647	-$18,791	0.041%	0.060%	0.084%
M	334	$558,633	$421,860	$231,205	$20,283	$69,184	$46,523	0.010%	0.013%	0.024%
N	27	$44,089	$35,319	$38,165	-$7,585	-$13,073	-$10,327	0.125%	0.156%	0.145%
O	21	$13,840	$17,438	$16,243	$2,884	$8,612	$38,074	0.399%	0.317%	0.340%
P	11	$12,679	$8,029	$2,264	-$34,510	$3,855	-$538	0.435%	0.688%	2.438%
Q	70	$13,208	$13,547	$12,106	$3,205	$3,542	$3,659	0.418%	0.407%	0.456%
R	419		$999,506	$248,322		-$1,222,662	-$53,885		0.006%	0.022%
S	2	$12,352	$13,126	$14,781	-$2,464	$3,353	-$2,359	0.447%	0.421%	0.373%
T	57	$171,418	$87,755	$49,940	$50,953	$49,342	-$153,791	0.032%	0.063%	0.111%
U	20	$3,221	$2,573	$2,366	-$2,152	$1,149	-$13,691	1.713%	2.145%	2.333%
V	29	$104,219	$46,223	$24,969	$28,853	$9,581	$12,124	0.053%	0.119%	0.221%
W	105	$208,553	$203,295	$180,845	-$353,136	-$95,186	-$84,202	0.026%	0.027%	0.031%
X	440	$391,469	$304,538	$159,937	-$143,474	-$222,176	-$132,708	0.014%	0.018%	0.035%
Y	164	$636,773	$431,468	$317,149	-$409,592	-$143,970	-$104,589	0.009%	0.013%	0.017%
Z	374	$1,431,289			$22,665			0.004%		
Average	**181**	**$521,086**	**$424,758**	**$344,028**	**$7,060**	**-$91,483**	**-$117,115**	**0.154%**	**0.183%**	**0.270%**

Appendix A-8: Detail Of Tribal Impacts

Table A-8a: Estimated Annual Total Costs Associated with Operations on Tribal Lands ($ in million)

Estimated Costs* - Capital Costs Annualized Using a 7% Discount Rate												
	Annual										2017-2026	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$1 - 3	$1 - 4	$6 - 11	$14 - 19	$17 - 23	$13 - 20	$10 - 20	$13 - 24	$14 - 24	$56 - 92	$72 - 120
Flare Measurement	$0.6	$0.6	$0.7	$0.7	$0.8	$0.8	$0.9	$0.9	$1.0	$1.0	$5.8	$6.9
Pnumatic Controllers	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$1.8	$2.1
Pneumatic Pumps	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$3.6	$4.2
Liquids Unloading	$0.6	$0.6	$0.6	$0.6	$0.6	$0.7	$0.7	$0.7	$0.7	$0.7	$4.8	$5.7
Storage Tanks	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$7.6	$8.9
LDAR	$10.9	$10.9	$10.9	$10.9	$10.9	$10.9	$10.9	$10.9	$10.9	$10.9	$81.9	$95.8
Administrative Burden	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$6.7	$7.8
Total	$15	$15 - 18	$16 - 19	$21 - 26	$29 - 34	$32 - 38	$28 - 35	$26 - 35	$29 - 39	$29 - 39	$168 - 204	$204 - 251
Estimated Costs* - Capital Costs Annualized Using a 3% Discount Rate												
	Annual										2017-2026	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$1 - 3	$1 - 4	$6 - 11	$14 - 19	$17 - 23	$13 - 20	$10 - 20	$13 - 24	$14 - 24	$56 - 92	$72 - 120
Flare Measurement	$0.5	$0.5	$0.6	$0.6	$0.7	$0.7	$0.8	$0.8	$0.9	$0.9	$5.0	$6.0
Pnumatic Controllers	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$1.5	$1.7
Pneumatic Pumps	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$3.0	$3.5
Liquids Unloading	$0.5	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$4.4	$5.1
Storage Tanks	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$6.6	$7.7
LDAR	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8	$81.2	$94.9
Administrative Burden	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$6.7	$7.8
Total	$14	$15 - 17	$16 - 19	$21 - 25	$28 - 33	$31 - 37	$27 - 34	$25 - 34	$28 - 38	$29 - 39	$164 - 201	$199 - 247

* Includes the monetized value of the CO2 additions which are relatively minor (less than $5,000 during any given year).

Table A-8b: Estimated Annual Total Benefits Associated with Operations on Tribal Lands ($ in million)

		Annual										2017-2026	
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Estimated Benefits - Cost Savings ($ in million)	Capture Target Req.	$0.0	$3.0	$4.3	$7.1	$7.7	$9.7	$11.9	$16.2	$18.6	$18.1	$59.7	$78.0
	Pnumatic Controllers	$0.1	$0.1	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$1.2	$1.4
	Pneumatic Pumps	$0.2	$0.2	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$2.1	$2.5
	Liquids Unloading	$0.5	$0.6	$0.7	$0.7	$0.7	$0.7	$0.8	$0.8	$0.8	$0.8	$5.2	$6.2
	Storage Tanks	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.2
	LDAR	$1.6	$1.9	$2.1	$2.3	$2.3	$2.3	$2.5	$2.6	$2.7	$2.6	$16.7	$19.8
	Total	$2.5	$5.9	$7.5	$10.7	$11.1	$13.1	$15.7	$20.1	$22.7	$22.0	$85.1	$108.2
		Annual										**2017-2026**	
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Estimated Benefits - Value of Methane Reductions	Capture Target Req.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Flare Measurement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Pnumatic Controllers	$2.5	$2.5	$2.8	$2.8	$2.8	$3.0	$3.0	$3.2	$3.2	$3.2	$21.4	$25.3
	Pneumatic Pumps	$3.2	$3.2	$3.5	$3.5	$3.5	$3.8	$3.8	$4.1	$4.1	$4.1	$27.0	$31.8
	Liquids Unloading	$4.0	$4.1	$4.5	$4.6	$4.6	$5.1	$5.2	$5.7	$5.7	$5.8	$36.2	$42.9
	Storage Tanks	$1.0	$1.0	$1.1	$1.1	$1.1	$1.2	$1.2	$1.3	$1.3	$1.3	$8.4	$10.0
	LDAR	$12.5	$12.5	$13.7	$13.7	$13.7	$14.8	$14.8	$16.0	$16.0	$16.0	$106.2	$125.3
	Total	$23.3	$23.3	$25.5	$25.6	$25.7	$27.9	$27.9	$30.2	$30.3	$30.3	$199.2	$235.3
		Annual										**2017-2026**	
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Total Estimated Benefits	Capture Target Req.	$0.0	$3.0	$4.3	$7.1	$7.7	$9.7	$11.9	$16.2	$18.6	$18.1	$59.7	$78.0
	Flare Measurement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Pnumatic Controllers	$2.6	$2.7	$2.9	$2.9	$2.9	$3.2	$3.2	$3.4	$3.4	$3.4	$22.6	$26.7
	Pneumatic Pumps	$3.4	$3.4	$3.7	$3.8	$3.8	$4.1	$4.1	$4.4	$4.4	$4.4	$29.1	$34.4
	Liquids Unloading	$4.5	$4.7	$5.2	$5.3	$5.4	$5.8	$6.0	$6.5	$6.6	$6.6	$41.4	$49.1
	Storage Tanks	$1.0	$1.0	$1.1	$1.1	$1.1	$1.2	$1.2	$1.3	$1.3	$1.3	$8.6	$10.1
	LDAR	$14.2	$14.4	$15.8	$16.0	$15.9	$17.1	$17.3	$18.6	$18.6	$18.6	$122.9	$145.1
	Total	$25.7	$29.2	$33.0	$36.2	$36.8	$41.0	$43.6	$50.3	$52.9	$52.3	$284.2	$343.4

Table A-8c: Estimated Net Benefits Associated with Operations on Tribal Lands ($ in million)

Net Benefits (Capital Costs Annualized at 7%) ($ MM)												
	Annual										2017-2026	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$0 - 2	$02 - 3	($4) - $1	($6 - 11)	($7 - 13)	($1 - 8)	($3) - $6	($5) - $5	($6) - $4	($33) - $4	($42) - $6
Flare Measurement	-$0.6	-$0.6	-$0.7	-$0.7	-$0.8	-$0.8	-$0.9	-$0.9	-$1.0	-$1.0	-$5.8	-$6.9
Pnumatic Controllers	$2.4	$2.4	$2.7	$2.7	$2.7	$2.9	$2.9	$3.2	$3.2	$3.2	$20.8	$24.6
Pneumatic Pumps	$2.9	$2.9	$3.3	$3.3	$3.3	$3.6	$3.6	$3.9	$3.9	$3.9	$25.5	$30.2
Liquids Unloading	$3.9	$4.0	$4.5	$4.7	$4.7	$5.2	$5.3	$5.8	$5.9	$5.9	$36.6	$43.4
Storage Tanks	$0.0	$0.0	$0.1	$0.1	$0.1	$0.2	$0.2	$0.3	$0.3	$0.3	$1.0	$1.2
LDAR	$3.3	$3.5	$4.9	$5.1	$5.0	$6.2	$6.4	$7.7	$7.7	$7.7	$41.0	$49.4
Administrative Burden	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$6.7	-$7.8
Total	$11	$12 - 14	$14 - 17	$10 - 15	$3 - 8	$3 - 9	$9 - 16	$16 - 25	$14 - 24	$13 - 23	$80 - 116	$92 - 140
Net Benefits (Capital Costs Annualized at 3%) ($ MM)												
	Annual										2017-2026	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$0 - 2	$02 - 3	($4) - $1	($6 - 11)	($7 - 13)	($1 - 8)	($3) - $6	($5) - $5	($6) - $4	($33) - $4	($42) - $6
Flare Measurement	-$0.5	-$0.5	-$0.6	-$0.6	-$0.7	-$0.7	-$0.8	-$0.8	-$0.9	-$0.9	-$5.0	-$6.0
Pnumatic Controllers	$2.4	$2.5	$2.7	$2.7	$2.7	$3.0	$3.0	$3.2	$3.2	$3.2	$21.1	$25.0
Pneumatic Pumps	$3.0	$3.0	$3.3	$3.4	$3.4	$3.7	$3.7	$4.0	$4.0	$4.0	$26.1	$30.9
Liquids Unloading	$4.0	$4.1	$4.6	$4.7	$4.8	$5.2	$5.4	$5.9	$6.0	$6.0	$37.0	$44.0
Storage Tanks	$0.1	$0.1	$0.2	$0.2	$0.2	$0.3	$0.3	$0.4	$0.4	$0.4	$2.0	$2.4
LDAR	$3.4	$3.6	$5.0	$5.2	$5.1	$6.3	$6.5	$7.8	$7.8	$7.8	$41.7	$50.2
Administrative Burden	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$6.7	-$7.8
Total	$12	$12 - 14	$14 - 17	$11 - 15	$3 - 9	$4 - 10	$9 - 16	$16 - 25	$15 - 25	$13 - 24	$84 - 120	$97 - 144

Table A-8d: Estimated Incremental Production Associated with Operations on Tribal Lands

Requirement	Annual										10 Years
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026
Natural Gas (Bcf)											
Capture Target Req.	0.0	1.1	1.4	2.1	2.3	2.9	3.3	4.2	4.7	4.7	26.5
Pnumatic Controllers	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.4
Pneumatic Pumps	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.9
Liquids Unloading	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.3
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
LDAR	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	6.7
Total Natural Gas	1.1	2.2	2.5	3.2	3.4	4.0	4.4	5.3	5.8	5.8	37.8

Requirement	Annual										10 Years
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026
Crude Oil (million bbl)											
Capture Target Req.	0.0	0.0	0.0	-0.2	-0.4	-0.5	-0.3	-0.3	-0.3	-0.3	-2.4
Total Crude	0.0	0.0	0.0	-0.2	-0.4	-0.5	-0.3	-0.3	-0.3	-0.3	-2.4

Table A-8e: Estimated Methane Reductions Associated with Operations on Tribal Lands (tons)

Requirement	Annual										10-Years 2017-2026
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	
Capture Target Req.	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE
Pnumatic Controllers	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	23,400
Pneumatic Pumps	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	29,500
Liquids Unloading	3,710	3,770	3,830	3,890	3,950	4,000	4,070	4,130	4,180	4,250	39,780
Storage Tanks	923	923	923	923	923	923	923	923	923	923	9,230
LDAR	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	116,000
Total	21,500	21,600	21,600	21,700	21,800	21,800	21,900	21,900	22,000	22,100	217,900

Table A-8f: Estimated VOC Reductions Associated with Operations on Tribal Lands (tons)

Requirement	Annual										10-Years 2017-2026
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	
Capture Target Req.	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE
Pnumatic Controllers	8,440	8,440	8,440	8,440	8,440	8,440	8,440	8,440	8,440	8,440	84,400
Pneumatic Pumps	770	770	770	770	770	770	770	770	770	770	7,700
Liquids Unloading	13,300	13,500	13,800	14,000	14,200	14,400	14,500	14,700	15,000	15,200	142,600
Storage Tanks	4,230	4,230	4,230	4,230	4,230	4,230	4,230	4,230	4,230	4,230	42,300
LDAR	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220	32,200
Total	30,000	30,200	30,500	30,700	30,900	31,100	31,200	31,400	31,700	31,900	309,600

Table A-8g: Estimated Incremental Royalty for Tribes, ($ in millions)

Requirement	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Natural Gas (Bcf)												
Capture Target Req.	0.0	0.4	0.5	0.9	1.0	1.2	1.5	2.0	2.3	2.3	$10.44	$13.63
Pnumatic Controllers	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	$0.42	$0.50
Pneumatic Pumps	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	$0.27	$0.32
Liquids Unloading	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	$0.71	$0.85
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	$0.02	$0.02
LDAR	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	$2.09	$2.48
Total Natural Gas	0.3	0.8	1.0	1.4	1.4	1.7	2.0	2.6	2.9	2.8	$13.95	$17.79
Requirement	**Annual**										**2017-2026**	
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Crude Oil (Difference in Royalty Value of Deferred Production)												
Capture Target Req.	$0.00	($0.01)	($0.07)	($0.51)	($1.15)	($1.35)	($0.98)	($0.72)	($0.96)	($1.01)	($4.22)	($5.48)
Total Crude	$0.00	($0.01)	($0.07)	($0.51)	($1.15)	($1.35)	($0.98)	($0.72)	($0.96)	($1.01)	($4.22)	($5.48)
Total Net Royalty	**$0.33**	**$0.77**	**$0.91**	**$0.87**	**$0.29**	**$0.34**	**$1.03**	**$1.85**	**$1.93**	**$1.80**	**$9.72**	**$12.31**