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

AQCC	Colorado Air Quality Control Division
Bcf	Billion Cubic Feet
BLM	Bureau of Land Management
CA	Communitized Agreement
CBM	Coalbed Methane
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DPHE	Colorado Department of Public Health and Environment
EIA	Energy Information Administration
EPA	Environmental Protection Agency
GAO	Government Accountability Office
Gg	Giga gram (or 1,000 Mg or 1,000 metric tons)
GHG	Greenhouse Gas
IMDA	Indian Mineral Development Act
IRR	Internal Rate of Return
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
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
Psia	Pounds per Square Inch Absolute
RFA	Regulatory Flexibility Act
SBREFA	Small Business Regulatory Enforcement Fairness Act
scf	Standard Cubic Feet
scfd	Standard Cubic Feet per Day
scfh	Standard Cubic Feet per Hour
TSD	Technical Support Document
VOC	Volatile Organic Compounds
2015 GHG Inventory	Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013

1. Executive Summary

1.1 Background

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

With respect to 43 CFR Part 3100, the proposed rule would conform the BLM's royalty rate provisions for competitive oil and gas leases to the corresponding statutory text, which prescribes a rate "not less than" 12.5%.

With respect to 43 CFR Part 3610, the proposed rule would require the operator to submit additional information to the BLM with its Application for Permit to Drill (APD) for a new oil well. Specifically, the operator must submit its plan to minimize the waste of natural gas from the planned well to the degree reasonably possible. The plan itself would not be incorporated in the APD or otherwise enforced.

Proposed Subpart 3178 would clarify the parameters for an operator to use production on lease without paying royalties on that production. The changes would ensure that the royalty free use of production applies only to uses on the lease, unit, or CA. The changes would not prohibit the operator from using the production off the lease, unit, or CA, but those uses would incur royalties.

Proposed Subpart 3179 would modify the requirements that limit the venting and flaring of produced natural gas. The main provisions are as follows. The proposed rule would prohibit venting of gas except in certain circumstances, and would limit gas flaring during normal production operations from development oil wells to 7,200 Mcf/month (on average, per well, across all of the producing wells on a lease) for the first year of the rule's implementation, 3,600 Mcf/month/well for the second year of the rule's implementation, and 1,800 Mcf/month/well thereafter.Gas flared from a well that is connected to infrastructure would be royalty-bearing except in certain narrow circumstances, such as emergencies.

The rule would also limit losses of gas through venting and leaks by placing requirements on other activities and equipment, including well drilling, completions and workovers, production testing, pneumatic controllers and pumps, storage tanks, liquids unloading, and leak detection and repair (LDAR). As a practical matter, many of the proposed requirements would impact only existing equipment or facilities that are not regulated by the Environmental Protection Agency's (EPA) existing New Source Performance Standards (NSPS) Subpart OOOO (nor by the EPA's recently proposed Subpart OOOOa, if that rule is finalized).

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). This 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 out on the ability to consume 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 are often not compensated for the loss if royalty is not assessed. 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,

[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.

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 Gas Loss Estimates

In 2013, we estimate that 98 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 $392 million and a royalty value of $49 million. Of the 98 Bcf, we estimate that 22 Bcf was vented and 76 Bcf was flared. We estimate that 44 Bcf of the flared gas came from the Federal and Indian mineral estates with 32 Bcf coming from the estates of other mineral owners.[2] With this analysis, the BLM estimates the costs and benefits of the proposed requirements, which pertain to vented and flared gas from the Federal and Indian mineral estates and to vented and flared gas from non-Federal and non-Indian mineral estates, where applicable.

Table 1a: Estimated Vented Gas from Federal and Indian Leases in 2013, by Source

Natural Gas Lost Through Venting	
Source	**Volume (Bcf)**
Well completions	2.08
Pneumatic controllers	5.37
Pneumatic pumps	2.46
Gas Engines	1.11
Compressors	0.42
Liquids Unloading	3.26
Storage Tanks	2.77
Other Production (Includes Leaks)	4.35
Total Venting	**21.82**

Table 1b: Estimated Flared Gas from Federal and Indian Leases in 2013, by Mineral Ownership, Volume in Bcf

	Mineral Ownership			
Source	**Federal**	**Indian**	**Non-Federal, Non-Indian**	**Total**
Flared oil-well gas (Bcf)	24.3	16.3	30.8	71.4
Flared gas-well gas (Bcf)	2.4	0.7	1.5	4.6
Total (Bcf)	26.7	16.9	32.3	75.9

[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.

1.3.2 Monetized Costs

We expect to see the highest levels of compliance activity during the first few, transitional years of the program. The requirements to replace existing equipment would necessitate immediate expenditures. 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] Also, we expect the flaring limit to have a more significant impact in the initial years of the regulation, before the industry transitions to higher capture rates.

After reviewing the proposed requirements, we estimate that, if the EPA does not finalize Subpart OOOOa, this rule would pose costs of about $139 – 174 million per year (with a 7% discount rate) or $130 – 147 million per year (with a 3% discount rate) over the next 10 years, as shown in Table 2a. 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).

If the EPA finalizes Subpart OOOOa as proposed, then the BLM rule would impact fewer sources and the estimated costs would be lower. Under that scenario, we estimate that this rule would pose costs of about $125 – 161 million per year (with a 7% discount rate) or $117 – 134 million per year (with a 3% discount rate), as shown in Table 2b.

We believe that the estimated costs represent the likely upper bound of potential impacts. The estimated impacts account for activities that available data suggest operators already undertake to comply with state or other federal regulations. To the extent that operators are already in compliance with the requirements, the estimated impacts overstate the likely actual impacts of the rule.

Table 2a: Estimated Annual Costs, 2017 – 2026 ($ in millions)

Requirement	7% Discount Rate	3% Discount Rate
Flaring Requirements	$33 – 69	$27 – 44
Well Completion	$8 – 12	$12
Pnumatic Controllers	$6	$5
Pneumatic Pumps	$3	$3
Liquids Unloading	$6	$5 – 6
Storage Tanks	$6	$6
LDAR	$71	$70 – 71
Administrative Burden	$2 – 3	$2 – 3
Total	$139 – 174	$130 – 147

[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 (currently in place), or proposed NSPS Subpart OOOOa (if finalized).

[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.

Table 2b: Estimated Annual Costs if EPA Finalizes Subpart OOOOa, 2017 – 2026 ($ in millions)

Requirement	7% Discount Rate	3% Discount Rate
Flaring Requirements	$33 – 69	$27 – 44
Well Completion	$0	$0
Pnumatic Controllers	$6	$5
Pneumatic Pumps	$3	$3
Liquids Unloading	$6	$5 – 6
Storage Tanks	$6	$6
LDAR	$69	$68
Administrative Burden	$2 – 3	$2 – 3
Total	$125 – 161	$117 – 134

1.3.3 Monetized Benefits

We identify the benefits of the rule as the cost savings that the industry would 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 proposed requirements, we estimate that, if the EPA does not finalize Subpart OOOOa, this rule would result in net benefits ranging from $270 – 354 million per year (present value of annual cost savings calculated using a 7% discount rate and using model averages of the social cost of methane with a 3% discount rate) or $270 – 384 million per year (present value of annual cost savings calculated using a 3% discount rate and using model averages of the social cost of methane with a 3% discount rate). Of that amount, we estimate cost savings to the industry of about $76 – 98 million per year (present value calculated using a 7% discount rate) or $77 – 108 million per year (present value calculated using a 3% discount rate). We estimate the monetized value of the methane reductions to be $193 – 195 million per year from 2017 – 2019, $232 – 237 million per year from 2020 – 2024, and $275 – 277 million per year from 2025 – 2026 (using model averages of the social cost of methane with a 3% discount rate; see section 7.2 for a discussion on the climate effects and evaluation).

If the EPA finalizes Subpart OOOOa as proposed, then the BLM rule would impact fewer sources, and the estimated benefits would be less. Under that scenario, we estimate that this rule would result in net benefits ranging from $255 – 329 million per year (present value of annual cost savings calculated using a 7% discount rate and using model averages of the social cost of methane with a 3% discount rate) or $255 – 357 million per year (present value of annual cost savings calculated using a 3% discount rate and using model averages of the social cost of methane with a 3% discount rate). Of that amount, we estimate cost savings to the industry of about $74 – 95 million per year (present value calculated using a 7% discount rate) or $75 – 105 million per year (present value calculated using a 3% discount rate). We estimate the monetized value of the methane reductions to be $180 – 182 million per year from 2017 – 2019, $215 – 218 million per year from 2020 – 2024, and $252 – 253 million per year from 2025 – 2026.

As with the estimated costs, these benefits are likely representative of upper bound estimates for the potential emissions reductions impacts. Where data are available, they suggest that operators already undertake some activities that reduce venting and flaring, either voluntarily or to comply with state or other federal regulations. The estimates do not, however, fully account for any such actions already undertaken by operators. To the extent that operators are already in compliance with the requirements of the proposed rule, the estimated impacts overstate the likely actual impacts of the rule.

Table 3a: Estimated Annual Benefits, 2017 – 2026 ($ in millions)

Requirement	7% Discount Rate	3% Discount Rate
Flaring Requirements	$40 – 58	$40 – 64
Well Completion	$15 – 24	$15 – 24
Pnumatic Controllers	$59 – 74	$59 – 78
Pneumatic Pumps	$20 – 28	$20 – 28
Liquids Unloading	$40 – 58	$40 – 61
Storage Tanks	$8 – 11	$8 – 11
LDAR	$89 – 115	$89 – 119
Total	$270 – 354	$270 – 384

Table 3b: Estimated Annual Benefits if EPA Finalizes Subpart OOOOa, 2017 – 2026 ($ in millions)

Requirement	7% Discount Rate	3% Discount Rate
Flaring Requirements	$40 – 58	$40 – 64
Well Completion	$1 – 2	$1 – 2
Pnumatic Controllers	$59 – 74	$59 – 78
Pneumatic Pumps	$19 – 25	$19 – 26
Liquids Unloading	$40 – 58	$40 – 61
Storage Tanks	$8 – 11	$8 – 11
LDAR	$88 – 112	$88 – 117
Total	$255 – 329	$255 – 357

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 other climate benefits, or the benefits to public health and the environment of reducing VOC emissions by 400,000 – 423,000 tons per year and reducing emissions of hazardous air pollutants. If the EPA finalizes Subpart OOOOa as proposed, then we estimate this rule would reduce VOC emissions by 391,000 – 411,000 tons per year. 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.

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, the net present value of cost savings 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).

If the EPA does not finalize Subpart OOOOa, we estimate that the rule would result in net benefits of:

- $119 – 203 million per year (costs and costs savings calculated using a 7% discount rate), over time as follows:
    - net benefits of $119 – 131 million per year from 2017 – 2019,
    - net benefits of $162 – 165 million per year from 2020 – 2024, and
    - net benefits of $202 – 203 million per year from 2025 – 2026; or
- $140 – 245 million per year (costs and costs savings calculated using a 3% discount rate), over time as follows:
    - net benefits of $140 – 154 million per year from 2017 – 2019,
    - net benefits of $199 – 205 million per year from 2020 – 2024, and
    - net benefits of $243 – 245 million per year from 2025 – 2026.

If the EPA finalizes Subpart OOOOa as proposed, we estimate that the rule would result in net benefits of:

- $115 – 188 million per year (costs and costs savings calculated using a 7% discount rate), over time as follows:
    - net benefits of $115 – 130 million per year from 2017 – 2019,
    - net benefits of $155 – 156 million per year from 2020 – 2024, and
    - net benefits of $188 million per year from 2025 – 2026; or
- $138 – 232 million per year (costs and costs savings calculated using a 3% discount rate), over time as follows:
    - net benefits of $138 – 151 million per year from 2017 – 2019,
    - net benefits of $192 – 196 million per year from 2020 – 2024, and
    - net benefits of $231 – 232 million per year from 2025 – 2026.

Table 4a: Estimated Annual Net Benefits if EPA Does Not Finalize Subpart OOOOa, 2017-2026 ($ in millions)

Requirement	7% Discount Rate	3% Discount Rate	Non-Monetized Benefits
Flaring Requirements	($11) – $7	$12 – 28	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; Incremenetal environmental benefits of combusting gas downstream.
Well Completion	$3 – 15	$3 – 13	
Pnumatic Controllers	$53 – 68	$54 – 73	
Pneumatic Pumps	$17 – 25	$17 – 25	
Liquids Unloading	$35 – 52	$35 – 55	
Storage Tanks	$2 – 5	$2 – 5	
LDAR	$19 – 43	$19 – 48	
Administrative Burden	($2 – 3)	($2 – 3)	
Total	$119 – 203	$140 – 245	

Table 4b: Estimated Annual Net Benefits if EPA Finalizes Subpart OOOOa, 2017-2026 ($ in millions)

Requirement	7% Discount Rate	3% Discount Rate	Non-Monetized Benefits
Flaring Requirements	($11) – $7	$12 – 28	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; Incremenetal environmental benefits of combusting gas downstream.
Well Completion	$1 – 2	$1 – 2	
Pnumatic Controllers	$53 – 68	$54 – 73	
Pneumatic Pumps	$17 – 23	$17 – 23	
Liquids Unloading	$35 – 52	$35 – 55	
Storage Tanks	$2 – 5	$2 – 5	
LDAR	$19 – 43	$20 – 48	
Administrative Burden	($2 – 3)	($2 – 3)	
Total	$115 – 188	$138 – 232	

1.3.6 Distributional Impacts

Energy System: The proposed 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 2014 for context.

Assuming that the EPA does not finalize Subpart OOOOa:
- Additional natural gas production ranging from about 12 – 15 Bcf per year (0.04 – 0.06% of the total U.S. production);
- The productive use of an additional 29 – 41 Bcf of natural gas, which we estimate would be used to generate 36 – 51 million gallons of NGL per year (0.08 – 0.11% of the total U.S. production).
- A reduction in crude oil production ranging from 0.6 – 3.2 million barrels per year (0.02 – 0.10% of the total U.S. production).

Separate from the volumes listed above, we also expect 1 Bcf of gas to be combusted onsite that would have otherwise been vented. Combined, the capture and combustion of gas represents 49 – 52% of the volume vented in 2013, and the capture or productive use of gas represents 41 – 60% of the volume flared in 2013.

Assuming that the EPA finalizes Subpart OOOOa, we estimate that this rule would result in slightly less additional natural gas production, ranging from 11.7 – 14.5 Bcf per year (representing 0.04 – 0.05% of the total U.S. production in 2014), and the same amount of additional natural gas liquid (NGL) production and reduced crude oil production as presented above. We also expect 0.5 Bcf of gas to be combusted onsite that would have otherwise been vented. Combined, the capture and combustion of gas represents 44 – 46% of the volume vented in 2013, and the capture or productive use of gas represents 41 – 60% of the volume vented and flared in 2013.

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

Royalty: We estimate that if the EPA does not finalize Subpart OOOOa, the rule would result in annual incremental royalties of $9 – 11 million per year (discounted at 7%) or $11 – 17 million per year (discounted at 3%). If the EPA finalizes Subpart OOOOa, we estimate additional royalties of $9 – 11 million per year (discounted at 7%) or $10 – 16 million per year (discounted at 3%).

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.[5]

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 would 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 proposed rule's estimated compliance costs would reduce the entities' profit margin, on average, by about 0.104 percentage points if the EPA does not finalize Subpart OOOOa, or 0.087 percentage points if the EPA finalizes Subpart OOOOa.

Based on this information, we conclude that the proposed rule would not have a significant impact on a substantial number of small entities and an Initial 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 proposal, 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 (see Section 9).

Employment: We examined the proposed requirements and the estimated compliance costs and determined that the proposed 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 leak detection and repair program, both of which would require labor to comply. The administrative burden required to comply with the proposed 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.

[5] 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 Proposed 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 proposed 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 proposed 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 proposed 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[6]:

- A statement of the need for the proposed 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.

[6] OMB Circular A-4.

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 regulatory flexibility analysis with the proposed rule and a final regulatory flexibility analysis with the final rule.[7]

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."[8] 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.[9] 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 proposed 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.

[7] The requirements are found in 5 U.S.C. 603 and 5 U.S.C. 604, respectively; the exception is found in 5 U.S.C. 605(b).
[8] Under 5 U.S.C. 804.
[9] Described in 5 U.S.C. 801.

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

The venting of natural gas from oil and gas leases has historically occurred during drilling and production activities (such as during well completions, liquids unloading, emergency events where the gas cannot be flared, etc.) 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). While older Federal and state regulations generally authorize venting from these sources without approval, newer regulations have focused on requiring operators to combust or capture the gas or limit the venting with more efficient equipment or leak detection programs. New and emerging technologies have also helped operators to make voluntary improvements in these areas.

Operators, depending on the circumstance, may also be authorized to flare natural gas from onshore leases. For example, the BLM's current policy document NTL-4A authorizes operators to flare (or vent in rare circumstances) gas on a short-term basis without approval and without incurring a royalty obligation. These circumstances are limited to emergencies, well purging, production tests, evaluation tests, and routine or special well tests. Under NTL-4A, operators may also flare associated gas royalty free after receiving approval. The BLM may grant approval if the operator: (1) has an action plan to install gathering equipment within a year, or (2) demonstrates that the conservation of associated gas is not economically justified and would lead to the premature abandonment of recoverable oil reserves.

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 proposed 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."[10] The AOFP is "the calculated maximum flow rate that a system may provide in the absence of restrictions."[11] 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.

[10] "Productivity test" as defined by the Schlumberger Oilfield Glossary.
[11] "Open flow potential" as defined by the Schlumberger Oilfield Glossary.

Emergency flaring or venting may be necessary for safety reasons. NTL-4A allows for short-term royalty-free flaring during emergencies, and due to the immediacy of the emergency situations, that royalty-free determination is typically made after the emergency event has been brought under control.

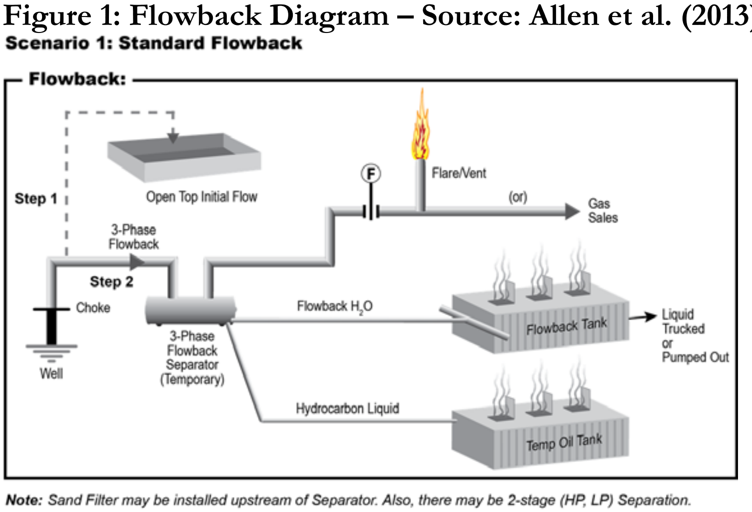
B. Well completions and workovers

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."[12] Refracturing is "an operation to restimulate a well after an initial period of production"[13] and is considered to be both a hydraulic fracturing completion and a workover.

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."[14] Figure 1 is a general flowback diagram, although there are variations to those operational processes.

During flowback, an operator may divert recovered fluids to an open top containment ("Step 1" of the diagram) or it may return recovered fluids to a temporary 3-phase flowback separator ("Step 2"). 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. CH_4 and/or CO_2 emissions may occur from the open top containment, venting or flaring after the separator, and from the flowback tank or hydrocarbon storage tank hatches. A third process (more likely if the flowback does not include hydrocarbon liquids) includes flowback directly to a flowback tank with the emissions vented from the tank.

Figure 1: Flowback Diagram – Source: Allen et al. (2013)



[12] "Workover" as defined by the Schlumberger Oilfield Glossary, http://www.glossary.oilfield.slb.com/en/.aspx.
[13] "Refracturing" as defined by the Schlumberger Oilfield Glossary.
[14] "Flowback" as defined by the Schlumberger Oilfield Glossary.

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. Therefore, continuous bleed controllers cannot replace intermittent controllers in most applications.

Other controllers are limited by their functionality and feasibility. Zero bleed controllers can only be used in applications with very low pressure and therefore may not be suitable to replace continuous bleed pneumatic controllers in many applications. Non-natural gas-driven pneumatic controllers, such as instrument air devices, can be used depending on the application. Instrument air systems 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 for chemical injection or glycol circulation and 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. Typical chemicals include biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and hydrogen sulfide scavengers.

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. Whereas gas wells naturally have sufficient pressure to produce both formation fluids and gas early on, 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:[15]

- 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. Meaning, as fluids continue to accumulate in the wellbore, an operator will need to conduct subsequent purging events. Generally, liquids accumulation may start to occur in gas wells once they begin to decline. At this point, the installation of a plunger lift or other artificial lift system has the greatest benefit, as they are often associated with increased well productivity (in addition to the capture of otherwise vented gas).

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

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[15] 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.

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 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. VRUs are more expensive than combustors and can be used to capture the gas or to direct it to a flare. Capturing the gas 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. Drilling down further, potential sources of leaks include "agitator seals, compressor seals, connectors, pump diaphragms, flanges, hatches, instruments, meters, open-ended lines, pressure relief devices, pump seals, valves, and improperly controlled liquids storage" (EPA 2014, p. 3).

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 Estimates for 2008

In its 2010 report,[16] 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).[17]

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.[18] The volume that it estimated to be economically recoverable represented about 40% of the total volume lost, $23 million in annual Federal royalties, and 16.5 million metric tons of CO_2 equivalent emissions.[19]

Table 5: 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.

[16] 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.
[17] Ibid., p. 12.
[18] Ibid., p. 20.
[19] Ibid., highlights.

4.2 BLM Estimates for 2013

The BLM reviewed data from the 2015 GHG Inventory, the Technical Support Document for the NSPS Subpart OOOOa proposed rule, and ONRR natural gas disposition data. After this review, we conclude that about 98 Bcf of natural gas was vented and flared from producing operations on Federal and Indian leases in 2013. Of that total, we estimate that 22 Bcf was vented and 76 Bcf was flared.

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). We estimate that, of the 76 Bcf of gas flared in 2013, about 44 Bcf of that total (or 57%) came from either the Federal or Indian mineral estates. The remaining 32 Bcf came from non-Federal and non-Indian mineral estates.

The sources of estimated whole natural gas losses from venting (and leaks) ranked by the percent of total volume from greatest to least, are pneumatic controllers (24.6%), fugitives (19.9%), liquids unloading (14.9%), storage tanks (12.7%), pneumatic pumps (11.3%), well completions and workovers (9.5%), gas engines (5.1%), and compressors (1.9%).

Table 6: Estimated Vented Natural Gas from Oil and Gas Operations on Federal and Indian Lands, in 2013

Source	Net Natural Gas Releases from Natural Gas Production Segment (Bcf)	Net Natural Gas Releases from Petroleum Production Segment (Bcf)	Net Natural Gas Releases Total (Bcf)	Percent of Total
Well Completions and Workovers	0.69	1.39	2.08	**9.5%**
Pneumatic Controllers	4.29	1.08	5.37	**24.6%**
Pneumatic Pumps	2.29	0.16	2.46	**11.3%**
Gas Engines	0.87	0.25	1.11	**5.1%**
Compressors	0.41	0.01	0.42	**1.9%**
Liquids Unloading	3.26	0.00	3.26	**14.9%**
Storage Tanks	1.82	0.95	2.77	**12.7%**
Fugitives	3.94	0.41	4.35	**19.9%**
Total	**17.57**	**4.24**	**21.82**	**100.0%**

With respect to the amount of natural gas flared from the Federal and Indian mineral estates, data reported to the ONRR indicate that gas flaring increased by 134% from 2009 to 2013. The total volumes of Federal and Indian gas reported to have been flared were 19 Bcf in 2009, 16 Bcf in 2010, 23 Bcf in 2011, 32 Bcf in 2012, and 44 Bcf in 2013. 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.

In calculating the estimates for vented gas, for most of the sources, we adjusted the EPA's national emissions estimates in the 2015 GHG Inventory downward based on the share of U.S. natural gas production in 2013 that came from Federal and Indian lands (about 12.7%) and the share of U.S. crude production in 2013 that came from Federal and Indian lands (about 7.43%).[20] 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.

For two sources, however, we deviated from that methodology. For well completions in the petroleum production sector using hydraulic fracturing, we estimated releases using a bottom-up approach. In the 2015 GHG Inventory, the EPA uses the same emission factor for oil well completions that use hydraulic fracturing and those that do not. Meanwhile, other research and the EPA's Technical Support Document for the NSPS Subpart OOOOa have indicated that the emissions from hydraulically fractured oil wells are orders of magnitude higher than the emission factor in the 2015 GHG Inventory. Next, for liquids unloading, we estimated releases using a bottom-up approach, basing our estimates on the regional activity data and emission factors in the 2015 GHG Inventory. For this source of losses, in particular, the 2015 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 a full discussion about releases from these sources and the following tables related to the discussion:

- U.S. Methane Emissions from U.S. Oil and Gas Production Segments in 2013, Estimates from the 2015 GHG Inventory;
- U.S. Dry Natural Gas and Crude Oil Production and Natural Gas and Crude Oil Production on Federal and Indian Lands, in 2013, by State Jurisdiction and NEMS Region;
- Methane Emission Factors and Calculated Natural Gas (Whole Gas) Emission Factors for the Natural Gas Production Stage, by Region; and
- Methane and Natural Gas (Whole Gas) Emission Factors for the Petroleum Production Stage.

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.[21] The NSPS applies

[20] Data from the EPA indicate that about 167 Bcf of natural gas was vented from U.S. onshore oil and gas production operations in 2013. Of that amount, about 129 Bcf was vented from the natural gas production segment and 38 Bcf was vented from the petroleum production segment. The breakdown of these releases, by source, is shown in the Appendix.
[21] The EPA also finalized its National Emission Standards for Hazardous Air Pollutants (NESHAP) Review which regulates hazardous air pollutants. While the NESHAP places certain control requirements on

to operations nationwide, including those on Federal and Indian lands, and has a co-benefit of reducing the loss of gas from certain sources.

Further, several states have published regulations and policies that have impacted Federal leases in those jurisdictions. Most notably, in 2014, the Colorado Department of Public Health and the Environment, Air Quality Control Division (AQCC), finalized a rule that extends many of the NSPS requirements to existing sources. Also in 2014, the North Dakota Industrial Commission (NDIC) approved policies aimed at reducing the flaring of natural gas from oil wells. These efforts apply to Federal lands (with likely carryover to Indian lands) in the respective jurisdictions and have a co-benefit of reducing the loss of gas and increasing production.

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 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 a deficiency 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 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.

pneumatic pumps, the NSPS is the preeminent Federal regulatory effort addressing vented gas from the oil and natural gas production sectors.

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" and "modified" sources in the oil and natural gas sectors.[22] 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 gas from certain sources.

In addition to the NSPS Subpart OOOO, the EPA has issued a proposed rule titled Subpart OOOOa that would address emissions from hydraulically fractured oil well completions, pneumatic pumps, leaks, and other sources. Like the NSPS Subpart OOOO, this proposed regulation would address new and modified sources in the oil and natural gas sectors, but not existing sources. It also would apply 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.

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[22] The EPA also finalized its National Emission Standards for Hazardous Air Pollutants (NESHAP) Review, which regulates hazardous air pollutants. While the NESHAP places certain control requirements on pneumatic pumps, the NSPS is the primary Federal regulatory effort addressing vented gas from the oil and natural gas production sectors.

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 that extends many of the NSPS requirements to existing sources in the state. Also in 2014, the North Dakota Industrial Commission (NDIC) adopted requirements aimed at reducing the flaring of natural gas from oil wells. These efforts apply to Federal lands (with likely carryover to Indian lands) in the respective jurisdictions and have a co-benefit of reducing the loss of gas and increasing production.

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.

Alaska: Historically, the State of Alaska had high rates of flaring, but the State adopted regulations in the 1970s to address the problem.[23] 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 VOCs from the oil and natural gas industry.[24] 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 a operators to implement a 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.[25] 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

[23] Alaska Regs is Alaska Administrative Code Title 20 - Chapter 25 235. Gas Disposition.
[24] 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).
[25] 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.

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.[26] The policy and order require well operators to meet flaring reduction targets according to a prescribed time line. 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 90 percent of production by October 2020.[27] 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: Approved a "General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery" on June 5, 2014.[28] 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.29 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 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.

[26] https://www.dmr.nd.gov/oilgas/or24665.pdf

[27] 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.

[28] http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf

[29] The BLM received an advanced copy of the final rule but do not have a citation with which the public can access the regulation.

6. Proposed Regulatory Action and Alternatives Considered

The section explains the proposed regulatory action and alternative policy approaches considered. See Table 7a for a summary of the proposed action and alternatives considered and Table 7b for a side-by-side comparison of the rule's requirements and the EPA's final and proposed NSPS regulations.

Royalty Rate: The BLM is proposing language that would 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 would provide the BLM greater discretion to change the rate in the future, following procedures specified in the preamble of the proposed rule. The royalty rate on existing Federal leases would remain unchanged. The royalty rate for Federal leases obtained non-competitively after the effective date of the final rule would also remain unchanged from its current level of 12.5%, as this level is specified by statute. Tribal leases would 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, the BLM is proposing regulations that would require 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 to the following amounts:
    - 7,200 Mcf/well/month on average across the lease for the first year of the rule's implementation;
    - 3,600 Mcf/well/month on average across the lease for the second year of the rule's implementation; and
    - 1,800 Mcf/well/month on average across the lease thereafter.
    - The BLM may approve an alternative flaring limit above those specified if the operator demonstrates that the specified limits would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.
    - The BLM would also provide a renewable, two-year exemption from the flaring limits to operators of existing wells that are located at least 50 miles from the nearest gas processing facility, and are flaring at least 50% above the specified limit.
- Meter flared gas if flaring exceeds 50 Mcf/day;
- Pay royalty on flared gas from a development well when the well is connected to gas capture infrastructure, but the operator nevertheless flares all or a portion of the gas due to, for example, insufficient line capacity, plant capacity, or maintenance of production facilities.

The respective flaring limits of 7,200 Mcf/month, 3,600 Mcf/month, and 1,800 Mcf/month equate to roughly 240 Mcf/day, 120 Mcf/day, and 60 Mcf/day, respectively. 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.[30] 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.

Like the North Dakota approach, the BLM's proposed approach has several advantages. It establishes a standard designed to impact the largest gas-flaring operations. The flaring limit affords the operator flexibility to choose how to meet the limits. For example, the operator could install capture infrastructure, use on-site capture and transportation technologies, use the gas for other production purposes, re-inject the gas, or curtail production sufficiently to meet the limits. The limit would reduce gas flaring and conserve a portion of the gas until the operator makes arrangements to capture the gas and bring it to market.

In developing the proposed rule, the BLM 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.

Flaring of gas during well testing: To reduce the amount of gas flared during well testing, the BLM is proposing to reduce 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. We reduced the limit to 20 MMcf to reflect the general upper bound of flaring that we are witnessing on operations on Federal and Indian Lands. We did not consider alternatives to limit the flaring further.

Gas loss during well drilling, completion, and workover: To reduce the amount of gas lost during well drilling, the BLM is proposing requirements that 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.

[30] 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 should capture the gas.

To reduce the amount of gas lost during well completions, the BLM is proposing requirements that the gas from well completions be either: captured and routed to a sales line, combusted, re-injected, or used for production purposes on site. The EPA already imposed such requirements for hydraulically fractured gas wells with NSPS Subpart OOOO and has proposed such requirements for hydraulically fractured oil wells with NSPS Subpart OOOOa. Those requirements apply to operations on Federal and Indian lands. As a result, the BLM's rule would practically impact the remainder of well completion operations, including those on hydraulically fractured oil wells (if the EPA does not finalize Subpart OOOOa), and conventional oil and gas wells. The impacts analysis (in the next section) differentiates the impacts by well type (e.g., conventional oil wells, conventional gas wells, and hydraulically fractured oil wells), depending on whether the EPA finalizes Subpart OOOOa.

To reduce the amount of gas lost during well during well completion and post-completion, drilling fluid recovery, or fracturing or refracturing fluid recovery operations, the BLM is proposing requirements that the gas be either: captured and routed to a sales line, combusted, re-injected, or used for production purposes on site. Workovers involving hydraulic fracturing on gas wells are already covered under the EPA's NSPS Subpart OOOO. The EPA also has proposed to cover workovers involving hydraulic fracturing on oil wells with its NSPS Subpart OOOOa.

<u>Gas loss from pneumatic controllers:</u> To reduce the amount of gas lost from pneumatic controllers, the BLM is proposing requirements 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.

<u>Gas loss from pneumatic pumps (chemical injection pumps):</u> To reduce the amount of gas lost from pneumatic pumps, the BLM is proposing requirements that operators replace chemical injection pumps and diaphragm pumps that use gas with zero-emission pumps or route the gas releases from the pumps to a flare. A pump is exempted from this requirement if: use of a pneumatic pump is required based on functional needs, including situations in which solar power would be insufficient, and there is no existing flare device on site; 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.

<u>Gas loss during liquids unloading:</u> To reduce the amount of gas lost during liquids unloading, the BLM is proposing various operational requirements, including that the operator be on site and monitor the liquids unloading event, if the well is not equipped with an automated system. The BLM is also proposing to prohibit well purging from any well drilled after the rule's effective date. In developing the proposal, the BLM considered whether it would be appropriate to require the installation of plunger lifts on existing wells, but determined that such a requirement would not be technically feasible in all cases. As such, we did not carry that alternative forward.

<u>Gas loss from oil and condensate storage tanks:</u> To reduce the amount of gas vapors vented or lost from storage tanks, the BLM is proposing to require that the operator either capture and route the vapors to a sales line or combust the vapors, if the VOC emissions from the tank or tank battery exceed 6 tpy. The EPA already imposed such requirements on new or modified storage tanks that exceed 6 tpy of VOC emissions. 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 BLM is proposing a requirement that the operator conduct periodic inspections of its well site. The operator would be required to assess the well site for leaks semi-annually, with the inspection frequency either lengthening or shortening depending on the number of leaks found during two consecutive inspections.

In developing the proposal, 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).

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 put forward the proposal 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 7a: Proposed Requirements and Alternative Considered

Source	Distinction Within Source	Proposed Requirements	Alternatives Considered to the Proposed Requirements or Maintaining the Status Quo
Flared (variety of sources)	Oil-well gas (associated gas)	The operator is required to submit information with its APD for a development oil well about anticipated gas volumes and planned disposition of any associated gas. The operator is not permitted to flare gas from a development oil well in excess of 7,200 Mcf/month/well (on average across a lease) for the first year of the rule's implementation, 3,600 Mcf/month/well for the second year of the rule's implementation, and 1,800 Mcf/month/well thereafter. The operator is required to meter flared associated gas if greater than 50 Mcf/day, monthly average. Royalty is specified on gas vented and flared during production operations when the well is connected to gas capture infrastructure (including during times of temporary line capacity issues, processing plant maintenance, etc). 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; Alternative flaring limits; Identifying gas capture zones and ordering the capture of gas under certain conditions.
	Well testing	Reduce maximum royalty-free volume limit to 20 MMcf.	None
Well drilling, completions, and well maintenance	None (practically affects all conventional completions and affects hydraulically fractured oil well completions only if the EPA does not finalize Subpart OOOOa)	Require gas to be captured and routed to a sales line, combusted, re-injected, or used for production purposes on site.	Placing the proposed requirements on a subset of the well completions rather than on all well completions.

Table 7a: Proposed Requirements and Alternative Considered

Source	Distinction Within Source	Proposed Requirements	Alternatives Considered to the Proposed Requirements or Maintaining the Status Quo
Pneumatic controllers	Continuous, high bleed (practically affects existing controllers)	Replace high-bleed continuous controllers with low-bleed controllers, with some exceptions.	None
Pneumatic pumps	Chemical injection pumps (practically affects existing pumps, and affects new pumps only if the EPA does not finalize Subpart OOOOa)	Replace pumps that use gas with solar powered units, with some exceptions. Operators are required to reduce releases from chemical injection pumps where feasible.	None
Gas well liquids unloading	None	Various operational and reporting requirements when conducting liquids unloading without an automated system; No well purging for wells drilled after the effective date.	Placing plunger lift requirements on existing wells
Oil and condensate storage tanks	None (practically affects existing uncontrolled tanks)	Require combustion (at a minimum) if VOC emissions exceed 6 tpy, 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, and affects new wellsite facilities only if the EPA does not finalize Subpart OOOOa)	Requires the operator to implement an LDAR program, initially requiring semi-annual inspections (with the inspection frequency adjustable depending on the number of leaks identified during successive inspections). The operator must use an infrared camera, portable analyzer (only if operator has less than 500 wells), or other method approved by the BLM. The operator must repair all leaks that it identifies. The BLM may approve an operator's LDAR or monitoring programs.	Alternative inspection frequencies and mechanisms for adjusting the frequencies, including different frequencies for marginal wells.

Table 7b: Proposed Requirements and Interaction with EPA's Enacted and Proposed Regulations

Source	EPA Subpart OOOO (Enacted)	EPA Subpart OOOOa (Proposed)	Practical Impact of BLM's Proposed Regulation
Flaring during normal production operations	None	None	Would regulate operations.
Well completions and workovers	Regulates hydraulically fractured gas well completions	Would regulate hydraulically fractured oil well completions	Would regulate completions except for hydraulically fractured gas wells and hydraulically fractured oil wells if Subpart OOOOa is finalized.
Pneumatic controllers	Regulates new pneumatic controllers	None	Would regulate pneumatic controllers installed before Subpart OOOO's implementation.
Pneumatic Pumps	None	Would regulate new pneumatic pumps	Would regulate pneumatic pumps except for new pumps if Subpart OOOOa is finalized.
Gas well liquids unloading	None	None	Would regulate operations.
Oil and condensate storage tanks	Regulates new or modified tanks	None	Would regulate tanks existing before Subpart OOOO's implementation.
Leaks	None	Would regulate new and modified wellsites	Would regulate wellsites except for new or modified wellsites if Subpart OOOOa is finalized.

7. Examination of the Proposed Requirements and Alternatives

This section estimates the impacts of the proposed 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. The rule would also pose administrative burdens to industry and the BLM. Those 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 proposed 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.

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 quanity of methane reductions and monetized the social benefits of those reductions using estimates for the social cost of methane.[31] We also estimated the quantity of carbon dioxide additions and monetized the social costs of those additions 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 estimated the social cost of methane using the values presented by Marten *et al.* (2014) and used by the EPA in its analysis of its Subpart OOOOa proposed regulation (see explanation that follows) and its proposed rule New Source Standards of Performance for Municipal Solid Waste Landfills.[32] We estimated the quantity of carbon dioxide additions 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.[33] We estimated the social cost of carbon dioxide per the values provided by the Interagency Working Group on Social Cost of Carbon.[34]

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[31] 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.

[32] Documents related to that rulemaking are available on the EPA website at http://www3.epa.gov/airtoxics/landfill/landflpg.html

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

[34] The publication, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866 (May 2013, Revised July 2015) https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf

The remaining discussion in this section is pulled directly from the EPA's Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector. It reads as follows:

> 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 were 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 2015 RIA, pp. 4-6)
>
> We calculated the global social benefits of methane emissions reductions expected from the proposed NSPS 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 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 developed by 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 Marten *et al.* SC-CH_4 estimates. Estimates of the SC-CO_2 have been used by 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 EPA and other executive branch agencies and offices 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 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).[35]

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. The new versions of the models offer some improvements in these areas, although further work is warranted.

Accordingly, EPA and other agencies continue to engage in research on modeling and valuation of climate impacts with the goal to improve these estimates. The EPA and other agencies also continue to consider feedback on the SC-CO_2 estimates from stakeholders through a range of channels, including public comments on Agency rulemakings that use the SC-CO_2 in supporting analyses and through regular interactions with stakeholders and research analysts implementing the SC-CO_2 methodology used by the IWG. In addition, OMB's Office of Information and Regulatory Affairs sought public comment on the approach used to develop the SC-CO_2 estimates through a separate comment period that ended on February 26, 2014.

After careful evaluation of the full range of comments, the IWG continues to recommend the use of the SC-CO_2 estimates in regulatory impact analysis. With the release of the response to comments, the IWG announced plans to obtain expert independent advice from the National Academy of Sciences to ensure that the SC-CO_2 estimates continue to reflect the best available scientific and economic information on climate change. The NRC review will be informed by the public comments received and focus on the technical

[35] Both the 2010 SC-CO_2 TSD and the current SC-CO_2 TSD are available at: https://www.whitehouse.gov/omb/inforeg_regpol_agency_review [click on "Social Cost of Carbon" at top of page or go directly to https://www.whitehouse.gov/omb/oira/social-cost-of-carbon].

merits and challenges of potential approaches to improving the SC-CO_2 estimates in future updates.

Concurrent with OMB's publication of the response to comments on SC-CO_2 and announcement of the NRC process, OMB posted a revised TSD that includes two minor technical corrections to the current estimates. One technical correction addressed an inadvertent omission of climate change damages in the last year of analysis (2300) in one model and the second addressed a minor indexing error in another model. On average the revised SC-CO_2 estimates are one dollar less than the mean SC-CO_2 estimates reported in the November 2013 TSD. The change in the estimates associated with the 95th percentile estimates when using a 3 percent discount rate is slightly larger, as those estimates are heavily influenced by the results from the model that was affected by the indexing error.

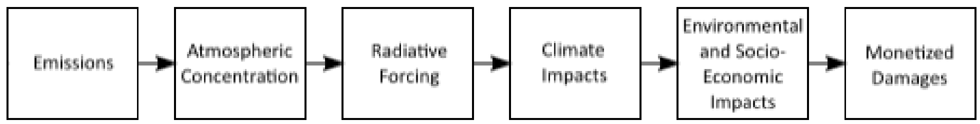
The four SC-CO_2 estimates are: $13, $45, $67, and $130 per metric ton of CO_2 emissions in the year 2020 (2012 dollars).[36] The first three values are based on the average SC-CO_2 from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. Estimates of the SC-CO_2 for several discount 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. 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.

A challenge particularly relevant to this proposal is that the IWG did not estimate the social costs of non-CO_2 GHG emissions at the time the SC-CO_2 estimates were developed. One alternative approach to value methane impacts is to use the global warming potential (GWP) to convert the emissions to CO_2 equivalents which are then valued using the SC-CO_2 estimates.

The GWP measures the cumulative radiative forcing from a perturbation of a non-CO_2 GHG relative to a perturbation of CO_2 over a fixed time horizon, often 100 years. The GWP mainly reflects differences in the radiative efficiency of gases and differences in their atmospheric lifetimes. While the GWP is a simple, transparent, and well-established metric for assessing the relative impacts of non-CO_2 emissions compared to CO_2 on a purely physical basis, there are several well-documented limitations in using it to value non-CO_2 GHG benefits, as discussed in the 2010 SC-CO_2 TSD and previous rulemakings (e.g., U.S.

[36] The current version of the SC-CO_2 TSD is available at: https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf. The TSDs present SC-CO_2 in $2007. The estimates were adjusted to 2012$ using the GDP Implicit Price Deflator. Also available at: http://www.gpo.gov/fdsys/pkg/ECONI-2013-02/pdf/ECONI-2013-02-Pg3.pdf. The SC-CO_2 values have been rounded to two significant digits. Unrounded numbers from the 2013 SCC TSD were adjusted to 2012$ and used to calculate the CO_2 benefits.

EPA 2012b, 2012d).[37] In particular, several recent studies found that GWP-weighted benefit estimates for methane are likely to be lower than the estimates derived using directly modeled social cost estimates for these gases. Gas comparison metrics, such as the GWP, are designed to measure the impact of non-CO_2 GHG emissions relative to CO_2 at a specific point along the pathway from emissions to monetized damages (depicted in Figure 4-1), and this point may differ across measures.



Source: Marten *et al.* 2014

Figure 7-1 Path from GHG Emissions to Monetized Damages

The GWP is not ideally suited for use in benefit-cost analyses to approximate the social cost of non-CO_2 GHGs because it ignores important nonlinear relationships beyond radiative forcing in the chain between emissions and damages. These can become relevant because gases have different lifetimes and the SC-CO_2 takes into account the fact that marginal damages from an increase in temperature are a function of existing temperature levels. Another limitation of gas comparison metrics for this purpose is that some environmental and socioeconomic impacts are not linked to all of the gases under consideration, or radiative forcing for that matter, and will therefore be incorrectly allocated. For example, the economic impacts associated with increased agricultural productivity due to higher atmospheric CO_2 concentrations included in the SC-CO_2 would be incorrectly allocated to methane emissions with the GWP-based valuation approach.

Also of concern is the fact that the assumptions made in estimating the GWP are not consistent with the assumptions underlying SC-CO_2 estimates in general, and the SC-CO_2 estimates developed by the IWG more specifically. For example, the 100-year time horizon usually used in estimating the GWP is less than the approximately 300-year horizon the IWG used in developing the SC-CO_2 estimates. The GWP approach also treats all impacts within the time horizon equally, independent of the time at which they occur. This is inconsistent with the role of discounting in economic analysis, which accounts for a basic preference for earlier over later gains in utility and expectations regarding future levels of economic growth. In the case of methane, which has a relatively short lifetime compared to CO_2, the temporal independence of the GWP could lead the GWP approach to underestimate the SC-CH_4 with a larger downward bias under higher discount rates (Marten and Newbold, 2012).[38]

EPA sought public comments on the valuation of non-CO_2 GHG impacts in previous rulemakings. In general, the commenters strongly encouraged EPA to incorporate the monetized value of non-CO_2 GHG impacts into the benefit cost analysis, however they noted the challenges associated with the GWP-approach, as discussed above, and encouraged the use of directly-modeled estimates of the SC-CH_4 to overcome those challenges.

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[37] See also Reilly and Richards, 1993; Schmalensee, 1993; Fankhauser, 1994; Marten and Newbold, 2012.

[38] We note that the truncation of the time period in the GWP calculation could lead to an overestimate of SC-CH_4 for near term perturbation years when the SC-CO_2 is based on a sufficiently low or steeply declining discount rate.

EPA had cited several researchers that had directly estimated the social cost of non-CO_2 emissions using IAMs but noted that the number of such estimates was small compared to the large number of SC-CO_2 estimates available in the literature. EPA found considerable variation among these published estimates in terms of the models and input assumptions they employ (U.S. EPA, 2012d). These studies differed in the emissions perturbation year, employed a wide range of constant and variable discount rate specifications, and considered a range of baseline socioeconomic and emissions scenarios that have been developed over the last 20 years. Furthermore, at the time, none of the other published estimates of the social cost of non-CO_2 GHG were consistent with the SC-CO_2 estimates developed by the IWG, and most were likely underestimates due to changes in the underlying science since their publication.

Therefore, EPA concluded that the GWP approach would serve as an interim method of analysis until directly modeled social cost estimates for non-CO_2 GHGs, consistent with the SC-CO_2 estimates developed by the IWG, were developed. EPA presented GWP-weighted estimates in sensitivity analyses rather than the main benefit-cost analyses.[39]

Since then, a paper by Marten *et al.* (2014) provided the first set of published SC-CH_4 estimates in the peer-reviewed literature that are consistent with the modeling assumptions underlying the SC-CO_2 estimates.[40] 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-CO_2 estimates. The aggregation method involved distilling the 45 distribution of the SC-CH_4 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. 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-CH_4, 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 28-36, 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 CO_2, changes in the lifetime estimate for

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[39] For example, the 2012 New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry are expected to reduce methane emissions by 900,000 metric tons annually, see http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf. Additionally, the 2017-2025 Light-duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, promulgated jointly with the National Highway Traffic Safety Administration, is expected to reduce methane emissions by over 100,000 metric tons in 2025 increasing to nearly 500,000 metric tons in 2050, see http://www.gpo.gov/fdsys/pkg/FR-2012-10-15/pdf/2012-21972.pdf

[40] 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.

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 how biogenic and fossil methane have different carbon cycle effects, and for *[sic]* whether to account for climate feedbacks on the carbon cycle for both methane and CO_2 (rather than just for CO_2 as was done in AR4).[41,42]

Marten *et al.* (2014) discuss these estimates, (SC-CH_4 estimates presented below in Table 7-1), and compare them with other recent estimates in the literature.[43] The authors noted that a direct comparison of their 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 7-1 Social Cost of Methane (SC-CH_4), 2012 – 2050[a] [in 2012$ per metric ton] (Source: Marten *et al.*, 2015[b])

Year	SC-CH_4			
	5 Percent Average	3 Percent Average	2.5 Percent Average	3 Percent 95th percentile
2012	$430	$1,000	$1,400	$2,800
2015	$490	$1,100	$1,500	$3,000
2020	$580	$1,300	$1,700	$3,500
2025	$700	$1,500	$1,900	$4,000
2030	$820	$1,700	$2,200	$4,500
2035	$970	$1,900	$2,500	$5,300
2040	$1,100	$2,200	$2,800	$5,900
2045	$1,300	$2,500	$3,000	$6,600
2050	$1,400	$2,700	$3,300	$7,200

[a] The values are emissions-year specific and are defined in real terms, i.e., adjusted for inflation using the GDP implicit price deflator.

[41] *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

[42] Note that this proposal uses a GWP value for methane of 25 for CO_2 equivalency calculations, consistent with the GHG emissions inventories and the IPCC Fourth Assessment Report (AR4).

[43] Marten *et al.* (2015) estimates are presented in 2007 dollars. These estimates were adjusted for inflation using National Income and Product Accounts Tables, Table 1.1.9, Implicit Price Deflators for Gross Domestic Product (US Department of Commerce, Bureau of Economic Analysis), http://www.bea.gov/iTable/index_nipa.cfm Accessed 3/3/15.

[b] The estimates in this table have been adjusted to reflect the minor technical corrections to the SC-CO_2 estimates described above. See erratum for more details (citation to be provided when available).

The application of directly modeled estimates from Marten *et al.* (2014) 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 7-1 are used to monetize the benefits of reductions in methane emissions expected as a result of the proposed rulemaking. Forecast changes in methane emissions in a given year, expected as a result of the proposed 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.

EPA recently conducted a peer review of the application of the Marten *et al.* (2014) non-CO_2 social cost estimates in regulatory analysis and received responses that supported this application. Three reviewers considered seven charge questions that covered issues such as EPA's interpretation of the Marten *et al.* estimates, the consistency of the estimates with the SC-CO_2 estimates, EPA's characterization of the limits of the GWP-approach to value non-CO_2 GHG impacts, and the appropriateness of using the Marten *et al.* estimates in regulatory impact analyses. The reviewers agreed with EPA's interpretation of Marten *et al.*'s estimates; generally found the estimates to be consistent with the SC-CO_2 estimates; and concurred with the limitations of the GWP approach, finding directly modeled estimates to be more appropriate. While outside of the scope of the review, the reviewers briefly considered the limitations in the SC-CO_2 methodology (e.g., those discussed earlier in this section) and noted that because the SC-CO_2 and SC-CH_4 methodologies are similar, the limitations also apply to the resulting SC-CH_4 estimates. Two of the reviewers concluded that use in RIAs of the SC-CH_4 estimates developed by Marten *et al.* and published in the peer-reviewed literature is appropriate, provided that the Agency discuss the limitations, similar to the discussion provided for SC-CO_2 and other economic analyses. All three reviewers encouraged continued improvements in the SC-CO_2 estimates and suggested that as those improvements are realized they should also be reflected in the SC-CH_4 estimates, with one reviewer suggesting the SC-CH_4 estimates lag this process. EPA supports continued improvement in the SC-CO_2 estimates developed by the U.S. government and agrees that improvements in the SC-CO_2 estimates should also be reflected in the SC-CH_4 estimates. The fact that the reviewers agree that the SC-CH_4 estimates are generally consistent with the SC-CO_2 estimates that are recommended by OMB's guidance on valuing CO_2 emissions reductions, leads EPA to conclude that use of the SC-CH_4 estimates is an analytical improvement over excluding methane emissions from the monetized portion of the benefit cost analysis.

In light of the favorable peer review and past comments urging EPA to value non-CO_2 GHG impacts in its rulemakings, the Agency has used the Marten *et al.* (2014) SC-CH_4 estimates to value methane impacts expected from this proposed rulemaking and has included those benefits in the main benefits analysis. . . .(EPA 2015. Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, pp. 4-7 – 4-16.)

The BLM notes that the EPA requested comment on the use of the directly modeled estimates, from the peer-reviewed literature, for the social cost of non-CO_2 GHGs in its RIA for the Subpart OOOOa proposal. In light of such comments, in preparing the RIA for the final Subpart OOOOa rule, the EPA will presumably retain, modify, or abandon its proposed approach to accounting for the social costs of methane emissions in the benefit-cost analysis. The BLM believes that it is appropriate for the BLM to defer to and rely on the subject matter expertise of EPA in evaluating and selecting estimates of the social costs of methane emissions. Thus, we anticipate that the BLM's RIA for the final rule will follow the same approach to accounting for the social costs of methane emissions that the EPA uses in its final OOOOa rule, after the EPA takes into account public comments on its proposed approach. We will continue to coordinate closely with the EPA on this matter.

7.3 Discount Rate

OMB Circular A-94 (Revised) "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs"[44] 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 proposed 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 Marten et al. (2015). The EPA used the same social cost of methane estimates in its regulatory impacts analysis for the NSPS Subpart OOOOa proposed rule, finding that the estimates are analogous to the use of the social cost of carbon estimates provided by the Interagency Working Group on Social Cost of

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

Carbon.[45] Marten et al. provide 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 generated by Marten using the middle discount rate of 3 percent. 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 SCC estimates in the analyses. We note that using the other SCC estimates would result in varying benefits and net benefits. Using the 2.5% SCC discount 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.

Beyond the initial 10-year period, we expect the rule to have less of an impact. After the initial replacement of existing equipment that would be required by this rule, 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 (currently in place), or proposed NSPS Subpart OOOOa (if finalized).

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 proposed requirements. Future commodity prices are subject to substantial uncertainty, so we believe it is reasonable to examine costs and benefits under a range of potential future prices.

With respect to the appropriate crude oil price to consider, we note that current prices are low and Energy Information Administration (EIA) projected prices are modestly higher. Crude oil prices in

45 EPA, "Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector" at 4-15. The Interagency Working Group's paper is available on the web at https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.

2015 have been among the lowest in recent history, ranging from $42/bbl to $61/bbl.[46] At the time we prepared this analysis, the crude oil price was below $40/bbl. The EIA's long-term price projections are $53/bbl in 2015, $67/bbl in 2016, $70/bbl in 2017, $73/bbl in 2020, $85/bbl in 2025, and $99/bbl in 2030, with an annual growth rate from 2013 to 2040 of 1.2%.[47]

Natural gas prices in 2015 have been among the lowest recent years, ranging from $2.56/Mcf to $3.32/Mcf, though not as low as prices in the first half of 2012.[48] At the time we prepared this analysis, the natural gas price was below $2.00/Mcf. The EIA's long-term price projections are $3.79/Mcf in 2015, $3.80/Mcf in 2016, $3.91/Mcf in 2017, $5.02/Mcf in 2020, $5.61/Mcf in 2025, and $5.85/Mcf in 2030, with an annual growth rate from 2013 to 2040 of 2.8%.[49]

The EIA does not forecast NGL prices sold from the production sector. However, we observed an average price of about $0.64 for NGL produced from Federal lands in FY 2015.[50] We then adjusted that value upwards based on the EIA crude oil price projections.

See Table 7c and 7d, on the following page, which show the projected commodity prices used in this analysis.

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 proposed 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 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 proposed specifications.

C. Uncertainty about Climate Effects

As described in Section 7.2, there are limitations in the methodology used to calculate the social cost of carbon dioxide and methane. These limitations include "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

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

47 EIA. Annual Energy Outlook, Table 12. April 14, 2015. Reference case for WTI spot price. Data available at http://www.eia.gov/forecasts/aeo/tables_ref.cfm

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

49 EIA. Annual Energy Outlook, Table 13. April 14, 2015. Natural gas spot price at Henry Hub. Prices converted from MMbtu to Mcf using a factor of 1.028. Data available at http://www.eia.gov/forecasts/aeo/tables_ref.cfm

50 See ONRR reporting tool at http://statistics.onrr.gov/.

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 CO2 reductions to inform benefit-cost analysis. The new versions of the models offer some improvements in these areas, although further work is warranted."[51]

D. 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. In addition, the impact of the flaring limit is likely to be influenced by a number of factors, many of which are somewhat or even highly uncertain. An operator's response to a flaring limit 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. There is also general uncertainty about an operator's response to the liquids unloading requirements, given that approaches to avoid well purging are likely to be dictated by well characteristics and operator choice.

Table 7c: EIA Crude Oil and Natural Gas Price Forecasts, 2015 – 2026

Year	Crude Oil – West Texas Intermediate Spot ($/bbl)	Natural Gas – Spot Price at Henry Hub ($/million Btu)
2015	52.72	3.69
2016	67.28	3.70
2017	70.14	3.80
2018	70.06	4.21
2019	71.50	4.55
2020	72.96	4.88
2021	75.10	5.02
2022	77.48	5.09
2023	79.95	5.25
2024	82.48	5.35
2025	85.02	5.46
2026	87.73	5.67

Source: EIA, Annual Energy Outlook 2015, Tables 12 and 13.

[51] Excerpt drawn from the EPA's Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, pp. 4-7 – 4-16.

Table 7d: Natural Gas Liquids Price Assumptions, 2010 – 2026

Year	NGL Price ($/gal)
2010	0.92
2011	1.15
2012	0.98
2013	0.85
2014	0.92
2015	0.64
2016	0.82
2017	0.85
2018	0.85
2019	0.87
2020	0.88
2021	0.91
2022	0.94
2023	0.97
2024	1.00
2025	1.03
2026	1.06

Source: Historical prices (2010 – 2015) are derived from the ONRR website for onshore production from Federal lands in all states. Prices for 2016-2026 are projected using the change in the EIA's forcasted crude oil price.

7.6 Flared Associated Gas

The proposed rule has several requirements to limit the flaring of associated gas from development oil wells. As presented in Section 5, according to ONRR data, operators flared roughly 76 Bcf of natural gas from BLM-administered leases in 2013. We estimate that roughly 44 Bcf of that amount was natural gas from the Federal and Indian mineral estates. Flaring from oil wells alone accounted for 71 Bcf (with about 41 Bcf of that amount being Federal and Indian mineral estate gas).

The BLM is proposing several requirements that would reduce the waste of associated gas through flaring. With respect to wells that produce both Federal or Indian, and non-Federal, non-Indian oil or gas, the proposed rule provides that the BLM would coordinate on a case-by-case basis with the state regulatory authority having jurisdiction, if any BLM action to enforce a prohibition, limitation, or order adversely affects production of oil or gas that comes from non-Federal and non-Indian mineral interests.

A. Flaring Limits

1. Background

The proposed rule would impose a gas flaring limit on development oil wells. The rule would limit the flaring to 7,200 Mcf/month/well (on average across a lease) for the first year of the rule's implementation, 3,600 Mcf/month/well (on average across a lease) for the second year of the rule's implementation, and 1,800 Mcf/month/well (on average across a lease) thereafter. These limits correlate to roughly 120 Mcf/day, 90 Mcf/day, and 60 Mcf/day, respectively. The BLM may approve an alternative flaring limit if the operator demonstrates that the proposed limits would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. In addition, the operator may receive an exemption from the limit if the lease is not connected to a gas pipeline, is located over 50 miles from the nearest gas processing plant, and if the flaring for the most recent month exceeds the limit in effect by at least 50%.

According to ONRR data, an average of 1,271 Federal and Indian leases flared oil-well gas during any given month in FY 2014. In total, the leases flared about 77 Bcf of gas, while producing about 137 million barrels of crude oil and 73 Bcf of gas during the months when they flared. See Table 8a. In addition, the ONRR data show that on average, about 43% of the estimated wells with oil-well gas flaring also marketed and sold gas at the time when they were flaring, indicating that a large number of operations flare despite being connected to a pipeline or having some ability to market and sell the gas.[52]

We note that these data include both development wells and exploration/wildcat oil wells. Since the rule would only apply flaring limits to development oil wells (which are the majority of all of the

[52] Similarly, Carbon Limits reports that in the Bakken Formation, 68% of the natural gas produced is captured and sold, 14% of the gas is flared from pipeline connected wells, and 18% of the gas is flared from isolated wells (CL 2015a, p. 51).

wells), all estimates presented here on the potential impacts of the flaring limit somewhat overstate the potential levels of production deferment and gas conservation.

Table 8a: Background on Oil Wells with Associated Gas Flaring in FY 2014

Month FY 2014	Number of lease agreements	Number of wells with oil production and oil-well gas flaring	Number of wells with oil-well gas flaring and gas marketed	Total oil production (bbl)	Total oil-well gas flared (Mcf)	Total oil-well gas production (Mcf)
October	1,271	3,858	1,788	10,956,987	6,022,995	6,604,600
November	1,213	3,484	1,539	10,497,510	6,245,183	5,470,819
December	1,275	3,558	1,630	10,515,272	6,310,534	5,107,437
January	1,223	3,261	1,386	10,209,648	6,227,200	5,105,289
February	1,238	3,610	1,414	10,008,858	5,903,818	4,982,544
March	1,292	3,577	1,497	11,862,642	6,267,724	6,704,517
April	1,240	3,505	1,488	11,000,297	6,128,755	5,305,193
May	1,283	4,276	2,201	12,441,886	7,375,036	6,210,270
June	1,254	3,250	1,262	12,037,697	6,707,276	6,213,053
July	1,333	3,374	1,262	12,543,726	6,643,625	7,521,963
August	1,335	3,938	1,836	12,590,756	6,701,583	7,315,636
September	1,293	3,313	1,379	11,968,484	6,262,607	6,891,104
Monthly average	**1,271**	**3,584**	**1,557**	**11,386,147**	**6,399,695**	**6,119,369**
Total FY 2014				**136,633,763**	**76,796,336**	**73,432,425**

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,[53] 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 where

[53] 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

building a pipeline to connect to the market is impractical. 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.[54]

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 and stored in tanks at the well site. Trucks would transport the stored NGLs 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.

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, the electricity produced for use on site would be viewed as beneficial use, and therefore 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, it would not be beneficial use and the gas used to generate the electricity would not be royalty free.

[54] *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).

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 comparision of these capture approaches and technologies, which we summarize here.

For gas gathering, 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 up to months and year and is not a mobile technology.[55]

For CNG, Carbon Limits shows capital costs if $400 – 1,000 per day and operating costs of $0.24 – 1.30 per Mcf. It also suggests revenues $5 – 6 per Mcf and a payback period of about 1 year. Equipment can be procured within weeks and deployed to or mobilized among operations in 1 day.[56]

For NGL recovery, Carbon Limits shows low to medium capital costs if $800 – 2,500 per Mcf per day and operating costs of $0 – 0.22 per Mcf. In contrast, high costs might reveal 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 can be procured in 15 – 24 weeks and deployed to or mobilized among operations in 1 day to 2 weeks.[57]

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.[58]

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 believe that if an operator expects to exceed the flaring limit for a development oil well, the operator might also curtail production from the well to reduce the amount of gas co-produced and flared until capture infrastructure becomes available, uses alternative capture technologies, or until the well production declines to a level that would not exceed the flaring limit.

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

Any curtailed production is not lost. Rather, it is deferred from the present to the future. We expect any potential deferment to be temporary, with the amount and duration of the deferment depending on the operator's response, 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, among other factors. Any curtailment would slow the flaring of oil-well gas, a substantial portion of which would be conserved for potential delivery to the market. The deferment of production receipts from the present to the future would pose a cost to the operator, but the additional receipts from conserved gas that would not have been otherwise realized would pose a benefit to the operator.

2. Modeling the Impact

As discussed earlier, the impact of the flaring limit will be influenced by a number of factors, many of which are somewhat or even highly uncertain. For the purpose of this analysis, we constructed several scenarios of operator response using the level of oil-well gas flaring that occurred in FY 2014. These scenarios necessarily rely on various simplifying assumptions, which imperfectly represent real-world conditions. While we believe that this is a reasonable approach to the analysis, given the numerous and highly uncertain factors that may affect the actual outcome, we recognize that even this broad range of possible impacts may not accurately model the actual effects of this provision.

First, we use the 2014 lease-level flaring data as a basis for the analysis, although the rule would likely not be implemented until 2017. Over the past few years, flaring rates have been rapidly increasing. However, the recent collapse in oil prices is slowing the rate of new oil development, at least for now, which should allow capture infrastructure to begin to catch up to development and eventually reduce flaring.

Also, the North Dakota regulations will reduce flaring in that state between now and 2017, which will also drive overall flaring rates down. Thus, we believe that assuming the same rate of flaring and production in 2017 as in FY 2014 is reasonable for this analysis, recognizing that this is a source of uncertainty for the results. We believe that operators, particularly in North Dakota, will continue to install pipelines to capture gas from leases that are currently not connected and that they will continue to push for increased downstream capacity to reduce flaring from leases that are currently connected or will be connected in the future.

After combining the ONRR 2014 data with data from the BLM's Automated Fluid Minerals Support System (AFMSS) to determine the number of wells associated with each lease agreement, we performed two additional operations on the dataset. First, we took a subset of the data, including the lease agreements in North Dakota and New Mexico (where aggregate flaring was the highest), and attempted to geo-locate the lease agreements. Using a geographic information system (GIS) data layer for Federal wells, we were able to locate about 36% of the lease agreements with flaring in North Dakota and New Mexico, and about 26% of the total lease agreements with flaring. The leases that we were not able to geo-locate were likely either Indian leases and not in the GIS layer or unmatched because of formatting differences in the lease identifiers.

With the matched lease agreements, we calculated the distance to the nearest gas processing plants. Lastly, we attempted to identify which of the geo-located lease agreements were connected to gas pipelines. In the dataset, where gas flaring and production levels were constant or consistent with what we would expect from a connected lease during the year, we assumed that the lease is connected to a pipeline. However, for leases with sporadic or alternating gas flaring and production, we assumed that the lease is not connected to a pipeline.

With these data, we constructed several scenarios that we believe represent reasonable operator responses to the proposed flaring limit.

- Case #1: Automatic exemption. These are leases that are unconnected to a pipeline, located over 50 miles from the nearest gas processing plant, and flaring in excess of the proposed limit by 50% or more. We assumed that these leases would not be impacted by the rule because they would obtain a renewable two-year exemption from the flaring limit.
- Case #2: Curtailment of oil production while associated gas production naturally declines. We believe that this response is likely at unconnected wells where the flaring is close to but slightly above the proposed limit. For the purpose of this analysis, we assumed that operators would choose this response if their flaring is above the limit by less than the monthly equivalent of 40 Mcf per well per day. We estimated the impact of the flaring limit on these leases as the cost of crude oil production curtailment, with the oil production (and associated gas production) occurring a year later.
- Case #3: Use of onsite capture. We believe this response is likely where the lease is unconnected to a gas pipeline and located within 20 miles of a gas processing plant. We also assumed that the operators most likely to follow this approach are operators that are currently flaring in excess of the limit by more than 40 Mcf per day, because we assumed that for operators flaring closer to the limit, it would likely be more cost-effective to temporarily curtail production. We estimated the impact on leases in case #3 as the production of the NGL from stripping operations, minus the presumed opportunity cost of the money invested in onsite capture (measured as 20% of the value of the flared gas).
- Case #4: Case-by-case exemption, or alternative limit, or curtailment. We believe that this response is likely on unconnected leases where the distance to a plant is greater than 20 miles but less than 50 miles, and the flaring levels are in excess of the limit by more than 40 Mcf per day. We measured the impact on these leases as the cost of crude oil curtailment, with the production occurring a year later, and the benefit of production of the conserved gas. We assume that, within one year, operators would either receive an approval for an exemption or production would decline to a level where optimal production could be achieved under the flaring limit. We do not assume that operators in this scenario would need to curtail production for longer than one year, and therefore the estimated costs and benefits are based on one year of deferred production. BLM seeks comment on this assumption.
- Case #5: Connected leases where the operator curtails production during the time of the process upset (such as maintenance to a gas processing plant, when bumped off by higher pressured wells, etc.) or waits for the well to naturally decline. We believe that this response is likely where the flaring is above but close to the limit. For the purpose of this analysis, we assumed that operators would choose this response if its flaring was above the limit by less than 40 Mcf per day. We measured the impact on these leases as the cost of crude oil curtailment, with the production occurring a year later, and the benefit of production of the conserved gas.

- Case #6: Connected leases where the operator can use onsite capture. We believe this response is likely where the lease is located within 20 miles of a gas processing plant. To generate mutually exclusive cases, we also assumed that flaring would be in excess of the limit by more than 40 Mcf per day. We measured the impact on these leases as the presumed opportunity cost of the onsite capture (measured as 20% of the value of the flared gas), and the production of the NGL from stripping operations.
- Case #7: Connected leases where the operator seeks an alternative limit or curtails. We believe that this response is likely where the distance to a plant is greater than 20 miles. To generate mutually exclusive cases, we also assumed that flaring would be in excess of the limit by more than 40 Mcf per day. We measured the impact on these leases as the cost of crude oil curtailment, with the production occurring a year later, and the production of the conserved gas. The impact of the curtailment might be less if the operator requests and receives approval for an alternative flaring limit. We assume that, within one year, operators would either (1) receive an approval for an exemption, (2) production would decline to a level where optimal production could be achieved under the flaring limit, or (3) necessary capacity would be built to enable these connected wells to transport more gas. We do not assume that operators in this scenario would need to curtail production for longer than one year, and therefore the estimated costs and benefits are based on one year of deferred production. BLM seeks comment on this assumption.
- Case #8: Leases where flaring is below the limit and the operator is not expected to change its behavior. We present this case to illustrate the leases where flaring occurs and on which the rule is not expected to have any impact.

Table 8b: Summary of Constructed Scenarios

Case No.	Connected (Yes/No)	Distance to Plant	Flaring Level	Assumed Operator Response
1	No	>50mi	>limit+50%	Automatic Exemption
2	No	NA	>limit & <limit+40Mcfd	Curtailment of oil production while associated gas production naturally declines
3	No	<20mi	>limit+40Mcfd	Use of onsite capture
4	No	>20mi (excluding case #1)	>limit+40Mcfd	Case-by-case exemption, or alternative limit, or curtailment
5	Yes	NA	>limit & <limit+40Mcfd	Curtailment of oil production until production declines or during upset
6	Yes	<20mi	>limit+40Mcfd	Use of onsite capture
7	Yes	>20mi	>limit+40Mcfd	Curtailment of oil production until production declines or during upset
8	NA	NA	<limit	None

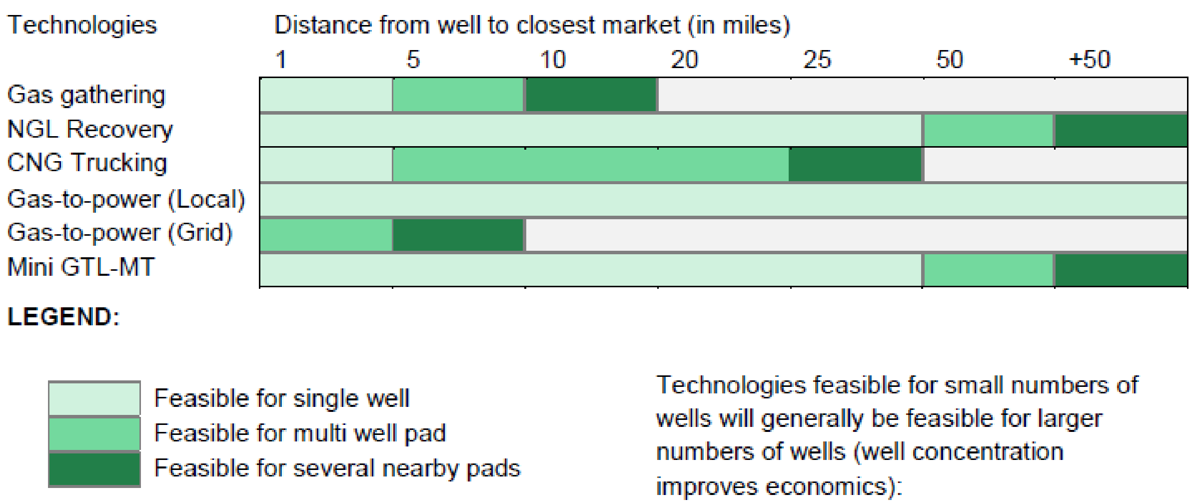
Our decision to assume that operators, if the lease flaring would be just above the limit, would curtail production until the associated gas production naturally declines is based on the rather sharp production declines that many of these wells experience. For example, Carbon Limits sampled wells in the Bakken Formation and found that the wells experienced:[59]

- Oil and gas production peaks at the 2nd month (38% of the wells over 300 Mcfd);
- 64% decline from the peak at the 12th month (11% of the wells over 300 Mcfd);
- 86% decline from the peak at the 24th month (4% of the wells over 300 Mcfd); and
- 93% decline from the peak at the 36th month (3% of the wells over 300 Mcfd).

These data lend support to the premise that if well flaring is close to the limit, that the period of curtailment is not likely to be extenuated.

Further, our decision to assume that operators would use onsite capture if the lease is located within 20 miles of a gas processing plant is based on the Carbon Limits' findings on the feasibility of capture technologies. The authors found that distance to gas gathering facilities had an impact on the feasibility of the various technology solutions, shown in Figure 2.[60] For example, within 20 miles of the market: gas gathering is feasible for several nearby pads; NGL recovery is feasible for a single well, multi well pad, and several nearby pads; CNG trucking is feasible for a single well and multi well pad; etc.

Figure 2: Feasibility Assessment of Selected Technologies as a Function of Geography – Source: Carbon Limits (2015a)



Tables 9a-c show the impacted leases from the matched dataset that would potentially be impacted by the proposed flaring limits (phased-in over 3 years) and the alternative flaring limits. Each table shows the total volume of gas flared, the number of impacted leases and wells, and the total distance of these wells to the closest respective processing plants, for each case scenario and for each of the potential flaring limits.

[59] Carbon Limits 2015a, p. 50. The authors found similar decline rates for wells in the Eagle Ford shale play (p. 49).
[60] Figure appears in Carbon Limits 2015a, p. 56.

For example, in Table 9a, the requirement proposed by the BLM would establish a flaring limit equivalent to 240 Mcf per day for the first year, 120 Mcf per day for the second year, and 60 Mcf per day for the third year and beyond. So in the first year, we would expect that 1 lease accounting for about 26,000 Mcf of flaring in a given year would fall in case #1 and be exempted. In the second year, we would expect 2 leases accounting for about 34,000 Mcf of total flaring in a given year would fall in case #1 and be exempted. We note that for the data in Tables 9a-c, the leases or wells did not necessarily flare or flare in excess of the limits in every month during the year. More simply, a lease was placed into a case if its flaring during any month fell exceeded the limit.

Table 9d shows the estimated crude oil deferment for the matched leases and for scenario cases 2, 4, 5, and 7, with the potentially conserved gas for production being the flared amount.

Using the data in Tables 9a-d, we estimated the impacts for the matched leases over the ten-year period from 2017 to 2026. For the first 3 years of implementation, we measured the impacts based on the phase-in equivalent shown in the tables. While we expect the existing unconnected leases will become connected to pipelines within the first 3 years of implementation and that the infrastructure for connected leases would bolster and thus reduce the need to flare, we also expect that new wells might not be connected to pipelines at the time of completion or that there might be temporary upsets in the line such that operators would want to flare. As such, for the remaining 7 years of the analysis period, we estimate the impacts based on the proposed 1,800 Mcf/month (or 60 Mcfd equivalent) limit and the 1,200 Mcf/month (or 40 Mcfd equivalent) and 2,400 Mcf/month (or 80 Mcfd equivalent) alternatives examined.

Other assumptions relevant to the estimation include the commodity prices (discussed previously) and the disposition of natural gas used in the onsite capture (for cases 3 and 6). While several options for onsite capture exist, our field experience tells us that NGL stripping is the most common option used today, particularly in gas-rich basins like the Bakken. While we assume a natural gas to NGL conversion factor of 1 Mcf to 1.25 gallons for this analysis, we note that the process can extract greater volumes of liquids (as much as 5.3 gallons per Mcf) in gas-rich basins.[61]

After estimating the impacts to the matched leases, we then scaled those impacts up by multiplying by a factor of 3.82 to represent the estimated impacts on all leases with oil-well gas flaring. The factor was calculated as the number of unique leases with oil-well gas flaring in the ONRR dataset (or 2,057) divided by the number of matched leases (or 539). Using this approach assumes that the matched leases are representative of the leases in the larger datatset.

[61] National Petroleum Council. (2011), p. 6.

Table 9a: Summary of Flaring Oil-Well Flaring, Observations from Matched Dataset, Proposed Limit of 7,200 / 3,600 / 1,800 Mcf per month

Scenario No.	Case #1					Case #2					Case #3					Case #4				
Lease Connection	Unconnected																			
Distance to nearest processing plant (D)	D > 50 miles					N/A					D < 20 miles					D > 20 miles (less Case #1 leases)				
Flared volume (X)	X > limit + 50%					limit < X < limit + 40 Mcfd					X > limit + 40 Mcfd					X > limit + 40 Mcfd				
Phase-In Flaring Limit Equivalent (Mcfd)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)
60	147,817	4	14	300.8	299.9	643,235	89	172	11.0	10.3	6,229,717	88	179	11.8	12.2	711,180	2	13	24.0	24.0
120	33,763	2	3	293.0	293.0	705,011	43	97	25.9	12.9	5,439,949	63	129	12.4	13.1	517,417	2	13	24.0	24.0
240	26,330	1	2	295.0	295.0	348,746	19	28	26.6	13.2	4,232,788	43	92	12.4	13.2	387,976	2	13	24.0	24.0
Scenario impact or Operator response:	Automatic exemption					Curtail - wait for natural well decline					Onsite capture					Case-by-case exemption; Curtail				

Scenario No.	Case #5					Case #6					Case #7					Case #8				
Lease Connection	Connected															N/A				
Distance to nearest processing plant (D)	N/A					D < 20 miles					D > 20 miles					N/A				
Flared volume (X)	limit < X < limit + 40 Mcfd					X > limit + 40 Mcfd					X > limit + 40 Mcfd					X < limit				
Phase-In Flaring Limit Equivalent (Mcfd)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)
60	687,574	58	110	11.7	11.6	4,460,995	58	108	11.0	11.6	626,398	11	38	226.9	298.6	2,038,450	468	1,173	10.2	9.8
120	300,681	29	51	10.7	11.0	3,949,790	44	75	11.1	11.6	575,091	9	23	240.1	298.6	4,002,228	481	1,194	10.2	9.8
240	300,477	18	30	11.5	12.4	3,232,673	25	45	12.0	13.8	513,044	6	18	256.4	299.6	6,212,108	491	1,215	10.2	9.8
Scenario impact or Operator response:	Curtailment of oil production until production declines or during upset; Gas is royalty bearing					Onsite capture; Gas is royalty bearing					Curtailment of oil production until production declines or during upset; Gas is royalty bearing					No response - Flaring below limit				

Table 9b: Summary of Flaring Oil-Well Flaring, Observations from Matched Dataset, Alternative Limit of 4,800 / 2,400 / 1,200 Mcf per month																				
Scenario No.	Case #1					Case #2					Case #3					Case #4				
Lease Connection	Unconnected																			
Distance to nearest processing plant (D)	D > 50 miles					N/A					D < 20 miles					D > 20 miles (less Case #1 leases)				
Flared volume (X)	X > limit + 50%					limit < X < limit + 40 Mcfd					X > limit + 40 Mcfd					X > limit + 40 Mcfd				
Phase-In Flaring Limit Equivalent (Mcfd)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)
40	147,817	4	14	300.8	299.9	755,019	109	210	16.3	10.6	6,494,249	106	203	11.6	12.0	711,180	2	13	24.0	24.0
80	117,347	4	14	300.8	299.9	657,106	67	131	15.7	11.0	5,867,613	76	151	12.3	13.0	711,180	2	13	24.0	24.0
160	33,763	2	3	292.8	292.8	451,415	34	68	11.9	12.2	5,011,349	55	114	12.7	13.2	494,602	2	13	24.0	24.0
Scenario impact or Operator response:	Automatic exemption					Curtail - wait for natural well decline					Onsite capture					Case-by-case exemption; Curtail				
Scenario No.	Case #5					Case #6					Case #7					Case #8				
Lease Connection	Connected															N/A				
Distance to nearest processing plant (D)	N/A					D < 20 miles					D > 20 miles					N/A				
Flared volume (X)	limit < X < limit + 40 Mcfd					X > limit + 40 Mcfd					X > limit + 40 Mcfd					X < limit				
Phase-In Flaring Limit Equivalent (Mcfd)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)
40	661,009	79	153	14.4	10.7	4,773,883	65	125	11.2	11.7	628,919	11	38	226.9	298.6	1,389,605	456	1,141	10.1	9.8
80	577,240	42	97	19.0	12.3	4,250,471	54	95	10.7	11.2	575,091	9	23	240.1	298.6	2,791,080	474	1,181	10.2	9.8
160	285,587	27	51	31.9	11.4	3,720,006	36	63	11.5	13.0	519,288	7	19	263.1	303.2	4,779,572	487	1,210	10.2	9.8
Scenario impact or Operator response:	Curtailment of oil production until production declines or during upset; Gas is royalty bearing					Onsite capture; Gas is royalty bearing					Curtailment of oil production until production declines or during upset; Gas is royalty bearing					No response - Flaring below limit				

Table 9c: Summary of Flaring Oil-Well Flaring, Observations from Matched Dataset, Alternative Limit of 9,600 / 4,800 / 2,400 Mcf per month

Scenario No.	Case #1					Case #2					Case #3					Case #4				
Lease Connection	Unconnected																			
nearest processing plant (D)	D > 50 miles					N/A					D < 20 miles					D > 20 miles (less Case #1 leases)				
Flared volume (X)	X > limit + 50%					limit < X < limit + 40 Mcfd					X > limit + 40 Mcfd					X > limit + 40 Mcfd				
Phase-In Flaring Limit Equivalent (Mcfd)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)
80	117,347	4	14	300.8	299.9	657,106	67	131	15.7	11.0	5,867,613	76	151	12.3	13.0	711,180	2	13	24.0	24.0
160	33,763	2	3	292.8	292.8	451,415	34	68	11.9	12.2	5,011,349	55	114	12.7	13.2	494,602	2	13	24.0	24.0
320	-	-	-	-	-	391,238	13	30	10.7	11.8	3,355,715	33	58	12.4	13.2	182,385	2	13	24.0	24.0
Scenario impact or Operator response:	Automatic exemption					Curtail - wait for natural well decline					Onsite capture					Case-by-case exemption; Curtail				
Scenario No.	Case #5					Case #6					Case #7					Case #8				
Lease Connection	Connected															N/A				
Distance to nearest processing plant (D)	N/A					D < 20 miles					D > 20 miles					N/A				
Flared volume (X)	limit < X < limit + 40 Mcfd					X > limit + 40 Mcfd					X > limit + 40 Mcfd					X < limit				
Phase-In Flaring Limit Equivalent (Mcfd)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)	Flared volume (Mcfy)	Leases	Wells	Average distance to processing plant (mi)	Median distance to processing plant (mi)
80	577,240	42	97	19.0	12.3	4,250,471	54	95	10.7	11.2	575,091	9	23	240.1	298.6	2,791,080	474	1,181	10.2	9.8
160	285,587	27	51	31.9	11.4	3,720,006	36	63	11.5	13.0	519,288	7	19	263.1	303.2	4,779,572	487	1,210	10.2	9.8
320	292,425	8	25	51.9	15.0	2,820,256	21	34	11.5	13.8	444,004	5	11	244.7	293.8	7,638,834	498	1,224	10.2	9.9
Scenario impact or Operator response:	Curtailment of oil production until production declines or during upset; Gas is royalty bearing					Onsite capture; Gas is royalty bearing					Curtailment of oil production until production declines or during upset; Gas is royalty bearing					No response - Flaring below limit				

Table 9d: Estimated Crude Oil Deferment for Cases 2, 4, 5, 7 of Matched Dataset

Scenario No.	Case #2			Case #4			Case #5			Case #7		
Phase-In Flaring Limit Equivalent (Mcfd)	Gas Volume Flared (Mcfy)	Oil Volume (bbly)	Oil Deferred (bbly)	Gas Volume Flared (Mcfy)	Oil Volume (bbly)	Oil Deferred (bbly)	Gas Volume Flared (Mcfy)	Oil Volume (bbly)	Oil Deferred (bbly)	Gas Volume Flared (Mcfy)	Oil Volume (bbly)	Oil Deferred (bbly)
60	643,235	1,494,392	291,815	711,180	1,890,660	1,324,762	687,574	1,290,909	287,645	626,398	284,770	224,529
120	705,011	1,635,157	270,114	517,417	1,132,265	685,894	300,681	666,611	90,893	575,091	259,760	165,409
240	348,746	386,660	34,097	387,976	865,871	258,923	300,477	285,256	17,972	513,044	178,808	98,281
40	755,019	2,002,288	578,476	711,180	1,890,660	1,513,395	661,009	1,716,879	537,138	628,919	291,869	248,329
80	657,106	1,072,658	194,432	711,180	1,950,170	1,174,994	577,240	783,954	156,499	575,091	259,760	196,859
160	451,415	551,416	63,734	494,602	1,126,542	535,165	285,587	372,021	36,137	519,288	195,372	128,954
80	657,106	1,072,658	194,432	711,180	1,950,170	1,174,994	577,240	783,954	156,499	575,091	259,760	196,859
160	451,415	551,416	63,734	494,602	1,126,542	535,165	285,587	372,021	36,137	519,288	195,372	128,954
320	391,238	472,371	31,648	182,385	342,992	110,525	292,425	181,380	10,308	444,004	169,721	71,197

Table 9e: Crosswalk for Calculation of Costs and Benefits for Proposed Flaring Limit Phase-in

Scenario No.	Metric	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Case 1	Number of leases	4	8	15	15	15	15	15	15	15	15
	Description of leases	Not connected; Farther than 50 miles from plant; Flaring in excess of the limit plus 50%									
	Assumed operator response	Automatic exemption									
	Method of cost/benefit estimation	No costs/benefits									
Case 2	Number of leases	73	164	340	340	340	340	340	340	340	340
	Description of leases	Not connected; Distance to plant irrelevant for estimation purposes; Flaring above the limit but less than 40 Mcfd above the limit									
	Assumed operator response	Curtail oil production while associated gas production naturally declines									
	Method of cost/benefit estimation	Estimated cost: Difference in the value of crude oil produced one year later; Estimated benefit (savings): Value of associated gas production occurring one year later									
	Crude oil deferred (bbl)	130,126	1,030,844	1,113,659	1,113,659	1,113,659	1,113,659	1,113,659	1,113,659	1,113,659	1,113,659
	Gas conserved (Mcf)	121,916	396,177	524,497	524,497	524,497	524,497	524,497	524,497	524,497	524,497
Case 3	Number of leases	164	240	336	336	336	336	336	336	336	336
	Description of leases	Not connected; Less than 20 miles from plant; Flaring in excess of the limit plus 40 Mcfd									
	Assumed operator response	Use onsite capture									
	Method of cost/benefit estimation	Estimated cost: 20% of the value of gas; Estimated benefit (savings): Value of NGL stripped from the gas (assuming 1.25 gal of NGL per 1 Mcf of gas)									
	Volume of gas (Mcf)	16,153,701	20,760,622	23,774,634	23,774,634	23,774,634	23,774,634	23,774,634	23,774,634	23,774,634	23,774,634
Case 4	Number of leases	8	8	8	8	8	8	8	8	8	8
	Description of leases	Not connected; More than 20 miles from plant (excluding leases in case 1); Flaring in excess of the limit plus 40 Mcfd									
	Assumed operator response	Apply for case-by-case exemption or alternative flaring limit, or curtail production									
	Method of cost/benefit estimation	Estimated cost: Difference in the value of crude oil produced one year later; Estimated benefit (savings): Value of associated gas production occurring one year later									
	Crude oil deferred (bbl)	988,136	2,617,596	5,055,724	5,055,724	5,055,724	5,055,724	5,055,724	5,055,724	5,055,724	5,055,724
	Gas conserved (Mcf)	309,869	960,053	1,462,890	1,462,890	1,462,890	1,462,890	1,462,890	1,462,890	1,462,890	1,462,890
Case 5	Number of leases	69	111	221	221	221	221	221	221	221	221
	Description of leases	Connected; Distance to plant irrelevant for estimation purposes; Flaring above the limit but less than 40 Mcfd above the limit									
	Assumed operator response	Curtail oil production until production naturally decline or the upset ceases									
	Method of cost/benefit estimation	Estimated cost: Difference in the value of crude oil produced one year later; Estimated benefit (savings): Value of associated gas production occurring one year later									

Scenario No.	Metric	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	Crude oil deferred (bbl)	68,587	346,878	1,097,745	1,097,745	1,097,745	1,097,745	1,097,745	1,097,745	1,097,745	1,097,745
	Gas conserved (Mcf)	75,094	172,044	618,146	618,146	618,146	618,146	618,146	618,146	618,146	618,146
Case 6	Number of leases	95	168	221	221	221	221	221	221	221	221
	Description of leases	Connected; Less than 20 miles from plant; Flaring in excess of the limit plus 40 Mcfd									
	Assumed operator response	Use onsite capture									
	Method of cost/benefit estimation	Estimated cost: 20% of the value of gas; Estimated benefit (savings): Value of NGL stripped from the gas (assuming 1.25 gal of NGL per 1 Mcf of gas)									
	Volume of gas (Mcf)	12,336,936	15,073,688	17,024,614	17,024,614	17,024,614	17,024,614	17,024,614	17,024,614	17,024,614	17,024,614
Case 7	Number of leases	23	34	42	42	42	42	42	42	42	42
	Description of leases	Connected; More than 20 miles from plant (excluding leases in case 1); Flaring in excess of the limit plus 40 Mcfd									
	Assumed operator response	Curtail oil production until production naturally decline or the upset ceases									
	Method of cost/benefit estimation	Estimated cost: Difference in the value of crude oil produced one year later; Estimated benefit (savings): Value of associated gas production occurring one year later									
	Crude oil deferred (bbl)	375,073	631,254	856,877	856,877	856,877	856,877	856,877	856,877	856,877	856,877
	Gas conserved (Mcf)	900,058	1,370,409	1,703,601	1,703,601	1,703,601	1,703,601	1,703,601	1,703,601	1,703,601	1,703,601
Case 8	Number of leases	1,874	1,836	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786
	Description of leases	Flaring below the limit; Connection status and distane to plant irrelevant for estimation purposes									
	Assumed operator response	None: Flaring is below the limit									
	Method of cost/benefit estimation	No costs/benefits									

3. Results

A summary of the estimated impacts of the proposed requirements and the alternatives considered are shown in Table 10 and with more detail in Tables 11a-c. Since these sources are not addressed by the EPA's proposed Subpart OOOOa, the estimated impacts of the requirements are not influenced by that proposal.

Proposed Flaring Limits: Phase in step-down limits of 7,200 / 3,600 / 1,800 Mcf per month

We estimate that the proposed flaring limits would:

- Impact an estimated 435 – 885 leases in any given year;
- Pose total costs of about $32 – 68 million per year (present value calculated using a 7% discount rate) or $26 – 43 million per year (present value calculated using a 3% discount rate);
- Pose total cost savings of about $40 – 58 million per year (present value calculated using a 7% discount rate) or $40 – 64 million per year (present value calculated using a 3% discount rate);
- Increase natural gas production by 2.5 – 5.0 Bcf per year;
- Increase NGL production by 36 – 51 million gallons per year (generated from the productive use of 28-41 Bcf of natural gas); and
- Result in net benefits ranging from ($10) – $8 million per year (present value calculated using a 7% discount rate) or $13 – 30 million per year (present value calculated using a 3% discount rate).

Alternative Flaring Limits: Phase in step-down limits of 4,800 / 2,400 / 1,200 Mcf per month

We estimate that these alternative requirements would:

- Impact an estimated 622 – 1,111 leases in any given year;
- Pose total costs of about $46 – 80 million per year (present value calculated using a 7% discount rate) or $35 – 47 million per year (present value calculated using a 3% discount rate);
- Pose total cost savings of about $47 – 64 million per year (present value calculated using a 7% discount rate) or $47 – 69 million per year (present value calculated using a 3% discount rate);
- Increase natural gas production by 3.0 – 5.8 Bcf per year;
- Increase NGL production by 42 – 54 million gallons per year (generated from the productive use of 33 – 43 Bcf of natural gas); and
- Result in net benefits ranging from ($16) – $1 million per year (present value calculated using a 7% discount rate) or $12 – 34 million per year (present value calculated using a 3% discount rate).

Alternative Flaring Limits: Phase in step-down limits of 9,600 / 4,800 / 2,400 Mcf per month

We estimate that these alternative requirements would:

- Impact an estimated 313 – 698 leases in any given year;
- Pose total costs of about $22 – 61 million per year (present value calculated using a 7% discount rate) or $20 – 40 million per year (present value calculated using a 3% discount rate);
- Pose total cost savings of about $33 – 54 million per year (present value calculated using a 7% discount rate) or $33 – 59 million per year (present value calculated using a 3% discount rate);
- Increase natural gas production by 2.0 – 4.4 Bcf per year;
- Increase NGL production by 29 – 48 million gallons per year (generated from the productive use of 24 – 39 Bcf of natural gas); and
- Result in net benefits ranging from ($7) – $10 million per year (present value calculated using a 7% discount rate) or $13 – 26 million per year (present value calculated using a 3% discount rate).

Comparison of Proposed Flaring Limit and Alternatives

The results of this analysis, illustrated in Table 10 below, show that among the alternatives examined, the flaring limit phase-in of 4,800 / 2,400 / 1,200 (Mcf/month) maximizes net benefits using a 3% discount rate and the flaring limit phase-in of 9,600 / 4,800 / 2,400 (Mcf/month) maximizes net benefits using a 7% discount rate. The BLM's proposed flaring limit phase-in of 7,200 / 3,600 / 1,800 (Mcf/month) lies within those two alternatives and was proposed because it maximizes net benefits at a mid-point discount rate.

Table 10: Summary of Annual Impacts for Flaring Limit Options and Alternatives

Metric	Flaring Limit Options, Phase-in Years 1-3 (Mcf/month)		
	4,800 / 2,400 / 1,200	7,200 / 3,600 / 1,800 (Proposed)	9,600 / 4,800 / 2,400
Impacted leases	622 – 1,111	435 – 885	313 – 698
Costs – Present value using 7% discount rate ($ in million)	$46 – 80	$32 – 68	$22 – 61
Costs – Present value using 3% discount rate ($ in million)	$35 – 47	$26 – 43	$20 – 40
Benefits – Present value of Cost Savings using 7% discount ($ in million)	$47 – 64	$40 – 58	$33 – 54
Benefits – Present value of Cost Savings using 3% discount ($ in million)	$47 – 69	$40 – 64	$33 – 59
Incremental Natural Gas Production (Bcf)	3.0 – 5.8	2.5 – 5.0	2.0 – 4.4
Incremental NGL Production (million gal)	42 – 54	36 – 51	29 – 48
Net Benefits – Present value using 7% discount rate ($ in million)			
Year 2017-2019	($16) – $1	($10) – $8	($7) – $10
Year 2020-2024	($5 – 8)	($2 – 4)	($2) – $0
Year 2025-2026	($4)	($1)	$0
Net Benefits – Present value using 3% discount rate ($ in million)			
Year 2017-2019	$12 – 22	$13 – 20	$13 – 19
Year 2020-2024	$30 – 33	$27 – 29	$24 – 26
Year 2025-2026	$34	$29 – 30	$26

Table 11a: Estimated Impacts of Proposed Flaring Limits (7,200 / 3,600 / 1,800 Mcf per month)										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Impacted leases										
Case 1	4	8	15	15	15	15	15	15	15	15
Case 2	73	164	340	340	340	340	340	340	340	340
Case 3	164	240	336	336	336	336	336	336	336	336
Case 4	8	8	8	8	8	8	8	8	8	8
Case 5	69	111	221	221	221	221	221	221	221	221
Case 6	95	168	221	221	221	221	221	221	221	221
Case 7	23	34	42	42	42	42	42	42	42	42
Total impacte	435	733	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183
Estimated Cost - Present Value Using 7% Rate ($ in million)										
Case 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Case 2	$0.61	$3.12	$3.22	$2.52	$2.28	$2.19	$2.13	$2.10	$1.96	$1.88
Case 3	$12.29	$16.34	$18.90	$18.94	$18.20	$17.25	$16.63	$15.84	$15.10	$14.66
Case 4	$4.61	$7.92	$14.63	$11.44	$10.37	$9.95	$9.65	$9.51	$8.91	$8.54
Case 5	$0.32	$1.05	$3.18	$2.48	$2.25	$2.16	$2.10	$2.07	$1.94	$1.85
Case 6	$9.39	$11.87	$13.54	$13.57	$13.04	$12.36	$11.91	$11.34	$10.81	$10.49
Case 7	$4.61	$7.92	$14.63	$11.44	$10.37	$9.95	$9.65	$9.51	$8.91	$8.54
Total	$31.82	$48.22	$68.10	$60.40	$56.52	$53.86	$52.06	$50.37	$47.64	$45.95
Estimated Cost - Present Value Using 3% Rate ($ in million)										
Case 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Case 2	$0.28	$0.64	$0.70	$0.05	-$0.12	-$0.14	-$0.12	-$0.06	-$0.14	-$0.16
Case 3	$12.29	$16.98	$20.40	$21.24	$21.20	$20.88	$20.90	$20.68	$20.48	$20.65
Case 4	$2.10	$1.63	$3.17	$0.22	-$0.55	-$0.62	-$0.54	-$0.26	-$0.62	-$0.71
Case 5	$0.15	$0.22	$0.69	$0.05	-$0.12	-$0.13	-$0.12	-$0.06	-$0.13	-$0.15
Case 6	$9.39	$12.33	$14.61	$15.21	$15.18	$14.95	$14.96	$14.81	$14.67	$14.79
Case 7	$2.10	$1.63	$3.17	$0.22	-$0.55	-$0.62	-$0.54	-$0.26	-$0.62	-$0.71
Total	$26.29	$33.43	$42.73	$36.98	$35.03	$34.32	$34.54	$34.85	$33.65	$33.71

Table 11a: Estimated Impacts of Proposed Flaring Limits (7,200 / 3,600 / 1,800 Mcf per month)										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Case 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Case 2	$0.46	$1.56	$2.09	$2.09	$2.01	$1.90	$1.83	$1.75	$1.67	$1.62
Case 3	$17.16	$20.59	$22.49	$21.45	$20.63	$19.90	$19.19	$18.50	$17.82	$17.19
Case 4	$1.18	$3.78	$5.82	$5.83	$5.60	$5.31	$5.11	$4.87	$4.65	$4.51
Case 5	$0.29	$0.68	$2.46	$2.46	$2.37	$2.24	$2.16	$2.06	$1.96	$1.91
Case 6	$13.11	$14.95	$16.11	$15.36	$14.78	$14.25	$13.74	$13.25	$12.76	$12.31
Case 7	$7.45	$8.64	$9.50	$9.52	$9.15	$8.67	$8.36	$7.96	$7.59	$7.37
Total	$39.65	$50.20	$58.46	$56.71	$54.54	$52.27	$50.39	$48.39	$46.45	$44.89
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Case 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Case 2	$0.46	$1.62	$2.25	$2.34	$2.34	$2.30	$2.30	$2.28	$2.26	$2.28
Case 3	$17.16	$21.39	$24.27	$24.05	$24.03	$24.07	$24.11	$24.15	$24.17	$24.22
Case 4	$1.18	$3.93	$6.28	$6.53	$6.52	$6.42	$6.43	$6.36	$6.30	$6.35
Case 5	$0.29	$0.70	$2.65	$2.76	$2.76	$2.71	$2.72	$2.69	$2.66	$2.68
Case 6	$13.11	$15.53	$17.38	$17.22	$17.21	$17.24	$17.27	$17.30	$17.31	$17.34
Case 7	$7.45	$8.97	$10.26	$10.68	$10.66	$10.50	$10.51	$10.40	$10.30	$10.38
Total	$39.65	$52.14	$63.09	$63.58	$63.52	$63.24	$63.34	$63.18	$63.00	$63.25
Estimated Benefits Incremental Production (Bcf)										
Case 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Case 2	0.12	0.40	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Case 4	0.31	0.96	1.46	1.46	1.46	1.46	1.46	1.46	1.46	1.46
Case 5	0.08	0.17	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62
Case 7	1.96	2.19	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39
Total	2.46	3.72	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Estimated Benefits Incremental Production (million gal of NGL)										
Case 3	20.19	25.95	29.72	29.72	29.72	29.72	29.72	29.72	29.72	29.72
Case 6	15.42	18.84	21.28	21.28	21.28	21.28	21.28	21.28	21.28	21.28
Total	35.61	44.79	51.00	51.00	51.00	51.00	51.00	51.00	51.00	51.00
Net Benefits										
Net Benefits	$8	$2	-$10	-$4	-$2	-$2	-$2	-$2	-$1	-$1
Net Benefits	$13	$19	$20	$27	$28	$29	$29	$28	$29	$30

Table 11b: Estimated Impacts of Alternative Flaring Limits (4,800 / 2,400 / 1,200 Mcf per month)										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Impacted leases										
Case 1	8	15	15	15	15	15	15	15	15	15
Case 2	130	256	416	416	416	416	416	416	416	416
Case 3	210	290	405	405	405	405	405	405	405	405
Case 4	8	8	8	8	8	8	8	8	8	8
Case 5	103	160	301	301	301	301	301	301	301	301
Case 6	137	206	248	248	248	248	248	248	248	248
Case 7	27	34	42	42	42	42	42	42	42	42
Total impact	622	969	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435
Estimated Cost - Present Value Using 7% Rate ($ in million)										
Case 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Case 2	$1.13	$2.25	$6.39	$5.00	$4.53	$4.34	$4.22	$4.15	$3.89	$3.73
Case 3	$14.55	$17.63	$19.71	$19.75	$18.98	$17.99	$17.33	$16.51	$15.74	$15.28
Case 4	$9.52	$13.57	$16.71	$13.07	$11.85	$11.37	$11.03	$10.87	$10.18	$9.75
Case 5	$0.64	$1.81	$5.93	$4.64	$4.20	$4.03	$3.91	$3.86	$3.61	$3.46
Case 6	$10.80	$12.77	$14.49	$14.52	$13.95	$13.22	$12.74	$12.14	$11.57	$11.23
Case 7	$9.52	$13.57	$16.71	$13.07	$11.85	$11.37	$11.03	$10.87	$10.18	$9.75
Total	$46.18	$61.58	$79.94	$70.05	$65.36	$62.32	$60.26	$58.40	$55.19	$53.20
Estimated Cost - Present Value Using 3% Rate ($ in million)										
Case 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Case 2	$0.52	$0.46	$1.38	$0.10	-$0.24	-$0.27	-$0.24	-$0.11	-$0.27	-$0.31
Case 3	$14.55	$18.31	$21.27	$22.14	$22.10	$21.76	$21.78	$21.56	$21.35	$21.53
Case 4	$4.33	$2.80	$3.62	$0.25	-$0.63	-$0.70	-$0.62	-$0.30	-$0.71	-$0.81
Case 5	$0.29	$0.37	$1.29	$0.09	-$0.22	-$0.25	-$0.22	-$0.11	-$0.25	-$0.29
Case 6	$10.80	$13.26	$15.63	$16.27	$16.25	$16.00	$16.01	$15.85	$15.70	$15.82
Case 7	$4.33	$2.80	$3.62	$0.25	-$0.63	-$0.70	-$0.62	-$0.30	-$0.71	-$0.81
Total	$34.82	$38.01	$46.81	$39.10	$36.62	$35.83	$36.10	$36.58	$35.12	$35.14

Table 11b: Estimated Impacts of Alternative Flaring Limits (4,800 / 2,400 / 1,200 Mcf per month)										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Case 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Case 2	$0.77	$2.08	$3.48	$3.49	$3.35	$3.18	$3.06	$2.92	$2.78	$2.70
Case 3	$20.32	$22.21	$23.45	$22.36	$21.51	$20.74	$20.00	$19.28	$18.58	$17.92
Case 4	$2.70	$4.97	$6.81	$6.83	$6.56	$6.22	$5.99	$5.71	$5.44	$5.28
Case 5	$0.38	$1.60	$3.27	$3.28	$3.15	$2.99	$2.88	$2.74	$2.62	$2.54
Case 6	$15.08	$16.09	$17.24	$16.44	$15.81	$15.25	$14.70	$14.18	$13.66	$13.17
Case 7	$7.54	$8.64	$9.54	$9.56	$9.19	$8.71	$8.39	$7.99	$7.62	$7.40
Total	$46.79	$55.60	$63.79	$61.95	$59.58	$57.08	$55.03	$52.82	$50.69	$49.00
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Case 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Case 2	$0.77	$2.16	$3.76	$3.91	$3.90	$3.84	$3.85	$3.81	$3.77	$3.80
Case 3	$20.32	$23.07	$25.30	$25.07	$25.05	$25.09	$25.14	$25.18	$25.20	$25.24
Case 4	$2.70	$5.17	$7.35	$7.65	$7.64	$7.52	$7.53	$7.45	$7.38	$7.44
Case 5	$0.38	$1.67	$3.53	$3.68	$3.67	$3.62	$3.62	$3.58	$3.55	$3.58
Case 6	$15.08	$16.71	$18.60	$18.43	$18.41	$18.45	$18.48	$18.51	$18.52	$18.56
Case 7	$7.54	$8.97	$10.30	$10.72	$10.70	$10.54	$10.55	$10.44	$10.34	$10.42
Total	$46.79	$57.76	$68.84	$69.46	$69.38	$69.06	$69.16	$68.96	$68.76	$69.04
Estimated Benefits Incremental Production (Bcf)										
Case 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Case 2	0.20	0.53	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Case 4	0.71	1.26	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71
Case 5	0.10	0.41	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82
Case 7	1.98	2.19	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40
Total	2.99	4.40	5.81	5.81	5.81	5.81	5.81	5.81	5.81	5.81
Estimated Benefits Incremental Production (million gal of NGL)										
Case 3	23.91	27.99	30.98	30.98	30.98	30.98	30.98	30.98	30.98	30.98
Case 6	17.75	20.28	22.77	22.77	22.77	22.77	22.77	22.77	22.77	22.77
Total	41.65	48.27	53.75	53.75	53.75	53.75	53.75	53.75	53.75	53.75
Net Benefits										
Net Benefits	$1	-$6	-$16	-$8	-$6	-$5	-$5	-$6	-$4	-$4
Net Benefits	$12	$20	$22	$30	$33	$33	$33	$32	$34	$34

Table 11c: Estimated Impacts of Alternative Flaring Limits (9,600 / 4,800 / 2,400 Mcf per month)										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Impacted leases										
Case 1	0	8	15	15	15	15	15	15	15	15
Case 2	50	130	256	256	256	256	256	256	256	256
Case 3	126	210	290	290	290	290	290	290	290	290
Case 4	8	8	8	8	8	8	8	8	8	8
Case 5	31	103	160	160	160	160	160	160	160	160
Case 6	80	137	206	206	206	206	206	206	206	206
Case 7	19	27	34	34	34	34	34	34	34	34
Total impact	313	622	969	969	969	969	969	969	969	969
Estimated Cost - Present Value Using 7% Rate ($ in million)										
Case 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Case 2	$0.56	$0.74	$2.15	$1.68	$1.52	$1.46	$1.42	$1.40	$1.31	$1.25
Case 3	$9.74	$15.05	$17.80	$17.84	$17.15	$16.25	$15.66	$14.92	$14.22	$13.80
Case 4	$1.97	$6.18	$12.98	$10.15	$9.20	$8.83	$8.56	$8.44	$7.91	$7.57
Case 5	$0.18	$0.42	$1.73	$1.35	$1.23	$1.18	$1.14	$1.12	$1.05	$1.01
Case 6	$8.19	$11.17	$12.90	$12.93	$12.42	$11.77	$11.34	$10.81	$10.30	$10.00
Case 7	$1.97	$6.18	$12.98	$10.15	$9.20	$8.83	$8.56	$8.44	$7.91	$7.57
Total	$22.61	$39.74	$60.53	$54.10	$50.71	$48.31	$46.69	$45.12	$42.70	$41.20
Estimated Cost - Present Value Using 3% Rate ($ in million)										
Case 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Case 2	$0.26	$0.15	$0.47	$0.03	-$0.08	-$0.09	-$0.08	-$0.04	-$0.09	-$0.10
Case 3	$9.74	$15.64	$19.21	$20.00	$19.97	$19.66	$19.68	$19.48	$19.29	$19.45
Case 4	$0.89	$1.27	$2.81	$0.19	-$0.49	-$0.55	-$0.48	-$0.23	-$0.55	-$0.63
Case 5	$0.08	$0.09	$0.37	$0.03	-$0.07	-$0.07	-$0.06	-$0.03	-$0.07	-$0.08
Case 6	$8.19	$11.61	$13.92	$14.49	$14.47	$14.24	$14.26	$14.11	$13.98	$14.09
Case 7	$0.89	$1.27	$2.81	$0.19	-$0.49	-$0.55	-$0.48	-$0.23	-$0.55	-$0.63
Total	$20.06	$30.03	$39.60	$34.94	$33.31	$32.65	$32.84	$33.05	$32.01	$32.10

Table 11c: Estimated Impacts of Alternative Flaring Limits (9,600 / 4,800 / 2,400 Mcf per month)										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Case 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Case 2	$0.38	$0.80	$2.10	$2.11	$2.03	$1.92	$1.85	$1.76	$1.68	$1.63
Case 3	$13.61	$18.97	$21.18	$20.20	$19.43	$18.74	$18.07	$17.42	$16.78	$16.19
Case 4	$0.61	$2.79	$5.02	$5.03	$4.84	$4.59	$4.42	$4.21	$4.01	$3.89
Case 5	$0.20	$0.40	$1.62	$1.62	$1.56	$1.48	$1.43	$1.36	$1.29	$1.26
Case 6	$11.44	$14.08	$15.35	$14.63	$14.08	$13.57	$13.09	$12.62	$12.16	$11.73
Case 7	$6.45	$7.80	$8.73	$8.74	$8.40	$7.96	$7.67	$7.31	$6.97	$6.76
Total	$32.69	$44.83	$54.00	$52.35	$50.34	$48.26	$46.53	$44.69	$42.90	$41.46
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Case 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Case 2	$0.38	$0.83	$2.27	$2.36	$2.36	$2.32	$2.33	$2.30	$2.28	$2.30
Case 3	$13.61	$19.71	$22.86	$22.65	$22.63	$22.67	$22.71	$22.75	$22.77	$22.81
Case 4	$0.61	$2.90	$5.42	$5.64	$5.63	$5.55	$5.55	$5.50	$5.44	$5.49
Case 5	$0.20	$0.41	$1.75	$1.82	$1.82	$1.79	$1.79	$1.77	$1.76	$1.77
Case 6	$11.44	$14.63	$16.56	$16.41	$16.40	$16.42	$16.45	$16.48	$16.49	$16.52
Case 7	$6.45	$8.10	$9.42	$9.80	$9.79	$9.64	$9.64	$9.54	$9.45	$9.53
Total	$32.69	$46.57	$58.28	$58.69	$58.63	$58.39	$58.48	$58.34	$58.19	$58.42
Estimated Benefits Incremental Production (Bcf)										
Case 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Case 2	0.10	0.20	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53
Case 4	0.16	0.71	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26
Case 5	0.05	0.10	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
Case 7	1.69	1.98	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19
Total	2.01	2.99	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40
Estimated Benefits Incremental Production (million gal of NGL)										
Case 3	16.01	23.91	27.99	27.99	27.99	27.99	27.99	27.99	27.99	27.99
Case 6	13.45	17.75	20.28	20.28	20.28	20.28	20.28	20.28	20.28	20.28
Total	29.46	41.65	48.27	48.27	48.27	48.27	48.27	48.27	48.27	48.27
Net Benefits										
Net Benefits	$10	$5	-$7	-$2	$0	$0	$0	$0	$0	$0
Net Benefits	$13	$17	$19	$24	$25	$26	$26	$25	$26	$26

B. Flare Metering Requirements

The rule would require the metering of flared volumes when gas flaring meets or exceeds 50 Mcf/day for a flare stack or manifold, unless measurement is impractical. We estimate for the impacted operations, compliance with this requirement would cost $7,500 per meter and about $500 per year in operating costs. Assuming an equipment life of 10 years, the cost per meter is about $1,570 per year when we annualize the capital costs using a 7% interest rate or $1,380 per year when we annualize the capital costs using a 3% interest rate.

We note that since we do not have a count of the flare meters or manifolds in operation, we used the number of wells as a basis for our impacts estimation. However, since a flare meter or manifold may serve multiple wells, whose combined flaring would count towards the threshold, the number of impacted operations might be understated. On the other hand, since we are assuming that a flare meter would cover a single well and not multiple wells, the number of installations could be overstated. We believe that these limitiations cancel each other out.

We estimated the number of impacted operations to be 90% of the number of wells flaring above 50 Mcf/day in FY 2014. This is based on the assumption that 10% of the wells currently flaring above these thresholds already have flare meters, which appears reasonable given input from our field offices. According to these assumptions, we believe that the provisions would impact about 575 existing stacks or manifolds units and about 60 additional new stacks or manifolds per year.

Accordingly, we estimate that the proposed flare metering requirement would impact 635 operations in 2017 with that number increasing on an annual basis to an estimated 1,175 operations in 2026. We estimate compliance costs ranging from $1.0 – 1.8 million per year when the capital costs of equipment are annualized with a 7% discount rate or $0.9 – 1.6 million per year when the capital costs of equipment are annualized with a 3% discount rate. Since these sources are not addressed by the EPA's proposed Subpart OOOOa, the estimated impacts of the requirements are not influenced by that proposal.

Table 12: Estimated Impacts of Proposed Flare Measurement Requirements

YEAR	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Impacted operations										
Existing	575	575	575	575	575	575	575	575	575	575
New	60	120	180	240	300	360	420	480	540	600
Total operations	635	695	755	815	875	935	995	1,055	1,115	1,175
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)										
Existing	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90
New	$0.09	$0.19	$0.28	$0.38	$0.47	$0.56	$0.66	$0.75	$0.85	$0.94
Total operations	$1.00	$1.09	$1.18	$1.28	$1.37	$1.47	$1.56	$1.65	$1.75	$1.84
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)										
Existing	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79
New	$0.08	$0.17	$0.25	$0.33	$0.41	$0.50	$0.58	$0.66	$0.74	$0.83
Total operations	$0.88	$0.96	$1.04	$1.12	$1.21	$1.29	$1.37	$1.45	$1.54	$1.62

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 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.[62]

The rule would specify that flared gas is royalty-bearing when a well or area is connected to gas capture infrastructure to deliver the gas to market. NTL-4A has provisions that allow for an operator to apply for royalty-free flaring if capturing the gas would render the lease uneconomic, meaning that if the operator were ordered to capture the gas, then it might choose to shut-in the well instead. This principle is most appropriately applied to situations where the gas capture infrastructure does not exist. In reality, operators have requested royalty-free flaring when the gas capture infrastructure exists but is temporarily unavailable due to gas plant maintenance (often planned) or disruptions to the capacity of the gathering system and pipelines. Often, the BLM has approved applications to flare royalty-free during these temporary events, but under some circumstances, it has denied these applications.

We note that 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, we only estimate incremental royalty for gas from Federal and Indian leases, and for the estimated Federal and Indian portion of gas produced from leases with mixed owndership.

With respect to the gas flared from gas wells and the impact of the royalty provisions on that flaring, we assumed that 100% of the gas wells are connected to infrastructure and that 100% of the gas-well gas that is presently flared would be royalty bearing under this proposed rule. In 2013, the amount of Federal and Indian gas-well gas flared was 2.4 Bcf and 0.67 Bcf, respectively. We believe that basing annual out-year estimates for royalty on these assumptions, including these levels of gas flaring, is reasonable given the recent trends in flaring.

With respect to gas flared from oil wells, we conducted a survey of royalty-free flaring applications received by the BLM, and found that the percent of gas flaring from connected wells varies by state, but that the average of the applications surveyed was 45%. After reviewing the flaring dataset from ONRR, we calculated the amount of gas flared up to the flaring limit equivalent and then assumed that 45% – corresponding to the 45% of leases that are connected – would be subject to the royalty requirements of this proposed rule.

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

We estimate annual incremental royalty from this requirement of about $1.2 – 1.6 million per year (present value calculated using a 7% discount rate) or $1.5 – 1.7 million per year (present value calculated using a 3% discount rate).

Table 13: Estimated Incremental Royalty from Specifying Royalty on Gas Flared from Connected Wells, Present Value ($ in million)

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Royalty - Present Value Calculated Using a 7% Discount Rate	$1.50	$1.55	$1.57	$1.57	$1.51	$1.43	$1.38	$1.31	$1.25	$1.21
Royalty - Present Value Calculated Using a 3% Discount Rate	$1.50	$1.61	$1.69	$1.76	$1.76	$1.73	$1.73	$1.71	$1.70	$1.71

7.7 Well Drilling, Completions, and Maintenance

A. Well Drilling

The proposed rule places capture or flaring requirements on gas generated during drilling operations. The operator may also reinject the gas or use it for production purposes. The operator would be allowed to vent the completion gas if it cannot be flared safely. 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 proposed rule places capture or flaring requirements on gas generated during well completion and post-completion, drilling fluid recovery, or fracturing or refracturing fluid recovery operations. The operator may also reinject the gas or use it for production purposes. The operator would be allowed to vent the completion gas if it cannot be flared safely.

For completion and workover operations on conventional oil and gas wells, operators will generally control gas as a matter of safety and operating practice. However, we expect that there are some completion and workover operations where the expected volumes of gas are expected to be small and so the operator might use a completion or workover rig that is not equipped to flare produced gas. While we expect these occurrences to be rare, the rule's requirements would instead compel the operator to use a rig equipped to flare gas, if the volume of gas is technically feasible to flare, at a cost that we anticipate being relatively small. We estimate these costs below, based on assumptions that follow.

For completion and workover operations on hydraulically fractured gas wells, operators already control gas in order to comply with the EPA's NSPS Subpart OOOO. Therefore, no costs would be associated with this requirement.

For completion and workover operations on hydraulically fractured oil wells, operators are currently not required to control gas through the EPA's NSPS Subpart OOOO. However, the EPA's proposed NSPS Subpart OOOOa provisions would require operators to control the gas. Therefore, assuming that the EPA finalizes that rule, the BLM's requirements would become effectively moot for hydraulically fractured or refractured oil wells.

Colorado has existing well completion requirements that cover hydraulic fracturing completions where recovered fluids are run through a separator; therefore, we removed those estimated completion activities on Federal and Indian leases from the impacted operations. We would also expect that some operators control gas from hydraulically fractured oil wells voluntarily; however, since we do not have data on voluntary compliance, we cannot account for those activities. As such, we believe that our resulting estimates overstate the true costs of the requirements.

We estimate the number of impacted completions and workovers of hydraulically fractured oil wells, using the following data points:

Metric	Value	Explanation
Number of well completions on Federal and Indian leases in 2016	2,500	The number of well completions on Federal and Indian lands have decreased over the past several years from about 3,900 in FY 2011, 3,800 in FY 2012, 3,100 in FY 2013, and 2,500 in FY 2014.
Growth rate in completion activity from 2016 baseline	3%	BLM assumption recognizing that well completions in 2014 were lower than any year from 2010 to 2013.
Percent of well completions on Federal and Indian leases not occurring in Colorado	90%	Four-year average from 2010 to 2013; AFMSS.
Percent of completions that are oil wells	71%	Based on 2014 data; AFMSS.
Percent of well completions using hydraulic fracturing	90%	Assumption based on field experience.
Percent of HF oil well completions where the gas can be separated (where gas to oil ratio is > 300 scf/bbl)	76.36%	Metric used in EPA's TSD for the NSPS Subpart OOOOa (p. 25).
Percent of wells that are exploratory/delineation wells	3.8%	Metric used in EPA's TSD for the NSPS Subpart OOOOa (p. 25).
Percent of wells that are development wells	96.2%	Metric used in EPA's TSD for the NSPS Subpart OOOOa (p. 25).

Further, we estimate the engineering costs and emissions reductions for hydraulically fractured oil wells using the following data points (all dollars are 2012):

Metric	Value	Explanation
Average daily production of natural gas (Mcf/event)	999	Metric used in EPA's TSD for the NSPS Subpart OOOOa (p. 23).
Potential methane emissions (tons/event)	9.72	Metric used in EPA's TSD for the NSPS Subpart OOOOa (p. 23).
Potential VOC emissions (tons/event)	8.14	Metric used in EPA's TSD for the NSPS Subpart OOOOa (p. 23).
REC cost without gas savings ($/event)	13,459	Metric used in EPA's TSD for the NSPS Subpart OOOOa (p. 31).
Amount of recovered gas (Mcf/event)	899	Assuming 90% gas recovery per event.
Combustor cost ($/event)	3,523	Metric used in EPA's TSD for the NSPS Subpart OOOOa (p. 34).
REC and Combustion device cost ($/event)	17,183	Metric used in EPA's TSD for the NSPS Subpart OOOOa (p. 37).
Emissions reduction (%)	95%	Control efficiency.
Percent of exploratory/delineation wells that will use combustion as control method (%)	100%	Metric used in EPA's TSD for the NSPS Subpart OOOOa (p. 42).
Percent of development wells that will use REC as control method (%)	50%	Metric used in EPA's TSD for the NSPS Subpart OOOOa (p. 42).
Percent of development wells that will use combustion as control method (%)	50%	Metric used in EPA's TSD for the NSPS Subpart OOOOa (p. 42).
Percent of conventional wells completions/workovers that are uncontrolled	50%	BLM assumption that half of the conventional completions would be controlled and half would be vented.

It is important to note that a single combustion device can be used for multiple operations within the same year and for future years within the lifetime of the device. Assuming that a combustor will be used for only one well completion will overstate the actual costs of the device per well completion. The EPA notes this same limitation in its TSD for Subpart OOOOa.

We also separately examine the requirements for conventional completions and workovers. For the purposes of the analysis, we assumed that half of the conventional completions and workovers would be uncontrolled absent the rule. Recovery of gas is not expected from these operations since the gas volumes are expected to be small. Similarly, we are unable to estimate emissions reductions for the requirements as they relate to conventional completions and workovers.

<u>Proposed Well Completion and Maintenance Requirements</u>

We estimate that if the EPA did not finalize Subpart OOOOa, the proposed well completion and well maintenance requirements would:

- Impact up to about 1,250 – 1,575 completions per year;
- Pose total costs of about $8 – 12 million per year (using a 7% discount rate) or $12 million per year (using a 3% discount rate);
- Result in cost savings of about $2 million per year (using a 7% discount rate) or $2 – 3 million per year (using a 3% discount rate);
- Increase gas production by 0.5 – 0.6 Bcf per year;
- Reduce methane emissions by 11,500 – 14,500 tons per year;
- Produce monetized benefits of the reduced methane emissions of $13 million per year in 2017 – 2019, $16 – 18 million per year in 2020 – 2024, and $21 – 22 million in 2025 and 2026; and
- Reduce VOC emissions by 9,600 – 12,200 tons per year; and
- Produce net benefits of $3 – 4 million per year in 2017 – 2019, $8 – 11 million per year in 2020 – 2024, and 15 million in 2025 and 2026 (considering the present value of costs and cost savings using a 7% discount rate) or net benefits of $3 – 4 million per year in 2017 – 2019, $7 – 9 million per year in 2020 – 2024, and $12 – 13 million in 2025 and 2026 (considering the present value of costs and cost savings using a 3% discount rate).

If the EPA finalizes Subpart OOOOa, the the BLM's requirements would practically only impact conventional well completions. In that case, we estimate that the BLM rule would impact between 115 – 150 completions per year and and pose costs to the industry of less than $430,000 per year. There would be only *de minimis* anticipated incremental production, incremental royalty, and emissions reductions.

Table 15: Estimated Impacts of Well Completion Requirements, if EPA does not Finalize Subpart OOOOa										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Impacted well completions										
Development oil wells (REC)	544	560	576	591	607	623	639	655	671	686
Development oil wells (Combustion)	544	560	576	591	607	623	639	655	671	686
Exploration/Delineation oil wells	43	44	45	47	48	49	50	52	53	54
Conventional well completions	116	119	123	126	129	133	136	140	143	146
Total well completions	1,247	1,283	1,319	1,356	1,392	1,428	1,465	1,501	1,537	1,573
Estimated Compliance Cost - Present Value Using 7% Rate ($ in million)										
HF Development oil wells (REC)	$9.35	$8.99	$8.64	$8.30	$7.96	$7.63	$7.32	$7.01	$6.71	$6.42
HF Development oil wells (Combustion)	$2.02	$1.95	$1.87	$1.80	$1.72	$1.65	$1.59	$1.52	$1.45	$1.39
HF Exploration/Delineation oil wells	$0.16	$0.15	$0.15	$0.14	$0.14	$0.13	$0.13	$0.12	$0.11	$0.11
Conventional well completions	$0.43	$0.41	$0.40	$0.38	$0.37	$0.35	$0.34	$0.32	$0.31	$0.30
Total well completions	$11.96	$11.51	$11.06	$10.62	$10.19	$9.77	$9.36	$8.97	$8.58	$8.21
Estimated Compliance Cost - Present Value Using 3% Rate ($ in million)										
HF Development oil wells (REC)	$9.35	$9.34	$9.32	$9.30	$9.27	$9.24	$9.20	$9.15	$9.10	$9.04
HF Development oil wells (Combustion)	$2.02	$2.02	$2.02	$2.02	$2.01	$2.00	$1.99	$1.98	$1.97	$1.96
HF Exploration/Delineation oil wells	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.15
Conventional well completions	$0.43	$0.43	$0.43	$0.43	$0.43	$0.43	$0.42	$0.42	$0.42	$0.42
Total well completions	$11.96	$11.95	$11.93	$11.90	$11.87	$11.82	$11.77	$11.71	$11.64	$11.57
Estimated Social Costs - CO2 Emissions Additions (tons)										
HF Development oil wells (REC)	19	19	20	20	21	21	22	22	23	23
HF Development oil wells (Combustion)	19	19	20	20	21	21	22	22	23	23
HF Exploration/Delineation oil wells	1	2	2	2	2	2	2	2	2	2
Conventional well completions	4	4	4	4	4	5	5	5	5	5
Total CO2 Additions	43	44	45	46	48	49	50	51	53	54
Value of CO2 Additions ($MM)	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.003

Table 15: Estimated Impacts of Well Completion Requirements, if EPA does not Finalize Subpart OOOOa										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
HF Development oil wells (REC)	$1.86	$1.98	$2.06	$2.12	$2.09	$2.03	$2.01	$1.96	$1.91	$1.90
HF Development oil wells (Combustion)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
HF Exploration/Delineation oil wells	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Conventional well completions	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total well completions	$1.86	$1.98	$2.06	$2.12	$2.09	$2.03	$2.01	$1.96	$1.91	$1.90
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
HF Development oil wells (REC)	$1.86	$2.06	$2.22	$2.37	$2.43	$2.46	$2.52	$2.56	$2.60	$2.68
HF Development oil wells (Combustion)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
HF Exploration/Delineation oil wells	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Conventional well completions	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total well completions	$1.86	$2.06	$2.22	$2.37	$2.43	$2.46	$2.52	$2.56	$2.60	$2.68
Estimated Benefits Incremental Production (Bcf)										
HF Development oil wells (REC)	0.49	0.50	0.52	0.53	0.55	0.56	0.57	0.59	0.60	0.62
HF Development oil wells (Combustion)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HF Exploration/Delineation oil wells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Conventional well completions	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total well completions	0.49	0.50	0.52	0.53	0.55	0.56	0.57	0.59	0.60	0.62
Estimated Methane Emissions Reductions (tons)										
HF Development oil wells (REC)	5,000	5,200	5,300	5,500	5,600	5,800	5,900	6,000	6,200	6,300
HF Development oil wells (Combustion)	5,000	5,200	5,300	5,500	5,600	5,800	5,900	6,000	6,200	6,300
HF Exploration/Delineation oil wells	400	400	400	400	400	500	500	500	500	500
Conventional well completions	1,100	1,100	1,100	1,200	1,200	1,200	1,300	1,300	1,300	1,400
Total CH4 reductions	11,500	11,800	12,200	12,500	12,900	13,200	13,500	13,900	14,200	14,500
Value of CH4 reductions ($MM)	$12.66	$13.03	$13.40	$16.27	$16.71	$17.14	$17.58	$18.02	$21.29	$21.79
Estimated VOC Emissions Reductions										
HF Development oil wells (REC)	4,200	4,300	4,500	4,600	4,700	4,800	4,900	5,100	5,200	5,300
HF Development oil wells (Combustion)	4,200	4,300	4,500	4,600	4,700	4,800	4,900	5,100	5,200	5,300
HF Exploration/Delineation oil wells	300	300	400	400	400	400	400	400	400	400
Conventional well completions	900	900	900	1,000	1,000	1,000	1,100	1,100	1,100	1,100
Total VOC reductions	9,600	9,900	10,200	10,500	10,800	11,000	11,300	11,600	11,900	12,200
Net Benefits										
Net Benefits - 7% ($ MM)	$3	$4	$4	$8	$9	$9	$10	$11	$15	$15
Net Benefits - 3% ($ MM)	$3	$3	$4	$7	$7	$8	$8	$9	$12	$13

7.8 Pneumatic Controllers

The proposed requirement, that continuous pneumatic controllers be low-bleed controllers, would compel operators to replace exisiting high-bleed continuous pneumatic controllers with low-bleed continuous pneumatic controllers. The requirements do not apply if a controller with a greater bleed rate is required based on functional needs, or if the controller exhaust is routed to a flare device. An exemption from the requirement would also apply if the operator demonstrated that the replacement would impose costs on the operator such that the operator would cease production and abandon significant oil reserves. Operators have been required to use low-bleed continuous controllers at wellsite operations nationwide, for any devices that have been newly installed or modified since August 23, 2011, to comply with the NSPS Subpart OOOO. Also, Colorado has a rule that requires the switch to low bleed controllers, and Wyoming requires all controllers in the Upper Green River Basin (UGRB) to be low bleed by January 2017.

As described in the appendix, we estimated the number of impacted controllers by scaling down the EPA's nationwide estimate for the number of pneumatic controllers (listed in the 2015 GHG Inventory, Annex 3) according to the share of oil and gas production (7.43% and 12.7%, respectively) coming from Federal and Indian lands in 2013. For the petroleum production segment, we estimated the number of high bleed pneumatic controllers on Federal and Indian lands to be about 7.43% of the nationwide amount. We then assumed that 10% of those controllers were high bleed continuous controllers and also 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.[63] Thus, 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.

The engineering costs come from data in the EPA's Technical Support Document for the NSPS Subpart OOOO, with costs escalated to 2012 dollars. 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. Methane reductions were calculated using a conversion factor, 1 Mcf of methane = 0.0193 tons of methane. VOC reductions were calculated using a conversion factor, 1 tpy VOC = 0.219 tpy methane.

[63] 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.

Proposed Requirements

We estimate that the proposed pneumatic controller requirements would:

- Impact up to about 15,600 existing low-bleed pneumatic devices;
- Pose total costs of about $6 million per year (capital costs annualized using a 7% discount rate) or $5 million per year (capital costs annualized using a 3% discount rate);
- Result in cost savings of about $9 – 11 million per year (using a 7% discount rate) or $11 – 12 million per year (using a 3% discount rate);
- Increase gas production by 2.9 Bcf per year;
- Reduce methane emissions by 43,000 tons per year;
- Produce monetized benefits of the reduced methane emissions of $48 million per year in 2017 – 2019, $56 million per year in 2020 – 2024, and $65 million in 2025 and 2026; and
- Reduce VOC emissions by about 200,000 tons per year; and
- Result in net benefits of $53 million per year in 2017 – 2019, $60 – 62 million per year in 2020 – 2024, and $68 million in 2025 and 2026 (using a 7% discount rate for costs and cost savings) or net benefits of $54 – 55 million per year in 2017 – 2019, $64 million per year in 2020 – 2024, and $73 million in 2025 and 2026 (using a 3% discount rate for costs and cost savings).

Since these sources are not addressed by the EPA's proposed Subpart OOOOa, the estimated impacts are not influenced by that proposal.

The estimates provided likely overestimate the impacts, both benefits and costs, of the pneumatic controller requirements, because the requirements do not apply to controllers where a greater bleed rate is required based on functional needs or if the operator demonstrates that the replacement would impose costs on the operator such that the operator would cease production and abandon significant oil reserves. We do not have estimates on the number of pneumatic controllers would fall into either of these categories.

Table 16: Estimated Impacts of Pneumatic Controller Requirements										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Impacted Pneumatic Controllers										
Existing controllers - petroleum sector	11,100	11,100	11,100	11,100	11,100	11,100	11,100	11,100	11,100	11,100
Existing controllers - natural gas sector	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500
Total controllers	15,600	15,600	15,600	15,600	15,600	15,600	15,600	15,600	15,600	15,600
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)										
Existing controllers - petroleum sector	$4.11	$4.11	$4.11	$4.11	$4.11	$4.11	$4.11	$4.11	$4.11	$4.11
Existing controllers - natural gas sector	$1.67	$1.67	$1.67	$1.67	$1.67	$1.67	$1.67	$1.67	$1.67	$1.67
Total controllers	$5.78	$5.78	$5.78	$5.78	$5.78	$5.78	$5.78	$5.78	$5.78	$5.78
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)										
Existing controllers - petroleum sector	$3.39	$3.39	$3.39	$3.39	$3.39	$3.39	$3.39	$3.39	$3.39	$3.39
Existing controllers - natural gas sector	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37
Total controllers	$4.76	$4.76	$4.76	$4.76	$4.76	$4.76	$4.76	$4.76	$4.76	$4.76
Estimated Costs - CO2 Emissions Additions (tons)										
Existing controllers - petroleum sector	55	55	55	55	55	55	55	55	55	55
Existing controllers - natural gas sector	54	54	54	54	54	54	54	54	54	54
Total controllers	109	109	109	109	109	109	109	109	109	109
Value of CO2 Additions ($MM)	$0.004	$0.004	$0.004	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Existing controllers - petroleum sector	$5.46	$5.65	$5.71	$5.72	$5.50	$5.21	$5.02	$4.78	$4.56	$4.43
Existing controllers - natural gas sector	$5.40	$5.59	$5.65	$5.66	$5.44	$5.15	$4.97	$4.73	$4.51	$4.38
Total controllers	$10.87	$11.24	$11.36	$11.38	$10.94	$10.36	$9.99	$9.51	$9.07	$8.80
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Existing controllers - petroleum sector	$5.46	$5.87	$6.16	$6.41	$6.40	$6.30	$6.31	$6.24	$6.19	$6.24
Existing controllers - natural gas sector	$5.40	$5.81	$6.09	$6.34	$6.33	$6.24	$6.24	$6.18	$6.12	$6.17
Total controllers	$10.87	$11.68	$12.25	$12.76	$12.74	$12.54	$12.55	$12.42	$12.30	$12.40
Estimated Benefits Incremental Production (Bcf)										
Existing controllers - petroleum sector	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44
Existing controllers - natural gas sector	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42
Total controllers	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86
Estimated Methane Emissions Reductions (tons)										
Existing controllers - petroleum sector	21,800	21,800	21,800	21,800	21,800	21,800	21,800	21,800	21,800	21,800
Existing controllers - natural gas sector	21,600	21,600	21,600	21,600	21,600	21,600	21,600	21,600	21,600	21,600
Total CH4 reductions	43,400	43,400	43,400	43,400	43,400	43,400	43,400	43,400	43,400	43,400
Value of CH4 reductions ($MM)	$47.78	$47.78	$47.78	$56.47	$56.47	$56.47	$56.47	$56.47	$65.16	$65.16
Estimated VOC Emissions Reductions										
Existing controllers - petroleum sector	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Existing controllers - natural gas sector	99,000	99,000	99,000	99,000	99,000	99,000	99,000	99,000	99,000	99,000
Total VOC reductions	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000
Net Benefits										
Net Benefits - 7% ($ MM)	53	53	53	62	62	61	61	60	68	68
Net Benefits - 3% ($ MM)	54	55	55	64	64	64	64	64	73	73

7.9 Pneumatic Pumps

The proposed requirements would require the operator either to replace a covered pneumatic pump with a zero-emissions pump or to control the releases from the pump by routing them to a flare. The requirements do not apply if the existing pump is required based on functional needs, and there either is no existing flare device on site or routing to an existing flare device is technically infeasible. An exemption from the requirement would also apply if the operator demonstrated that the replacement would impose costs on the operator such that the operator would cease production and abandon significant oil reserves.

The NSPS Subpart OOOOa proposal would require operators to control the emissions from new or modified pneumatic pumps. Therefore, to the extent that the EPA finalizes that rule, the BLM's requirements would not apply to new or modified pumps, but would apply to pumps exisiting prior to the publication date of the Subpart OOOOa proposal. Accordingly, we analyze the potential impacts of the BLM's proposal under two scenarios: if the EPA finalizes Subpart OOOOa and if it does not. In addition, Wyoming will regulate pneumatic pumps in the UGRB 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 controllers (listed in the 2015 GHG Inventory, Annex 3) according to the share of oil and gas production coming from Federal and Indian lands in 2013. We then reduced the number of impacted pumps by 12%, or the share of producing oil and gas wells in Wyoming's UGRB, since those pumps should already be in compliance with the BLM's rule by the time it would be effective. We estimated the number of impacted new pumps per year by scaling down the estimated number of pumps impacted by the Subpart OOOOa regulations by 20% (roughly the combined share of oil and gas production coming from Federal and Indian lands in 2013). We then reduced that number by 40.5%, or the share of well completions in Utah and Wyoming's UGRB in 2013.

As a result of this formulation, we estimate that if the Subpart OOOOa were not finalized, the BLM's requirements would impact about 8,775 existing pumps and about 75 new pumps per year. The actual number of impacted pumps is expected to be lower than the estimate due to the exemptions provided in the rule.

The replacement of gas-assisted pumps may vary in cost and feasibility. We describe the costs and considerations presented in the EPA's Technical Support Document for the NSPS Subpart OOOOa (pp. 174-175):

- Cost to convert to solar powered pump: $2,300/device;
- Cost to convert to electric pump: $1,807 to $5,352/device, plus $263/yr in maintenance;
- Cost to convert to instrument air: varies, depending on the size of the compressor, power supply, labor, and equipment;
- Cost to route to an existing control device: $1,500/device;
- Cost to route to new control device: $48,500/device, plus $104,000/yr in operating costs;
- Cost to route to an existing capture system: $1,500/device; and
- Cost to route to a new capture system: $36,000/device, plus $7,500/yr in operating costs.

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

Metric	Value	Explanation
Percent of new pumps that are diaphragm pumps (%)	50%	EPA's TSD for the NSPS Subpart OOOOa (p. 172).
Percent of new pumps that are piston pumps (%)	50%	EPA's TSD for the NSPS Subpart OOOOa (p. 172).
Methane emission factor for diaphragm pumps (tpy/pump)	3.46	EPA's TSD for the NSPS Subpart OOOOa (p. 172).
Methane emission factor for piston pumps (tpy/pump)	0.38	EPA's TSD for the NSPS Subpart OOOOa (p. 172).
VOC emission factor for diaphragm pumps (tpy/pump)	0.96	EPA's TSD for the NSPS Subpart OOOOa (p. 172).
VOC emission factor for piston pumps (tpy/pump)	0.11	EPA's TSD for the NSPS Subpart OOOOa (p. 172).
Percent emission reduction for all pumps (%)	95%	EPA's TSD for the NSPS Subpart OOOOa (p. 202).
Annualized cost of control or replacement ($/pump) (in 2012 dollars)	$285	EPA's TSD for the NSPS Subpart OOOOa (p. 201). The EPA presents costs using a 7% discount rate only, explaining that the difference in costs among the discount rates is minor.
Gas savings for diaphragm pump control or replacement (Mcf/yr)	187	EPA's TSD for the NSPS Subpart OOOOa (p. 201).
Gas savings for piston pump control or replacement (Mcf/yr)	21	EPA's TSD for the NSPS Subpart OOOOa (p. 201).
Percent of controls or replacements that will capture gas	50%	BLM assumption.
Percent of controls or replacements that will route to combustor	50%	BLM assumption.

<u>Proposed Requirements</u>

We estimate that if the Subpart OOOOa proposal is not finalized, the proposed pneumatic pump requirements would:

- Impact up to about 8,775 existing pumps and about 75 new pumps per year;
- Pose total costs of about $2.5 – 2.7 million per year (capital costs annualized using 7% and 3% discount rates);
- Result in cost savings of about $2 million per year (present value of costs savings calculated using 7% and 3% discount rates);
- Increase gas production by 0.5 Bcf per year;
- Reduce methane emissions by about 16,000 – 17,000 tons per year;
- Produce monetized benefits of the reduced methane emissions of $18 million per year in 2017 – 2019, $22 million per year in 2020 – 2024, and $26 million in 2025 and 2026;
- Reduce VOC emissions by about 4,000 tons per year; and
- Result in net benefits of $17 million per year in 2017 – 2019, $21 – 22 million per year in 2020 – 2024, and $25 million in 2025 and 2026.

If the EPA finalizes Subpart OOOOa, the BLM's requirements would practically only impact existing pumps and not new pumps. Therefore, we estimate that the rule would impact up to 8,775 existing pumps, pose compliance costs of about $2.5 million per year, result in cost savings of $1.5 – 1.9 million per year (using a 7% discount rate) or $1.75 – 2.15 million per year (using a 3% discount rate), increase gas production by 0.46 Bcf per year, reduce methane emissions by 16,000 tons per year, produce monetized benefits of the reduced methane emissions of $18 million per year in 2017 – 2019, $21 million per year in 2020 – 2024, and $24 million per year in 2025 and 2026, reduce VOC emissions by 4,000 tons per year, and result in net benefits of $17 million per year in 2017 – 2019, $20 million per year in 2020 – 2024, and $23 million per year in 2025 and 2026.

Table 17: Estimated Impacts of Pneumatic Pump Requirements										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Impacted Pneumatic Pumps										
Existing pumps	8,775	8,775	8,775	8,775	8,775	8,775	8,775	8,775	8,775	8,775
New pumps	75	150	225	300	375	450	525	600	675	750
Total pumps	8,850	8,925	9,000	9,075	9,150	9,225	9,300	9,375	9,450	9,525
Estimated Costs - Capital Costs Annualized Using a 7% and 3% Discount Rate ($ in million)										
Existing pumps	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50
New pumps	$0.02	$0.04	$0.06	$0.09	$0.11	$0.13	$0.15	$0.17	$0.19	$0.21
Total pumps	$2.52	$2.54	$2.57	$2.59	$2.61	$2.63	$2.65	$2.67	$2.69	$2.71
Estimated Costs - CO2 Emissions Additions (tons)										
Existing pumps	35	35	35	35	35	35	35	35	35	35
New pumps	0	1	1	1	1	2	2	2	3	3
Total pumps	35	35	36	36	36	36	37	37	37	38
Value of CO2 Additions ($MM)	$0.001	$0.001	$0.001	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Existing pumps	$1.74	$1.80	$1.81	$1.82	$1.75	$1.66	$1.60	$1.52	$1.45	$1.41
New pumps	$0.01	$0.03	$0.05	$0.06	$0.07	$0.08	$0.10	$0.10	$0.11	$0.12
Total pumps	$1.75	$1.83	$1.86	$1.88	$1.82	$1.74	$1.69	$1.62	$1.56	$1.53
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Existing pumps	$1.74	$1.87	$1.96	$2.04	$2.03	$2.00	$2.01	$1.98	$1.97	$1.98
New pumps	$0.01	$0.03	$0.05	$0.07	$0.09	$0.10	$0.12	$0.14	$0.15	$0.17
Total pumps	$1.75	$1.90	$2.01	$2.11	$2.12	$2.11	$2.13	$2.12	$2.12	$2.15
Estimated Benefits Incremental Production (Bcf)										
Existing pumps	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
New pumps	0.00	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.04	0.04
Total pumps	0.46	0.46	0.47	0.47	0.48	0.48	0.48	0.49	0.49	0.50
Estimated Methane Emissions Reductions (tons)										
Existing pumps	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000
New pumps	100	300	400	500	700	800	1,000	1,100	1,200	1,400
Total CH4 reductions	16,100	16,300	16,400	16,600	16,700	16,800	17,000	17,100	17,200	17,400
Value of CH4 reductions ($MM)	$17.76	$17.91	$18.06	$21.52	$21.70	$21.87	$22.05	$22.23	$25.86	$26.06
Estimated VOC Emissions Reductions (tons)										
Existing pumps	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
New pumps	40	80	110	150	190	230	270	300	340	380
Total VOC reductions	4,040	4,080	4,110	4,150	4,190	4,230	4,270	4,300	4,340	4,380
Net Benefits										
Net Benefits - 7% ($ MM)	17	17	17	21	21	21	21	21	25	25
Net Benefits - 3% ($ MM)	17	17	17	21	21	21	22	22	25	25

7.10 Liquids Unloading

The rule requires operators to monitor and report on liquids unloading activities, if the operator does not use an automated system, to help minimize the venting and loss of gas during liquids unloading to only the amount necessary to bring the well back into production. The operator may choose to install an automated system and avoid the monitoring and reporting requirements altogether. The proposed requirements covering liquids unloading activities will have an unclear impact. First, we do not know precisely how many wells would be affected by the requirements. 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 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.

The actual impact on the affected wells is also uncertain. Operators may choose to install equipment to remove liquids, if appropriate, or they may undertake monitoring activities. Regarding the monitoring requirements, we do not anticipate any additional burdens to the operator for two reasons. First, a prudent operator is expected to remain onsite for the duration of the liquids unloading activity to minimize the unnecessary loss of gas. 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 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.

For wells drilled after the effective date of the rule, the rule would prohibit the operator from using well purging to unload liquids. It is also unclear what impact this requirement would have. According to the 2015 GHG Inventory, almost 8% of all gas wells vent during liquids unloading but are not equipped with plunger lifts, while almost 5% vent but have plunger lifts. In the Rocky Mountain region, where 90% of the gas wells on Federal and 94% of the gas wells on Indian lands are located, gas wells with plunger lifts are far more common relative to the national average. In this region, about 1.5% of wells vent but are not equipped with plunger lifts, while almost 13% vent and have plunger lifts.

These data demonstrate that operators commonly use plunger lift systems in areas where the vast majority of gas wells on Federal and Indian lands are located. As a consequence, we would expect a high degree of voluntary compliance with this requirement, but we also might expect that roughly 25 gas wells per year might develop liquids loading problems where the operators would not install plunger lifts absent this rule. We developed these estimates assuming about 900 gas well completions per year in the future on Federal and Indian lands[64] and a regional distribution of new wells consistent with the distribution of currently producing gas wells.[65] The estimated number of wells without plunger lifts, by region, are based on data from the 2015 GHG Inventory, Annex 3.

Table 18: Estimated Annual New Gas Wells Completions and Wells that Would Not be Equipped with Plunger Lifts

Region	Federal Lands		Indian Lands	
	Estimated gas well completions	Estimated wells that would develop liquids loading problems and not use plunger lifts	Estimated gas well completions	Estimated wells that would develop liquids loading problems and not use 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**

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 20 (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.

[64] 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.
[65] As of January 1, 2015.

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 19: 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. Our assumptions 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 most recent EPA GHG Inventory, Annex 3.

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

- Methane reductions in tons were calculated using a conversion factor, 1 Mcf of methane = 0.0193 tons of methane;
- VOC reductions were calculated using a conversion factor, 1 tpy VOC = 0.219 tpy methane.

Proposed Requirements

We estimate that the proposed liquids unloading requirements would:

- Impact up to about 1,550 existing wells and about 25 new wells per year;
- Pose total 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);
- Result in cost savings of about $7 – 8 million per year (using a 7% discount rate) or $7 – 10 million per year (using a 3% discount rate);
- Increase gas production by roughly 2 Bcf per year;
- Reduce methane emissions by 30,000 – 34,000 tons per year;
- Produce monetized benefits of the reduced methane emissions of $33 – 34 million per year in 2017 – 2019, $41-43 million per year in 2020 – 2024, and $50 – 51 million in 2025 and 2026; and
- Reduce VOC emissions by about 136,000 – 156,000 tons per year; and
- Result in net benefits of $35 – 36 million per year in 2017 – 2019, $43 – 44 million per year in 2020 – 2024, and $51 – 52 million in 2025 and 2026 (using a 7% discount rate for costs and cost savings) or $35 – 37 million per year in 2017 – 2019, $45 – 47 million per year in 2020 – 2024, and $54 – 55 million in 2025 and 2026 (using a 3% discount rate for costs and cost savings).

Since these sources are not addressed by the EPA's proposed Subpart OOOOa, the estimated impacts are not influenced by that proposal.

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 in all circumstances. 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 realize the amount of gas savings assumed in conducting this analysis.

Table 20: Estimated Impacts ofLiquids Unloading Requirements										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Impacted Pneumatic Controllers										
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
New wells	$0.09	$0.18	$0.26	$0.35	$0.44	$0.53	$0.61	$0.70	$0.79	$0.88
Total wells	$5.51	$5.60	$5.69	$5.78	$5.86	$5.95	$6.04	$6.13	$6.21	$6.30
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)										
Existing wells	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88
New wells	$0.08	$0.16	$0.24	$0.32	$0.39	$0.47	$0.55	$0.63	$0.71	$0.79
Total wells	$4.96	$5.04	$5.12	$5.20	$5.28	$5.36	$5.43	$5.51	$5.59	$5.67
Estimated Costs - CO2 Emissions Additions (tons)										
Existing wells	73	73	73	73	73	73	73	73	73	73
New wells	1	2	4	5	6	7	8	9	11	12
Total wells	74	76	77	78	79	80	82	83	84	85
Value of CO2 Additions ($MM)	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.004	$0.004	$0.004	$0.004
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Existing wells	$7.34	$7.59	$7.67	$7.68	$7.38	$7.00	$6.74	$6.42	$6.12	$5.94
New wells	$0.12	$0.24	$0.37	$0.50	$0.60	$0.68	$0.76	$0.83	$0.89	$0.96
Total wells	$7.45	$7.83	$8.04	$8.18	$7.98	$7.67	$7.50	$7.25	$7.01	$6.90
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Existing wells	$7.34	$7.88	$8.27	$8.61	$8.60	$8.47	$8.47	$8.39	$8.31	$8.37
New wells	$0.12	$0.25	$0.40	$0.56	$0.69	$0.82	$0.96	$1.08	$1.21	$1.35
Total wells	$7.45	$8.14	$8.67	$9.17	$9.29	$9.28	$9.43	$9.47	$9.51	$9.72
Estimated Benefits Incremental Production (Bcf)										
Existing wells	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93
New wells	0.03	0.06	0.09	0.12	0.16	0.19	0.22	0.25	0.28	0.31
Total wells	1.96	1.99	2.02	2.05	2.08	2.11	2.15	2.18	2.21	2.24
Estimated Methane Emissions Reductions (tons)										
Existing wells	29,300	29,300	29,300	29,300	29,300	29,300	29,300	29,300	29,300	29,300
New wells	500	900	1,400	1,900	2,400	2,800	3,300	3,800	4,300	4,700
Total CH4 reductions	29,800	30,300	30,700	31,200	31,700	32,200	32,600	33,100	33,600	34,100
Value of CH4 reductions ($MM)	$32.78	$33.30	$33.82	$40.58	$41.20	$41.81	$42.43	$43.04	$50.37	$51.08
Estimated VOC Emissions Reductions										
Existing wells	134,000	134,000	134,000	134,000	134,000	134,000	134,000	134,000	134,000	134,000
New wells	2,000	4,000	6,000	9,000	11,000	13,000	15,000	17,000	19,000	22,000
Total VOC reductions	136,000	138,000	140,000	143,000	145,000	147,000	149,000	151,000	153,000	156,000
Net Benefits										
Net Benefits - 7% ($ MM)	35	36	36	43	43	44	44	44	51	52
Net Benefits - 3% ($ MM)	35	36	37	45	45	46	46	47	54	55

7.11 Storage Tanks

The proposed requirements, that operators either capture or combust gases coming from storage tanks with the potential to emit at or above 6 tpy of VOC (with exceptions to this requirement), would impact an estimated 292 storage tanks or tank batteries on Federal and Indian lands. The EPA's NSPS currently regulates new or modified storage tanks above a 6 tpy of VOC threshold, and the proposed rule would not affect those tanks. Similarly, the state of Colorado regulates new and existing storage tanks above a 6 tpy of VOC threshold and the state of Utah requires the control of tank emissions, and the proposed rule would not, as a practical matter, require any additional controls on tanks in Colorado and Utah. Wyoming regulates new and existing storage tanks in the UGRB beginning in January 2017, and so again, the BLM's proposed rule will not, as a practical matter, require any additional controls on tanks in Wyoming's UGRB. We used data from the EPA's analysis for the NSPS Subpart OOOO, and that analysis considered existing operator activity to comply with state requirements. Although it is unlikely that the EPA's analysis accounted for the 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.

We estimated the impacts using a similar methodology as 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 21). 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 chose that point in time, since the NSPS, which covers new and modified storage vessels, was finalized in 2012 with the requirements for tanks taking effect in 2013. 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 controlled 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 22.

Table 21: Baseline Activity Data for Crude Oil and Condensate Storage Vessels

Parameter	Model Crude Oil Tank Batteries			
	A	B	C	D
Percent of number 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 number 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 wells nationwide (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 22: 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. Engineering costs for each option have been cited at around $20,000 per year, when the capital investments are annualized basis over the life of the equipment. VRU costs can potentially range higher, depending on the the capacity required.

We believe that in most cases the operator will comply with the proposed requirements depending on 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. 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 additional resource recovery helping to offset the engineering costs. For this analysis, we assume that a VRU would return about 296 Mcf per year in additional production. We based that assumption upon 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 proposed 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 22). Total estimated emissions reductions for the policy options were calculated as the additive emissions reductions from the models, if impacted by the threshold.

Table 25 shows the cost-effectiveness analysis for crude oil and condensate storage vessels at different emissions thresholds and the number of units that we estimate would be impacted at the respective thresholds. Regulating both crude oil and condensate storage tanks with uncontrolled emissions at or above 6 tpy of VOC would result in a cost-effectiveness of $3,678 per ton of VOC reduced and impact 292 units. In its decision to implement a 6 tpy of VOC threshold, the EPA determined that the cost-effectiveness associated with that threshold was acceptable and therefore pursued that option. Again, viewing the table, regulating tanks at the higher threshold of 20 tpy results in the same number of impacted units but a cost effectiveness of $1,103 per ton of VOC reduced. This highlights the tiered organization of the data into the model tank categories. Naturally, fewer units would be impacted as the emissions threshold increases; however, potentially, at the given emissions levels we do not see this distinction.

Table 23: Total Capital Investment and Total Annualized Cost of a Combustor

Cost Item	Capital Costs ($)	Non-Recurring, One-Time Costs ($)	Total Capital Investment ($)	O&M Costs ($/yr)	Annualized Total Cost ($/yr)
Combustor	$16,540				
Freight and Design		$1,500			
Combustor Installation		$6,354			
Auto Igniter	$1,500				
Surveillance System	$3,600				
Pilot Fuel				$1,897	
Operating Labor				$9,743	
Maintenance				$2,000	
Data Management				$1,000	
Subtotal Costs (2007)	$21,640	$7,854		$14,640	
Subtotal Costs (2012)	$24,078	$8,739	$32,817	$16,290	
Annualized costs (using 3% interest, 10 year equipment life)	$3,428.21	$1,024		na	$20,742
Annualized costs (using 7% interest, 10 year equipment life)	$3,428	$1,244		na	$20,962

Source: Capital costs, one-time costs, O&M costs, and savings due to fuel saves come from EPA (2011), p. 7-14. Costs are escalated to 2012 dollars using the CE Indices for 2007 (525.4) and 2012 (584.6).

Table 24: Total Capital Investment and Total Annualized Cost of a Vapor Recovery Unit

Cost Item	Capital Costs ($)	Non-Recurring One-time Costs ($)	Total Capital Investment ($)	O&M Costs ($/yr)	Annualized Total Cost ($/yr)	Savings due to Fuel Sales ($/yr)	Annualized Total Cost with Gas Savings ($/yr)
VRU	$78,000						
Freight and Design		$1,500					
Combustor Installation		$10,154					
Maintenance				$8,553			
Recovered Natural Gas						$1,063	
Subtotal Costs (2007)	$78,000	$11,654		$8,553		$1,063	
Subtotal Costs (2012)	$86,789	$12,967	$99,756	$9,517		$1,183	
Annualized costs (using 3% interest, 15 year equipment life)	$7,270	$1,086		n/a	$17,873	n/a	$16,690
Annualized costs (using 7% interest, 15 year equipment life)	$9,529	$1,424		n/a	$20,469	n/a	$19,287

Source: Capital costs, one-time costs, O&M costs, and savings due to fuel saves come from EPA (2011), p. 7-14. Costs are escalated to 2012 dollars using the CE Indices for 2007 (525.4) and 2012 (584.6).

Table 25: Options for VOC Emissions Thresholds for Storage Vessels

Regulatory Option	VOC Emissions Threshold (tpy)	VOC Emission Reduction (tpy)[1]	Annual Costs for Combustor ($/yr)	Cost Effectiveness ($/ton VOC)	Number of Impacted Units
Crude Oil Storage Vessels					
1	0.3	0.29	$20,962	$73,551	11,694
2	3	2.85	$20,962	$7,355	619
3	6	5.70	$20,962	$3,678	157
4	20	19.00	$20,962	$1,103	157
5	30	28.50	$20,962	$736	65
Condensate Storage Vessels					
1	3	2.85	$20,962	$7,355	2,558
2	6	5.70	$20,962	$3,678	135
3	20	19.00	$20,962	$1,103	135
4	30	28.50	$20,962	$736	34

[1] Assumes a 95% reduction.

A summary of the estimated impacts of the proposed requirements and the alternatives considered are shown in Table 26 and with more detail in Tables 27a-c.

Since these sources are not addressed by the EPA's proposed Subpart OOOOa, the estimated impacts are not influenced by that proposal.

Proposed Tank Requirements – 6 tpy VOC Threshold

We estimate that the proposed tank requirements would:

- Impact about 300 existing storage tanks;
- Pose total costs of about $6 million per year (capital costs annualized using 7% and 3% discount rates);
- Result in cost savings of about $0.1 – 0.2 million per year (present value of costs savings calculated using 7% and 3% discount rates);
- Increase gas production by 0.04 Bcf per year;
- Reduce methane emissions by 7,000 tons per year;
- Produce monetized benefits of the reduced methane emissions of $8 million per year in 2017 – 2019, $9 million per year in 2020 – 2024, and $11 million in 2025 and 2026; and
- Reduce VOC emissions by 32,500 tons per year; and
- Result in net benefits of $2 million per year in 2017 – 2019, $3 – 4 million per year in 2020 – 2024, and $5 million in 2025 and 2026.

Alternative Tank Requirements – 3 tpy VOC Threshold

We estimate that the alternative tank requirements (3 tpy VOC threshold) would:

- Impact about 3,200 existing storage tanks;
- Pose total costs of about $61 – 66 million per year (capital costs annualized using 7% and 3% discount rates);
- Result in cost savings of about $1 – 2 million per year (present value of costs savings calculated using 7% and 3% discount rates);
- Increase gas production by 0.5 Bcf per year;
- Reduce methane emissions by 9,000 tons per year;
- Produce monetized benefits of the reduced methane emissions of $10 million per year in 2017 – 2019, $12 million per year in 2020 – 2024, and $14 million in 2025 and 2026; and
- Reduce VOC emissions by 41,000 tons per year; and
- Result in net costs of $49 – 54 million per year in 2017 – 2019, $47 – 52 million per year in 2020 – 2024, and $46 – 51 million in 2025 and 2026.

Alternative Tank Requirements – 30 tpy VOC Threshold

We estimate that the alternative tank requirements (30 tpy VOC threshold) would:

- Impact about 100 existing storage tanks;
- Pose total costs of about $2 million per year (capital costs annualized using 7% and 3% discount rates);
- Result in cost savings of about $1 million per year (present value of costs savings calculated using 7% and 3% discount rates);
- Increase gas production by 0.01 Bcf per year;
- Reduce methane emissions by 6,000 tons per year;
- Produce monetized benefits of the reduced methane emissions of $7 million per year in 2017 – 2019, $8 million per year in 2020 – 2024, and $9 million in 2025 and 2026; and
- Reduce VOC emissions by 28,000 tons per year; and
- Result in net benefits of $5 million per year in 2017 – 2019, $6 million per year in 2020 – 2024, and $7 million in 2025 and 2026.

Comparison of Proposed Storage Tank Threshold and Alternatives

The results of this analysis, illustrated in Table 26 below, show that among the alternatives examined, the VOC threshold of 30 tpy maximizes net benefits. By comparison, the BLM's proposed VOC threshold of 6 tpy poses slightly less net benefits. The BLM decided to propose the 6 tpy VOC threshold, because it is the same threshold that the EPA uses in the NSPS Subpart OOOO regulation.

Table 26: Summary of Annual Impacts for Storage Tank Options and Alternatives

Metric	VOC Threshold		
	3 tpy	6 tpy (Proposed)	30 tpy
Impacted tanks	3,176	292	99
Costs – Engineering Costs ($ in million)	$61 – 66	$6	$2
Carbon Dioxide Additions (tons)	36	3	1
Value of Carbon Dioxide Additions 2017-2019 ($ in million)	$0.001	$0.000	$0.000
Value of Carbon Dioxide Additions 2020-2024 ($ in million)	$0.002	$0.000	$0.000
Value of Carbon Dioxide Additions 2025-2026 ($ in million)	$0.002	$0.000	$0.000
Benefits – Cost Savings ($ in million)	$1 – 2	$0.1 – 0.2	$0.05 – 0.06
Methane Reductions (tons)	9,000	7,000	6,000
Value of Methane Reductions 2017-2019 ($ in million)	$10	$8	$7
Value of Methane Reductions 2020-2024 ($ in million)	$12	$9	$8
Value of Methane Reductions 2025-2026 ($ in million)	$14	$11	$9
Incremental Production (Bcf)	0.5	0.04	0.01
VOC Reductions (tons)	41,000	32,500	28,000
Net Benefits 2017-2019 ($ in million)	($49 – 54)	$2	$5
Net Benefits 2020-2024 ($ in million)	($47 – 52)	$3 – 4	$6
Net Benefits 2025-2026 ($ in million)	($46 – 51)	$5	$7

Table 27a: Impacts of a the Proposed Requirement to Control Storage Tanks Exceeding 6 tpy of VOC										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
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
Crude - model C	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91
Crude - model D	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34
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	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09
Condensate - model G	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42
Condensate - model H	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29
Total costs	$6.05	$6.05	$6.05	$6.05	$6.05	$6.05	$6.05	$6.05	$6.05	$6.05
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ 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
Crude - model C	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78
Crude - model D	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25
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	$1.95	$1.95	$1.95	$1.95	$1.95	$1.95	$1.95	$1.95	$1.95	$1.95
Condensate - model G	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39
Condensate - model H	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27
Total costs	$5.64	$5.64	$5.64	$5.64	$5.64	$5.64	$5.64	$5.64	$5.64	$5.64
Estimated Costs - CO2 Emissions Additions (tons)										
Crude - model B	0	0	0	0	0	0	0	0	0	0
Crude - model C	1	1	1	1	1	1	1	1	1	1
Crude - model D	1	1	1	1	1	1	1	1	1	1
Condensate - model E	0	0	0	0	0	0	0	0	0	0
Condensate - model F	1	1	1	1	1	1	1	1	1	1
Condensate - model G	0	0	0	0	0	0	0	0	0	0
Condensate - model H	0	0	0	0	0	0	0	0	0	0
Total CO2 Additions	3	3	3	3	3	3	3	3	3	3
Value of CO2 Additions ($MM)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000

Table 27a: Impacts of a the Proposed Requirement to Control Storage Tanks Exceeding 6 tpy of VOC										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Estimated Benefits - Cost Savings Present Value Using 7% 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
Crude - model C	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.04	$0.04
Crude - model D	$0.04	$0.04	$0.04	$0.04	$0.04	$0.03	$0.03	$0.03	$0.03	$0.03
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	$0.06	$0.06	$0.06	$0.06	$0.06	$0.05	$0.05	$0.05	$0.05	$0.05
Condensate - model G	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Condensate - model H	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Total cost savings	$0.16	$0.17	$0.17	$0.17	$0.17	$0.16	$0.15	$0.14	$0.14	$0.13
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ 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
Crude - model C	$0.05	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06
Crude - model D	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
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	$0.06	$0.06	$0.06	$0.07	$0.07	$0.07	$0.07	$0.06	$0.06	$0.06
Condensate - model G	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Condensate - model H	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Total cost savings	$0.16	$0.18	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19
Estimated Benefits Incremental Production (Bcf)										
Crude - model B	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Crude - model C	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Crude - model D	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Condensate - model E	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Condensate - model F	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Condensate - model G	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Condensate - model H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total incremental production	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Estimated Benefits - Methane Emissions Reductions (tons)										
Crude - model B	0	0	0	0	0	0	0	0	0	0
Crude - model C	500	500	500	500	500	500	500	500	500	500
Crude - model D	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Condensate - model E	0	0	0	0	0	0	0	0	0	0
Condensate - model F	500	500	500	500	500	500	500	500	500	500
Condensate - model G	900	900	900	900	900	900	900	900	900	900
Condensate - model H	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
Total CH4 reductions	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100
Value of CH4 reductions ($MM)	$7.82	$7.82	$7.82	$9.24	$9.24	$9.24	$9.24	$9.24	$10.67	$10.67
Estimated VOC Emissions Reductions										
Crude - model B	0	0	0	0	0	0	0	0	0	0
Crude - model C	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Crude - model D	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600
Condensate - model E	0	0	0	0	0	0	0	0	0	0
Condensate - model F	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Condensate - model G	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300
Condensate - model H	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Total VOC reductions	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500
Net Benefits										
Net Benefits - 7% ($ MM)	2	2	2	3	3	3	3	3	5	5
Net Benefits - 3% ($ MM)	2	2	2	4	4	4	4	4	5	5

Table 27b: Impacts of a the Alternative Requirement to Control Storage Tanks Exceeding 3 tpy of VOC										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
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	$9.57	$9.57	$9.57	$9.57	$9.57	$9.57	$9.57	$9.57	$9.57	$9.57
Crude - model C	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91
Crude - model D	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34
Condensate - model E	$50.18	$50.18	$50.18	$50.18	$50.18	$50.18	$50.18	$50.18	$50.18	$50.18
Condensate - model F	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09
Condensate - model G	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42
Condensate - model H	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29
Total costs	$65.80	$65.80	$65.80	$65.80	$65.80	$65.80	$65.80	$65.80	$65.80	$65.80
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)										
Crude - model B	$8.92	$8.92	$8.92	$8.92	$8.92	$8.92	$8.92	$8.92	$8.92	$8.92
Crude - model C	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78	$1.78
Crude - model D	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25
Condensate - model E	$46.77	$46.77	$46.77	$46.77	$46.77	$46.77	$46.77	$46.77	$46.77	$46.77
Condensate - model F	$1.95	$1.95	$1.95	$1.95	$1.95	$1.95	$1.95	$1.95	$1.95	$1.95
Condensate - model G	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39
Condensate - model H	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27
Total costs	$61.33	$61.33	$61.33	$61.33	$61.33	$61.33	$61.33	$61.33	$61.33	$61.33
Estimated Costs - CO2 Emissions Additions (tons)										
Crude - model B	5	5	5	5	5	5	5	5	5	5
Crude - model C	1	1	1	1	1	1	1	1	1	1
Crude - model D	1	1	1	1	1	1	1	1	1	1
Condensate - model E	27	27	27	27	27	27	27	27	27	27
Condensate - model F	1	1	1	1	1	1	1	1	1	1
Condensate - model G	0	0	0	0	0	0	0	0	0	0
Condensate - model H	0	0	0	0	0	0	0	0	0	0
Total CO2 Additions	36	36	36	36	36	36	36	36	36	36
Value of CO2 Additions ($MM)	$0.001	$0.001	$0.001	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002

Table 27b: Impacts of a the Alternative Requirement to Control Storage Tanks Exceeding 3 tpy of VOC										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Crude - model B	$0.26	$0.27	$0.27	$0.27	$0.26	$0.25	$0.24	$0.23	$0.22	$0.21
Crude - model C	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.04	$0.04
Crude - model D	$0.04	$0.04	$0.04	$0.04	$0.04	$0.03	$0.03	$0.03	$0.03	$0.03
Condensate - model E	$1.36	$1.41	$1.43	$1.43	$1.37	$1.30	$1.25	$1.19	$1.14	$1.10
Condensate - model F	$0.06	$0.06	$0.06	$0.06	$0.06	$0.05	$0.05	$0.05	$0.05	$0.05
Condensate - model G	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Condensate - model H	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Total cost savings	$1.79	$1.85	$1.87	$1.87	$1.80	$1.71	$1.64	$1.57	$1.49	$1.45
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Crude - model B	$0.26	$0.28	$0.29	$0.31	$0.30	$0.30	$0.30	$0.30	$0.29	$0.30
Crude - model C	$0.05	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06
Crude - model D	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
Condensate - model E	$1.36	$1.47	$1.54	$1.60	$1.60	$1.57	$1.58	$1.56	$1.54	$1.56
Condensate - model F	$0.06	$0.06	$0.06	$0.07	$0.07	$0.07	$0.07	$0.06	$0.06	$0.06
Condensate - model G	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Condensate - model H	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Total cost savings	$1.79	$1.92	$2.02	$2.10	$2.10	$2.06	$2.07	$2.04	$2.03	$2.04
Estimated Benefits Incremental Production (Bcf)										
Crude - model B	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Crude - model C	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Crude - model D	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Condensate - model E	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
Condensate - model F	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Condensate - model G	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Condensate - model H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total incremental production	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
Estimated Benefits - Methane Emissions Reductions (tons)										
Crude - model B	300	300	300	300	300	300	300	300	300	300
Crude - model C	500	500	500	500	500	500	500	500	500	500
Crude - model D	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Condensate - model E	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
Condensate - model F	500	500	500	500	500	500	500	500	500	500
Condensate - model G	900	900	900	900	900	900	900	900	900	900
Condensate - model H	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
Total CH4 reductions	9,100	9,100	9,100	9,100	9,100	9,100	9,100	9,100	9,100	9,100
Value of CH4 reductions ($MM)	$9.97	$9.97	$9.97	$11.79	$11.79	$11.79	$11.79	$11.79	$13.60	$13.60
Estimated VOC Emissions Reductions										
Crude - model B	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Crude - model C	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Crude - model D	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600
Condensate - model E	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700
Condensate - model F	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Condensate - model G	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300
Condensate - model H	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Total VOC reductions	41,400	41,400	41,400	41,400	41,400	41,400	41,400	41,400	41,400	41,400
Net Benefits										
Net Benefits - 7% ($ MM)	-54	-54	-54	-52	-52	-52	-52	-52	-51	-51
Net Benefits - 3% ($ MM)	-50	-49	-49	-47	-47	-47	-47	-47	-46	-46

Table 27c: Impacts of a the Alternative Requirement to Control Storage Tanks Exceeding 30 tpy of VOC										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
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
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	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34
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	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42	$0.42
Condensate - model H	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29
Total costs	$2.05	$2.05	$2.05	$2.05	$2.05	$2.05	$2.05	$2.05	$2.05	$2.05
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ 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
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	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25
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	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39
Condensate - model H	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27
Total costs	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91
Estimated Costs - CO2 Emissions Additions (tons)										
Crude - model B	0	0	0	0	0	0	0	0	0	0
Crude - model C	0	0	0	0	0	0	0	0	0	0
Crude - model D	1	1	1	1	1	1	1	1	1	1
Condensate - model E	0	0	0	0	0	0	0	0	0	0
Condensate - model F	0	0	0	0	0	0	0	0	0	0
Condensate - model G	0	0	0	0	0	0	0	0	0	0
Condensate - model H	0	0	0	0	0	0	0	0	0	0
Total CO2 Additions	1	1	1	1	1	1	1	1	1	1
Value of CO2 Additions ($MM)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000

Table 27c: Impacts of a the Alternative Requirement to Control Storage Tanks Exceeding 30 tpy of VOC										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Estimated Benefits - Cost Savings Present Value Using 7% 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
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	$0.04	$0.04	$0.04	$0.04	$0.04	$0.03	$0.03	$0.03	$0.03	$0.03
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	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Condensate - model H	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Total cost savings	$0.06	$0.06	$0.06	$0.06	$0.06	$0.05	$0.05	$0.05	$0.05	$0.05
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ 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
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	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
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	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Condensate - model H	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Total cost savings	$0.06	$0.06	$0.06	$0.07	$0.07	$0.06	$0.06	$0.06	$0.06	$0.06
Estimated Benefits Incremental Production (Bcf)										
Crude - model B	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Crude - model C	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Crude - model D	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Condensate - model E	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Condensate - model F	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Condensate - model G	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Condensate - model H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total incremental production	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Estimated Benefits - Methane Emissions Reductions (tons)										
Crude - model B	0	0	0	0	0	0	0	0	0	0
Crude - model C	0	0	0	0	0	0	0	0	0	0
Crude - model D	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Condensate - model E	0	0	0	0	0	0	0	0	0	0
Condensate - model F	0	0	0	0	0	0	0	0	0	0
Condensate - model G	900	900	900	900	900	900	900	900	900	900
Condensate - model H	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
Total CH4 reductions	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100
Value of CH4 reductions ($MM)	$6.72	$6.72	$6.72	$7.94	$7.94	$7.94	$7.94	$7.94	$9.16	$9.16
Estimated VOC Emissions Reductions										
Crude - model B	0	0	0	0	0	0	0	0	0	0
Crude - model C	0	0	0	0	0	0	0	0	0	0
Crude - model D	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600
Condensate - model E	0	0	0	0	0	0	0	0	0	0
Condensate - model F	0	0	0	0	0	0	0	0	0	0
Condensate - model G	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300
Condensate - model H	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Total VOC reductions	27,900	27,900	27,900	27,900	27,900	27,900	27,900	27,900	27,900	27,900
Net Benefits										
Net Benefits - 7% ($ MM)	5	5	5	6	6	6	6	6	7	7
Net Benefits - 3% ($ MM)	5	5	5	6	6	6	6	6	7	7

7.12 Leak Detection and Repair

In general, the impacts of an LDAR requirement are uncertain given that the extent of voluntary efforts within the industry are unknown. Generally, we believe that a substantial number of operators currently conduct LDAR activities on oil and gas wells on Federal and Indian leases and would continue to do so absent this rule. The 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). We would not expect incremental costs if an operator currently administers an LDAR program that is consistent with the proposed requirements.

The proposed requirements specify that inspections must be conducted using one of the following: optical gas imaging (OGI) (such as an infra-red camera); other instrument-based monitoring device or method approved by the BLM; or a portable analyzer device, assisted by audio, visual, and olfactory (AVO) inspection. If an operator operates 500 or more wells within the jurisdiction of a single BLM field office, the operator must use OGI or another instrument-based monitoring device or method approved by the BLM to detect leaks. In order to comply with the inspection requirements, the operator is likely either to contract with a service provider to conduct the inspections or to conduct the inspections itself. In either scenario, the inspections must meet the equipment and frequency standards established by the rule.

If the operator chooses to contract a service provider to conduct the inspections, it might anticipate the following costs (Carbon Limits 2014, p. 32). These inspection costs do not include the costs to repair potential leaks or the cost savings from the gas recovered after leaks are repaired. See below:

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

If conducting the inspections itself, then the operator would potentially encounter the following equipment and labor costs. Infrared cameras have been reported to cost between $85,000 - $124,000 per device (EPA 2014, p. 40).[66] Infrared cameras, while requiring larger capital investment, can monitor more pieces of equipment per hour, with estimates ranging up to 2,100 components per hour. Portable analyzers have been reported to cost $10,800 per device, plus additional labor costs associated with the inspections (EPA 2014, p. 39).[67] Portable analyzers, while requiring less capital investment than infrared cameras, require frequent calibration during the inspection and thus limit the speed with which an inspection may be accomplished. These analyzers require approximately 1 hour to inspect about 30-40 components (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.[68]

In terms of repairing identified leaks, the Carbon Limits study offers average leak rates and repair costs of several main components, including valves, connectors, regulators, and instrument

[66] Reported by Meister 2009 and ICF International 2014, respectively.
[67] Reported costs from RTI memorandum.
[68] For example, Honeywell PhD6, http://www.honeywellanalytics.com/en/products/PhD6

controllers. The average repair costs range from $56 to $189. We note that these repair costs are for the equipment and replacement only, and do not consider potential cost savings from the sale of the conserved gas.

Table 28: 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 recoved gas.

Table 29: 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

However, 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, even 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.

That finding is supported by experiences within the industry. In its comment letter[69] 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 and generally supports the claim that most leaks are easy to repair and, as such, are cost effective to repair.

[69] Southwestern Energy 2014, p. 9.

Potential leak reductions and volumes of gas conserved will generally vary depending on the frequency of the inspection program. In its regulatory analysis for the Colorado AQCC regulations, the Colorado Department of Public Health and 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) uses 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 the TSD for the NSPS Subpart OOOOa proposed rule, the EPA assumes a 40%, 60%, and 80% emissions reductions for annual, semi-annual, and quarterly inspection frequency programs, respectively.

When considering the full costs of an LDAR program (including the inspections, repairs, and value of the conserved gas, Carbon Limits 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 disount 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 increase the overall costs, with additional surveys being conducted and fewer remaining gas conservation opportunities as the leaks are identified and repaired.

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, we note that the negative NPVs indicate that the average LDAR program for a well site or battery would pose a net cost to the operator (a positive NPV would indicate cost savings). These data, in Table 30, 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).

Other research indicates that LDAR programs with quarterly inspection requirements would pose cost savings to the operator at well pads, gathering and processing facilities. 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. Looking at their estimates for well pads only, 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 recoved gas of $9,340 (p. 2).

Table 30: Carbon Limits - Average NPV for LDAR Programs, by Inspection Frequency

Site or Facility	NPV using a 7% Discount Rate				
	All Surveys[1]	Inspection Frequency[2]			
		Annual	Semi-Annual	Quarterly	Monthly
Compressor station	$3,376	$2,890	($466)	($7,319)	($34,886)
Gas plant	$9,403	$12,600	$5,405	($9,442)	($69,338)
Wellsite and well battery	($35)	$2,435	$854	($2,401)	($15,521)
Site or Facility	**NPV using a 3% Discount Rate**				
	All Surveys[1]	**Inspection Frequency[2]**			
		Annual	**Semi-Annual**	**Quarterly**	**Monthly**
Compressor station	$3,881	$3,349	($56)	($6,934)	($34,519)
Gas plant	$10,694	$14,229	$6,873	($8,054)	($68,005)
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 available data and comments indicate that there are cost savings available to operators who conduct LDAR programs on wellsites and well batteries. As such, we would expect that some portion of operators currently conduct LDAR programs and would continue to do so regardless of the proposed rule. The available data also indicate that increasing the inspection frequencies would result in greater gas savings but there would be diminishing returns. Carbon Limits (2015b) shows that, for wellsites and well batteries, an LDAR program with a semi-annual inspection requirement would result in cost savings to the operator while a program with a quarterly inspection requirement would pose a cost to the operator.

We note that many of the analyses referenced to this point present the net costs or costs savings on a well, wellsite, or inspection basis, and do not provide the full costs that an operator might encounter when developing a comprehensive company-wide LDAR program.

The NSPS Subpart OOOOa proposal includes LDAR provisions that would require Optical Gas Imaging (OGI) inspections on a semi-annual basis, and allows for operators with existing company-wide LDAR programs to continue with those efforts. The Technical Support Document for the Subpart OOOOa proposed rule 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. We calculated LDAR program costs using the EPA's cost formulation for equipment needs, inspections, and leak repair, but did not include the EPA's program formulation and reporting cost assumptions. The administrative burden required to comply with the LDAR requirements are monetized and included in the costs estimates provided in Section 8.1. The Supporting Statement for the Paperwork Reduction Act discusses the burdens posed by this requirement in greater detail.

Table 31: 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	$1,279	$1,267	1.82	0.50	105
	Oil wellsite	$1,279	$1,267	0.44	0.12	25
Semi-annual	Gas wellsite	$1,879	$1,867	2.72	0.76	158
	Oil wellsite	$1,879	$1,867	0.65	0.18	38
Quarterly	Gas wellsite	$3,079	$3,067	3.63	1.01	210
	Oil wellsite	$3,079	$3,067	0.87	0.24	50

[1] Costs do not consider the value of the gas recovered. Uses only the annualized equipment costs, and the inspection and repair costs, of the data available in the TSD for the NSPS Subpart OOOOa proposed rule, pp. 85-89. The costs using a 3% discount rate are calculated using the EPA data.
[2] Emissions reductions per facility are available in the EPA's Technical Support Document for the NSPS Subpart OOOOa proposed rule, pp. 85-89.
[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.

We estimate the number of existing wellsites that would be impacted by the rule using a similar formulation as the EPA. 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 only). Colorado has existing LDAR requirements and Wyoming's new requirements will take effect on January 1, 2017. Then, in order to calculate the number of impacted wellsites, we used an assumed factor of 2 wells per wellsite. This assumption was made by EPA based on analysis that it conducted. That derivation yields a total of 36,690 existing wellsites (about 20,660 gas wellsites and 16,030 oil wellsites) that would be impacted by the BLM's proposed rule. However, some of these affected existing wellsites would be modified over time. Assuming the Subpart OOOOa regulation is finalized as proposed, those modified wellsites would be covered by Subpart OOOOa. As such, the number of existing wellsites impacted by the BLM rule would decrease over time.

Table 32: 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 proposed rule, p. 60.

We estimate the number of new wellsites that would be impacted by assuming that there would be 2,500 well completions in 2016 and that there would be a 3% growth rate in subsequent years. We also assume that 71% of completions would be oil wells and 29% would be gas wells. We then reduce the impacted wells by the number estimated to be completed in Colorado and Wyoming (in the Upper Green River Basin only). Then, in order to calculate the number of impacted wellsites, we used an assumed factor of 2 wells per wellsite. This assumption was made by EPA based on analysis that it conducted. That derivation yields a total of 983 new wellsites (about 230 gas wellsites and 753 oil wellsites) that would be impacted by the BLM's proposed rule in 2017, with the number of new wellsites impacted increasing during the period of analysis. These wellsites would presumably be covered by the EPA's proposed regulation Subpart OOOOa, if that rule is finalized as proposed.

Based on these activity data and the per-facility cost, incremental production (or gas recovery) per wellsite, and emissions reductions data from the TSD, we estimate the impacts of the BLM's proposal and alternatives. The summary of the proposal and alternatives are shown in Table 33 with the details of each proposal and alternative in Tables 34a-g. The cost estimates are in 2012 dollars. The cost savings estimates use projected natural gas prices found in the EIA's Annual Energy Outlook 2015.[70]

The description of impacts below assume a baseline in which the EPA does not finalize its proposed Subpart OOOOa regulations. However, if the EPA finalizes that regulation, the BLM rule would only practically impact existing wellsites, and the impacts for that subset of wellsites is presented in Table 34a-g, although the number of existing wells impacted by the BLM rule would decrease over time as wellsites are modified.

As a simplifying assumption, we analyzed the proposed LDAR provisions as resulting in semi-annual inspections. Because we have proposed to vary the required inspection frequency based on the number of leaks that are found, it is likely that the proposed provisions would actually require some portion of the inspections to be performed annually, and some portion to be performed semi-annually.

<u>Proposed Semi-Annual LDAR Requirement</u>

If the Subpart OOOOa proposal is not finalized, we estimate that the proposed LDAR requirements would:

- Impact up to about 37,000 – 38,000 wellsites per year;
- Pose total costs of about $70 – 71 million per year (capital costs annualized using 7% and 3% discount rates);
- Result in cost savings of about $12 – 18 million per year (present value of costs savings calculated using 7% and 3% discount rates);
- Increase gas production by 3.9 – 4.0 Bcf per year;

[70] AEO 2015, Table 13, access on November 16, 2015 at http://www.eia.gov/forecasts/aeo/tables_ref.cfm.

- Reduce methane emissions by 68,000 tons per year;
- Produce monetized benefits of the reduced methane emissions of $75 million per year in 2017 – 2019, $88 million per year in 2020 – 2024, and $102 million in 2025 and 2026; and
- Reduce VOC emissions by 19,000 tons per year; and
- Result in net benefits of $19 – 21 million per year in 2017 – 2019, $30 – 35 million per year in 2020 – 2024, and $43 – 48 million in 2025 and 2026.

If the EPA finalizes Subpart OOOOa, then the rule would practically impact only existing facilities. In addition, if an existing facility were modified in the future, it would be regulated by the EPA. Therefore, we estimate that the rule would impact up to 36,700 existing wellsites, pose compliance costs of about $69 – 70 million per year, result in cost savings of $12 – 15 million per year (using a 7% discount rate) or $15 – 17 million per year (using a 3% discount rate), increase gas production by 3.9 Bcf per year, reduce methane emissions by 67,000 tons per year, produce monetized benefits of the reduced methane emissions of $73 million per year in 2017 – 2019, $87 million per year in 2020 – 2024, and $100 million per year in 2025 and 2026, reduce VOC emissions by 18,600 tons per year, and result in net benefits of $19 – 21 million per year in 2017 – 2019, $31 – 35 million per year in 2020 – 2024, and $43 – 48 million per year in 2025 and 2026.

For both of these scenarios and the alternatives that follow, the BLM believes that the estimates represent the maximum likely impact. As noted previously, some operators currently have existing LDAR programs. This analysis accounts for state requirements in Colorado, Utah, and Wyoming (in the Upper Green River Basin only), but it does not account for voluntary or existing LDAR activities conducted by operators outside of these states. If we could account for these voluntary activities, then the cost, emissions reductions, incremental production, and royalty estimates would likely be less than that shown.

We used the EPA's information, because we believe it represents an approximate picture of what a company would have to undertake to implement an LDAR program. However, we recognize 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.

We also analyzed the projected benefits and costs of several alternative LDAR requirements, focusing on different possible inspection frequencies. These analyses use a baseline without a final Subpart OOOOa. Assuming that EPA finalizes Subpart OOOOa, both the costs and benefits of these alternatives would be slightly lower.

Alternative: Annual LDAR Requirement

We estimate that the alternative of requiring annual LDAR inspections would impact up to about 37,000-38,000 wellsites per year and pose total costs of about $48-49 million per year (capital costs annualized using 7% and 3% discount rates), result in cost savings of about $8-12 million per year (present value of costs savings calculated using 7% and 3% discount rates), increase gas production by 2.6 Bcf per year, reduce methane emissions by 45,000-46,000 tons per year, produce monetized benefits of the reduced methane emissions of $50 million per year in 2017-2019, $59 million per year in 2020-2024, and $68 million in 2025 and 2026; and reduce VOC emissions by about 12,500 tons per year. We estimate net benefits of $12-13 million per year in 2017-2019, $20-23 million per year in 2020-2024, and $28-32 million in 2025 and 2026.

Alternative: Quarterly LDAR Requirement

We estimate that the alternative of requiring quarterly LDAR inspections would impact up to about 37,000-38,000 wellsites per year and pose total costs of about $116-117 million per year (capital costs annualized using 7% and 3% discount rates), result in cost savings of about $16-23 million per year (present value of costs savings calculated using 7% and 3% discount rates), increase gas production by about 5.2-5.3 Bcf per year, reduce methane emissions by 90,000-91,000 tons per year, produce monetized benefits of the reduced methane emissions of $99-100 million per year in 2017-2019, $118 million per year in 2020-2024, and $136 million in 2025 and 2026; and reduce VOC emissions by about 25,000 tons per year. We estimate net benefits of $3-6 million per year in 2017-2019, $19-25 million per year in 2020-2024, and $36-43 million in 2025 and 2026.

Further, we examine additional variations to the proposed approach, where operators would be required to conduct annual LDAR inspections on marginal wells and semi-annual LDAR inspections on all other wells. We define marginal wells as those producing less than 15 bbl of oil equivalent per day. According to 2009 data from the EIA, 85.4% of oil wells are marginal wells and 73.3% of gas wells are marginal wells.[71] To analyze the impacts, we applied these rates to the existing oil and gas wellsites expected to be impacted by the rule and calculated the costs and benefits of an annual LDAR requirement. For the remaining existing wellsites and new wellsites, we calculated costs and benefits of a semi-annual LDAR requirement,

Alternative: Semi-Annual LDAR Requirement; One-Time LDAR on Marginal Oil Wellsites

We estimate that the alternative of requiring semi-annual LDAR inspections with a one-time LDAR requirement for marginal oil wells would impact up to about 37,000-38,000 wellsites in 2017 and 24,000 wellsites per year from 2018 to 2026. We estimate that the requirements would pose total costs of about $65 million in 2017 and $45-46 million per year from 2018 to 2026 (capital costs annualized using 7% and 3% discount rates), result in cost savings of about $11-15 million per year (present value of costs savings calculated using 7% and 3% discount rates), increase gas production by about 3.8 Bcf in 2017 and 3.4 Bcf per year from 2018 to 2026, reduce methane emissions by 65,000 tons in 2017 and 59,000 tons per year from 2018 to 2026, produce monetized benefits of the reduced methane emissions of $65-71 million per year in 2017-2019, $77 million per year in 2020-2024, and $89 million in 2025 and 2026; and reduce VOC emissions by about 18,000 tons in 2017 and 16,500 tons per year from 2018 to 2026. We estimate net benefits of $23-35 million per year in 2017-2019, $43-47 million per year in 2020-2024, and $54-58 million in 2025 and 2026.

Alternative: Semi-Annual LDAR Requirement; Annual LDAR Requirement for Marginal Oil Wellsites

We estimate that the alternative of requiring annual LDAR on marginal oil wells and semi-annual LDAR on all other wells would impact up to about 37,000-38,000 wellsites per year and pose total

[71] Energy Information Administration. *United States Total 2009 Distribution of Wells by Production Rate Bracket.* Retrieved November 13, 2015, from http://www.eia.gov/pub/oil_gas/petrosystem/us_table.html.

costs of about $62-63 million per year (capital costs annualized using 7% and 3% discount rates), result in cost savings of about $12-17 million per year (present value of costs savings calculated using 7% and 3% discount rates), increase gas production by about 3.8 Bcf per year, reduce methane emissions by 65,000 tons per year, produce monetized benefits of the reduced methane emissions of $71 million per year in 2017-2019, $85 million per year in 2020-2024, and $98 million in 2025 and 2026; and reduce VOC emissions by about 18,000 tons per year. We estimate net benefits of $23-25 million per year in 2017-2019, $34-39 million per year in 2020-2024, and $46-52 million in 2025 and 2026.

Alternative: Semi-Annual LDAR Requirement; Annual LDAR Requirement for Marginal Oil and Gas Wellsites

We estimate that the alternative of requiring annual LDAR on marginal oil and gas wells and semi-annual LDAR on all other wells would impact up to about 37,000-38,000 wellsites per year and pose total costs of about $53-54 million per year (capital costs annualized using 7% and 3% discount rates), result in cost savings of about $9-13 million per year (present value of costs savings calculated using 7% and 3% discount rates), increase gas production by about 3 Bcf per year, reduce methane emissions by 51,000-52,000 tons per year, produce monetized benefits of the reduced methane emissions of $56 million per year in 2017-2019, $67 million per year in 2020-2024, and $77 million in 2025 and 2026; and reduce VOC emissions by about 14,000 tons per year. We estimate net benefits of $14-16 million per year in 2017-2019, $23-27 million per year in 2020-2024, and $32-37 million in 2025 and 2026.

Alternative: Quarterly LDAR Requirement for Gas Wellsites; Annual LDAR Requirement for Oil Wellsites

We estimate that the alternative of requiring quarterly LDAR on gas wellsites and annual LDAR on oil wellsites would impact up to about 37,000-38,000 wellsites per year and pose total costs of about $85-86 million per year (capital costs annualized using 7% and 3% discount rates), result in cost savings of about $15-21 million per year (present value of costs savings calculated using 7% and 3% discount rates), increase gas production by about 4.8 Bcf per year, reduce methane emissions by 83,000-84,000 tons per year, produce monetized benefits of the reduced methane emissions of $92 million per year in 2017-2019, $108 million per year in 2020-2024, and $125 million in 2025 and 2026; and reduce VOC emissions by about 23,000 tons per year. We estimate net benefits of $24-27 million per year in 2017-2019, $38-44 million per year in 2020-2024, and $54-60 million in 2025 and 2026.

We note that for the two alternatives examining quarterly LDAR for all or a portion of the wellsites, the potential incremental gas production exceeds the amount of gas that we estimate to have been lost through fugitive emissions in 2013. This discrepancy is likely due to differences in the emissions factors between the latest GHG Inventory and the emissions reductions estimates provided in the analysis for the Subpart OOOOa proposed rule.

Comparison of Proposed LDAR Requirement and Alternatives

The results of this analysis, illustrated in Table 33 below, show that among the alternatives examined, two options (1. a quarterly LDAR program for gas wells and annual LDAR program for oil wells, and 2. a semi-annual LDAR program and a one-time LDAR inspection for marginal oil wells) would maximize net benefits. By comparison, the BLM's proposed semi-annual LDAR program requirement poses slightly less net benefits. The BLM decided to propose the semi-annual LDAR requirement with adjustable inspection frequencies, because it more closely resembles the EPA's proposal, but we seek comment on all of the alternatives presented.

Table 33: Summary of Annual Impacts for LDAR Options and Alternatives

Metric	Annual LDAR	Semi-Annual LDAR (Proposed)	Quarterly LDAR	Semi-Annual LDAR; One-Time LDAR on Marginal Oil Wells	Semi-Annual LDAR; Annual LDAR for Marginal Oil Wells	Semi-Annual LDAR; Annual LDAR for Marginal Oil and Gas Wells	Quarterly LDAR for Gas Wells; Annual LDAR for Oil Wells
Impacted wellsites	37,000 – 38,000	37,000 – 38,000	37,000 – 38,000	37,000 – 38,000 in 2017; 24,000 in 2018 – 2026	37,000 – 38,000	37,000 – 38,000	37,000 – 38,000
Costs – Engineering Costs ($ in million)	$48 – 49	$70 – 71	$116 – 117	$63 in 2017; $45 – 46 in 2018 – 2026	$62 – 63	$53 – 54	$85 – 86
Carbon Dioxide Additions (tons)	100	150	200	140 in 2017; 130 in 2018 – 2026	140	110	180
Value of Carbon Dioxide Additions 2017-2019 ($ in million)	$0.004	$0.006	$0.007	$0.005	$0.005	$0.004	$0.007
Value of Carbon Dioxide Additions 2020-2024 ($ in million)	$0.004	$0.006	$0.009	$0.006	$0.006	$0.005	$0.008
Value of Carbon Dioxide Additions 2025-2026 ($ in million)	$0.005	$0.007	$0.009	$0.006	$0.007	$0.005	$0.009
Benefits – Cost Savings ($ in million)	$8 – 12	$12 – 18	$16 – 23	$11 – 15	$12 – 17	$9 – 13	$15 – 21
Methane Reductions (tons)	45,000 – 46,000	68,000	90,000 – 91,000	65,000 in 2017; 59,000 in 2018 – 2026	65,000	51,000 – 52,000	83,000 – 84,000
Value of Methane Reductions 2017-2019 ($ in million)	$50	$75	$99 – 100	$65 – 71	$71	$56	$92
Value of Methane Reductions 2020-2024 ($ in million)	$59	$88	$118	$77	$85	$67	$108
Value of Methane Reductions 2025-2026 ($ in million)	$68	$102	$136	$89	$98	$77	$125
Incremental Production (Bcf)	2.6	3.9 – 4.0	5.2 – 5.3	3.8 in 2017; 3.4 in 2018 – 2026	3.8	3.0	4.8
VOC Reductions (tons)	12,500	19,000	25,000	18,000 in 2017; 16,500 in 2018 – 2026	18,000	14,000	23,000
Net Benefits 2017-2019 ($ in million)	$12 – 13	$19 – 21	$3 – 6	$23 – 35	$23 – 25	$14 – 16	$24 – 27
Net Benefits 2020-2024 ($ in million)	$20 – 23	$30 – 35	$19 – 25	$43 – 47	$34 – 39	$23 – 27	$38 – 44
Net Benefits 2025-2026 ($ in million)	$28 – 32	$43 – 48	$36 – 43	$54 – 58	$46 – 52	$32 – 37	$54 – 60

Table 34a: Estimates for OGI Monitoring and Repair - Semi-Annual LDAR Program										
YEAR	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Impacted wellsites										
Existing gas wellsites	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661
Existing oil wellsites	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029
New gas wellsites	230	236	243	250	256	263	270	276	283	290
New oil wellsites	753	775	797	818	840	862	884	906	928	950
Total wellsites	37,672	37,700	37,729	37,758	37,786	37,815	37,843	37,872	37,901	37,929
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)										
Existing gas wellsites	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82
Existing oil wellsites	$30.12	$30.12	$30.12	$30.12	$30.12	$30.12	$30.12	$30.12	$30.12	$30.12
New gas wellsites	$0.43	$0.44	$0.46	$0.47	$0.48	$0.49	$0.51	$0.52	$0.53	$0.54
New oil wellsites	$1.41	$1.46	$1.50	$1.54	$1.58	$1.62	$1.66	$1.70	$1.74	$1.78
Total costs	$70.79	$70.84	$70.89	$70.95	$71.00	$71.05	$71.11	$71.16	$71.22	$71.27
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)										
Existing gas wellsites	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57
Existing oil wellsites	$29.93	$29.93	$29.93	$29.93	$29.93	$29.93	$29.93	$29.93	$29.93	$29.93
New gas wellsites	$0.43	$0.44	$0.45	$0.47	$0.48	$0.49	$0.50	$0.52	$0.53	$0.54
New oil wellsites	$1.41	$1.45	$1.49	$1.53	$1.57	$1.61	$1.65	$1.69	$1.73	$1.77
Total costs	$70.33	$70.39	$70.44	$70.49	$70.55	$70.60	$70.65	$70.71	$70.76	$70.81
Estimated Costs - CO2 Emissions Additions (tons)										
Existing gas wellsites	124	124	124	124	124	124	124	124	124	124
Existing oil wellsites	23	23	23	23	23	23	23	23	23	23
New gas wellsites	1	1	1	1	2	2	2	2	2	2
New oil wellsites	1	1	1	1	1	1	1	1	1	1
Total CO2 Additions	150	150	150	150	150	150	150	150	150	150
Value of CO2 Additions ($MM)	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	$0.007	$0.007
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Existing gas wellsites	$12.42	$12.85	$12.98	$13.01	$12.50	$11.85	$11.41	$10.87	$10.37	$10.06
Existing oil wellsites	$2.32	$2.40	$2.42	$2.43	$2.33	$2.21	$2.13	$2.03	$1.93	$1.88
New gas wellsites	$0.14	$0.15	$0.15	$0.16	$0.16	$0.15	$0.15	$0.15	$0.14	$0.14
New oil wellsites	$0.11	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.11	$0.11	$0.11
Total cost savings	$14.98	$15.51	$15.67	$15.71	$15.11	$14.33	$13.81	$13.16	$12.56	$12.19
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Existing gas wellsites	$12.42	$13.35	$14.01	$14.58	$14.56	$14.33	$14.35	$14.20	$14.06	$14.18
Existing oil wellsites	$2.32	$2.49	$2.61	$2.72	$2.72	$2.67	$2.68	$2.65	$2.62	$2.65
New gas wellsites	$0.14	$0.15	$0.16	$0.18	$0.18	$0.18	$0.19	$0.19	$0.19	$0.20
New oil wellsites	$0.11	$0.12	$0.13	$0.14	$0.14	$0.14	$0.15	$0.15	$0.15	$0.16
Total cost savings	$14.98	$16.11	$16.91	$17.62	$17.59	$17.33	$17.36	$17.19	$17.03	$17.18
Estimated Benefits Incremental Production (Bcf)										
Existing gas wellsites	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26
Existing oil wellsites	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
New gas wellsites	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05
New oil wellsites	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04
Total incremental production	3.94	3.94	3.94	3.94	3.95	3.95	3.95	3.95	3.95	3.96
Estimated Benefits - Methane Emissions Reductions (tons)										
Existing gas wellsites	56,200	56,200	56,200	56,200	56,200	56,200	56,200	56,200	56,200	56,200
Existing oil wellsites	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400
New gas wellsites	600	600	700	700	700	700	700	800	800	800
New oil wellsites	500	500	500	500	500	600	600	600	600	600
Total CH4 reductions	67,700	67,800	67,800	67,800	67,900	67,900	67,900	68,000	68,000	68,000
Value of CH4 reductions ($MM)	$74.50	$74.54	$74.57	$88.18	$88.22	$88.26	$88.30	$88.34	$101.98	$102.03
Estimated VOC Emissions Reductions										
Existing gas wellsites	15,700	15,700	15,700	15,700	15,700	15,700	15,700	15,700	15,700	15,700
Existing oil wellsites	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900
New gas wellsites	200	200	200	200	200	200	200	200	200	200
New oil wellsites	100	100	100	100	200	200	200	200	200	200
Total VOC reductions	18,900	18,900	18,900	18,900	18,900	18,900	19,000	19,000	19,000	19,000
Net Benefits										
Net Benefits - 7% ($ MM)	19	19	19	33	32	32	31	30	43	43
Net Benefits - 3% ($ MM)	19	20	21	35	35	35	35	35	48	48

Table 34b: Estimates for OGI Monitoring and Repair - Annual LDAR Program										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Impacted wellsites										
Existing gas wellsites	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661
Existing oil wellsites	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029
New gas wellsites	230	236	243	250	256	263	270	276	283	290
New oil wellsites	753	775	797	818	840	862	884	906	928	950
Total wellsites	37,672	37,700	37,729	37,758	37,786	37,815	37,843	37,872	37,901	37,929
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)										
Existing gas wellsites	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43	$26.43
Existing oil wellsites	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50
New gas wellsites	$0.29	$0.30	$0.31	$0.32	$0.33	$0.34	$0.34	$0.35	$0.36	$0.37
New oil wellsites	$0.96	$0.99	$1.02	$1.05	$1.07	$1.10	$1.13	$1.16	$1.19	$1.21
Total costs	$48.18	$48.22	$48.26	$48.29	$48.33	$48.37	$48.40	$48.44	$48.47	$48.51
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)										
Existing gas wellsites	$26.18	$26.18	$26.18	$26.18	$26.18	$26.18	$26.18	$26.18	$26.18	$26.18
Existing oil wellsites	$20.31	$20.31	$20.31	$20.31	$20.31	$20.31	$20.31	$20.31	$20.31	$20.31
New gas wellsites	$0.29	$0.30	$0.31	$0.32	$0.32	$0.33	$0.34	$0.35	$0.36	$0.37
New oil wellsites	$0.95	$0.98	$1.01	$1.04	$1.06	$1.09	$1.12	$1.15	$1.18	$1.20
Total costs	$47.73	$47.77	$47.80	$47.84	$47.88	$47.91	$47.95	$47.98	$48.02	$48.06
Estimated Costs - CO2 Emissions Additions (tons)										
Existing gas wellsites	82	82	82	82	82	82	82	82	82	82
Existing oil wellsites	15	15	15	15	15	15	15	15	15	15
New gas wellsites	1	1	1	1	1	1	1	1	1	1
New oil wellsites	1	1	1	1	1	1	1	1	1	1
Total CO2 Additions	99	99	99	99	99	100	100	100	100	100
Value of CO2 Additions ($MM)	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.005	$0.005
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Existing gas wellsites	$8.25	$8.54	$8.62	$8.64	$8.31	$7.87	$7.59	$7.23	$6.89	$6.69
Existing oil wellsites	$1.52	$1.58	$1.59	$1.60	$1.53	$1.45	$1.40	$1.33	$1.27	$1.24
New gas wellsites	$0.09	$0.10	$0.10	$0.10	$0.10	$0.10	$0.10	$0.10	$0.09	$0.09
New oil wellsites	$0.07	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.07	$0.07
Total cost savings	$9.94	$10.29	$10.40	$10.43	$10.02	$9.50	$9.16	$8.73	$8.33	$8.09
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Existing gas wellsites	$8.25	$8.87	$9.31	$9.69	$9.67	$9.52	$9.53	$9.43	$9.35	$9.42
Existing oil wellsites	$1.52	$1.64	$1.72	$1.79	$1.79	$1.76	$1.76	$1.74	$1.73	$1.74
New gas wellsites	$0.09	$0.10	$0.11	$0.12	$0.12	$0.12	$0.12	$0.13	$0.13	$0.13
New oil wellsites	$0.07	$0.08	$0.09	$0.09	$0.09	$0.09	$0.10	$0.10	$0.10	$0.10
Total cost savings	$9.94	$10.69	$11.22	$11.69	$11.67	$11.50	$11.52	$11.40	$11.30	$11.40
Estimated Benefits Incremental Production (Bcf)										
Existing gas wellsites	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17
Existing oil wellsites	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
New gas wellsites	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
New oil wellsites	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Total incremental production	2.61	2.61	2.62	2.62	2.62	2.62	2.62	2.62	2.62	2.62
Estimated Benefits - Methane Emissions Reductions (tons)										
Existing gas wellsites	37,600	37,600	37,600	37,600	37,600	37,600	37,600	37,600	37,600	37,600
Existing oil wellsites	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100
New gas wellsites	400	400	400	500	500	500	500	500	500	500
New oil wellsites	300	300	400	400	400	400	400	400	400	400
Total CH4 reductions	45,400	45,400	45,400	45,500	45,500	45,500	45,500	45,600	45,600	45,600
Value of CH4 reductions ($MM)	$49.95	$49.97	$49.99	$59.11	$59.14	$59.17	$59.20	$59.22	$68.37	$68.40
Estimated VOC Emissions Reductions										
Existing gas wellsites	10,300	10,300	10,300	10,300	10,300	10,300	10,300	10,300	10,300	10,300
Existing oil wellsites	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
New gas wellsites	100	100	100	100	100	100	100	100	100	100
New oil wellsites	100	100	100	100	100	100	100	100	100	100
Total VOC reductions	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500
Net Benefits										
Net Benefits - 7% ($ MM)	12	12	12	21	21	20	20	20	28	28
Net Benefits - 3% ($ MM)	12	13	13	23	23	23	23	23	32	32

Table 34c: Estimates for OGI Monitoring and Repair - Quarterly LDAR Program										
YEAR	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Impacted wellsites										
Existing gas wellsites	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661
Existing oil wellsites	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029
New gas wellsites	230	236	243	250	256	263	270	276	283	290
New oil wellsites	753	775	797	818	840	862	884	906	928	950
Total wellsites	37,672	37,700	37,729	37,758	37,786	37,815	37,843	37,872	37,901	37,929
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)										
Existing gas wellsites	$63.62	$63.62	$63.62	$63.62	$63.62	$63.62	$63.62	$63.62	$63.62	$63.62
Existing oil wellsites	$49.35	$49.35	$49.35	$49.35	$49.35	$49.35	$49.35	$49.35	$49.35	$49.35
New gas wellsites	$0.71	$0.73	$0.75	$0.77	$0.79	$0.81	$0.83	$0.85	$0.87	$0.89
New oil wellsites	$2.32	$2.38	$2.45	$2.52	$2.59	$2.65	$2.72	$2.79	$2.86	$2.92
Total costs	$115.99	$116.08	$116.17	$116.26	$116.34	$116.43	$116.52	$116.61	$116.70	$116.78
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)										
Existing gas wellsites	$63.37	$63.37	$63.37	$63.37	$63.37	$63.37	$63.37	$63.37	$63.37	$63.37
Existing oil wellsites	$49.16	$49.16	$49.16	$49.16	$49.16	$49.16	$49.16	$49.16	$49.16	$49.16
New gas wellsites	$0.70	$0.72	$0.75	$0.77	$0.79	$0.81	$0.83	$0.85	$0.87	$0.89
New oil wellsites	$2.31	$2.38	$2.44	$2.51	$2.58	$2.64	$2.71	$2.78	$2.85	$2.91
Total costs	$115.54	$115.63	$115.71	$115.80	$115.89	$115.98	$116.07	$116.15	$116.24	$116.33
Estimated Costs - CO2 Emissions Additions (tons)										
Existing gas wellsites	165	165	165	165	165	165	165	165	165	165
Existing oil wellsites	30	30	30	30	30	30	30	30	30	30
New gas wellsites	2	2	2	2	2	2	2	2	2	2
New oil wellsites	1	1	2	2	2	2	2	2	2	2
Total CO2 Additions	199	199	199	199	199	199	199	199	199	199
Value of CO2 Additions ($MM)	$0.007	$0.007	$0.007	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Existing gas wellsites	$16.51	$17.08	$17.25	$17.29	$16.61	$15.74	$15.17	$14.45	$13.78	$13.37
Existing oil wellsites	$3.05	$3.15	$3.19	$3.19	$3.07	$2.91	$2.80	$2.67	$2.55	$2.47
New gas wellsites	$0.18	$0.20	$0.20	$0.21	$0.21	$0.20	$0.20	$0.19	$0.19	$0.19
New oil wellsites	$0.14	$0.15	$0.16	$0.16	$0.16	$0.16	$0.15	$0.15	$0.15	$0.15
Total cost savings	$19.88	$20.58	$20.80	$20.85	$20.05	$19.01	$18.33	$17.47	$16.66	$16.18
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Existing gas wellsites	$16.51	$17.74	$18.62	$19.38	$19.35	$19.05	$19.07	$18.87	$18.69	$18.84
Existing oil wellsites	$3.05	$3.28	$3.44	$3.58	$3.57	$3.52	$3.52	$3.49	$3.45	$3.48
New gas wellsites	$0.18	$0.20	$0.22	$0.23	$0.24	$0.24	$0.25	$0.25	$0.26	$0.26
New oil wellsites	$0.14	$0.16	$0.17	$0.18	$0.19	$0.19	$0.19	$0.20	$0.20	$0.21
Total cost savings	$19.88	$21.38	$22.44	$23.38	$23.35	$23.00	$23.03	$22.80	$22.60	$22.79
Estimated Benefits Incremental Production (Bcf)										
Existing gas wellsites	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34
Existing oil wellsites	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
New gas wellsites	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06
New oil wellsites	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05
Total incremental production	5.23	5.23	5.23	5.23	5.24	5.24	5.24	5.24	5.25	5.25
Estimated Benefits - Methane Emissions Reductions (tons)										
Existing gas wellsites	75,000	75,000	75,000	75,000	75,000	75,000	75,000	75,000	75,000	75,000
Existing oil wellsites	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900
New gas wellsites	800	900	900	900	900	1,000	1,000	1,000	1,000	1,100
New oil wellsites	700	700	700	700	700	800	800	800	800	800
Total CH4 reductions	90,400	90,500	90,500	90,600	90,600	90,600	90,700	90,700	90,800	90,800
Value of CH4 reductions ($MM)	$99.48	$99.52	$99.57	$117.73	$117.79	$117.84	$117.90	$117.96	$136.17	$136.23
Estimated VOC Emissions Reductions										
Existing gas wellsites	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900
Existing oil wellsites	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800
New gas wellsites	200	200	200	300	300	300	300	300	300	300
New oil wellsites	200	200	200	200	200	200	200	200	200	200
Total VOC reductions	25,100	25,100	25,200	25,200	25,200	25,200	25,200	25,200	25,200	25,200
Net Benefits										
Net Benefits - 7% ($ MM)	3	4	4	22	21	20	20	19	36	36
Net Benefits - 3% ($ MM)	4	5	6	25	25	25	25	25	43	43

Table 34d: Semi-Annual LDAR Program; Marginal Oil Wells One-Time										
YEAR	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Impacted wellsites										
Existing gas wellsites	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661
Existing oil wellsites	16,029	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340
New gas wellsites	230	236	243	250	256	263	270	276	283	290
New oil wellsites	753	775	797	818	840	862	884	906	928	950
Total wellsites	37,672	24,012	24,041	24,069	24,098	24,126	24,155	24,184	24,212	24,241
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)										
Existing gas wellsites	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82
Existing oil wellsites	$21.90	$4.40	$4.40	$4.40	$4.40	$4.40	$4.40	$4.40	$4.40	$4.40
New gas wellsites	$0.43	$0.44	$0.46	$0.47	$0.48	$0.49	$0.51	$0.52	$0.53	$0.54
New oil wellsites	$1.41	$1.46	$1.50	$1.54	$1.58	$1.62	$1.66	$1.70	$1.74	$1.78
Total costs	$62.57	$45.12	$45.17	$45.23	$45.28	$45.33	$45.39	$45.44	$45.49	$45.55
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)										
Existing gas wellsites	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57
Existing oil wellsites	$21.71	$4.37	$4.37	$4.37	$4.37	$4.37	$4.37	$4.37	$4.37	$4.37
New gas wellsites	$0.43	$0.44	$0.45	$0.47	$0.48	$0.49	$0.50	$0.52	$0.53	$0.54
New oil wellsites	$1.41	$1.45	$1.49	$1.53	$1.57	$1.61	$1.65	$1.69	$1.73	$1.77
Total costs	$62.12	$44.83	$44.88	$44.94	$44.99	$45.04	$45.10	$45.15	$45.20	$45.26
Estimated Costs - CO2 Emissions Additions (tons)										
Existing gas wellsites	124	124	124	124	124	124	124	124	124	124
Existing oil wellsites	16	3	3	3	3	3	3	3	3	3
New gas wellsites	1	1	1	1	2	2	2	2	2	2
New oil wellsites	1	1	1	1	1	1	1	1	1	1
Total CO2 Additions	143	130	130	130	130	130	130	130	130	131
Value of CO2 Additions ($MM)	$0.005	$0.005	$0.005	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Existing gas wellsites	$12.42	$12.85	$12.98	$13.01	$12.50	$11.85	$11.41	$10.87	$10.37	$10.06
Existing oil wellsites	$1.64	$0.35	$0.35	$0.35	$0.34	$0.32	$0.31	$0.30	$0.28	$0.27
New gas wellsites	$0.14	$0.15	$0.15	$0.16	$0.16	$0.15	$0.15	$0.15	$0.14	$0.14
New oil wellsites	$0.11	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.11	$0.11	$0.11
Total cost savings	$14.31	$13.46	$13.60	$13.64	$13.12	$12.44	$11.99	$11.43	$10.90	$10.59
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Existing gas wellsites	$12.42	$13.35	$14.01	$14.58	$14.56	$14.33	$14.35	$14.20	$14.06	$14.18
Existing oil wellsites	$1.64	$0.36	$0.38	$0.40	$0.40	$0.39	$0.39	$0.39	$0.38	$0.39
New gas wellsites	$0.14	$0.15	$0.16	$0.18	$0.18	$0.18	$0.19	$0.19	$0.19	$0.20
New oil wellsites	$0.11	$0.12	$0.13	$0.14	$0.14	$0.14	$0.15	$0.15	$0.15	$0.16
Total cost savings	$14.31	$13.98	$14.68	$15.29	$15.28	$15.05	$15.07	$14.92	$14.79	$14.92
Estimated Benefits Incremental Production (Bcf)										
Existing gas wellsites	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26
Existing oil wellsites	0.43	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
New gas wellsites	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05
New oil wellsites	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04
Total incremental production	3.76	3.42	3.42	3.42	3.43	3.43	3.43	3.43	3.43	3.44
Estimated Benefits - Methane Emissions Reductions (tons)										
Existing gas wellsites	56,200	56,200	56,200	56,200	56,200	56,200	56,200	56,200	56,200	56,200
Existing oil wellsites	7,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
New gas wellsites	600	600	700	700	700	700	700	800	800	800
New oil wellsites	500	500	500	500	500	600	600	600	600	600
Total CH4 reductions	64,900	58,900	58,900	58,900	59,000	59,000	59,000	59,100	59,100	59,100
Value of CH4 reductions ($MM)	$71.34	$64.75	$64.79	$76.61	$76.65	$76.69	$76.74	$76.78	$88.64	$88.69
Estimated VOC Emissions Reductions										
Existing gas wellsites	15,700	15,700	15,700	15,700	15,700	15,700	15,700	15,700	15,700	15,700
Existing oil wellsites	2,100	400	400	400	400	400	400	400	400	400
New gas wellsites	200	200	200	200	200	200	200	200	200	200
New oil wellsites	100	100	100	100	200	200	200	200	200	200
Total VOC reductions	18,100	16,400	16,500	16,500	16,500	16,500	16,500	16,500	16,500	16,500
Net Benefits										
Net Benefits - 7% ($ MM)	23	33	33	45	44	44	43	43	54	54
Net Benefits - 3% ($ MM)	24	34	35	47	47	47	47	47	58	58

Table 34e: Annual LDAR Program for Marginal Oil Wells; Semi-Annual LDAR Program for All Other Wells										
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Impacted wellsites										
Existing gas wellsites	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661
Existing oil wellsites	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029
New gas wellsites	230	236	243	250	256	263	270	276	283	290
New oil wellsites	753	775	797	818	840	862	884	906	928	950
Total wellsites	37,672	37,700	37,729	37,758	37,786	37,815	37,843	37,872	37,901	37,929
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)										
Existing gas wellsites	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82	$38.82
Existing oil wellsites	$21.90	$21.90	$21.90	$21.90	$21.90	$21.90	$21.90	$21.90	$21.90	$21.90
New gas wellsites	$0.43	$0.44	$0.46	$0.47	$0.48	$0.49	$0.51	$0.52	$0.53	$0.54
New oil wellsites	$1.41	$1.46	$1.50	$1.54	$1.58	$1.62	$1.66	$1.70	$1.74	$1.78
Total costs	$62.57	$62.63	$62.68	$62.73	$62.79	$62.84	$62.89	$62.95	$63.00	$63.06
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)										
Existing gas wellsites	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57	$38.57
Existing oil wellsites	$21.71	$21.71	$21.71	$21.71	$21.71	$21.71	$21.71	$21.71	$21.71	$21.71
New gas wellsites	$0.43	$0.44	$0.45	$0.47	$0.48	$0.49	$0.50	$0.52	$0.53	$0.54
New oil wellsites	$1.41	$1.45	$1.49	$1.53	$1.57	$1.61	$1.65	$1.69	$1.73	$1.77
Total costs	$62.12	$62.17	$62.23	$62.28	$62.33	$62.39	$62.44	$62.49	$62.55	$62.60
Estimated Costs - CO2 Emissions Additions (tons)										
Existing gas wellsites	124	124	124	124	124	124	124	124	124	124
Existing oil wellsites	16	16	16	16	16	16	16	16	16	16
New gas wellsites	1	1	1	1	2	2	2	2	2	2
New oil wellsites	1	1	1	1	1	1	1	1	1	1
Total CO2 Additions	143	143	143	143	143	143	143	143	143	144
Value of CO2 Additions ($MM)	$0.005	$0.005	$0.005	$0.006	$0.006	$0.006	$0.006	$0.006	$0.007	$0.007
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Existing gas wellsites	$12.42	$12.85	$12.98	$13.01	$12.50	$11.85	$11.41	$10.87	$10.37	$10.06
Existing oil wellsites	$1.64	$1.70	$1.71	$1.72	$1.65	$1.56	$1.51	$1.44	$1.37	$1.33
New gas wellsites	$0.14	$0.15	$0.15	$0.16	$0.16	$0.15	$0.15	$0.15	$0.14	$0.14
New oil wellsites	$0.11	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.11	$0.11	$0.11
Total cost savings	$14.31	$14.81	$14.96	$15.00	$14.43	$13.68	$13.19	$12.57	$11.99	$11.64
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Existing gas wellsites	$12.42	$13.35	$14.01	$14.58	$14.56	$14.33	$14.35	$14.20	$14.06	$14.18
Existing oil wellsites	$1.64	$1.76	$1.85	$1.93	$1.92	$1.89	$1.89	$1.87	$1.86	$1.87
New gas wellsites	$0.14	$0.15	$0.16	$0.18	$0.18	$0.18	$0.19	$0.19	$0.19	$0.20
New oil wellsites	$0.11	$0.12	$0.13	$0.14	$0.14	$0.14	$0.15	$0.15	$0.15	$0.16
Total cost savings	$14.31	$15.38	$16.15	$16.82	$16.80	$16.55	$16.57	$16.41	$16.26	$16.40
Estimated Benefits Incremental Production (Bcf)										
Existing gas wellsites	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26
Existing oil wellsites	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
New gas wellsites	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05
New oil wellsites	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04
Total incremental production	3.76	3.76	3.76	3.77	3.77	3.77	3.77	3.77	3.78	3.78
Estimated Benefits - Methane Emissions Reductions (tons)										
Existing gas wellsites	56,200	56,200	56,200	56,200	56,200	56,200	56,200	56,200	56,200	56,200
Existing oil wellsites	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500
New gas wellsites	600	600	700	700	700	700	700	800	800	800
New oil wellsites	500	500	500	500	500	600	600	600	600	600
Total CH4 reductions	64,900	64,900	64,900	65,000	65,000	65,000	65,100	65,100	65,100	65,100
Value of CH4 reductions ($MM)	$71.34	$71.38	$71.41	$84.44	$84.48	$84.52	$84.57	$84.61	$97.67	$97.72
Estimated VOC Emissions Reductions										
Existing gas wellsites	15,700	15,700	15,700	15,700	15,700	15,700	15,700	15,700	15,700	15,700
Existing oil wellsites	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
New gas wellsites	200	200	200	200	200	200	200	200	200	200
New oil wellsites	100	100	100	100	200	200	200	200	200	200
Total VOC reductions	18,100	18,100	18,100	18,100	18,100	18,100	18,100	18,100	18,100	18,200
Net Benefits										
Net Benefits - 7% ($ MM)	23	24	24	37	36	35	35	34	47	46
Net Benefits - 3% ($ MM)	24	25	25	39	39	39	39	39	51	52

Table 34f: Annual LDAR Program for Marginal Oil and Gas Wells; Semi-Annual LDAR Program for All Other Wells										
YEAR	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Impacted wellsites										
Existing gas wellsites	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661
Existing oil wellsites	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029
New gas wellsites	230	236	243	250	256	263	270	276	283	290
New oil wellsites	753	775	797	818	840	862	884	906	928	950
Total wellsites	37,672	37,700	37,729	37,758	37,786	37,815	37,843	37,872	37,901	37,929
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)										
Existing gas wellsites	$29.74	$29.74	$29.74	$29.74	$29.74	$29.74	$29.74	$29.74	$29.74	$29.74
Existing oil wellsites	$21.90	$21.90	$21.90	$21.90	$21.90	$21.90	$21.90	$21.90	$21.90	$21.90
New gas wellsites	$0.43	$0.44	$0.46	$0.47	$0.48	$0.49	$0.51	$0.52	$0.53	$0.54
New oil wellsites	$1.41	$1.46	$1.50	$1.54	$1.58	$1.62	$1.66	$1.70	$1.74	$1.78
Total costs	$53.49	$53.54	$53.59	$53.65	$53.70	$53.75	$53.81	$53.86	$53.92	$53.97
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)										
Existing gas wellsites	$29.49	$29.49	$29.49	$29.49	$29.49	$29.49	$29.49	$29.49	$29.49	$29.49
Existing oil wellsites	$21.71	$21.71	$21.71	$21.71	$21.71	$21.71	$21.71	$21.71	$21.71	$21.71
New gas wellsites	$0.43	$0.44	$0.45	$0.47	$0.48	$0.49	$0.50	$0.52	$0.53	$0.54
New oil wellsites	$1.41	$1.45	$1.49	$1.53	$1.57	$1.61	$1.65	$1.69	$1.73	$1.77
Total costs	$53.03	$53.09	$53.14	$53.19	$53.25	$53.30	$53.35	$53.41	$53.46	$53.51
Estimated Costs - CO2 Emissions Additions (tons)										
Existing gas wellsites	94	94	94	94	94	94	94	94	94	94
Existing oil wellsites	16	16	16	16	16	16	16	16	16	16
New gas wellsites	1	1	1	1	2	2	2	2	2	2
New oil wellsites	1	1	1	1	1	1	1	1	1	1
Total CO2 Additions	112	112	113	113	113	113	113	113	113	113
Value of CO2 Additions ($MM)	$0.004	$0.004	$0.004	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Existing gas wellsites	$9.37	$9.69	$9.79	$9.81	$9.43	$8.93	$8.61	$8.20	$7.82	$7.59
Existing oil wellsites	$1.64	$1.70	$1.71	$1.72	$1.65	$1.56	$1.51	$1.44	$1.37	$1.33
New gas wellsites	$0.14	$0.15	$0.15	$0.16	$0.16	$0.15	$0.15	$0.15	$0.14	$0.14
New oil wellsites	$0.11	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.11	$0.11	$0.11
Total cost savings	$11.25	$11.65	$11.77	$11.81	$11.35	$10.77	$10.38	$9.90	$9.44	$9.17
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Existing gas wellsites	$9.37	$10.07	$10.56	$11.00	$10.98	$10.81	$10.82	$10.71	$10.60	$10.69
Existing oil wellsites	$1.64	$1.76	$1.85	$1.93	$1.92	$1.89	$1.89	$1.87	$1.86	$1.87
New gas wellsites	$0.14	$0.15	$0.16	$0.18	$0.18	$0.18	$0.19	$0.19	$0.19	$0.20
New oil wellsites	$0.11	$0.12	$0.13	$0.14	$0.14	$0.14	$0.15	$0.15	$0.15	$0.16
Total cost savings	$11.25	$12.10	$12.71	$13.24	$13.22	$13.03	$13.05	$12.92	$12.81	$12.92
Estimated Benefits Incremental Production (Bcf)										
Existing gas wellsites	2.46	2.46	2.46	2.46	2.46	2.46	2.46	2.46	2.46	2.46
Existing oil wellsites	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
New gas wellsites	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05
New oil wellsites	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04
Total incremental production	2.96	2.96	2.96	2.96	2.97	2.97	2.97	2.97	2.97	2.97
Estimated Benefits - Methane Emissions Reductions (tons)										
Existing gas wellsites	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600	42,600
Existing oil wellsites	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500
New gas wellsites	600	600	700	700	700	700	700	800	800	800
New oil wellsites	500	500	500	500	500	600	600	600	600	600
Total CH4 reductions	51,200	51,300	51,300	51,300	51,400	51,400	51,400	51,500	51,500	51,500
Value of CH4 reductions ($MM)	$56.35	$56.38	$56.42	$66.72	$66.76	$66.80	$66.85	$66.89	$77.23	$77.28
Estimated VOC Emissions Reductions										
Existing gas wellsites	11,800	11,800	11,800	11,800	11,800	11,800	11,800	11,800	11,800	11,800
Existing oil wellsites	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
New gas wellsites	200	200	200	200	200	200	200	200	200	200
New oil wellsites	100	100	100	100	200	200	200	200	200	200
Total VOC reductions	14,100	14,100	14,200	14,200	14,200	14,200	14,200	14,200	14,200	14,200
Net Benefits										
Net Benefits - 7% ($ MM)	14	14	15	25	24	24	23	23	33	32
Net Benefits - 3% ($ MM)	15	15	16	27	27	27	27	26	37	37

Table 34g: Quarterly LDAR Program for Gas Wells; Annual LDAR Program for Oil Wells										
YEAR	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Impacted wellsites										
Existing gas wellsites	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661
Existing oil wellsites	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029	16,029
New gas wellsites	230	236	243	250	256	263	270	276	283	290
New oil wellsites	753	775	797	818	840	862	884	906	928	950
Total wellsites	37,672	37,700	37,729	37,758	37,786	37,815	37,843	37,872	37,901	37,929
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)										
Existing gas wellsites	$63.62	$63.62	$63.62	$63.62	$63.62	$63.62	$63.62	$63.62	$63.62	$63.62
Existing oil wellsites	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50
New gas wellsites	$0.71	$0.73	$0.75	$0.77	$0.79	$0.81	$0.83	$0.85	$0.87	$0.89
New oil wellsites	$0.96	$0.99	$1.02	$1.05	$1.07	$1.10	$1.13	$1.16	$1.19	$1.21
Total costs	$85.79	$85.83	$85.88	$85.93	$85.98	$86.03	$86.08	$86.13	$86.17	$86.22
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)										
Existing gas wellsites	$63.37	$63.37	$63.37	$63.37	$63.37	$63.37	$63.37	$63.37	$63.37	$63.37
Existing oil wellsites	$20.31	$20.31	$20.31	$20.31	$20.31	$20.31	$20.31	$20.31	$20.31	$20.31
New gas wellsites	$0.70	$0.72	$0.75	$0.77	$0.79	$0.81	$0.83	$0.85	$0.87	$0.89
New oil wellsites	$0.95	$0.98	$1.01	$1.04	$1.06	$1.09	$1.12	$1.15	$1.18	$1.20
Total costs	$85.33	$85.38	$85.43	$85.48	$85.53	$85.57	$85.62	$85.67	$85.72	$85.77
Estimated Costs - CO2 Emissions Additions (tons)										
Existing gas wellsites	165	165	165	165	165	165	165	165	165	165
Existing oil wellsites	15	15	15	15	15	15	15	15	15	15
New gas wellsites	2	2	2	2	2	2	2	2	2	2
New oil wellsites	1	1	1	1	1	1	1	1	1	1
Total CO2 Additions	183	183	183	183	183	183	183	183	183	183
Value of CO2 Additions ($MM)	$0.007	$0.007	$0.007	$0.008	$0.008	$0.008	$0.008	$0.008	$0.009	$0.009
Estimated Benefits - Cost Savings Present Value Using 7% Rate ($ in million)										
Existing gas wellsites	$16.51	$17.08	$17.25	$17.29	$16.61	$15.74	$15.17	$14.45	$13.78	$13.37
Existing oil wellsites	$1.52	$1.58	$1.59	$1.60	$1.53	$1.45	$1.40	$1.33	$1.27	$1.24
New gas wellsites	$0.18	$0.20	$0.20	$0.21	$0.21	$0.20	$0.20	$0.19	$0.19	$0.19
New oil wellsites	$0.07	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.07	$0.07
Total cost savings	$18.29	$18.93	$19.12	$19.17	$18.43	$17.48	$16.85	$16.06	$15.32	$14.87
Estimated Benefits - Cost Savings Present Value Using 3% Rate ($ in million)										
Existing gas wellsites	$16.51	$17.74	$18.62	$19.38	$19.35	$19.05	$19.07	$18.87	$18.69	$18.84
Existing oil wellsites	$1.52	$1.64	$1.72	$1.79	$1.79	$1.76	$1.76	$1.74	$1.73	$1.74
New gas wellsites	$0.18	$0.20	$0.22	$0.23	$0.24	$0.24	$0.25	$0.25	$0.26	$0.26
New oil wellsites	$0.07	$0.08	$0.09	$0.09	$0.09	$0.09	$0.10	$0.10	$0.10	$0.10
Total cost savings	$18.29	$19.66	$20.64	$21.49	$21.47	$21.15	$21.17	$20.96	$20.77	$20.95
Estimated Benefits Incremental Production (Bcf)										
Existing gas wellsites	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34
Existing oil wellsites	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
New gas wellsites	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06
New oil wellsites	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Total incremental production	4.81	4.81	4.81	4.81	4.81	4.82	4.82	4.82	4.82	4.82
Estimated Benefits - Methane Emissions Reductions (tons)										
Existing gas wellsites	75,000	75,000	75,000	75,000	75,000	75,000	75,000	75,000	75,000	75,000
Existing oil wellsites	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100
New gas wellsites	800	900	900	900	900	1,000	1,000	1,000	1,000	1,100
New oil wellsites	300	300	400	400	400	400	400	400	400	400
Total CH4 reductions	83,200	83,300	83,300	83,300	83,400	83,400	83,400	83,500	83,500	83,500
Value of CH4 reductions ($MM)	$91.54	$91.58	$91.61	$108.31	$108.36	$108.40	$108.45	$108.49	$125.23	$125.28
Estimated VOC Emissions Reductions										
Existing gas wellsites	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900
Existing oil wellsites	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
New gas wellsites	200	200	200	300	300	300	300	300	300	300
New oil wellsites	100	100	100	100	100	100	100	100	100	100
Total VOC reductions	23,100	23,100	23,100	23,100	23,200	23,200	23,200	23,200	23,200	23,200
Net Benefits										
Net Benefits - 7% ($ MM)	24	25	25	42	41	40	39	38	54	54
Net Benefits - 3% ($ MM)	24	26	27	44	44	44	44	44	60	60

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 $2.56 million per year and $536,000 per year, respectively, in nominal terms. 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 to industry is as follows:

Type of Response	Number of Responses	Hours per Response	Total Hours	Total Wage Cost (at $63.30/ hour)
Plan to Minimize Waste of Natural Gas 43 CFR 3162.3-1 Form 3160-3	2,000	2	4,000	$253,200
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	8	400	$25,320
Request for Approval of Alternative Volume Limits 43 CFR 3179.7(b) Form 3160-5	185	16	2,960	$187,368
Certification in Support of Exemption from Volume Limits 43 CFR 3179.7(d) Form 3160-5	15	16	240	$15,192
Well Completion and Related Operations 43 CFR 3179.102(b) Form 3160-5	5	2	10	$633
Initial Production Testing Request for Extension 43 CFR 3179.103 Form 3160-5	5	2	10	$633
Subsequent Well Tests Request for Extension 43 CFR 3179.104 Form 3160-5	5	2	10	$633

Type of Response	Number of Responses	Hours per Response	Total Hours	Total Wage Cost (at $63.30/ hour)
Reporting of Emergency Venting and Flaring Beyond Specified Timeframes 43 CFR 3179.105 Form 3160-5	25	2	50	$3,165
Pneumatic Controller Report 43 CFR 3179.201(b) and (c) Form 3160-5	200	2	400	$25,320
Pneumatic Pump Report 43 CFR 3179.202 Form 3160-5	500	4	2,000	$126,600
Crude Oil and Condensate Storage Vessel Report 43 CFR 3179.203(c) Form 3160-5	100	8	800	$50,640
Downhole Well Maintenance and Liquids Unloading — Documentation and Reporting 43 CFR 3179.204(a) and (d) Form 3160-5	5,000	1	5,000	$316,500
Downhole Well Maintenance and Liquids Unloading Documentation and Reporting 43 CFR 3179.204(c)	5,000	0.25	1,250	$79,125
Downhole Well Maintenance and Liquids Unloading — Notification of Excessive Duration or Volume 43 CFR 3179.204(e) Form 3160-5	120	1	120	$7,596
Leak Detection — Compliance with EPA Regulations 43 CFR 3179.301(e) Form 3160-5	500	8	4,000	$253,200
Leak Detection — Request to Use and Alternative Device, Program, or Method 43 CFR 3179.303(b) Form 3160-5	200	40	8,000	$506,400
Leak Detection — Notification of Delay in Repairing Leaks 43 CFR 3179.304(a) Form 3160-5	100	1	100	$6,330

Type of Response	Number of Responses	Hours per Response	Total Hours	Total Wage Cost (at $63.30/ hour)
Leak Detection — Inspection Recordkeeping 43 CFR 3179.305	52,000	0.25	13,000	$822,900
Gas Flaring (43 CFR 3162.7-1(d), 3164.1, and Notice to Lessees and Operators 4A)	(120)	(16)	(1,920)	($121,536)
Total			**40,430**	**$2,559,219**

The estimated administrative burden to the BLM is as follows:

Type of Response	Number of Responses	Hours per Response	Total Hours	Total Wage Cost (at $40.94/ hour)
Plan to Minimize Waste of Natural Gas 43 CFR 3162.3-1 Form 3160-3	2,000	2	4,000	$163,760
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	2	100	$4,094
Request for Approval of Alternative Volume Limits 43 CFR 3179.7 Form 3160-5	200	4	800	$32,752
Well Completion and Related Operations 43 CFR 3179.102(b) Form 3160-5	5	1	5	$205
Initial Production Testing Request for Extension 43 CFR 3179.103 Form 3160-5	5	1	5	$205
Subsequent Well Tests Request for Extension 43 CFR 3179.104 Form 3160-5	5	1	5	$205

Type of Response	Number of Responses	Hours per Response	Total Hours	Total Wage Cost (at $40.94/ hour)
Reporting of Emergency Venting and Flaring Beyond Specified Timeframes 43 CFR 3179.105 Form 3160-5	25	2	50	$2,047
Pneumatic Controller Report 43 CFR 3179.201(b) and (c) Form 3160-5	200	2	400	$16,376
Crude Oil and Condensate Storage Vessel Report 43 CFR 3179.203(c) Form 3160-5	100	2	200	$8,188
Downhole Well Maintenance and Liquids Unloading — Documentation and Reporting 43 CFR 3179.204(a) and (d) Form 3160-5	5,000	0.083	417	$17,058
Downhole Well Maintenance and Liquids Unloading — Recordkeeping 43 CFR 3179.204(c)	5,000	0.083	417	$17,058
Downhole Well Maintenance and Liquids Unloading — Notification of Excessive Duration or Volume 43 CFR 3179.204(e) Form 3160-5	120	0.25	30	$1,228
Leak Detection — Compliance with EPA Regulations 43 CFR 3179.301(e) Form 3160-5	500	1	500	$20,470
Leak Detection — Request to Use and Alternative Device, Program, or Method 43 CFR 3179.303(b)	200	4	800	$32,752
Leak Detection — Notification of Delay in Repairing Leaks 43 CFR 3179.304(a) Form 3160-5	100	0.5	50	$2,047
Leak Detection — Inspection Recordkeeping 43 CFR 3179.305	52,000	0.083	4,333	$177,407
Totals			**13,112**	**$536,792**

7.14 Royalty Free Use of Production

The proposed 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 proposed 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 proposed requirements. As such, any impacts of the proposed 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.[72] That report concluded that the United States' oil and gas "government take" is among the lowest in the world.[73]

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.[74] 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").[75] The IHS CERA Study identified four factors amenable to comparison: government take, internal rate of return, profit-investment ratio, and progressivity.[76] The study also considered measures of revenue

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72 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.

73 GAO-07-676R at 2.

74 GAO-08-691 at 6.

75 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

76 A "progressive" royalty rate refers to a rate that increases with the quantity or price of the resource being sold.

risk and fiscal system stability. Overall, the study found that, as of the time of the study, the Federal 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.[77] 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.[78] 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.[79] The BLM received over 80,000 comments on the ANPR. The preamble of this rule discusses the content of those comments.

This proposed 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 proposed 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.

[77] 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.
[78] 80 FR 22148.
[79] 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.

After reviewing the proposed requirements, we estimate that the largest compliance costs are associated with the LDAR and flaring limit requirements. Since we are unable to account for existing LDAR programs, these costs are likely to overstate the true costs of the rule. The estimated compliance costs are as follows:

If the EPA does not finalize Subpart OOOOa (see Table 37a):

- Using a 7% discount rate to annualize costs, we estimate that the proposed rule would pose costs ranging from \$139 – \$174 million per year.
- Using a 3% discount rate to annualize costs, we estimate that the proposed rule would pose costs ranging from \$130 – \$147 million per year.

If the EPA finalizes Subpart OOOOa (see Table 37b):

- Using a 7% discount rate to annualize costs, we estimate that the proposed rule would pose costs ranging from \$125 – \$161 million per year.
- Using a 3% discount rate to annualize costs, we estimate that the proposed rule would pose costs ranging from \$117 – \$134 million per year.

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 37a: Estimated Annual Total Costs if EPA does not Finalize Subpart OOOOa ($ in million)

	Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate	Flaring Requirements	$33	$49	$69	$62	$58	$55	$54	$52	$49	$48
	Well Completion	$12	$12	$11	$11	$10	$10	$9	$9	$9	$8
	Pnumatic Controllers	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6
	Pneumatic Pumps	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
	Liquids Unloading	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6
	Storage Tanks	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6
	LDAR	$71	$71	$71	$71	$71	$71	$71	$71	$71	$71
	Administrative Burden	$3	$3	$3	$3	$2	$2	$2	$2	$2	$2
	Total	$139	$155	$174	$166	$162	$159	$157	$155	$152	$150
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$27	$34	$44	$38	$36	$36	$36	$36	$35	$35
	Well Completion	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12
	Pnumatic Controllers	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
	Pneumatic Pumps	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
	Liquids Unloading	$5	$5	$5	$5	$5	$5	$5	$6	$6	$6
	Storage Tanks	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6
	LDAR	$70	$70	$70	$70	$71	$71	$71	$71	$71	$71
	Administrative Burden	$3	$3	$3	$3	$3	$3	$3	$3	$2	$2
	Total	$130	$138	$147	$142	$140	$139	$139	$140	$139	$139

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

Table 37b: Estimated Annual Total Costs if EPA Finalizes Subpart OOOOa ($ in million)

	Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate	Flaring Requirements	$33	$49	$69	$62	$58	$55	$54	$52	$49	$48
	Well Completion	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Pnumatic Controllers	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6
	Pneumatic Pumps	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
	Liquids Unloading	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6
	Storage Tanks	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6
	LDAR	$69	$69	$69	$69	$69	$69	$69	$69	$69	$69
	Administrative Burden	$3	$3	$3	$3	$2	$2	$2	$2	$2	$2
	Total	$125	$141	$161	$154	$150	$147	$145	$144	$141	$139
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$27	$34	$44	$38	$36	$36	$36	$36	$35	$35
	Well Completion	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Pnumatic Controllers	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
	Pneumatic Pumps	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
	Liquids Unloading	$5	$5	$5	$5	$5	$5	$5	$6	$6	$6
	Storage Tanks	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6
	LDAR	$68	$68	$68	$68	$68	$68	$68	$68	$68	$68
	Administrative Burden	$3	$3	$3	$3	$3	$3	$3	$3	$2	$2
	Total	$117	$124	$134	$128	$126	$125	$126	$126	$125	$125

* 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 (EPA 2015, p. 1-8).

After reviewing the proposed 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:

If the EPA does not finalize Subpart OOOOa (see Table 38a):

- Benefits range from $270 – 354 million per year, using a 7% discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.
- Benefits range from $270 – 384 million per year, using a 3% discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.

If the EPA finalizes Subpart OOOOa (see Table 38b):

- Benefits range from $255 – 329 million per year, using a 7% discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.
- Benefits range from $255 – 357 million per year, using a 3% discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.

We estimate that the proposed rule would reduce methane emissions by 176,000 – 185,000 tons per year (see Table 38c) or 164,000 – 169,000 tons per year if the EPA finalizes Subpart OOOOa (see Table 38d). We monetized these reductions and included them in the monetized benefits. We estimate that the proposed rule would reduce VOC emissions by 400,000 – 423,000 tons per year (see Table 38e) or 391,000 – 411,000 tons per year if the EPA finalizes Subpart OOOOa (see Table 38f). The VOC emissions reductions are not monetized.

Again, we believe that the estimated benefits represent the likely upper bound of monetized and quantified 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 38a: Estimated Annual Total Benefits ($ in million)

	Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Estimated Benefits - Cost Savings PV Using 7% Rate ($ in million)	Flaring Requirements	$40	$50	$58	$57	$55	$52	$50	$48	$46	$45
	Well Completion	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
	Pnumatic Controllers	$11	$11	$11	$11	$11	$10	$10	$10	$9	$9
	Pneumatic Pumps	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
	Liquids Unloading	$7	$8	$8	$8	$8	$8	$8	$7	$7	$7
	Storage Tanks	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	LDAR	$15	$16	$16	$16	$15	$14	$14	$13	$13	$12
	Total	$77	$89	$98	$96	$93	$89	$86	$82	$79	$76
Estimated Benefits - Cost Savings PV Using 3% Rate ($ in million)	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$40	$52	$63	$64	$64	$63	$63	$63	$63	$63
	Well Completion	$2	$2	$2	$2	$2	$2	$3	$3	$3	$3
	Pnumatic Controllers	$11	$12	$12	$13	$13	$13	$13	$12	$12	$12
	Pneumatic Pumps	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
	Liquids Unloading	$7	$8	$9	$9	$9	$9	$9	$9	$10	$10
	Storage Tanks	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	LDAR	$15	$16	$17	$18	$18	$17	$17	$17	$17	$17
	Total	$77	$92	$105	$108	$108	$107	$108	$107	$107	$108
Estimated Benefits - Value of Methane Reductions	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Well Completion	$13	$13	$13	$16	$17	$17	$18	$18	$21	$22
	Pnumatic Controllers	$48	$48	$48	$56	$56	$56	$56	$56	$65	$65
	Pneumatic Pumps	$18	$18	$18	$22	$22	$22	$22	$22	$26	$26
	Liquids Unloading	$33	$33	$34	$41	$41	$42	$42	$43	$50	$51
	Storage Tanks	$8	$8	$8	$9	$9	$9	$9	$9	$11	$11
	LDAR	$75	$75	$75	$88	$88	$88	$88	$88	$102	$102
	Total	$193	$194	$195	$232	$234	$235	$236	$237	$275	$277

	Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Estimated Benefits - 7%	Flaring Requirements	$40	$50	$58	$57	$55	$52	$50	$48	$46	$45
	Well Completion	$15	$15	$15	$18	$19	$19	$20	$20	$23	$24
	Pnumatic Controllers	$59	$59	$59	$68	$67	$67	$66	$66	$74	$74
	Pneumatic Pumps	$20	$20	$20	$23	$24	$24	$24	$24	$27	$28
	Liquids Unloading	$40	$41	$42	$49	$49	$49	$50	$50	$57	$58
	Storage Tanks	$8	$8	$8	$9	$9	$9	$9	$9	$11	$11
	LDAR	$89	$90	$90	$104	$103	$103	$102	$102	$115	$114
	Total	$270	$283	$293	$328	$326	$323	$322	$319	$354	$353
Total Estimated Benefits - 3%	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$40	$52	$63	$64	$64	$63	$63	$63	$63	$63
	Well Completion	$15	$15	$16	$19	$19	$20	$20	$21	$24	$24
	Pnumatic Controllers	$59	$59	$60	$69	$69	$69	$69	$69	$77	$78
	Pneumatic Pumps	$20	$20	$20	$24	$24	$24	$24	$24	$28	$28
	Liquids Unloading	$40	$41	$42	$50	$50	$51	$52	$53	$60	$61
	Storage Tanks	$8	$8	$8	$9	$9	$9	$9	$9	$11	$11
	LDAR	$89	$91	$91	$106	$106	$106	$106	$106	$119	$119
	Total	$270	$287	$301	$340	$341	$342	$344	$344	$382	$384

Table 38b: Estimated Annual Total Benefits if EPA Finalizes Subpart OOOOa ($ in million)

	Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Estimated Benefits - Cost Savings PV Using 7% Rate ($ in million)	Flaring Requirements	$40	$50	$58	$57	$55	$52	$50	$48	$46	$45
	Well Completion	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Pnumatic Controllers	$11	$11	$11	$11	$11	$10	$10	$10	$9	$9
	Pneumatic Pumps	$2	$2	$2	$2	$2	$2	$2	$2	$1	$1
	Liquids Unloading	$7	$8	$8	$8	$8	$8	$8	$7	$7	$7
	Storage Tanks	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	LDAR	$15	$15	$15	$15	$15	$14	$14	$13	$12	$12
	Total	$75	$86	$95	$94	$90	$86	$83	$80	$76	$74
Estimated Benefits - Cost Savings PV Using 3% Rate ($ in million)	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$40	$52	$63	$64	$64	$63	$63	$63	$63	$63
	Well Completion	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Pnumatic Controllers	$11	$12	$12	$13	$13	$13	$13	$12	$12	$12
	Pneumatic Pumps	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
	Liquids Unloading	$7	$8	$9	$9	$9	$9	$9	$9	$10	$10
	Storage Tanks	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	LDAR	$15	$16	$17	$17	$17	$17	$17	$17	$17	$17
	Total	$75	$90	$103	$105	$105	$104	$105	$104	$104	$104
Estimated Benefits - Value of Methane Reductions	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Well Completion	$1	$1	$1	$2	$2	$2	$2	$2	$2	$2
	Pnumatic Controllers	$48	$48	$48	$56	$56	$56	$56	$56	$65	$65
	Pneumatic Pumps	$18	$18	$18	$21	$21	$21	$21	$21	$24	$24
	Liquids Unloading	$33	$33	$34	$41	$41	$42	$42	$43	$50	$51
	Storage Tanks	$8	$8	$8	$9	$9	$9	$9	$9	$11	$11
	LDAR	$73	$73	$73	$87	$87	$87	$87	$87	$100	$100

	Total	$180	$181	$182	$215	$216	$217	$217	$218	$252	$253
Total Estimated Benefits - 7%	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$40	$50	$58	$57	$55	$52	$50	$48	$46	$45
	Well Completion	$1	$1	$1	$2	$2	$2	$2	$2	$2	$2
	Pnumatic Controllers	$59	$59	$59	$68	$67	$67	$66	$66	$74	$74
	Pneumatic Pumps	$19	$19	$19	$23	$23	$22	$22	$22	$25	$25
	Liquids Unloading	$40	$41	$42	$49	$49	$49	$50	$50	$57	$58
	Storage Tanks	$8	$8	$8	$9	$9	$9	$9	$9	$11	$11
	LDAR	$88	$89	$89	$102	$101	$101	$100	$100	$112	$112
	Total	$255	$267	$277	$309	$306	$303	$300	$298	$329	$327
Total Estimated Benefits - 3%	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$40	$52	$63	$64	$64	$63	$63	$63	$63	$63
	Well Completion	$1	$1	$1	$2	$2	$2	$2	$2	$2	$2
	Pnumatic Controllers	$59	$59	$60	$69	$69	$69	$69	$69	$77	$78
	Pneumatic Pumps	$19	$19	$20	$23	$23	$23	$23	$23	$26	$26
	Liquids Unloading	$40	$41	$42	$50	$50	$51	$52	$53	$60	$61
	Storage Tanks	$8	$8	$8	$9	$9	$9	$9	$9	$11	$11
	LDAR	$88	$89	$90	$104	$104	$104	$104	$103	$117	$117
	Total	$255	$271	$284	$320	$321	$321	$322	$322	$356	$357

Table 38c: Estimated Methane Reductions (tons)

Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Flaring Requirements	0	0	0	0	0	0	0	0	0	0
Well Completion	11,500	11,800	12,200	12,500	12,900	13,200	13,500	13,900	14,200	14,500
Pnumatic Controllers	43,400	43,400	43,400	43,400	43,400	43,400	43,400	43,400	43,400	43,400
Pneumatic Pumps	16,100	16,300	16,400	16,600	16,700	16,800	17,000	17,100	17,200	17,400
Liquids Unloading	29,800	30,300	30,700	31,200	31,700	32,200	32,600	33,100	33,600	34,100
Storage Tanks	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100
LDAR	67,700	67,800	67,800	67,800	67,900	67,900	67,900	68,000	68,000	68,000
Total	176,000	177,000	178,000	179,000	180,000	181,000	182,000	183,000	184,000	185,000

Table 38d: Estimated Methane Reductions if EPA Finalizes Subpart OOOOa (tons)

Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Flaring Requirements	0	0	0	0	0	0	0	0	0	0
Well Completion	1,100	1,100	1,100	1,200	1,200	1,200	1,300	1,300	1,300	1,400
Pnumatic Controllers	43,400	43,400	43,400	43,400	43,400	43,400	43,400	43,400	43,400	43,400
Pneumatic Pumps	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000
Liquids Unloading	29,800	30,300	30,700	31,200	31,700	32,200	32,600	33,100	33,600	34,100
Storage Tanks	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100
LDAR	66,600	66,600	66,600	66,600	66,600	66,600	66,600	66,600	66,600	66,600
Total	164,000	165,000	165,000	166,000	166,000	167,000	167,000	168,000	168,000	169,000

Table 38e: Estimated VOC Reductions (tons)

Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Flaring Requirements	0	0	0	0	0	0	0	0	0	0
Well Completion	9,600	9,900	10,200	10,500	10,800	11,000	11,300	11,600	11,900	12,200
Pnumatic Controllers	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000
Pneumatic Pumps	4,040	4,080	4,110	4,150	4,190	4,230	4,270	4,300	4,340	4,380
Liquids Unloading	136,000	138,000	140,000	143,000	145,000	147,000	149,000	151,000	153,000	156,000
Storage Tanks	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500
LDAR	18,900	18,900	18,900	18,900	18,900	18,900	19,000	19,000	19,000	19,000
Total	400,000	402,000	405,000	408,000	410,000	413,000	415,000	417,000	420,000	423,000

Table 38f: Estimated VOC Reductions if EPA Finalizes Subpart OOOOa (tons)

Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Flaring Requirements	0	0	0	0	0	0	0	0	0	0
Well Completion	900	900	900	1,000	1,000	1,000	1,100	1,100	1,100	1,100
Pnumatic Controllers	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000	199,000
Pneumatic Pumps	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Liquids Unloading	136,000	138,000	140,000	143,000	145,000	147,000	149,000	151,000	153,000	156,000
Storage Tanks	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500
LDAR	18,600	18,600	18,600	18,600	18,600	18,600	18,600	18,600	18,600	18,600
Total	391,000	393,000	395,000	398,000	400,000	402,000	404,000	406,000	408,000	411,000

8.3 Net Benefits

The net benefits are calculated as the estimated benefits minus the estimated costs of the rule. After reviewing the proposed 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:

If the EPA does not finalize Subpart OOOOa (see Table 39a):

- Net benefits range from $131 – 203 million per year, using a 7% discount rate to annualize capital costs and to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.
- Net benefits range from $140 – 245 million per year, using a 3% discount rate to annualize capital costs and to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.

If the EPA finalizes Subpart OOOOa (see Table 39b):

- Net benefits range from $130 – 188 million per year, using a 7% discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.
- Net benefits range from $138 – 232 million per year, using a 3% discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.

Table 39a: Estimated Net Benefits if the EPA does not Finalize Subpart OOOOa ($ in million)

	Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Estimated Net Benefits - 7%	Flaring Requirements	$7	$1	-$11	-$5	-$3	-$3	-$3	-$4	-$3	-$3
	Well Completion	$3	$4	$4	$8	$9	$9	$10	$11	$15	$15
	Pnumatic Controllers	$53	$53	$53	$62	$62	$61	$61	$60	$68	$68
	Pneumatic Pumps	$17	$17	$17	$21	$21	$21	$21	$21	$25	$25
	Liquids Unloading	$35	$36	$36	$43	$43	$44	$44	$44	$51	$52
	Storage Tanks	$2	$2	$2	$3	$3	$3	$3	$3	$5	$5
	LDAR	$19	$19	$19	$33	$32	$32	$31	$30	$43	$43
	Administrative Burden	-$3	-$3	-$3	-$3	-$2	-$2	-$2	-$2	-$2	-$2
	Total	$131	$129	$119	$162	$164	$165	$165	$165	$202	$203
Total Estimated Net Benefits - 3%	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$12	$18	$19	$25	$27	$28	$27	$27	$28	$28
	Well Completion	$3	$3	$4	$7	$7	$8	$8	$9	$12	$13
	Pnumatic Controllers	$54	$55	$55	$64	$64	$64	$64	$64	$73	$73
	Pneumatic Pumps	$17	$17	$17	$21	$21	$21	$22	$22	$25	$25
	Liquids Unloading	$35	$36	$37	$45	$45	$46	$46	$47	$54	$55
	Storage Tanks	$2	$2	$2	$4	$4	$4	$4	$4	$5	$5
	LDAR	$19	$20	$21	$35	$35	$35	$35	$35	$48	$48
	Administrative Burden	-$3	-$3	-$3	-$3	-$3	-$3	-$3	-$3	-$2	-$2
	Total	$140	$149	$154	$199	$202	$203	$204	$205	$243	$245

Table 39b: Estimated Net Benefits if EPA Finalizes Subpart OOOOa ($ in million)

	Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Estimated Net Benefits - 7%	Flaring Requirements	$7	$1	-$11	-$5	-$3	-$3	-$3	-$4	-$3	-$3
	Well Completion	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2
	Pnumatic Controllers	$53	$53	$53	$62	$62	$61	$61	$60	$68	$68
	Pneumatic Pumps	$17	$17	$17	$20	$20	$20	$20	$20	$23	$23
	Liquids Unloading	$35	$36	$36	$43	$43	$44	$44	$44	$51	$52
	Storage Tanks	$2	$2	$2	$3	$3	$3	$3	$3	$5	$5
	LDAR	$19	$20	$20	$33	$32	$32	$31	$31	$43	$43
	Administrative Burden	-$3	-$3	-$3	-$3	-$2	-$2	-$2	-$2	-$2	-$2
	Total	$130	$126	$115	$155	$156	$156	$155	$154	$188	$188
Total Estimated Net Benefits - 3%	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$12	$18	$19	$25	$27	$28	$27	$27	$28	$28
	Well Completion	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2
	Pnumatic Controllers	$54	$55	$55	$64	$64	$64	$64	$64	$73	$73
	Pneumatic Pumps	$17	$17	$17	$20	$20	$20	$20	$20	$23	$23
	Liquids Unloading	$35	$36	$37	$45	$45	$46	$46	$47	$54	$55
	Storage Tanks	$2	$2	$2	$4	$4	$4	$4	$4	$5	$5
	LDAR	$20	$21	$21	$35	$35	$35	$35	$35	$48	$48
	Administrative Burden	-$3	-$3	-$3	-$3	-$3	-$3	-$3	-$3	-$2	-$2
	Total	$138	$147	$151	$192	$195	$195	$196	$196	$231	$232

8.4 Distributional Impacts

8.4.1 Energy Systems

The proposed 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.

If Subpart OOOOa were not finalized, we estimate the following incremental changes in production, noting the representative share of the total U.S. production in 2014 for context:

- Additional natural gas production ranging from 12 – 15 Bcf per year (0.04 – 0.06% of the total U.S. production);
- The productive use of an additional 29 – 41 Bcf of natural gas, which we estimate would be used to generate 36 – 51 million gallons of NGL per year (0.08 – 0.11% of the total U.S. production).
- A reduction in crude oil production ranging from 0.6 – 3.2 million barrels per year (0.02 – 0.10% of the total U.S. production).

Separate from the volumes listed above, we also expect 1 Bcf of gas to be combusted onsite that would have otherwise been vented. Combined, the capture or combustion of gas represents 49 – 52% of the volume vented in 2013 and the capture and/or productive use of gas represents 41 – 60% of the volume flared in 2013.

If the EPA finalizes Subpart OOOOa, we estimate slightly less additional natural gas production, ranging from 11.7 – 14.5 Bcf per year (representing 0.04 – 0.05% of the total U.S. production in 2014), and the same amount of additional natural gas liquid (NGL) production and reduced crude oil production as presented above. We also expect 0.5 Bcf of gas to be combusted onsite that would have otherwise been vented. Combined, the capture or combustion of gas represents 44 – 46% of the volume vented in 2013 and the capture and/or productive use of the gas 41 – 60% of the volume flared in 2013.

Since the relative changes in production are expected to be small, we do not expect that the proposed 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 40a: Estimated Incremental Production

Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Natural Gas (Bcf)										
Flaring Requirements	2.5	3.7	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Well Completion	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
Pnumatic Controllers	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Pneumatic Pumps	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Liquids Unloading	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.2	2.2	2.2
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LDAR	3.9	3.9	3.9	3.9	3.9	3.9	3.9	4.0	4.0	4.0
Total Natural Gas	12.2	13.5	14.8	14.9	14.9	15.0	15.0	15.1	15.2	15.2
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NGL (million gallons)										
Flaring Requirements	35.6	44.8	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
Total NGL	35.6	44.8	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Crude Oil (million bbl)										
Flaring Requirements	-0.6	-1.7	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2
Total NGL	-0.6	-1.7	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2

Table 40b: Estimated Incremental Production if EPA Finalizes Subpart OOOOa

Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Natural Gas (Bcf)										
Flaring Requirements	2.5	3.7	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Well Completion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pnumatic Controllers	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Pneumatic Pumps	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Liquids Unloading	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.2	2.2	2.2
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LDAR	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Total Natural Gas	11.7	12.9	14.2	14.3	14.3	14.3	14.4	14.4	14.4	14.5
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NGL (million gallons)										
Flaring Requirements	35.6	44.8	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
Total NGL	35.6	44.8	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Crude Oil (million bbl)										
Flaring Requirements	-0.6	-1.7	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2
Total NGL	-0.6	-1.7	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2

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.[80]

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 net present value of the royalty received one year later (using 7% and 3% discount rates) and the value of the royalty received now.

If Subpart OOOOa is not finalized, we estimate that the rule would result in additional royalties of $9 – 11 million per year (discounted at 7%) or $11 – 17 million per year (discounted at 3%). If the EPA finalizes Subpart OOOOa, we estimate additional royalties of $9 – 11 million per year (discounted at 7%) or $10 – 16 million per year (discounted at 3%). See tables that follow.

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

Table 41a: Estimated Incremental Royalty, Present Value Calculated with 7% Discount Rate ($ in millions)

Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Natural Gas										
Flaring Requirements	1.2	1.8	2.5	2.5	2.4	2.3	2.2	2.1	2.0	1.9
Royalty on Flaring	1.5	1.6	1.6	1.6	1.5	1.4	1.4	1.3	1.3	1.2
Well Completion	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Pnumatic Controllers	1.4	1.4	1.4	1.4	1.4	1.3	1.2	1.2	1.1	1.1
Pneumatic Pumps	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Liquids Unloading	0.9	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LDAR	1.9	1.9	2.0	2.0	1.9	1.8	1.7	1.6	1.6	1.5
Total Natural Gas	7.3	8.2	8.9	9.0	8.7	8.2	8.0	7.6	7.3	7.1
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NGL										
Flaring Requirements	3.8	4.9	5.7	5.7	5.5	5.2	5.0	4.7	4.5	4.4
Total NGL	3.8	4.9	5.7	5.7	5.5	5.2	5.0	4.7	4.5	4.4
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Crude Oil (Difference in Royalty Value of Deferred Production)										
Flaring Requirements	-1.3	-2.5	-4.5	-3.5	-3.2	-3.0	-2.9	-2.9	-2.7	-2.6
Total Crude	-1.3	-2.5	-4.5	-3.5	-3.2	-3.0	-2.9	-2.9	-2.7	-2.6
Total Net Royalty	**9.8**	**10.6**	**10.1**	**11.2**	**11.0**	**10.4**	**10.0**	**9.4**	**9.1**	**8.9**

Table 41b: Estimated Incremental Royalty, Present Value Calculated with 3% Discount Rate ($ in millions)

Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Natural Gas										
Flaring Requirements	1.2	1.9	2.7	2.8	2.8	2.7	2.7	2.7	2.7	2.7
Royalty on Flaring	1.5	1.6	1.7	1.8	1.8	1.7	1.7	1.7	1.7	1.7
Well Completion	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Pnumatic Controllers	1.4	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.5	1.6
Pneumatic Pumps	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Liquids Unloading	0.9	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LDAR	1.9	2.0	2.1	2.2	2.2	2.2	2.2	2.1	2.1	2.1
Total Natural Gas	7.3	8.5	9.7	10.1	10.1	10.0	10.0	9.9	9.9	10.0
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NGL										
Flaring Requirements	3.8	5.1	6.1	6.4	6.4	6.3	6.3	6.2	6.1	6.2
Total NGL	3.8	5.1	6.1	6.4	6.4	6.3	6.3	6.2	6.1	6.2
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Crude Oil (Difference in Royalty Value of Deferred Production)										
Flaring Requirements	-0.6	-0.5	-1.0	-0.1	0.2	0.2	0.2	0.1	0.2	0.2
Total Crude	-0.6	-0.5	-1.0	-0.1	0.2	0.2	0.2	0.1	0.2	0.2
Total Net Royalty	**10.5**	**13.1**	**14.8**	**16.4**	**16.6**	**16.4**	**16.4**	**16.2**	**16.2**	**16.4**

Table 42a: Estimated Incremental Royalty if EPA Finalizes Subpart OOOOa, Present Value Calculated with 7% Discount Rate ($ in millions)

Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Natural Gas (Bcf)										
Flaring Requirements	1.2	1.8	2.5	2.5	2.4	2.3	2.2	2.1	2.0	1.9
Royalty on Flaring	1.5	1.6	1.6	1.6	1.5	1.4	1.4	1.3	1.3	1.2
Well Completion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pnumatic Controllers	1.4	1.4	1.4	1.4	1.4	1.3	1.2	1.2	1.1	1.1
Pneumatic Pumps	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Liquids Unloading	0.9	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LDAR	1.8	1.9	1.9	1.9	1.9	1.8	1.7	1.6	1.5	1.5
Total Natural Gas	7.0	7.9	8.6	8.7	8.4	7.9	7.7	7.3	7.0	6.8
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NGL (million gallons)										
Flaring Requirements	3.8	4.9	5.7	5.7	5.5	5.2	5.0	4.7	4.5	4.4
Total NGL	3.8	4.9	5.7	5.7	5.5	5.2	5.0	4.7	4.5	4.4
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Crude Oil (Difference in Royalty Value of Deferred Production)										
Flaring Requirements	-1.3	-2.5	-4.5	-3.5	-3.2	-3.0	-2.9	-2.9	-2.7	-2.6
Total Crude	-1.3	-2.5	-4.5	-3.5	-3.2	-3.0	-2.9	-2.9	-2.7	-2.6
Total Net Royalty	**9.6**	**10.3**	**9.9**	**10.9**	**10.6**	**10.1**	**9.7**	**9.2**	**8.8**	**8.6**

Table 42b: Estimated Incremental Royalty if EPA Finalizes Subpart OOOOa, Present Value Calculated with 3% Discount Rate ($ in millions)

Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Natural Gas (Bcf)										
Flaring Requirements	1.2	1.9	2.7	2.8	2.8	2.7	2.7	2.7	2.7	2.7
Royalty on Flaring	1.5	1.6	1.7	1.8	1.8	1.7	1.7	1.7	1.7	1.7
Well Completion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pnumatic Controllers	1.4	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.5	1.6
Pneumatic Pumps	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Liquids Unloading	0.9	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LDAR	1.8	2.0	2.1	2.2	2.2	2.1	2.1	2.1	2.1	2.1
Total Natural Gas	7.0	8.2	9.3	9.7	9.7	9.6	9.6	9.5	9.5	9.6
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NGL (million gallons)										
Flaring Requirements	3.8	5.1	6.1	6.4	6.4	6.3	6.3	6.2	6.1	6.2
Total NGL	3.8	5.1	6.1	6.4	6.4	6.3	6.3	6.2	6.1	6.2
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Crude Oil (Difference in Royalty Value of Deferred Production)										
Flaring Requirements	-0.6	-0.5	-1.0	-0.1	0.2	0.2	0.2	0.1	0.2	0.2
Total Crude	-0.6	-0.5	-1.0	-0.1	0.2	0.2	0.2	0.1	0.2	0.2
Total Net Royalty	**10.2**	**12.8**	**14.5**	**16.0**	**16.3**	**16.0**	**16.0**	**15.8**	**15.8**	**16.0**

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 proposed 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 proposed rule would not alter the investment or employment decisions of firms or significantly adversely impact employment. The proposed 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 proposed 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 of well completions occurring on Indian lands, the share of oil wells on Indian lands, and the share of gas wells on Indian Lands. In FY 2014, AFMSS data indicate that about 18.87% of well completions occurred on Indian leases and that oil and gas wells on Indian leases accounted for 15.66% and 10.99%, 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:

If the EPA does not finalize Subpart OOOOa:

- Using a 7% discount rate to annualize costs, we estimate that the proposed rule would pose costs ranging from \$20 – \$25 million per year.
- Using a 3% discount rate to annualize costs, we estimate that the proposed rule would pose costs ranging from \$18 – \$21 million per year.

If the EPA finalizes Subpart OOOOa:

- Using a 7% discount rate to annualize costs, we estimate that the proposed rule would pose costs ranging from \$17 – \$23 million per year.
- Using a 3% discount rate to annualize costs, we estimate that the proposed rule would pose costs ranging from \$16 – \$18 million per year.

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:

If the EPA does not finalize Subpart OOOOa:

- Benefits range from $35 – 46 million per year, using a 7% discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.
- Benefits range from $35 – 50 million per year, using a 3% discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.

If the EPA finalizes Subpart OOOOa:

- Benefits range from $31 – 39 million per year, using a 7% discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.
- Benefits range from $31 – 43 million per year, using a 3% discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.

We estimate that the proposed rule would reduce methane emissions by 22,000 – 23,000 tons per year if Subpart OOOOa is not finalized, or 20,000 tons per year if the EPA finalizes Subpart OOOOa. We monetized these reductions and included them in the monetized benefits.

We estimate that the proposed rule would reduce VOC emissions by 50,000 – 53,000 tons per year if Subpart OOOOa is not finalized, or 48,000 – 51,000 tons per year if the EPA finalizes Subpart OOOOa. 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:

If the EPA does not finalize Subpart OOOOa:

- Net benefits range from $13 – 24 million per year, using a 7% discount rate to annualize capital costs and to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.
- Net benefits range from $17 – 31 million per year, using a 3% discount rate to annualize capital costs and to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.

If the EPA finalizes Subpart OOOOa:

- Net benefits range from $11 – 20 million per year, using a 7% discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3% discount rate.
- Net benefits range from $15 – 27 million per year, using a 3% discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with 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:

If the EPA does not finalize Subpart OOOOa:

- Additional natural gas production ranging from 1.6 – 2.1 Bcf per year;
- The productive use of an additional 4.5 – 6.4 Bcf of natural gas, which we estimate would be used to generate 5.6 – 8.0 million gallons of NGL per year; and
- A reduction in crude oil production ranging from 0.1 – 0.5 million barrels per year.

If the EPA finalizes Subpart OOOOa:

- Additional natural gas production ranging from 1.1 – 1.5 Bcf per year;
- The productive use of an additional 4.5 – 6.4 Bcf of natural gas, which we estimate would be used to generate 5.6 – 8.0 million gallons of NGL per year; and
- A reduction in crude oil production ranging from 0.1 – 0.5 million barrels per year.

Incremental royalty associated with operations on Indian leases.
If the EPA does not finalize Subpart OOOOa, we estimate that the rule would result in additional royalties of $1.4 – 1.9 million per year (discounted at 7%) or $1.4 – 2.1 million per year (discounted at 3%). If the EPA finalizes Subpart OOOOa, then we estimate additional royalties of $1.1 – 1.6 million per year (discounted at 7%) or $1.1 – 1.8 million per year (discounted at 3%).

8.4.5 Additional Considerations

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

Potential impact on new drilling on Federal lands. The proposed rule is expected to increase the costs of developing new oil and gas resources on Federal and Indian Lands. If the EPA finalizes Subpart OOOOa, then as a practical matter, this rule would impact new conventional well completions, 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 most, if not all new conventional well completions, we estimate that the compliance costs less cost savings are small. For liquids unloading, we estimate positive returns to the industry, meaning the cost savings exceed the compliance costs. In both areas, 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 proposed 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 proposed rule are significant for new leases. If the EPA finalizes Subpart OOOOa, then as a practical matter, this rule would impact new conventional well completions, 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. We estimate that the compliance costs less cost savings are small for new conventional well completions. For liquids unloading, we estimate positive returns to the industry, meaning the cost savings exceed the compliance costs. In both areas, 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 in excess of the proposed limits. 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 proposed 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 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. Initial 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)).

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 500 employees (or revenues of less than $7 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[81].

Based on the analysis below, the BLM believes that the proposed 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. As described in more detail below, 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 simply 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 for this proposed 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 flaring requirements. In addition, the BLM is taking comment on a wide range of alternatives to some of the proposed requirements, and some of these alternatives could affect the costs of the rule if the BLM were to adopt them in the final rule. This further enhances the uncertainty regarding the cost projections for the rule. Second, there is no question that if the costs of the rule for affected entities were economically significant, the BLM would be required to prepare an IRFA for the rule, given that the rule will affect a substantial number of small entities.

Thus, given the unique circumstances present in this rulemaking, the BLM believes it is prudent, and potentially helpful to small entities, to prepare an IRFA at this stage in the rulemaking. We do not

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

believe this decision should be viewed as a precedent for preparing an IRFA in other rulemakings, and we may choose not to prepare a final regulatory flexibility analysis for the final rule, if our best estimate at that time is that the final rule would not have a significant economic effect on a substantial number of small entities.

Under Section 603 of the RFA, an IRFA must contain:

- A description of the reasons why action by the agency is being considered;
- A succinct statement of the objectives of, and legal basis for, the proposed rule;
- A description of and, where feasible, an estimate of the number of small entities to which the proposed rule will apply;
- A description of the projected reporting, recordkeeping and other compliance requirements of the proposed 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 proposed rule; and,
- A description of any significant alternatives to the proposed rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed 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. The proposed 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, this proposed 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 Proposed Rule

This proposed 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[82].

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 proposal 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

[82] 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.

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 proposed 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 Small Business Act.[83] 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 500 employees. For firms drilling oil and gas wells, the threshold is also 500 employees. For firms involved in support activities, the standard is annual receipts of less than $38.5 million.

Of the 6,628 domestic firms involved in oil and gas extraction, 99 percent or 6,530 had fewer than 500 employees. There are another 2,041 firms involved in drilling. Of those firms, 98 percent of those firms had fewer than 500 employees.

To estimate a percentage for firms involved in oil and gas support activities we reference Tables 43a-b, which provide the NAICS information for firms involved in oil and gas support activities based on the size of receipts. Unfortunately the most recent data available from the U.S. Census Bureau for establishment/firm size based on receipts is for 2007. Of the 5,880 firms in oil and gas support activities in 2007, 97 percent had annual receipts of less than $35 million.[84]

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 would be potentially affected by the proposed rule.

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

[84] 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.

Table 43a: Oil and Gas Extraction, Drilling and Support Activities by Employment Size - 2011

NAICS Code	Description	Data Type[85]	Employment Size		
			Total	<500	500+
21111	Oil and Gas Extraction	Firms	6,628	6,530	98
21111	Oil and Gas Extraction	Employment	118,959	47,374	71,585
21111	Oil and Gas Extraction	Annual Payroll ($1,000)	14,484,598	4,630,887	9,853,711
213111	Drilling Oil and Gas Wells	Firms	2,041	1,993	48
213111	Drilling Oil and Gas Wells	Employment	94,506	36,663	57,843
213111	Drilling Oil and Gas Wells	Annual Payroll ($1,000)	7,553,892	2,659,010	4,894,882
213112	Support Activities	Firms	8,119	8,012	107
213112	Support Activities	Employment	219,827	100,372	119,455
213112	Support Activities	Annual Payroll ($1,000)	17,768,348	6,690,907	11,077,441

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 2011 – (http://www.census.gov/econ/susb/).*

Table 43b: 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).

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

[85] Firms are business organizations consisting of one or more domestic establishments in the same state and industry that were specified under common ownership or control. An establishment is a single physical location where business is conducted or where services or industrial operations are performed.

considered when estimating costs to the industry. Those per-entity compliance costs are in Table 44. For example, if the EPA finalizes Subpart OOOOa and using a 7% discount rate to estimate total costs, we estimate per-entity compliance costs ranging from about $27,000 to $36,000 per-entity per year.

Recognizing that the SBA definition for a small business for oil and gas producers (21111) is one with fewer than 500 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-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[86] 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 average per-entity cost increase figures of $31,345 and $37,535 which represent the middle of the range of potential per-entity costs assuming the EPA finalizes and does not finalize Subpart OOOOa, respectively. Both figures include compliance costs and cost savings, calculated using a 7% discount rate.

For these 26 small companies, a per-entity compliance cost increase of $31,345 would result in an average reduction in profit margin of 0.087 percentage points (based on the 2014 company data) and a per entity cost increase of 37,535 would result in an average reduction in profit margin of 0.104 percentage points (also 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.

Table 44: Per-Entity Costs

Scenario	Discount Rate	Years 2017 – 2026	
		Low	High
EPA finalizes Subpart OOOOa	7%	$27,054	$35,635
	3%	$11,170	$22,932
EPA does not finalize Subpart OOOOa	7%	$33,521	$41,550
	3%	$16,908	$29,099

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

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 500 employees. For firms drilling oil and gas wells the threshold is also 500 employees. For firms involved in support activities the standard is annual receipts of less than $38.5 million.
Of the 6,628 domestic firms involved in oil and gas extraction, 99 percent, or 6,530, had fewer than 500 employees. There are another 2,041 firms involved in drilling. Of those firms, 98 percent of the firms had fewer than 500 employees.

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 proposed rule, although not significantly.

The Regulatory Impact Analysis for the proposed rule identifies annual costs of the rule as being between $114 and $159 Million depending on the discount rate used whether EPA finalizes NSPS Subpart OOOOa. Greater details of the regulatory provisions are provided in the proposed rule preamble. This section primarily discusses the paperwork burden on operators.

The Paperwork Reduction section of the proposed rule identifies 40,430 net hours of paperwork, reporting, and recordkeeping required annually by the regulations. Using the Bureau of Labor Statistics weighted hourly rate of $63.30 per hour, the estimated hour burden to industry for this rulemaking is about $2.56 million.

The estimated administrative burden to industry is as follows:

Type of Response	Number of Responses	Hours per Response	Total Hours	Total Wage Cost (at $63.30/ hour)
Plan to Minimize Waste of Natural Gas 43 CFR 3162.3-1 Form 3160-3	2,000	2	4,000	$253,200
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	8	400	$25,320
Request for Approval of Alternative Volume Limits 43 CFR 3179.7(b) Form 3160-5	185	16	2,960	$187,368

Type of Response	Number of Responses	Hours per Response	Total Hours	Total Wage Cost (at $63.30/ hour)
Certification in Support of Exemption from Volume Limits 43 CFR 3179.7(d) Form 3160-5	15	16	240	$15,192
Well Completion and Related Operations 43 CFR 3179.102(b) Form 3160-5	5	2	10	$633
Initial Production Testing Request for Extension 43 CFR 3179.103 Form 3160-5	5	2	10	$633
Subsequent Well Tests Request for Extension 43 CFR 3179.104 Form 3160-5	5	2	10	$633
Reporting of Emergency Venting and Flaring Beyond Specified Timeframes 43 CFR 3179.105 Form 3160-5	25	2	50	$3,165
Pneumatic Controller Report 43 CFR 3179.201(b) and (c) Form 3160-5	200	2	400	$25,320
Pneumatic Pump Report 43 CFR 3179.202 Form 3160-5	500	4	2,000	$126,600
Crude Oil and Condensate Storage Vessel Report 43 CFR 3179.203(c) Form 3160-5	100	8	800	$50,640
Downhole Well Maintenance and Liquids Unloading — Documentation and Reporting 43 CFR 3179.204(a) and (d) Form 3160-5	5,000	1	5,000	$316,500
Downhole Well Maintenance and Liquids Unloading Documentation and Reporting 43 CFR 3179.204(c)	5,000	0.25	1,250	$79,125
Downhole Well Maintenance and Liquids Unloading — Notification of Excessive Duration or Volume	120	1	120	$7,596

Type of Response	Number of Responses	Hours per Response	Total Hours	Total Wage Cost (at $63.30/ hour)
43 CFR 3179.204(e) Form 3160-5				
Leak Detection — Compliance with EPA Regulations 43 CFR 3179.301(e) Form 3160-5	500	8	4,000	$253,200
Leak Detection — Request to Use and Alternative Device, Program, or Method 43 CFR 3179.303(b) Form 3160-5	200	40	8,000	$506,400
Leak Detection — Notification of Delay in Repairing Leaks 43 CFR 3179.304(a) Form 3160-5	100	1	100	$6,330
Leak Detection — Inspection Recordkeeping 43 CFR 3179.305	52,000	0.25	13,000	$822,900
Gas Flaring (43 CFR 3162.7-1(d), 3164.1, and Notice to Lessees and Operators 4A)	(120)	(16)	(1,920)	($121,536)
Total			**40,430**	**$2,559,219**

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 recently proposed regulations to 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).[87] This EPA proposal would have the effect of further reducing gas losses through venting and leaks. The EPA currently requires new hydraulically fractured and refractured gas wells to capture or flare gas that otherwise would be released during drilling and completion operations, and EPA has announced that it plans to extend these requirements to new hydraulically fractured and refractured oil wells.

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 proposed 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 proposed 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 sections below provide a description of alternatives and flexibilities that can minimize significant economic impacts on the regulated sector, which is includes a large number of small entities.

[87] EPA, Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, Proposed Rule (Aug. 27, 2015), 80 FR 51,991.

9.7.1 Developmental Oil Wells

The draft rule would require operators submitting certain Applications for Permit to Drill (APDs) to provide information in addition to that required under existing regulation. This additional information would ensure the operator is actively seeking opportunity to market natural gas that is expected to be produced in association with oil production before the well is drilled so that less gas would be flared in reaction to a newly drilled well with associated gas production.

The additional information requirement would be limited to only those APDs associated with developmental oil wells. Operators would have economic incentives to market the natural gas that would be produced from gas wells. An operator proposing to drill a non-developmental well would not have sufficient information to accurately project that well's ability to produce oil and gas prior to drilling it. Therefore, the collection of additional information when filing an APD is limited to APDs for developmental oil wells.

9.7.2 Flaring Limitation

The proposed rule would establish a maximum limit on the average volume of associated gas that could be flared per day from each oil well, as determined from monthly production volumes. This is expanded in the three sections below.

9.7.2.1 Phasing in Flaring Limits

Limits on the volume of gas that could be flared would be phased in over a two year period, thereby allowing operators time in which to evaluate their operations to determine the optimal means of gaining compliance. The initial threshold, beginning on the effective date of the rule, would limit flaring to a maximum of 240 Mcf gas per day per well (based on monthly production average). Beginning 1 year after the effective date of the rule, the maximum flaring limit would reduce to 120 Mcf gas per day. Beginning 2 years after the effective date of the rule, the maximum flaring limit would reduce to 60 Mcf gas per day, and would remain at that level thereafter.

9.7.2.2 Alternate Flaring Limits (Volume)

The proposed rule provides for the use of alternate flaring limits in certain instances. When the operator of a lease that predates the draft rule demonstrates to the BLM with engineering and economic data that the lease could not be economically produced under the standard flaring limits, the BLM may approve flaring at higher volumes. The operator must make a showing that limiting a well's production to the flaring limit would cause undue economic hardship or would cause premature abandonment of recoverable oil reserves.

9.7.2.3 Transitioning from Existing Flaring Approvals to New Proposals

Any authorization to flare gas that is in effect on the effective date of this draft rule, will remain in effect for 90 days. This provides an opportunity for operators of wells flaring above the threshold established in the draft rule to adjust their production operations to comply with the flaring limits established by this draft rule, or to demonstrate to the BLM that an alternate flaring limit is appropriate.

9.7.3 Requirements for Pneumatic Controllers

The proposed regulations would require that pneumatic controllers be replaced with zero emissions controllers. To provide flexibility to marginal well operators, the BLM added various provisions to the proposed rule to reduce costs associated with compliance while still providing waste prevention and emissions reductions. The operator would not have to replace existing pneumatic controllers(s) (1) if controller is required for function need and there is no existing flare device to feasibility route the vent gas; or (2) the operator can demonstrate the cost to replace controller(s) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. Further, if the life expectancy of the lease is 3 years or less, pump(s) replacement would not be required.

9.7.4 Requirements for Pneumatic Chemical Injection or Pneumatic Diaphragm Pumps

The proposed regulations would require that pneumatic chemical injection and diaphragm pumps be replaced with zero emissions pumps. To provide flexibility to marginal well operators, the BLM added various provisions to the proposed rule to reduce costs associated with compliance while still providing waste prevention and emissions reductions. The operator would not have to replace existing pneumatic pump(s) (1) if pump is required for function need and there is no existing flare device to feasibility route the vent gas; or (2) the operator can demonstrate the cost to replace pump(s) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. Further, if the life expectancy of the lease is 3 years or less, pump(s) replacement would not be required.

9.7.5 Storage Vessels

The proposed regulations would require the operator to route all tank vapor gas from a storage vessel that has emissions greater than 6 tons per year to a combustion device, continuous flare, or to a sales line. To provide flexibility to these marginal well operators, the BLM added a provision to the proposed rule to 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.

9.7.6 Leak Detection and Repair (LDAR) Programs

The proposed regulations would require the operator to inspect for leaks on its operations at varying frequencies based on the number of leaks found during these inspections. To provide flexibility to marginal well operators, the BLM added several provisions to the proposed rule to reduce costs associated with compliance. The operator may conduct a comprehensive inspection program that uses instrument-based monitoring devices or alternatively rely on continuous emissions monitoring that matches the operator's abilities and programs in place, if so approved by the BLM. Additionally, for operators with fewer than 500 wells within a BLM field office, the BLM drafted a provision that would allow the use of less expensive leak detection tools. The intent of this provision is to limit the requirement to use more costly instrument-based methods to larger operators with more wells over which to spread the costs of the required inspections.

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 proposed 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 proposed 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 for this proposed 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 flaring requirements. In addition, the BLM is taking comment on a wide range of alternatives to some of the proposed requirements, and some of these alternatives could affect the costs of the rule if the BLM were to adopt them in the final rule. This further enhances the uncertainty regarding the cost projections for the rule. Second, there is no question that if the costs of the rule for affected entities were economically significant, the BLM would be required to prepare an IRFA for the rule, given that the rule will affect a substantial number of small entities.

Thus, given the unique circumstances present in this rulemaking, the BLM believes it is prudent, and potentially helpful to small entities, to prepare an IRFA at this stage in the rulemaking. We do not believe this decision should be viewed as a precedent for preparing an IRFA in other rulemakings, and we may choose not to prepare a final regulatory flexibility analysis for the final rule, if our best estimate at that time is that the final rule would not have a significant economic effect on a substantial number of small entities.

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 proposed 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 proposed 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 proposed rulemaking, and notices of proposed 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 the proposed rule would 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, 2015 GHG Inventory

Sector	Gas Category	Emissions Source	Source Cat. No.	Inventory Calculated Potential	Net Methane (tonnes)	Net Methane (Bcf)
Gas	Normal Fugitives	Gas Wells				
Gas	Normal Fugitives	Associated Gas Wells	9	-	-	
Gas	Normal Fugitives	Non-associated Gas Wells (less fractured wells)	9	18,164	11,133	0.578
Gas	Normal Fugitives	Gas Wells with Hydraulic Fracturing	9	34,481	21,134	1.097
Gas	Normal Fugitives	Field Separation Equipment			-	0.000
Gas	Normal Fugitives	Heaters	9	32,137	19,698	1.023
Gas	Normal Fugitives	Separators	9	103,226	63,271	3.285
Gas	Normal Fugitives	Dehydrators	9	31,366	19,225	0.998
Gas	Normal Fugitives	Meters/Piping	9	105,611	64,733	3.361
Gas	Normal Fugitives	Gathering Compressors			-	0.000
Gas	Normal Fugitives	Small Reciprocating Comp.	5	69,846	42,811	2.223
Gas	Normal Fugitives	Large Reciprocating Comp.	5	14,425	8,841	0.459
Gas	Normal Fugitives	Large Reciprocating Stations	9	978	599	0.031
Gas	Normal Fugitives	Pipeline Leaks	9	169,698	169,698	8.811
Gas	Vented and Combusted	Drilling, Well Completion, and Well Workover			-	0.000
Gas	Vented and Combusted	Gas Well Completions without Hydraulic Fracturing	1	11	7	0.000
Gas	Vented and Combusted	Gas Well Workovers without Hydraulic Fracturing	1	450	276	0.014
Gas	Vented and Combusted	Hydraulic Fracturing Completions and Workovers that vent	1	61,737	61,737	3.205
Gas	Vented and Combusted	Flared Hydraulic Fracturing Completions and Workovers	1	4,100	4,100	0.213
Gas	Vented and Combusted	Hydraulic Fracturing Completions and Workovers with RECs	1	10,229	10,229	0.531
Gas	Vented and Combusted	Hydraulic Fracturing Completions and Workovers with RECs that flare	1	10,326	10,326	0.536
Gas	Vented and Combusted	Well Drilling	9	972	596	0.031
Gas	Vented and Combusted	Produced Water from Coal Bed Methane			-	0.000
Gas	Vented and Combusted	Powder River	9	12,695	7,781	0.404
Gas	Vented and Combusted	Black Warrior	9	47,139	28,893	1.500
Gas	Vented and Combusted	Normal Operations			-	0.000
Gas	Vented and Combusted	Pneumatic Device Vents	2	1,159,306	539,120	27.991
Gas	Vented and Combusted	Chemical Injection Pumps	3	64,518	61,258	3.180
Gas	Vented and Combusted	Kimray Pumps	3	370,599	227,152	11.794
Gas	Vented and Combusted	Dehydrator Vents	9	115,557	78,476	4.074

Sector	Gas Category	Emissions Source	Source Cat. No.	Inventory Calculated Potential	Net Methane (tonnes)	Net Methane (Bcf)
Gas	Vented and Combusted	Condensate Tank Vents			-	0.000
Gas	Vented and Combusted	Condensate Tanks s	7	312,691	228,981	11.889
Gas	Vented and Combusted	Compressor Exhaust Vented			-	0.000
Gas	Vented and Combusted	Gas Engines	4	249,362	108,884	5.653
Gas	Vented and Combusted	Well Clean Ups			-	0.000
Gas	Vented and Combusted	Well Clean Ups (LP Gas Wells) - Vent Using Plungers	6	111,634	111,634	5.796
Gas	Vented and Combusted	Well Clean Ups (LP Gas Wells) - Vent Without Using Plungers	6	147,056	147,056	7.635
Gas	Vented and Combusted	Blowdowns			-	0.000
Gas	Vented and Combusted	Vessel BD	9	690	423	0.022
Gas	Vented and Combusted	Pipeline BD	9	2,703	1,657	0.086
Gas	Vented and Combusted	Compressor BD	9	2,697	1,653	0.086
Gas	Vented and Combusted	Compressor Starts	9	6,034	5,522	0.287
Gas	Vented and Combusted	Upsets			-	0.000
Gas	Vented and Combusted	Pressure Relief Valves	9	679	416	0.022
Gas	Vented and Combusted	Mishaps	9	1,463	897	0.047
Oil	Vented	Oil Tanks	7	317,468	194,586	10.103
Oil	Vented	Pneumatic Devices, all	2	474,305	220,184	11.432
Oil	Vented	Chemical Injection Pumps	3	54,089	33,153	1.721
Oil	Vented	Vessel Blowdowns	9	310	190	0.010
Oil	Vented	Compressor Blowdowns	9	205	125	0.007
Oil	Vented	Compressor Starts	9	458	281	0.015
Oil	Vented	Stripper wells	9	14,215	8,713	0.452
Oil	Vented	Well Completion Venting	1	222	136	0.007
Oil	Vented	Well Workovers	1	120	73	0.004
Oil	Vented	Pipeline Pigging	9	-	-	0.000
Oil	Fugitive	Oil Wellheads (heavy crude)	9	34	21	0.001
Oil	Fugitive	Oil Wellheads (light crude)	9	59,533	36,490	1.895
Oil	Fugitive	Separators (heavy crude)	9	13	8	0.000
Oil	Fugitive	Separators (light crude)	9	10,744	6,585	0.342
Oil	Fugitive	Heater/Treaters (light crude)	9	11,352	6,958	0.361
Oil	Fugitive	Headers (heavy crude)	9	12	7	0.000
Oil	Fugitive	Headers (light crude)	9	5,323	3,263	0.169
Oil	Fugitive	Floating Roof Tanks	9	159	97	0.005
Oil	Fugitive	Compressors	5	1,979	1,213	0.063

Sector	Gas Category	Emissions Source	Source Cat. No.	Inventory Calculated Potential	Net Methane (tonnes)	Net Methane (Bcf)
Oil	Fugitive	Large Compressors	5	-	-	0.000
Oil	Fugitive	Sales Areas	9	1,767	1,083	0.056
Oil	Fugitive	Pipelines	9	-	-	0.000
Oil	Fugitive	Well Drilling	9	-	-	0.000
Oil	Fugitive	Battery Pumps	9	437	268	0.014
Oil	Combusted	Gas Engines	4	81,987	50,253	2.609
Oil	Combusted	Heaters	9	27,254	16,705	0.867
Oil	Combusted	Well Drilling	9	838	514	0.027
Oil	Combusted	Flares	9	140	86	0.004
Oil	Upset	Pressure Relief Valves	9	152	93	0.005
Oil	Upset	Well Blowouts Onshore	9	2,848	1,746	0.091

Appendix A-2: U.S. Dry Natural Gas and Crude Oil Production and Natural Gas and Crude Oil Production on Federal and Indian Lands, in 2013, by State Jurisdiction and NEMS Region

	U.S.	Federal/ Indian Lands		U.S.	Federal/ Indian Lands	
Jurisdiction	Gas Production (MMcf)	Gas Production (MMcf)	% of U.S. Gas Production	Crude Oil Production (bbl)	Crude Oil Production (bbl)	% of U.S. Oil Production
Alabama	117,083	499	0.43%	10,391,000	23,104	0.22%
Alaska	259,422	12,923	4.98%	187,954,000	519,987	0.28%
Arizona	72	0	0.00%	60,000	62,951	104.92%
Arkansas	1,139,168	10,459	0.92%	6,640,000	0	0.00%
California	205,088	6,498	3.17%	198,754,000	15,262,435	7.68%
Colorado	1,517,347	467,571	30.82%	65,331,000	3,042,989	4.66%
Florida	292	0	0.00%	2,174,000	0	0.00%
Illinois	2,887	0	0.00%	9,488,000	26,730	0.28%
Indiana	7,938	0	0.00%	2,399,000	2,204	0.09%
Kansas	277,022	4,422	1.60%	46,842,000	234,081	0.50%
Kentucky	88,221	84	0.09%	2,893,000	11,865	0.41%
Louisiana	2,292,605	15,780	0.69%	71,814,000	235,451	0.33%
Maryland	32	0	0.00%	0	0	NA
Michigan	121,277	1,476	1.22%	7,701,000	267	0.00%
Mississippi	58,806	509	0.87%	24,345,000	399,950	1.64%
Missouri	0	0	NA	199,000	0	0.00%
Montana	61,597	13,688	22.22%	29,288,000	2,481,291	8.47%
Nebraska	1,032	2	0.17%	2,778,000	26,705	0.96%
Nevada	3	0	0.00%	334,000	335,340	100.40%
New Mexico	1,108,636	701,906	63.31%	100,855,000	48,288,342	47.88%
New York	23,458	11	0.05%	313,000	0	0.00%
North Dakota	198,871	19,989	10.05%	313,905,000	45,915,082	14.63%
Ohio	184,065	397	0.22%	11,611,000	16,229	0.14%
Oklahoma	2,001,404	33,765	1.69%	114,182,000	1,157,793	1.01%
Oregon	770	0	0.00%	0	0	NA
Pennsylvania	3,232,290	23	0.00%	5,246,000	1,704	0.03%
South Dakota	16,180	143	0.88%	1,843,000	181,796	9.86%
Tennessee	4,912	0	0.00%	276,000	0	0.00%
Texas	6,841,477	46,001	0.67%	923,682,000	181,263	0.02%
Utah	455,454	289,950	63.66%	35,119,000	19,321,292	55.02%
Virginia	139,382	163	0.12%	8,000	7	0.09%
West Virginia	703,685	159	0.02%	6,937,000	0	0.00%
Wyoming	1,783,798	1,274,878	71.47%	63,374,000	29,093,295	45.91%
Total	**22,844,274**	**2,901,295**	**12.70%**	2,246,736,000	166,822,152	**7.43%**
	U.S.	**Federal/ Indian Lands**		**U.S.**	**Federal/ Indian Lands**	
NEMS Region	**Gas Production (MMcf)**	**Gas Production (MMcf)**	**% of U.S. Gas Production**	**Oil Production (MMbbl)**	**Oil Production (MMbbl)**	**% of U.S. Oil Production**
North East	4,508,147	2,312	0.05%	46,872,000	59,007	0.13%
Midcontinent	3,418,626	48,648	1.42%	170,641,000	1,418,579	0.83%
Rocky Mountain	5,008,922	2,683,896	53.58%	524,382,250	107,677,287	20.53%
South West	6,974,513	130,230	1.87%	1,009,408,750	41,226,354	4.08%
West Coast	465,280	19,421	4.17%	386,708,000	15,782,421	4.08%
Gulf Coast	2,468,786	16,789	0.68%	108,724,000	658,505	0.61%
Total	**22,844,274**	**2,901,295**	**12.70%**	**2,246,736,000**	**166,822,152**	**7.43%**

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, by Region

Emission Classification	Emission Source Category	Unit of Measurement	Emission Factor (Natural Gas)					
			North East	Mid Continent	Rocky Mountain	South West	West Coast	Gulf Coast
Normal Fugitives	Gas Wells							
	Associated Gas Wells	NA						
	Non-associated Gas Wells (less fractured wells)	scfd/well	7.55	7.44	35.33	37.23	42.49	7.96
	Gas Wells with Hydraulic Fracturing	scfd/well	7.59	8.35	40.64	37.23	42.49	7.96
	Field Separation Equipment							
	Heaters	scfd/heater	15.19	14.87	57.09	58.97	67.29	64.61
	Separators	scfd/separator	0.96	0.94	120.69	124.66	142.27	136.60
	Dehydrators	scfd/dehydrator	23.24	95.35	90.14	93.10	106.25	102.02
	Meters/Piping	scfd/meter	9.63	9.43	52.33	54.05	61.68	59.23
	Gathering Compressors							
	Small Reciprocating Comp.	scfd/compressor	286.09	280.16	264.84	273.55	312.19	299.75
	Large Reciprocating Comp.	scfd/compressor	16,246.46	15,909.56	15,039.44	15,534.58	17,728.38	17,022.46
	Large Reciprocating Stations	scfd/station	8,811.42	8,628.70	8,156.78	8,425.33	9,615.15	9,232.29
	Pipeline Leaks	scfd/mile	56.79	55.61	52.57	54.30	61.97	59.50
Vented and Combusted	Drilling, Well Completion, and Well Workover							
	Gas Well Completions without Hydraulic Fracturing	scf/completion	778.57	766.66	710.51	748.89	854.65	820.51
	Gas Well Workovers without Hydraulic Fracturing	scf/workover	2,606.55	2,566.70	2,378.69	2,507.19	2,861.26	2,746.96
	Hydraulic Fracturing Completions and Workovers that vent	Mg/event	36.80	36.80	36.80	36.80	36.80	36.80
	Flared Hydraulic Fracturing Completions and Workovers	Mg/event	4.90	4.90	4.90	4.90	4.90	4.90
	Hydraulic Fracturing Completions and Workovers with RECs	Mg/event	3.20	3.20	3.20	3.20	3.20	3.20
	Hydraulic Fracturing Completions and Workovers with RECs that flare	Mg/event	4.90	4.90	4.90	4.90	4.90	4.90
	Well Drilling	scf/well	2,717.18	2,660.84	2,515.31	2,598.12	2,965.03	2,846.97
	Produced Water from Coal Bed Methane							
	Powder River	kt/gal			0.00			
	Black Warrior	kt/well						0.00

	Normal Operations							
	Pneumatic Device Vents	scfd/controller	368.63	360.99	341.24	352.48	402.26	386.24
	Chemical Injection Pumps	scfd/pump	264.99	259.49	245.30	253.38	289.16	277.64
	Kimray Pumps	scf/MMscf	1,059.95	1,037.97	981.20	1,013.50	1,156.63	1,110.57
	Dehydrator Vents	scf/MMscf	294.48	288.37	272.60	281.57	321.34	308.54
	Condensate Tank Vents							
	Condensate Tanks without Control Devices	scf/bbl	21.87	302.75	21.87	302.75	21.87	21.87
	Condensate Tanks with Control Devices	scf/bbl	4.37	60.55	4.37	60.55	4.37	4.37
	Compressor Exhaust Vented							
	Gas Engines	scf/HPhr	0.26	0.25	0.24	0.25	0.28	0.27
	Well Clean Ups							
	Well Clean Ups (LP Gas Wells) - Vent Using Plungers	scfy/venting well	264,906.76	1,137,794.18	120,264.50	2,855.62	317,292.27	61,771.81
	Well Clean Ups (LP Gas Wells) - Vent Without Using Plungers	scfy/venting well	139,914.11	189,802.21	2,010,470.06	77,889.92	279,351.48	265,179.21
	Blowdowns							
	Vessel BD	scfy/vessel	83.34	81.61	77.15	79.69	90.94	87.32
	Pipeline BD	scfy/mile	330.16	323.32	305.64	315.70	360.28	345.93
	Compressor BD	scfy/compressor	4,032.50	3,948.88	3,732.91	3,855.80	4,400.32	4,225.11
	Compressor Starts	scfy/compressor	9,021.30	8,834.22	8,351.07	8,626.01	9,844.18	9,452.19
	Upsets							
	Pressure Relief Valves	scfy/PRV	36.33	35.58	33.63	34.74	39.64	38.06
	Mishaps	scf/mile	714.82	700.00	661.72	683.50	780.03	748.97

Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013, Annex 3.

Appendix A-4: Natural Gas (Whole Gas) Emission Factors for the Natural Gas Production Stage, by Region

Emission Classification	Emission Source Category	Unit of Measurement	Emission Factor (Natural Gas)					
			North East	Mid Continent	Rocky Mountain	South West	West Coast	Gulf Coast
Normal Fugitives	Gas Wells							
	Associated Gas Wells	NA						
	Non-associated Gas Wells (less fractured wells)	scfd/well	8.97	9.02	45.35	46.25	46.24	9.02
	Gas Wells with Hydraulic Fracturing	scfd/well	9.01	10.12	52.17	46.25	46.24	9.02
	Field Separation Equipment							
	Heaters	scfd/heater	18.04	18.02	73.29	73.25	73.22	73.25
	Separators	scfd/separator	1.14	1.14	154.93	154.86	154.81	154.88
	Dehydrators	scfd/dehydrator	27.60	115.58	115.71	115.65	115.61	115.67
	Meters/Piping	scfd/meter	11.44	11.43	67.18	67.14	67.12	67.15
	Gathering Compressors							
	Small Reciprocating Comp.	scfd/compressor	339.77	339.59	339.97	339.81	339.71	339.85
	Large Reciprocating Comp.	scfd/compressor	19,295.08	19,284.32	19,306.08	19,297.61	19,290.95	19,299.84
	Large Reciprocating Stations	scfd/station	10,464.87	10,459.03	10,470.83	10,466.25	10,462.62	10,467.45
	Pipeline Leaks	scfd/mile	67.45	67.41	67.48	67.45	67.43	67.46
Vented and Combusted	Drilling, Well Completion, and Well Workover							
	Gas Well Completions without Hydraulic Fracturing	scf/completion	924.67	929.28	912.08	930.30	929.98	930.28
	Gas Well Workovers without Hydraulic Fracturing	scf/workover	3,095.67	3,111.15	3,053.52	3,114.52	3,113.45	3,114.47
	Hydraulic Fracturing Completions and Workovers that vent	Mg/event	43.71	44.61	47.24	45.71	40.04	41.72
	Flared Hydraulic Fracturing Completions and Workovers	Mg/event	5.82	5.94	6.29	6.09	5.33	5.56
	Hydraulic Fracturing Completions and Workovers with RECs	Mg/event	3.80	3.88	4.11	3.98	3.48	3.63
	Hydraulic Fracturing Completions and Workovers with RECs that flare	Mg/event	5.82	5.94	6.29	6.09	5.33	5.56
	Well Drilling	scf/well	3,227.05	3,225.26	3,228.90	3,227.48	3,226.37	3,227.86
	Produced Water from Coal Bed Methane							
	Powder River	kt/gal	0.00	0.00	0.00	0.00	0.00	0.00
	Black Warrior	kt/well	0.00	0.00	0.00	0.00	0.00	0.00

	Normal Operations							
	Pneumatic Device Vents	scfd/controller	437.80	437.56	438.05	437.86	437.71	437.91
	Chemical Injection Pumps	scfd/pump	314.71	314.53	314.89	314.76	314.65	314.78
	Kimray Pumps	scf/MMscf	1,258.85	1,258.15	1,259.56	1,259.01	1,258.57	1,259.15
	Dehydrator Vents	scf/MMscf	349.74	349.54	349.94	349.78	349.66	349.82
	Condensate Tank Vents							
	Condensate Tanks without Control Devices	scf/bbl	25.97	366.97	28.07	376.09	23.80	24.80
	Condensate Tanks with Control Devices	scf/bbl	5.19	73.39	5.61	75.22	4.76	4.95
	Compressor Exhaust Vented							
	Gas Engines	scf/HPhr	0.31	0.30	0.31	0.31	0.30	0.31
	Well Clean Ups							
	Well Clean Ups (LP Gas Wells) - Vent Using Plungers	scfy/venting well	314,616.10	1,379,144.46	154,383.18	3,547.35	345,258.18	70,036.07
	Well Clean Ups (LP Gas Wells) - Vent Without Using Plungers	scfy/venting well	166,168.78	230,063.28	2,580,834.48	96,757.66	303,973.32	300,656.70
	Blowdowns							
	Vessel BD	scfy/vessel	98.98	98.92	99.04	98.99	98.96	99.00
	Pipeline BD	scfy/mile	392.11	391.90	392.35	392.17	392.03	392.21
	Compressor BD	scfy/compressor	4,789.19	4,786.52	4,791.93	4,789.81	4,788.16	4,790.37
	Compressor Starts	scfy/compressor	10,714.13	10,708.15	10,720.24	10,715.54	10,711.84	10,716.77
	Upsets							
	Pressure Relief Valves	scfy/PRV	43.15	43.13	43.17	43.16	43.13	43.15
	Mishaps	scf/mile	848.95	848.48	849.45	849.07	848.78	849.17

Source: Data derived from the methane emission factors listed in the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013, Annex 3, using regional methane concentrations of natural gas (also listed in Annex 3).

Appendix A-5: Methane and Natural Gas (Whole Gas) Emission Factors for the Petroleum Production Stage

Emission Classification	Emission Source Category	Unit of Measurement	Emission Factor (Methane)	Emission Factor (Natural Gas)
Vented	Oil Tanks	scf/bbl	7.40	9.39
	Pneumatic Devices, High Bleed	scfd/controller	330.00	418.78
	Pneumatic Devices, Low Bleed	scfd/controller	52.00	65.99
	Chemical Injection Pumps	scfd/pump	248.00	314.72
	Vessel Blowdowns	scfy/vessel	78.00	98.98
	Compressor Blowdowns	scfy/compressor	3,775.00	4,790.61
	Compressor Starts	scfy/compressor	8,443.00	10,714.47
	Stripper wells	scfy/stripper well	2,345.00	2,975.89
	Well Completion Venting	scf/completion	733.00	930.20
	Well Workovers	scf/workover	96.00	121.83
	Pipeline Pigging	scfd/pig station	2.40	3.05
Fugitive	Oil Wellheads (heavy crude)	scfd/well	0.13	0.16
	Oil Wellheads (light crude)	scfd/well	17.00	21.57
	Separators (heavy crude)	scfd/separator	0.15	0.19
	Separators (light crude)	scfd/separator	14.00	17.77
	Heater/Treaters (light crude)	scfd/heater	19.00	24.11
	Headers (heavy crude)	scfd/header	0.08	0.10
	Headers (light crude)	scfd/header	11.00	13.96
	Floating Roof Tanks	scfy/floating roof	338,306.00	429,322.34
	Compressors	scfd/compressor	100.00	126.90
	Large Compressors	scfd/compressor	16,360.00	20,761.42
	Sales Areas	scf/loading	41.00	52.03
	Pipelines	scfd/mile or pipeline	NE	NE
	Well Drilling	scfd/well drilled	NE	NE
	Battery Pumps	scfd/pump	0.24	0.30
Combusted	Gas Engines	scf/HP-hr	0.24	0.30
	Heaters	scf/bbl	0.52	0.66
	Well Drilling	scf/well drilled	2,453.00	3,112.94
	Flares	scf/Mcf flared	20.00	25.38
Upset	Pressure Relief Valves	scfy/PR valve	35.00	44.42
	Well Blowouts Onshore	MMscf/blowout	2.50	3.17

Source: Methane emission factors are listed in the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013, Annex 3. The natural gas (whole gas) emission factors were calculated using a methane concentration of natural gas of 78.8%.

Appendix A-6: Social Cost of Carbon Estimates

Year	SC - CH4 (2012$ per metric ton)[1]			
	5 Percent Average	3 Percent Average	2.5 Percent Average	3 Percent 95th percentile
2015	$490	$1,100	$1,500	$3,000
2020	$580	$1,300	$1,700	$2,500
2025	$700	$1,500	$1,900	$4,000
2030	$820	$1,700	$2,200	$4,500
2035	$970	$1,900	$2,500	$5,300
2040	$1,100	$2,200	$2,800	$5,900
2045	$1,300	$2,500	$3,000	$6,600
2050	$1,400	$2,700	$3,300	$7,200
Year	**SC - CO2 (2012$ per metric ton)[2]**			
	5 Percent Average	**3 Percent Average**	**2.5 Percent Average**	**3 Percent 95th percentile**
2015	$12	$38	$60	$112
2020	$12	$45	$66	$135
2025	$15	$49	$73	$144
2030	$17	$54	$78	$163
2035	$19	$59	$84	$183
2040	$22	$64	$89	$192
2045	$25	$68	$95	$212
2050	$28	$74	$102	$231

[1] Values from Marten et al. (2014)
[2] Values from EPA website "The Social Cost of Carbon" available at http://www.epa.gov/climatechange/EPAactivities/economics/scc.html. Values scaled to 2012 dollars using the GDP deflator.

Appendix A-7: Detail of Small Business Impacts Analysis

Table A-7a: Difference in Profit Margin if the EPA does not finalize Subpart OOOOa

Company	Number of Employees (last reported)	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	0.001%	0.002%	0.004%
B	384	$795,542	$974,179	$951,489	-$189,543	$117,634	$149,426	0.004%	0.003%	0.003%
C	15	$1,558,758	$1,983,388	$1,934,642	$253,285	-$553,889	$141,571	0.002%	0.002%	0.002%
D	75	$793,885	$665,257	$583,894	$265,573	$118,000	$61,654	0.004%	0.005%	0.005%
E	293	$569,428	$561,562	$709,038	-$103,100	$161,618	-$2,352,606	0.006%	0.006%	0.004%
F	159	$298,204	$197,372	$231,315	-$139,907	-$277,979	-$150,602	0.011%	0.016%	0.014%
G	300	$532,299	$485,489	$346,460	-$283,645	-$35,272	$68,637	0.006%	0.006%	0.009%
H	225	$616,207	$355,792	$319,299	$99,200	-$153,715	-$95,875	0.005%	0.009%	0.010%
I	158	$224,209	$317,502	$356,516	$120,437	$14,319	-$46,587	0.014%	0.010%	0.009%
J	247	$710,187	$520,182	$368,180	$226,343	$43,683	$55,487	0.004%	0.006%	0.009%
K	202	$472,291	$568,093	$700,195	$15,081	-$192,733	$582	0.007%	0.006%	0.004%
L	123	$133,776	$92,324	$65,664	$63,269	$38,647	-$18,791	0.023%	0.034%	0.048%
M	334	$558,633	$421,860	$231,205	$20,283	$69,184	$46,523	0.006%	0.007%	0.014%
N	27	$44,089	$35,319	$38,165	-$7,585	-$13,073	-$10,327	0.071%	0.089%	0.082%
O	21	$13,840	$17,438	$16,243	$2,884	$8,612	$38,074	0.226%	0.180%	0.193%
P	11	$12,679	$8,029	$2,264	-$34,510	$3,855	-$538	0.247%	0.390%	1.384%
Q	70	$13,208	$13,547	$12,106	$3,205	$3,542	$3,659	0.237%	0.231%	0.259%
R	419		$999,506	$248,322		-$1,222,662	-$53,885		0.003%	0.013%
S	2	$12,352	$13,126	$14,781	-$2,464	$3,353	-$2,359	0.254%	0.239%	0.212%
T	57	$171,418	$87,755	$49,940	$50,953	$49,342	-$153,791	0.018%	0.036%	0.063%
U	20	$3,221	$2,573	$2,366	-$2,152	$1,149	-$13,691	0.973%	1.218%	1.325%
V	29	$104,219	$46,223	$24,969	$28,853	$9,581	$12,124	0.030%	0.068%	0.126%
W	105	$208,553	$203,295	$180,845	-$353,136	-$95,186	-$84,202	0.015%	0.015%	0.017%
X	440	$391,469	$304,538	$159,937	-$143,474	-$222,176	-$132,708	0.008%	0.010%	0.020%
Y	164	$636,773	$431,468	$317,149	-$409,592	-$143,970	-$104,589	0.005%	0.007%	0.010%
Z	374	$1,431,289			$22,665			0.002%		
Average	**181**	**$521,086**	**$424,758**	**$344,028**	**$7,060**	**-$91,483**	**-$117,115**	**0.087%**	**0.104%**	**0.154%**

Table A-7b: Difference in Profit Margin if the EPA finalizes Subpart OOOOa

Company	Number of Employees (last reported)	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	0.001%	0.002%	0.004%
B	384	$795,542	$974,179	$951,489	-$189,543	$117,634	$149,426	0.004%	0.003%	0.003%
C	15	$1,558,758	$1,983,388	$1,934,642	$253,285	-$553,889	$141,571	0.002%	0.002%	0.002%
D	75	$793,885	$665,257	$583,894	$265,573	$118,000	$61,654	0.004%	0.005%	0.005%
E	293	$569,428	$561,562	$709,038	-$103,100	$161,618	-$2,352,606	0.006%	0.006%	0.004%
F	159	$298,204	$197,372	$231,315	-$139,907	-$277,979	-$150,602	0.011%	0.016%	0.014%
G	300	$532,299	$485,489	$346,460	-$283,645	-$35,272	$68,637	0.006%	0.006%	0.009%
H	225	$616,207	$355,792	$319,299	$99,200	-$153,715	-$95,875	0.005%	0.009%	0.010%
I	158	$224,209	$317,502	$356,516	$120,437	$14,319	-$46,587	0.014%	0.010%	0.009%
J	247	$710,187	$520,182	$368,180	$226,343	$43,683	$55,487	0.004%	0.006%	0.009%
K	202	$472,291	$568,093	$700,195	$15,081	-$192,733	$582	0.007%	0.006%	0.004%
L	123	$133,776	$92,324	$65,664	$63,269	$38,647	-$18,791	0.024%	0.034%	0.048%
M	334	$558,633	$421,860	$231,205	$20,283	$69,184	$46,523	0.006%	0.007%	0.014%
N	27	$44,089	$35,319	$38,165	-$7,585	-$13,073	-$10,327	0.071%	0.089%	0.082%
O	21	$13,840	$17,438	$16,243	$2,884	$8,612	$38,074	0.227%	0.180%	0.194%
P	11	$12,679	$8,029	$2,264	-$34,510	$3,855	-$538	0.248%	0.392%	1.389%
Q	70	$13,208	$13,547	$12,106	$3,205	$3,542	$3,659	0.238%	0.232%	0.260%
R	419		$999,506	$248,322		-$1,222,662	-$53,885		0.003%	0.013%
S	2	$12,352	$13,126	$14,781	-$2,464	$3,353	-$2,359	0.255%	0.240%	0.213%
T	57	$171,418	$87,755	$49,940	$50,953	$49,342	-$153,791	0.018%	0.036%	0.063%
U	20	$3,221	$2,573	$2,366	-$2,152	$1,149	-$13,691	0.976%	1.222%	1.329%
V	29	$104,219	$46,223	$24,969	$28,853	$9,581	$12,124	0.030%	0.068%	0.126%
W	105	$208,553	$203,295	$180,845	-$353,136	-$95,186	-$84,202	0.015%	0.015%	0.017%
X	440	$391,469	$304,538	$159,937	-$143,474	-$222,176	-$132,708	0.008%	0.010%	0.020%
Y	164	$636,773	$431,468	$317,149	-$409,592	-$143,970	-$104,589	0.005%	0.007%	0.010%
Z	374	$1,431,289			$22,665			0.002%		
Average	**181**	**$521,086**	**$424,758**	**$344,028**	**$7,060**	**-$91,483**	**-$117,115**	**0.087%**	**0.104%**	**0.154%**

Appendix A-8: Detail Of Tribal Impacts

Table A-8-1a: Estimated Annual Total Costs Associated with Operations on Tribal Lands ($ in million)

	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate	Flaring Requirements	$5.1	$7.7	$10.8	$9.7	$9.1	$8.7	$8.4	$8.1	$7.7	$7.5
	Well Completion	$2.3	$2.2	$2.1	$2.0	$1.9	$1.8	$1.8	$1.7	$1.6	$1.6
	Pnumatic Controllers	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
	Pneumatic Pumps	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
	Liquids Unloading	$0.6	$0.6	$0.6	$0.6	$0.6	$0.7	$0.7	$0.7	$0.7	$0.7
	Storage Tanks	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
	LDAR	$9.3	$9.3	$9.3	$9.3	$9.3	$9.3	$9.3	$9.3	$9.3	$9.3
	Administrative Burden	$0.5	$0.5	$0.4	$0.4	$0.4	$0.3	$0.3	$0.3	$0.3	$0.3
	Total	$19.7	$22.1	$25.2	$23.9	$23.2	$22.7	$22.4	$22.1	$21.6	$21.3
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$4.3	$5.4	$6.9	$6.0	$5.7	$5.6	$5.6	$5.7	$5.5	$5.5
	Well Completion	$2.3	$2.3	$2.3	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2
	Pnumatic Controllers	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7
	Pneumatic Pumps	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
	Liquids Unloading	$0.5	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6
	Storage Tanks	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
	LDAR	$9.2	$9.2	$9.2	$9.2	$9.2	$9.2	$9.2	$9.2	$9.3	$9.3
	Administrative Burden	$0.5	$0.5	$0.5	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4
	Total	$18.2	$19.3	$20.8	$19.9	$19.6	$19.5	$19.5	$19.6	$19.4	$19.4

* Includes the monetized value of the CO_2 additions which are relatively minor (less than $5,000 during any given year).

Table A-8-1b: Estimated Annual Total Costs Associated with Operations on Tribal Lands if EPA Finalizes Subpart OOOOa ($ in million)											
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate	Flaring Requirements	$5.1	$7.7	$10.8	$9.7	$9.1	$8.7	$8.4	$8.1	$7.7	$7.5
	Well Completion	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
	Pnumatic Controllers	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
	Pneumatic Pumps	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
	Liquids Unloading	$0.6	$0.6	$0.6	$0.6	$0.6	$0.7	$0.7	$0.7	$0.7	$0.7
	Storage Tanks	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
	LDAR	$9.0	$9.0	$9.0	$9.0	$9.0	$9.0	$9.0	$9.0	$9.0	$9.0
	Administrative Burden	$0.5	$0.5	$0.4	$0.4	$0.4	$0.3	$0.3	$0.3	$0.3	$0.3
	Total	$17.2	$19.8	$22.9	$21.7	$21.1	$20.6	$20.3	$20.1	$19.7	$19.4
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$4.3	$5.4	$6.9	$6.0	$5.7	$5.6	$5.6	$5.7	$5.5	$5.5
	Well Completion	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
	Pnumatic Controllers	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7
	Pneumatic Pumps	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
	Liquids Unloading	$0.5	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6
	Storage Tanks	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
	LDAR	$8.9	$8.9	$8.9	$8.9	$8.9	$8.9	$8.9	$8.9	$8.9	$8.9
	Administrative Burden	$0.5	$0.5	$0.5	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4
	Total	$15.7	$16.8	$18.3	$17.4	$17.1	$17.0	$17.1	$17.1	$16.9	$17.0

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

Table A-8-2a: Estimated Annual Total Benefits Associated with Operations on Tribal Lands ($ in million)											
Estimated Benefits - Cost Savings PV Using 7% Rate ($ in million)	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$6.2	$7.9	$9.2	$8.9	$8.5	$8.2	$7.9	$7.6	$7.3	$7.0
	Well Completion	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4
	Pnumatic Controllers	$1.4	$1.5	$1.5	$1.5	$1.5	$1.4	$1.3	$1.3	$1.2	$1.2
	Pneumatic Pumps	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
	Liquids Unloading	$0.8	$0.9	$0.9	$0.9	$0.9	$0.8	$0.8	$0.8	$0.8	$0.8
	Storage Tanks	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	LDAR	$1.8	$1.8	$1.8	$1.8	$1.8	$1.7	$1.6	$1.5	$1.5	$1.4
	Total	$10.8	$12.6	$14.0	$13.8	$13.3	$12.7	$12.3	$11.8	$11.3	$10.9
Estimated Benefits - Cost Savings PV Using 3% Rate ($ in million)	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$6.2	$8.2	$9.9	$10.0	$9.9	$9.9	$9.9	$9.9	$9.9	$9.9
	Well Completion	$0.4	$0.4	$0.4	$0.4	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
	Pnumatic Controllers	$1.4	$1.6	$1.6	$1.7	$1.7	$1.7	$1.7	$1.7	$1.6	$1.7
	Pneumatic Pumps	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
	Liquids Unloading	$0.8	$0.9	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.1
	Storage Tanks	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	LDAR	$1.8	$1.9	$2.0	$2.1	$2.1	$2.0	$2.0	$2.0	$2.0	$2.0
	Total	$10.8	$13.1	$15.1	$15.4	$15.5	$15.4	$15.4	$15.4	$15.3	$15.4
Estimated Benefits - Value of Methane Reductions	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Well Completion	$2.4	$2.5	$2.5	$3.1	$3.2	$3.2	$3.3	$3.4	$4.0	$4.1
	Pnumatic Controllers	$6.4	$6.4	$6.4	$7.5	$7.5	$7.5	$7.5	$7.5	$8.7	$8.7
	Pneumatic Pumps	$2.0	$2.0	$2.0	$2.4	$2.4	$2.4	$2.4	$2.4	$2.8	$2.9
	Liquids Unloading	$3.6	$3.7	$3.7	$4.5	$4.5	$4.6	$4.7	$4.7	$5.5	$5.6
	Storage Tanks	$1.0	$1.0	$1.0	$1.2	$1.2	$1.2	$1.2	$1.2	$1.3	$1.3
	LDAR	$8.7	$8.7	$8.8	$10.3	$10.3	$10.4	$10.4	$10.4	$12.0	$12.0
	Total	$24.0	$24.2	$24.3	$28.9	$29.1	$29.3	$29.5	$29.6	$34.4	$34.6
Total Estimated Benefits - 7%	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$6.2	$7.9	$9.2	$8.9	$8.5	$8.2	$7.9	$7.6	$7.3	$7.0
	Well Completion	$2.7	$2.8	$2.9	$3.5	$3.5	$3.6	$3.7	$3.8	$4.4	$4.5
	Pnumatic Controllers	$7.8	$7.9	$7.9	$9.0	$9.0	$8.9	$8.9	$8.8	$9.9	$9.9
	Pneumatic Pumps	$2.1	$2.2	$2.2	$2.6	$2.6	$2.6	$2.6	$2.6	$3.0	$3.0
	Liquids Unloading	$4.4	$4.5	$4.6	$5.4	$5.4	$5.4	$5.5	$5.5	$6.3	$6.4
	Storage Tanks	$1.0	$1.0	$1.0	$1.2	$1.2	$1.2	$1.2	$1.2	$1.4	$1.4
	LDAR	$10.5	$10.6	$10.6	$12.2	$12.1	$12.1	$12.0	$11.9	$13.5	$13.4
	Total	$34.8	$36.8	$38.3	$42.7	$42.4	$42.0	$41.7	$41.4	$45.7	$45.5
Total Estimated Benefits - 3%	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$6.2	$8.2	$9.9	$10.0	$9.9	$9.9	$9.9	$9.9	$9.9	$9.9
	Well Completion	$2.7	$2.8	$2.9	$3.5	$3.6	$3.7	$3.8	$3.9	$4.5	$4.6
	Pnumatic Controllers	$7.8	$7.9	$8.0	$9.2	$9.2	$9.2	$9.2	$9.2	$10.3	$10.3
	Pneumatic Pumps	$2.1	$2.2	$2.2	$2.6	$2.6	$2.6	$2.7	$2.7	$3.1	$3.1
	Liquids Unloading	$4.4	$4.6	$4.7	$5.5	$5.5	$5.6	$5.7	$5.8	$6.6	$6.7
	Storage Tanks	$1.0	$1.0	$1.0	$1.2	$1.2	$1.2	$1.2	$1.2	$1.4	$1.4
	LDAR	$10.5	$10.6	$10.7	$12.4	$12.4	$12.4	$12.4	$12.4	$14.0	$14.0
	Total	$34.8	$37.3	$39.5	$44.4	$44.5	$44.6	$44.9	$45.0	$49.7	$50.0

Table A-8-2b: Estimated Annual Total Benefits Associated with Operations on Tribal Lands if EPA Finalizes Subpart OOOOa ($ in million)

	Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Estimated Benefits - Cost Savings PV Using 7% Rate ($ in million)	Flaring Requirements	$6.2	$7.9	$9.2	$8.9	$8.5	$8.2	$7.9	$7.6	$7.3	$7.0
	Well Completion	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Pnumatic Controllers	$1.4	$1.5	$1.5	$1.5	$1.5	$1.4	$1.3	$1.3	$1.2	$1.2
	Pneumatic Pumps	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
	Liquids Unloading	$0.8	$0.9	$0.9	$0.9	$0.9	$0.8	$0.8	$0.8	$0.8	$0.8
	Storage Tanks	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	LDAR	$1.7	$1.8	$1.8	$1.8	$1.7	$1.6	$1.6	$1.5	$1.4	$1.4
	Total	$10.4	$12.2	$13.6	$13.3	$12.8	$12.3	$11.8	$11.3	$10.9	$10.5
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Estimated Benefits - Cost Savings PV Using 3% Rate ($ in million)	Flaring Requirements	$6.2	$8.2	$9.9	$10.0	$9.9	$9.9	$9.9	$9.9	$9.9	$9.9
	Well Completion	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Pnumatic Controllers	$1.4	$1.6	$1.6	$1.7	$1.7	$1.7	$1.7	$1.7	$1.6	$1.7
	Pneumatic Pumps	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
	Liquids Unloading	$0.8	$0.9	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.1
	Storage Tanks	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	LDAR	$1.7	$1.9	$1.9	$2.0	$2.0	$2.0	$2.0	$2.0	$2.0	$2.0
	Total	$10.4	$12.7	$14.7	$14.9	$14.9	$14.8	$14.9	$14.8	$14.8	$14.8
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Estimated Benefits - Value of Methane Reductions	Flaring Requirements	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Well Completion	$0.2	$0.2	$0.2	$0.3	$0.3	$0.3	$0.3	$0.3	$0.4	$0.4
	Pnumatic Controllers	$6.4	$6.4	$6.4	$7.5	$7.5	$7.5	$7.5	$7.5	$8.7	$8.7
	Pneumatic Pumps	$1.9	$1.9	$1.9	$2.3	$2.3	$2.3	$2.3	$2.3	$2.6	$2.6
	Liquids Unloading	$3.6	$3.7	$3.7	$4.5	$4.5	$4.6	$4.7	$4.7	$5.5	$5.6
	Storage Tanks	$1.0	$1.0	$1.0	$1.2	$1.2	$1.2	$1.2	$1.2	$1.3	$1.3
	LDAR	$7.3	$7.3	$7.3	$8.6	$8.6	$8.6	$8.6	$8.6	$9.9	$9.9
	Total	$20.4	$20.5	$20.5	$24.3	$24.4	$24.5	$24.6	$24.6	$28.5	$28.6
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Total Estimated Benefits - 7%	Flaring Requirements	$6.2	$7.9	$9.2	$8.9	$8.5	$8.2	$7.9	$7.6	$7.3	$7.0
	Well Completion	$0.2	$0.2	$0.2	$0.3	$0.3	$0.3	$0.3	$0.3	$0.4	$0.4
	Pnumatic Controllers	$7.8	$7.9	$7.9	$9.0	$9.0	$8.9	$8.9	$8.8	$9.9	$9.9
	Pneumatic Pumps	$2.1	$2.1	$2.1	$2.5	$2.5	$2.5	$2.5	$2.5	$2.8	$2.8
	Liquids Unloading	$4.4	$4.5	$4.6	$5.4	$5.4	$5.4	$5.5	$5.5	$6.3	$6.4
	Storage Tanks	$1.0	$1.0	$1.0	$1.2	$1.2	$1.2	$1.2	$1.2	$1.4	$1.4
	LDAR	$9.0	$9.1	$9.1	$10.4	$10.4	$10.3	$10.2	$10.1	$11.4	$11.3
	Total	$30.8	$32.7	$34.1	$37.7	$37.2	$36.7	$36.4	$36.0	$39.4	$39.1
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Total Estimated Benefits - 3%	Flaring Requirements	$6.2	$8.2	$9.9	$10.0	$9.9	$9.9	$9.9	$9.9	$9.9	$9.9
	Well Completion	$0.2	$0.2	$0.2	$0.3	$0.3	$0.3	$0.3	$0.3	$0.4	$0.4
	Pnumatic Controllers	$7.8	$7.9	$8.0	$9.2	$9.2	$9.2	$9.2	$9.2	$10.3	$10.3
	Pneumatic Pumps	$2.1	$2.1	$2.2	$2.5	$2.5	$2.5	$2.5	$2.5	$2.9	$2.9
	Liquids Unloading	$4.4	$4.6	$4.7	$5.5	$5.5	$5.6	$5.7	$5.8	$6.6	$6.7
	Storage Tanks	$1.0	$1.0	$1.0	$1.2	$1.2	$1.2	$1.2	$1.2	$1.4	$1.4
	LDAR	$9.0	$9.2	$9.2	$10.6	$10.6	$10.6	$10.6	$10.6	$11.9	$11.9
	Total	$30.8	$33.2	$35.2	$39.3	$39.4	$39.3	$39.4	$39.4	$43.3	$43.4

Table A-8-3a: Estimated Net Benefits Associated with Operations on Tribal Lands ($ in million)											
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Total Estimated Net Benefits - 7%	Flaring Requirements	$1.1	$0.1	-$1.7	-$0.8	-$0.5	-$0.5	-$0.5	-$0.6	-$0.5	-$0.5
	Well Completion	$0.5	$0.7	$0.8	$1.5	$1.6	$1.8	$1.9	$2.1	$2.8	$2.9
	Pnumatic Controllers	$7.0	$7.0	$7.1	$8.2	$8.2	$8.1	$8.0	$8.0	$9.1	$9.0
	Pneumatic Pumps	$1.9	$1.9	$1.9	$2.3	$2.3	$2.3	$2.3	$2.3	$2.7	$2.7
	Liquids Unloading	$3.8	$3.9	$4.0	$4.7	$4.8	$4.8	$4.8	$4.9	$5.6	$5.7
	Storage Tanks	$0.2	$0.2	$0.2	$0.4	$0.4	$0.4	$0.4	$0.4	$0.5	$0.5
	LDAR	$1.3	$1.3	$1.3	$2.9	$2.8	$2.8	$2.7	$2.6	$4.1	$4.1
	Administrative Burden	-$0.5	-$0.5	-$0.4	-$0.4	-$0.4	-$0.3	-$0.3	-$0.3	-$0.3	-$0.3
	Total	$15.2	$14.7	$13.2	$18.8	$19.1	$19.2	$19.3	$19.3	$24.1	$24.3
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Total Estimated Net Benefits - 3%	Flaring Requirements	$2.0	$2.8	$3.0	$4.0	$4.3	$4.3	$4.3	$4.2	$4.4	$4.4
	Well Completion	$0.5	$0.6	$0.7	$1.3	$1.4	$1.5	$1.6	$1.7	$2.3	$2.4
	Pnumatic Controllers	$7.1	$7.2	$7.3	$8.5	$8.5	$8.5	$8.5	$8.5	$9.6	$9.7
	Pneumatic Pumps	$1.9	$1.9	$1.9	$2.3	$2.3	$2.3	$2.4	$2.4	$2.8	$2.8
	Liquids Unloading	$3.9	$4.0	$4.1	$4.9	$5.0	$5.0	$5.1	$5.2	$6.0	$6.1
	Storage Tanks	$0.5	$0.5	$0.5	$0.7	$0.7	$0.7	$0.7	$0.7	$0.9	$0.9
	LDAR	$1.3	$1.4	$1.5	$3.2	$3.2	$3.2	$3.2	$3.2	$4.7	$4.7
	Administrative Burden	-$0.5	-$0.5	-$0.5	-$0.4	-$0.4	-$0.4	-$0.4	-$0.4	-$0.4	-$0.4
	Total	$16.7	$18.0	$18.7	$24.5	$25.0	$25.1	$25.3	$25.4	$30.3	$30.6

Table A-8-3b: Estimated Net Benefits Associated with Operations on Tribal Lands if EPA Finalizes Subpart OOOOa ($ in million)

	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Total Estimated Net Benefits - 7%	Flaring Requirements	$1.1	$0.1	-$1.7	-$0.8	-$0.5	-$0.5	-$0.5	-$0.6	-$0.5	-$0.5
	Well Completion	$0.1	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.3	$0.3	$0.3
	Pnumatic Controllers	$7.0	$7.0	$7.1	$8.2	$8.2	$8.1	$8.0	$8.0	$9.1	$9.0
	Pneumatic Pumps	$1.9	$1.9	$1.9	$2.2	$2.2	$2.2	$2.2	$2.2	$2.5	$2.5
	Liquids Unloading	$3.8	$3.9	$4.0	$4.7	$4.8	$4.8	$4.8	$4.9	$5.6	$5.7
	Storage Tanks	$0.2	$0.2	$0.2	$0.4	$0.4	$0.4	$0.4	$0.4	$0.5	$0.5
	LDAR	$0.0	$0.1	$0.1	$1.4	$1.4	$1.3	$1.2	$1.1	$2.4	$2.4
	Administrative Burden	-$0.5	-$0.5	-$0.4	-$0.4	-$0.4	-$0.3	-$0.3	-$0.3	-$0.3	-$0.3
	Total	$13.6	$12.9	$11.2	$16.0	$16.2	$16.1	$16.0	$15.9	$19.7	$19.7
Total Estimated Net Benefits - 3%	**Requirement**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Flaring Requirements	$2.0	$2.8	$3.0	$4.0	$4.3	$4.3	$4.3	$4.2	$4.4	$4.4
	Well Completion	$0.1	$0.1	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.3	$0.3
	Pnumatic Controllers	$7.1	$7.2	$7.3	$8.5	$8.5	$8.5	$8.5	$8.5	$9.6	$9.7
	Pneumatic Pumps	$1.9	$1.9	$1.9	$2.2	$2.2	$2.2	$2.2	$2.2	$2.6	$2.6
	Liquids Unloading	$3.9	$4.0	$4.1	$4.9	$5.0	$5.0	$5.1	$5.2	$6.0	$6.1
	Storage Tanks	$0.5	$0.5	$0.5	$0.7	$0.7	$0.7	$0.7	$0.7	$0.9	$0.9
	LDAR	$0.1	$0.2	$0.3	$1.7	$1.7	$1.7	$1.7	$1.7	$3.0	$3.0
	Administrative Burden	-$0.5	-$0.5	-$0.5	-$0.4	-$0.4	-$0.4	-$0.4	-$0.4	-$0.4	-$0.4
	Total	$15.1	$16.3	$16.9	$21.9	$22.2	$22.3	$22.4	$22.3	$26.3	$26.5

Table A-8-4a: Estimated Incremental Production Associated with Operations on Tribal Lands										
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Natural Gas (Bcf)										
Flaring Requirements	0.4	0.6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Well Completion	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Pnumatic Controllers	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Pneumatic Pumps	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Liquids Unloading	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LDAR	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total Natural Gas	1.6	1.8	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NGL (million gallons)										
Flaring Requirements	5.6	7.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Total NGL	5.6	7.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Crude Oil (million bbl)										
Flaring Requirements	-0.1	-0.3	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
Total Crude	-0.1	-0.3	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5

Table A-8-4b: Estimated Incremental Production Associated with Operations on Tribal Lands if EPA Finalizes Subpart OOOOa

Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Natural Gas (Bcf)										
Flaring Requirements	0.4	0.6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Well Completion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pnumatic Controllers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pneumatic Pumps	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Liquids Unloading	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LDAR	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total Natural Gas	1.1	1.3	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NGL (million gallons)										
Flaring Requirements	5.6	7.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Total NGL	5.6	7.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Crude Oil (million bbl)										
Flaring Requirements	-0.1	-0.3	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
Total Crude	-0.1	-0.3	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5

Table A-8-5a: Estimated Methane Reductions Associated with Operations on Tribal Lands (tons)										
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Flaring Requirements	0	0	0	0	0	0	0	0	0	0
Well Completion	2,200	2,200	2,300	2,400	2,400	2,500	2,500	2,600	2,700	2,700
Pnumatic Controllers	5,800	5,800	5,800	5,800	5,800	5,800	5,800	5,800	5,800	5,800
Pneumatic Pumps	1,800	1,800	1,800	1,800	1,800	1,800	1,900	1,900	1,900	1,900
Liquids Unloading	3,300	3,300	3,400	3,400	3,500	3,500	3,600	3,600	3,700	3,700
Storage Tanks	900	900	900	900	900	900	900	900	900	900
LDAR	7,900	7,900	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
Total	22,000	22,000	22,000	22,000	22,000	23,000	23,000	23,000	23,000	23,000

Table A-8-5b: Estimated Methane Reductions Associated with Operations on Tribal Lands if EPA Finalizes Subpart OOOOa (tons)										
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Flaring Requirements	0	0	0	0	0	0	0	0	0	0
Well Completion	208	208	208	226	226	226	245	245	245	264
Pnumatic Controllers	5,800	5,800	5,800	5,800	5,800	5,800	5,800	5,800	5,800	5,800
Pneumatic Pumps	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800
Liquids Unloading	3,300	3,300	3,400	3,400	3,500	3,500	3,600	3,600	3,700	3,700
Storage Tanks	900	900	900	900	900	900	900	900	900	900
LDAR	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800
Total	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000

Table A-8-6a: Estimated VOC Reductions Associated with Operations on Tribal Lands (tons)										
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Flaring Requirements	0	0	0	0	0	0	0	0	0	0
Well Completion	1,800	1,900	1,900	2,000	2,000	2,100	2,100	2,200	2,200	2,300
Pnumatic Controllers	26,500	26,500	26,500	26,500	26,500	26,500	26,500	26,500	26,500	26,500
Pneumatic Pumps	400	400	500	500	500	500	500	500	500	500
Liquids Unloading	14,900	15,200	15,400	15,700	15,900	16,200	16,400	16,600	16,800	17,100
Storage Tanks	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100
LDAR	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200
Total	50,000	50,000	51,000	51,000	51,000	52,000	52,000	52,000	52,000	53,000

Table A-8-6b: Estimated VOC Reductions Associated with Operations on Tribal Lands if EPA Finalizes Subpart OOOOa (tons)										
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Flaring Requirements	0	0	0	0	0	0	0	0	0	0
Well Completion	170	170	170	189	189	189	208	208	208	208
Pnumatic Controllers	26,500	26,500	26,500	26,500	26,500	26,500	26,500	26,500	26,500	26,500
Pneumatic Pumps	400	400	400	400	400	400	400	400	400	400
Liquids Unloading	14,900	15,200	15,400	15,700	15,900	16,200	16,400	16,600	16,800	17,100
Storage Tanks	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100
LDAR	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200
Total	48,000	49,000	49,000	49,000	49,000	50,000	50,000	50,000	50,000	51,000

Table A-8-7a: Estimated Incremental Royalty for Tribes, Present Value Calculated with 7% Discount Rate ($ in million

Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Natural Gas										
Flaring Requirements	0.2	0.3	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3
Royalty on Flaring	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Well Completion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pnumatic Controllers	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
Pneumatic Pumps	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Liquids Unloading	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LDAR	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total Natural Gas	0.8	0.9	1.0	1.0	1.0	0.9	0.9	0.8	0.8	0.8
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NGL										
Flaring Requirements	0.6	0.8	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7
Total NGL	0.6	0.8	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Crude Oil (Difference in Royalty Value of Deferred Production)										
Flaring Requirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Crude	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Net Royalty	1.4	1.7	1.9	1.9	1.8	1.7	1.7	1.6	1.5	1.5

Table A-8-7b: Estimated Incremental Royalty for Tribes, Present Value Calculated with 3% Discount Rate ($ in millions)										
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Natural Gas										
Flaring Requirements	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Royalty on Flaring	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Well Completion	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Pnumatic Controllers	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Pneumatic Pumps	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Liquids Unloading	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LDAR	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Natural Gas	0.8	0.9	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NGL										
Flaring Requirements	0.6	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total NGL	0.6	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Crude Oil (Difference in Royalty Value of Deferred Production)										
Flaring Requirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Crude	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Net Royalty	1.4	1.7	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1

Table A-8-8a: Estimated Incremental Royalty for Tribes if EPA Finalizes Subpart OOOOa, Present Value Calculated with 7% Discount Rate ($ in millions)										
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Natural Gas										
Flaring Requirements	0.2	0.3	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3
Royalty on Flaring	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Well Completion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pnumatic Controllers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pneumatic Pumps	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Liquids Unloading	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LDAR	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total Natural Gas	0.5	0.6	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.6
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NGL										
Flaring Requirements	0.6	0.8	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7
Total NGL	0.6	0.8	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Crude Oil (Difference in Royalty Value of Deferred Production)										
Flaring Requirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Crude	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Net Royalty	1.1	1.4	1.6	1.6	1.6	1.5	1.4	1.4	1.3	1.3

Table A-8-8b: Estimated Incremental Royalty for Tribes if EPA Finalizes Subpart OOOOa, Present Value Calculated with 3% Discount Rate ($ in millions)										
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Natural Gas										
Flaring Requirements	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Royalty on Flaring	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Well Completion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pnumatic Controllers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pneumatic Pumps	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Liquids Unloading	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LDAR	0.2	0.2	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.2
Total Natural Gas	0.5	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NGL										
Flaring Requirements	0.6	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total NGL	0.6	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Crude Oil (Difference in Royalty Value of Deferred Production)										
Flaring Requirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Crude	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Net Royalty	1.1	1.5	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8

Appendix A-9: Detail Of BLM's Venting And Flaring Estimates

A. Gas flaring from production operations, including associated gas

The GAO estimated that 28 Bcf of natural gas was flared from onshore Federal oil and gas operations in 2008, representing about 22% of the total volume of gas vented and flared.[88] The GAO did not differentiate between gas that was flared from gas wells and gas that was flared from oil wells. It also did not identify potential reductions in its report.

In general, the GAO determined that the volume of gas reported as vented or flared in ONRR's Oil and Gas Operations Report (OGOR) system was about 0.13 per of the natural gas produced on onshore federal leases between 2006 and 2008. It concluded that the venting and flaring data from OGOR underreported the actual amount of gas lost, noting that operators did not report venting from certain sources and that there was a lack of consistency among BLM field offices about what volumes should be reported. Specifically, operators varied in whether they included quantities of vented or flared gas where the BLM had authorized the venting or flaring or where the quantities were under the BLM's permissible limits. Operators are also not always required to meter the quantities of vented or flared gas reported on their OGOR-Bs. Instead they may use BLM-approved methods to estimate the quantities to be reported. In reviewing these data, the GAO found that they "likely underestimate venting and flaring because they do not account for all sources of lost gas."[89]

We note the GAO's conclusions here for two reasons. First, we use data from ONRR to estimate the amount of gas flaring (but not the amount of gas venting) from Federal and Indian lands. As such, the data that we report for gas flaring is likely to underreport the amount of flaring that is actually occurring, specifically since it does not include all volumes flared during short-term events or with BLM approval. Also, the GAO report identified a weakness in reporting. In recent years, certain field offices have incorporated conditions of approval to flaring applications that require the operator to report flared volumes to OGOR. These actions may help explain some of the increase in reported gas flaring over the past several years.

What is the current level of natural gas flaring on BLM-administered leases?

ONRR tracks the disposition of natural gas from offshore Federal Lands and onshore Federal and Indian Lands for the purpose of collecting, disbursing, and verifying Federal and Indian energy and other natural resource revenues (we noted the limitations of the data previously). Two disposition codes pertain to the general flaring of gas during production operations – "flared gas-well gas" and "flared oil-well gas." The data include 4 land classes – Federal, Indian, mixed ownership, and fee.

In 2013, according to the most recent available data from ONRR, about 76 Bcf of natural gas was flared from BLM-administered leases, including Federal and Indian gas and non-Federal and non-Indian gas. Of that total volume, about 71 Bcf was flared oil-well gas while about 5 Bcf was flared

[88] GAO 2010, pp. 12, 20.
[89] GAO-11-34, Oct. 2010.

gas-well gas. Table 1 shows that the flaring of oil-well gas increased by 292% from 2009 to 2013, while the flaring of gas-well gas decreased by 75% over that same period. Overall, all gas flaring increased by 109% from 2009 to 2013.

Table 1: Gas Flared from BLM-Administered Leases in 2009 to 2013, by Well Type

Well Type	2009	2010	2011	2012	2013	% Change 2009-2013
Oil Wells	18.21	30.61	41.36	57.63	71.37	292%
Gas Wells	18.13	5.66	4.91	3.55	4.58	-75%
Total	**36.34**	**36.27**	**46.27**	**61.18**	**75.94**	**109%**

The flared volumes reported in the mixed ownership land class include gas that comes from various mineral owners and is not limited to the Federal and Indian mineral estates. For Tables 2 and 3, we estimate the volumes of flared gas originating from the Federal and Indian mineral estates by applying the share of Federal and Indian production that ONRR estimated came from the areas of mixed ownership to the flared volumes reported from those areas.[90]

When we consider the flaring of Federal and Indian gas only, we estimate that in 2013, about 44 Bcf of natural gas was flared. Of that total volume, about 41 Bcf was flared oil-well gas while about 3 Bcf was flared gas-well gas. Table 2 shows that the flaring of Federal and Indian oil-well gas increased by 467% from 2009 to 2013, while the flaring of gas-well gas decreased by 75% over that same period. The trends are similar as in the previous table, with the flaring of oil-well gas increasing more sharply. Overall, the flaring of Federal and Indian gas increased by 134% from 2009 to 2013.

Table 3 shows the flared gas from BLM-administered leases in 2013, with the flared gas identified by estimated mineral ownership. This distinction in volumes is important, because while the proposed rule's royalty provisions would only impact the volume of gas flared originating from the Federal and Indian mineral estate, the gas capture provisions would impact the volume of gas flared from BLM-administered leases.

Table 2: Gas Flared Estimated to have Originated from the Federal and Indian Mineral Estates in 2009 to 2013, by Well Type

Well Type	2009	2010	2011	2012	2013	% Change 2009-2013
Oil Wells	7.15	12.40	19.74	29.71	40.53	467%
Gas Wells	11.49	3.80	3.40	2.46	3.07	-73%
Total	**18.64**	**16.20**	**23.14**	**32.16**	**43.60**	**134%**

[90] The shares of mixed production are as follows: 2013 oil production – 29% Federal, 11% Indian; 2013 gas production – 51% Federal, 4% Indian; 2012 oil production – 32% Federal, 7% Indian; 2012 gas production – 53% Federal, 3% Indian; 2011 oil production – 24% Federal, 6% Indian; 2011 gas production – 55% Federal, 3% Indian; 2010 oil production – 33% Federal, 4% Indian; 2010 gas production – 56% Federal, 3% Indian; 2009 oil production – 32% Federal, 3% Indian; 2009 gas production – 57% Federal, 3% Indian.

Table 3: Flared Gas on BLM-Administered Leases in 2013 - Gas Identified by Mineral Ownership

Mineral Ownership	Flared Oil-Well Gas (Bcf)	Flared Gas-Well Gas (Bcf)	Total (Bcf)
Federal Lands	9.37	0.70	10.07
Federal Gas in Areas of Mixed Ownership	14.91	1.70	16.61
Indian Lands	10.60	0.54	11.14
Indian Gas in Areas of Mixed Ownership	5.65	0.13	5.79
Federal and Indian Subtotal	**40.53**	**3.07**	**43.60**
Non-Federal and Non-Indian Gas	30.84	1.50	32.34
Total	**71.37**	**4.58**	**75.94**

We further examine the oil-well gas flaring, by geographic state and land class (see Table 4). According to these data, 91% of the flared Federal and Indian gas from oil wells occurred in three states – North Dakota, South Dakota, and New Mexico. In 2013, the volumes of flared Federal and Indian oil-well gas in these states were about 25 Bcf for South Dakota and about 6 Bcf for each of New Mexico and South Dakota. When we examine the states separately, as in Table 5, the data show that the volumes of flared oil-well gas have increased dramatically since 2009, while oil production increased in North Dakota and either remained relatively constant or declined in New Mexico and South Dakota.

Recognizing this issue, in 2014, the NDIC took two actions designed at reducing the flaring of natural gas from oil wells. First, it required that operators planning to drill a well have a gas capture plan in place. Second, it issued a rule requiring the operator to capture given percentage of the gas that it produces, either on a well, field, or state-wide basis. If the operator fails to capture this amount, then the NDIC would impose limits on its oil production. These actions apply to operations on Federal and Indian Lands in North Dakota and have a co-benefit of reducing the loss of gas on Federal and Indian lands.

Table 4: Flared Oil-Well Gas in 2013, by Land Class and Mineral Ownership (Mcf)

Geographic State	Flared Oil-Well Gas, by Mineral Ownership				
	Federal	Indian	Subtotal - Federal and Indian	Non-Federal and Non-Indian	Total
Alaska	6,578	0	**6,578**	0	**6,578**
California	313,672	18,202	**331,875**	99,284	**431,159**
Colorado	189,120	62,251	**251,372**	186,766	**438,138**
Illinois	5,320	0	**5,320**	0	**5,320**
Louisiana	59,072	4,853	**63,924**	26,470	**90,394**
Michigan	32,021	12,146	**44,167**	66,251	**110,418**
Montana	707,888	257,667	**965,555**	993,706	**1,959,261**
North Dakota	11,899,965	13,238,341	**25,138,306**	17,014,376	**42,152,683**
New Mexico	5,466,244	456,483	**5,922,727**	2,254,070	**8,176,797**
Ohio	24	0	**24**	0	**24**
Oklahoma	5,533	19,205	**24,737**	11,447	**36,184**
South Dakota	4,256,801	1,614,649	**5,871,450**	8,807,174	**14,678,624**
Texas	1,052	150	**1,202**	818	**2,020**
Utah	284,581	310,991	**595,572**	294,481	**890,053**
Wyoming	1,048,858	254,295	**1,303,153**	1,085,471	**2,388,624**
Total	**24,276,728**	**16,249,233**	**40,525,961**	**30,840,316**	**71,366,277**

Table 5: Oil Production and Flared Oil-Well Gas in Three Highest Flaring States, 2009-2013

Metric/Geographic State	2009	2010	2011	2012	2013	% Change 2009-2013
Oil Production (mmbbl)						
New Mexico	2,154.20	2,137.91	2,163.33	2,172.95	2,082.58	-3%
North Dakota	25.67	30.79	41.99	81.50	115.46	350%
South Dakota	0.59	0.47	0.39	0.36	0.32	-45%
Flared Oil-Well Gas (Bcf)						
New Mexico	0.35	0.45	1.09	4.25	8.18	2255%
North Dakota	9.33	15.52	23.45	33.83	42.15	352%
South Dakota	1.08	9.03	11.33	13.75	14.68	1255%

B. Well completions and workovers

The GAO estimated that 30 Bcf of natural gas was lost during well completion operations from onshore Federal leases in 2008. According to its findings, that volume represented about 24% of the total volume of gas vented and flared from onshore federal leases. It concluded that emissions could be reduced by 14.7 Bcf per year (a 49% reduction), through the expanded use of reduced emissions completions (RECs).[91] The GAO did not estimate volumes of gas lost during well drilling and well workovers, though possibly the volumes were included in the "other" category.

Since the GAO report, the EPA finalized the NSPS Subpart OOOO which places requirements on hydraulically fractured gas well completions. The NSPS establishes criteria for two groups of hydraulically fractured gas wells:

- Wells that are either wildcat wells, delineation wells, or low-pressure gas wells – At a minimum, operators must capture and direct flowback emissions to a completion combustion device, except in conditions that may result in a fire hazard, explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.
- Wells that are neither wildcat wells, delineation wells, nor low-pressure gas wells – Operators must route the recovered liquids into one or more storage vessels or re-inject the recovered liquids into the well or another well, and do any of the following with the recovered gas:[92]
    - Route it to a gas flow line or collection system,
    - Re-inject it into the well or another well,
    - Use it as an on-site fuel source, or
    - Or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

If any of those four options are infeasible, the operator must capture and direct flowback emissions to a completion combustion device, except when there are concerns about safety or high heat.

In addition, the Colorado AQCC recently finalized a rule that essentially extends the NSPS requirements to well completions where produced fluids are returned to a separator. The rule states that "normal operation gas coming off of a separator produced from any newly constructed, hydraulically fractured, or recompleted oil or gas well must be either routed to a gas gathering line or controlled by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95% from the date of first production. If a combustion device is used, it shall have a design destruction efficiency of at least 98% of hydrocarbons."[93]

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[91] GAO 2010, pp. 12, 20.

[92] Wells are phased-in to these requirements. Operators that complete wells before January 1, 2015, are required to capture and combust flowback emissions at a minimum.

[93] Regulation Number 7, Section XVII.G, available on the web at http://www.colorado.gov/cs/Satellite/CDPHE-AQCC/CBON/1251647985820

How much natural gas loss is associated with oil and gas well completions and workovers on Federal and Indian lands?

We estimate that 2.08 Bcf of natural gas was lost in 2013 from well completions and workovers on Federal and Indian lands. Releases for the natural gas production segment were calculated using data from the 2015 GHG Inventory and the share of natural gas production coming from Federal and Indian Lands. Releases for the conventional wells in the petroleum production segment were calculated using data from the 2015 GHG Inventory and the share of petroleum production coming from Federal and Indian Lands. Releases for the unconventional wells in the petroleum production segment were calculated using data from the EPA's Technical Support Document for the NSPS Subpart OOOOa.

Table 6: Estimated Emissions from Well Completions and Workovers, 2013

Production Segment	Natural Gas Releases (Bcf)	Methane Emissions (tons)	VOC Emissions (tons)
Natural Gas	0.69	11,031	50,368
Petroleum (conventional)	0.00	16	71
Petroleum (unconventional)	1.39	13,549	11,347
Total	**2.08**	**24,595**	**61,786**

What is the variability in gas loss from well completions, workover, and drilling activities, among the different types of wells?

According to the 2015 GHG Inventory, well completion emissions from hydraulically fractured gas wells are much higher, as an aggregate and on a per-unit basis, than completion emissions from conventional gas wells and oil wells. See Table 7. Emission factors for well drilling and workover activities on conventional gas wells and oil wells (without distinction for conventional or unconventional wells) are also relatively low. Again, as noted previously, the EPA regulates completion and workover emissions from hydraulically fractured gas wells under the NSPS.

Other research studies provide insight into emissions from gas well completions, though we note that the studies were carried out prior to the implementation of the NSPS. Allen et al. (2013) measured methane emissions from 27 gas well completions with hydraulic fracturing and found average methane emissions much lower than the factors listed in the 2015 GHG Inventory. The researchers found average methane emissions of 1.7 Mg of CH_4 (range of 0.01 to 17 Mg), or 90 Mcf of CH_4 per event (range of 0.5 to 880 Mcf). For the 10 completions in the Rocky Mountain region (where most activity on Federal lands occurs), average methane emissions were lower and about 24 Mcf of CH_4 per event (range of 0.5 Mcf to 440 Mcf).

Researchers observed that the completions with the lowest emissions were those where the flowback was sent immediately to a separator and the gases from the separator were sent to sales. Some of completions with relatively high emissions were those where the gases were combusted. The completions with the highest emissions were those where the gases were vented for the entire event. Despite having lower than average emissions, 6 of the 10 completions in the Rocky Mountain region involved flowback that was returned to an open top tank with the gases vented. The 4 remaining completions involved a combination of venting and combustion.

The results indicate that the completions in the Rocky Mountain region tend to have fewer emissions than the nationwide average, despite the fact that all of the completions involved venting gases to the atmosphere (to various degrees). The results also show that operators on 4 completions in the Rocky Mountain region used combustion to reduce methane emissions from those completions by 91%.

The study provides useful insight into emissions from gas well completions with hydraulic fracturing. However, the EPA now regulates the well completions on hydraulically fractured gas wells, including coalbed methane (CBM) wells, through the NSPS. And while it does not regulate well completions on hydraulically fractured oil wells or on conventional oil or gas wells, it requires that operators control gas vapor emissions from storage vessels.

Table 7: 2015 GHG Inventory Emission Factors for Well Completions, Workovers, and Drilling Operations, by Well Type

Well type / Activity	Natural gas releases (Mcf per event)	Currently Covered by NSPS
Gas wells		
Completions without hydraulic fracturing (Mcf/completion) (1)(3)	0.91 - 0.93	
Workovers without hydraulic fracturing (Mcf/workover) (1)(3)	3.0 - 3.1	
Hydraulic fracturing completions and workovers that vent (Mcf/completion or workover) (2)(4)	2,075 - 2,448	X
Flared hydraulic fracturing completions and workovers (Mcf/completion or workover) (2)(4)	276 - 326	X
Hydraulic fracturing completions and workovers with RECs (Mcf/completion or workover) (2)(4)	180 - 213	X
Hydraulic fracturing completions and workovers with RECs that flare (Mcf/completion or workover) (2)(4)	276 - 326	X
Well drilling (Mcf/well) (1)(3)	3.2	
Oil wells		
Well completion venting (Mcf/completion) (1)(5)	0.93	
Well workovers (Mcf/workover) (1)(5)	0.12	
Well drilling (Mcf/well)	Not estimated	

Source: Data from Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013 (EPA 2015), Annex 3

(1) Potential emissions

(2) Actual emissions

(3) The Inventory lists CH_4 emission factors by region, which when converted using the regional CH_4 concentrations of gas, return roughly these values.

(4) The Inventory lists CH_4 emission factors in tons per event which were converted to Mcf of gas. Assumes 0.0193 tons of CH_4 per Mcf of CH_4 and regional methane concentration of natural gas from 77.9% - 91.9%.

(5) The Inventory lists CH_4 emission factors which were converted using a 78.8% methane concentration.

Recent research on oil wells, particularly those completed with hydraulic fracturing, reveal higher volumes of gas loss during completion operations than the emission factors listed in the 2015 GHG Inventory. These studies are described in the EPA's white paper on well completions, and the gas releases are shown in Table 8.

In 2013, the EPA reviewed 154 applications for synthetic minor new source review permits as part of the Fort Berthold Federal Implementation Plan (FIP). Its analysis of these permits included 533 production wells from 5 major operators. The wells were located in the Bakken and Three Forks formations, tight-oil formations requiring hydraulic fracturing completions in North Dakota. The data indicated average uncontrolled gas volumes of 351.5 Mcf/day or 2,460 Mcf/completion. Next, ERG Inc. and EPA conducted an analysis of the HPDI, LLC database and estimated gas releases of 262 Mcf/day for oil well completions, equating to 786 Mcf for completions lasting 3 days and 1,834 Mcf for completions lasting 7 days. Next EDF and Stratus Consulting conducted an analysis of HPDI data for oil wells in 3 major unconventional oil plays and estimated uncontrolled releases of 624 Mcf/completion, 1,183 Mcf/completion, and 1,628 Mcf/completion for the Wattenburg (CO), Bakken (ND), and Eagle Ford (TX) formations, respectively.

Lastly, Allen et al. (2013) measured well completion releases from natural gas sites but 6 wells had gas-to-oil ratios that technically classify them oil wells. For these wells, potential gas releases were 5,482 Mcf/completion while actual gas releases were 114 Mcf/completion.[94] For all of these wells, the operator controlled the releases either through a REC (2 of the 6 wells) or by a flare (4 of the 6 wells).

Table 8: Uncontrolled Gas Releases from Hydraulically Fractured Oil Wells

Data from EPA review of FIP	**Average**
Average gas volume (Mcfd/well)	352
Average gas volume (Mcf/completion)	2,460
Data from ERG/EPA analysis	**Average**
Uncontrolled gas volume (Mcfd/well)	262
Uncontrolled gas volume (Mcf/completion/well; 3-day completion)	786
Uncontrolled gas volume (Mcf/completion/well; 7-day completion)	1,834
Data from EDF	**Average**
Uncontrolled gas releases in Wattenburg (CO) (Mcf/completion)	624
Uncontrolled gas releases in Bakken (ND) (Mcf/completion)	1,183
Uncontrolled gas releases in Eagle Ford (TX) (Mcf/completion)	1,628
Data from Allen et al.	**Average**
Potential gas releases (Mcf/completion)	5,482
Actual gas releases (Mcf/completion)	114

[94] Note, the researchers reported emissions in Mcf of CH4, which we converted to Mcf of gas using a methane concentration of 78.8%.

In the EPA's Technical Support Document for the NSPS Subpart OOOOa, the EPA uses for its analysis to examine the impacts of its rulemaking, the following emissions factors or metrics:

- Average daily natural gas produced: 999 Mcf/event;
- Potential methane emissions: 9.72 tons/event; and
- Potential VOC emissions: 8.14 tons/event.

C. Pneumatic Controllers

The GAO estimated that 16 Bcf of natural gas was vented from pneumatic devices on onshore federal leases in 2008. According to its findings, that volume represented about 12.7% of the total volume of gas vented and flared from onshore federal leases. It concluded that emissions could be reduced by 9.7 Bcf per year (a 61% reduction).[95] In its report, the GAO uses the word "device" rather than controller, so we believe that this source category included both pneumatic controllers and pneumatic pumps. We discuss pneumatic controllers and pneumatic pumps separately because the proposed requirements are different.

The regulatory landscape has changed since 2010 with action on the federal and state levels. In 2012, the EPA finalized its Oil and Natural Gas Sector: NSPS, requiring that new or modified continuous bleed pneumatic controllers be low-bleed controllers. The EPA finalized the NSPS on October 15, 2012, but the requirements for pneumatic controllers did not take effect for 1 year. On the state level, in 2014, the Colorado AQCC finalized a rule that extends the requirement for low bleed controllers to existing sources, requiring operators to replace high bleed controllers by 2015.

What are more recent estimates of gas loss from pneumatic controllers on Federal and Indian leases? In 2013, we estimate that 5.37 Bcf of natural gas was lost from the use of pneumatic controllers on Federal and Indian lands. The estimate was calculated using data from the 2015 GHG Inventory and the share of natural gas and crude oil production coming from Federal and Indian lands.[96]

What is the variability in gas loss from among the different types of pneumatic controllers? The 2015 GHG Inventory lists *potential* methane emission factors for pneumatic controllers in the natural gas production stage, by region, but it does not distinguish controllers by bleed rate or flow. We converted those potential emission factors from methane to whole gas using regional methane concentrations of natural gas and found that the the potential emission factors are about 18.25 scfh of whole gas per device across the regions. The EPA then calculates the net emissions by subtracting the estimated emissions reductions from the potential emissions, accounting for the voluntary and regulatory efforts to reduce the emissions from pneumatic controllers. In the 2015 GHG Inventory, the emissions reductions represent 54% of the potential emissions.

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[95] GAO 2010, pp. 12, 20.

[96] An ICF report concluded that the EPA's 2014 GHG Inventory emission estimates for pneumatic devices were underestimated, and that according to its analysis, emissions from pneumatic devices, at the well site and at gathering/compressor stations, represented a 41% increase from the Inventory's estimates. The ICF's high-level findings attribute 49.4 Bcf of methane emissions to high bleed continuous and intermittent devices in the U.S., which is roughly equivalent to 59.3 Bcf of natural gas using a methane content of 83.3%. Therefore, since our estimates are based on the 2015 GHG Inventory data, they too may be understated.

For the petroleum production sector, the 2015 GHG Inventory lists methane emission factors for low bleed and high bleed devices. Again, we converted those factors from methane to whole gas and found potential emission factors of 2.75 scfh of whole gas and 17.46 scfh of whole gas for low bleed and high bleed devices, respectively.

The EPA's Subpart W greenhouse gas reporting program instructs operators to report emissions using whole gas emission factors of 1.39 scfh, 13.5 scfh, and 37.3 scfh for low bleed, intermittent, and high bleed pneumatic devices.[97]

Allen et al. (2013) measured emissions from 79 natural gas sites and found average whole gas emissions of 5.1 scfh from low bleed devices and 17.4 scfh from intermittent devices. None of the sampled sites were equipped with high bleed devices. These data are summarized in Table 9.

Table 9: Pneumatic Device Natural Gas Emission Factors (scfh of whole gas)

Data Source	Description	Low Bleed Continuous	Intermittent Bleed	High Bleed Continuous
2015 GHG Inventory[1]	Potential emissions, Controllers on gas wells		18.25	
2015 GHG Inventory[2]	Emissions, Controllers on oil wells	2.75	na	17.46
EPA Subpart W	Emissions, Controllers on onshore oil and gas wells	1.39	13.5	37.3
Allen et al. (2013)	Measured emissions, Controllers on gas wells	5.1	17.4	nm

na = not available
nm = not measured
[1] The 2015 GHG Inventory lists potential emission factors for the natural gas production sector in scfd of methane, by region, which converted to scfh of whole natural gas (using regional methane content of natural gas) returns about 18.25 scfh of whole natural gas. The 2015 GHG Inventory then accounts for emissions reductions.
[2] The 2015 GHG Inventory lists potential emission factors for the petroleum production sector in scfd of methane, by type of continuous bleed device, which converted to scfh of whole natural gas (using the national methane content value) returns about 2.75 and 17.46 scfh of whole natural gas for low bleed and high bleed continuous devices, respectively. The 2015 GHG Inventory does not apply emissions reductions to pneumatic controllers in the petroleum production sector.

How common are the various types of pneumatic controllers? Due to the NSPS, we presume that all of the new or replacement continuous pneumatic devices ordered after August 23, 2011, have been low bleed devices, except for those instances where low bleed continuous devices may not have been technically feasible.

We do not have exact data on the number and variety of existing pneumatic controllers on Federal and Indian lands and must rely on estimates. The 2015 GHG Inventory suggests that there were 451,449 pneumatic controllers in the petroleum production system nationwide in 2013, including

[97] Code of Federal Regulations (CFR) at Title 40, Table W-1A of Subpart W of Part 98.

158,259 high bleed controllers and 293,190 low bleed controllers. Since crude oil production on Federal and Indian lands accounted for about 7.43% of the U.S. total crude production in 2013, we might expect that there were about 33,520 pneumatic controllers in the controllers in the petroleum production system on Federal and Indian lands, including about 11,750 high bleed controllers and 21,770 low bleed controllers.

The 2015 GHG Inventory does not provide an estimate for the number of high or low bleed pneumatic controllers in the natural gas production segment in 2013. Instead, it only provides the total number of controllers, without distinction. Using the regional share of natural gas production that came from Federal and Indian lands in 2013, we estimate the number of pneumatic controllers on Federal and Indian lands to be about 64,000. Of that amount, we might expect that 10% (or 6,400) are high bleed continuous pneumatic controllers.

Table 10: Estimated Number of Pneumatic Controllers on Federal and Indian Lands

NEMS Region	Number of Pneumatic Controllers, U.S.[1]	Federal and Indian Share of U.S. Gas and Oil Production (%)[2]	Estimated Number of Pneumatic Controllers on Federal and Indian Lands
Natural Gas System			
Northeast	74,171	0.05%	38
Midcontinent	156,870	1.42%	2,232
Rocky Mountain	112,463	53.58%	60,260
Southwest	66,275	1.87%	1,238
West Coast	2,564	4.17%	107
Gulf Coast	47,961	0.68%	326
Subtotal	**460,304**		**64,201**
Petroleum System			
High Bleed	158,259	7.43%	11,751
Low Bleed	293,190		21,770
Subtotal	**451,449**		**33,520**
Total	**911,753**		**97,722**

[1] Data from Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013 (EPA 2015), Annex 3.
[2] Based on ONRR sales data for 2013 and EIA production data for 2013.

Data on the distribution of low-bleed, high-bleed, and intermittent pneumatic controllers are available from two sources. An analysis of an American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) survey (see Table 11), published in 2012, showed a ratio of controllers per well or site of 0.99 and that 27% of pneumatic controllers at gas well sites were low-bleed, 49% were intermittent, and 24% were high-bleed. In addition, 33% of pneumatic controllers at gathering/compressor sites were low-bleed, 61% were intermittent, and 7% were high-bleed (percentages do not add to 100% due to rounding).

In contrast, ICF (2014) analyzed EPA's Subpart W data and determined the prevalence of high bleed continuous controllers to be lower. It determined that a ratio of controllers per well of 0.94 (as identified by the EPA's Inventory) was appropriate and that 40% of pneumatic devices were low bleed, 50% were intermittent, and 10% were high bleed. Further, it estimated that 75% of the intermittent devices were dump valves and 25% were non-dump valves. Dump valve devices, it asserts, have approximately 80% fewer emissions than non-dump valve devices, making them more akin to low bleed continuous devices.

When estimating the number of high bleed continuous pneumatic controllers in the natural gas production segment, we chose to use the assumption that 10% were high bleed devices (based on the ICF data), since the result of that calculation (6,400 high bleed controllers) in combination with the estimate for the petroleum production segment (11,750 high bleed controllers), returned a total number of controllers (18,150 high bleed controllers or 18.6% of the estimated number of total pneumatic controllers on Federal and Indian lands) that was in the middle of the range suggested by ICF and Shires & Lev-on.

We then remove the estimated number of existing controllers that would have been converted from high bleed to low bleed under recent regulations in Colorado and under Wyoming's regulation for the UGRB that will take effect in January 2017. We based the reductions on the percent of producing oil and gas wells in these states and areas (5% and 29%) for pneumatic controllers in the petroleum and natural gas sectors respectively. The remainder is an estimated 11,143 high bleed controllers in the petroleum production sector and 4,515 high bleed controllers in the natural gas production sector that would be impacted by the BLM's rule.

Table 11: API/ANGA Survey Data on Pneumatic Controllers

Parameter	Gas well sites		Gathering/compressor sites	
Number of wells or sites	48,046		1,988	
Number of controllers per well or site	0.99		8.6	
Number & percent of low-bleed controllers	12,850	27%	5,596	33%
Number & percent of high-bleed controllers	11,188	24%	1,183	7%
Number & percent of intermittent controllers	23,501	49%	10,368	61%

Source: Data come from Shires & Lev-on (2012)

D. Pneumatic Pumps

As previously discussed, the GAO provided estimates of gas lost from "pneumatic devices" which we believe includes estimates for pneumatic controllers and pneumatic pumps. As such, we believe that pneumatic pumps were included in the GAO's estimate that 16 Bcf of natural gas were vented from pneumatic devices on onshore federal leases in 2008.

The regulatory landscape has changed since 2010. In 2012, the EPA finalized its National Emissions Standards for Hazardous Air Pollutants (NESHAP) Review, requiring certain controls on glycol dehydration units (also referred to as the Kimray pumps).[98]

How much gas is lost from pneumatic pumps on Federal and Indian leases? We estimate that 2.46 Bcf of natural gas was lost in 2013 from the use of pneumatic pumps on Federal and Indian lands. Of that volume, we estimate that 0.65 Bcf was lost through the use of chemical injection pumps and that 1.81 Bcf was lost through the use of Kimray pumps.[99] These estimates were calculated using data from the 2015 GHG Inventory and the share of natural gas and crude oil production from Federal and Indian lands in 2013.

Further, the EPA indicates that within the chemical injection pump category, we would expect that piston pumps represent roughly half of the pumps and account for 10% of the emissions while diaphragm pumps represent the other half but account for 90% of the emissions. Accordingly, we estimate that of 0.65 Bcf of gas loss from chemical injection pumps, 0.065 Bcf was attributable to piston pumps and 0.585 Bcf was attributable to diaphragm pumps.

How common are the various types of pneumatic pumps and what is the variability in gas loss from among the different types of pumps?

The 2015 GHG Inventory lists activity data and potential[100] methane emission factors for chemical injection pumps (number of pumps) and Kimray pumps (MMscf per year of natural gas used), separately. Using those data, we estimate the number of chemical injection pumps using the same methodology described above. For 2013, we estimate that there were almost 10,000 gas-assisted chemical injection pumps on Federal and Indian lands, with about 5,000 being piston pumps and 5,000 being diaphragm pumps. We also estimate that 1.8 Tcf of natural gas was used by Kimray pumps on Federal and Indian lands. See Table 12. Data from the 2015 GHG Inventory, Annex 3, suggests that the potential natural gas emission factor is 315 scf per day (or 0.315 Mcf per day) for a chemical injection pump and 1,259 scf (or 1.259 Mcf) per MMscf of natural gas used by Kimray pumps. See Table 13.

The 2015 GHG Inventory indicates that emissions reductions account for 39% of the potential emissions from chemical injection pumps in the petroleum system, 5% of the potential emissions from chemical injection pumps in the natural gas system, and 39% of the potential emissions from the Kimray pumps.

For chemical injection pumps, we note that the emission factor in the 2015 GHG Inventory is 315 scf of natural gas per day per device, or 115 Mcf of natural gas per year per device. Potential emissions from chemical injection pumps are reported to be higher by several additional sources. The EPA's white paper on pneumatic devices explains that replacing a gas-assisted chemical injection pump with a solar-powered pump (with zero emissions) would net 183 Mcf of gas recovery per year per device (the data come from the EPA's Natural Gas STAR program). In its study, the ICF puts the gas recovery at 180 Mcf per year per device.

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[98] CITE NESHAP rule Fed reg. notice.

[99] Fugitive emissions from dehydrators are considered in the section detailing fugitive emissions.

[100] Potential emissions factors are emissions in absence of pollution controls.

These levels of gas recovery are about 70 Mcf per year per device higher than that suggested by the 2015 GHG Inventory emission factors. If we use the gas emissions level of 183 Mcf per year per device, instead of the 2015 GHG Inventory emission factors, then we might expect gas-driven chemical injection pumps to account for an additional 0.7 Bcf of lost natural gas in 2013.

Table 12: Estimated Activity Data for Pneumatic Pumps on Federal and Indian Lands, in 2013

NEMS Region	Number of Chemical Injection Pumps, U.S. (Count)	Natural Gas Using Kimray Pumps, U.S. (MMscf/y)	Federal and Indian Share of U.S. Gas and Oil Production (%)	Estimated Number of Chemical Injection Pumps on Federal and Indian Lands (Count)	Estimated Natural Gas Using Kimray Pumps on Federal and Indian Lands (MMscf/y)
Natural Gas System					
Northeast	763	6,227,750	0.05%	0	3,194
Midcontinent	14,362	4,127,254	1.42%	204	58,732
Rocky Mountain	13,674	3,134,748	53.58%	7,327	1,679,671
Southwest	2,998	2,005,783	1.87%	56	37,452
West Coast	1,738	104,425	4.17%	73	4,359
Gulf Coast	2,277	2,816,046	0.68%	15	19,150
Subtotal	**35,812**	**18,416,006**		**7,676**	**1,802,557**
Petroleum System					
No regional distinction	31,066	0	7.43%	2,307	0
Subtotal	**31,066**	**0**		**2,307**	**0**
Total	**66,878**	**18,416,006**		**9,982**	**1,802,557**

Table 13: 2015 GHG Inventory Potential Emission Factors for Pneumatic Pumps

Sector	Emission Factor for Chemical Injection Pumps (scf/day/pump)	Emission Factor for Kimray Pumps (scf/MMscf)
Natural Gas System	315	1,259
Petroleum System	315	NA

E. Liquids unloading

The GAO estimated that 17 Bcf of natural gas was vented or flared during liquids unloading on onshore Federal leases in 2008. According to its findings, that volume represented about 13.5% of the total volume of gas vented and flared from onshore federal leases. It concluded that releases could be reduced by 7.2 Bcf per year (a 42% reduction).[101] Since the publication of the GAO report, additional data about liquids unloading has become available.

What are more recent estimates of gas loss associated with liquids unloading on Federal and Indian lands? We estimate that 3.26 Bcf of natural gas was lost in 2013 during liquids unloading operations on Federal and Indian lands. Of that volume, we estimate that 1.1 Bcf of gas was lost from wells with plunger lifts and that 2.16 Bcf of gas was lost from wells without plunger lifts. These estimates were calculated using data from the 2015 GHG Inventory, Annex 3, including the regional prevalence of wells with plunger lifts, the regional prevalence of wells without plunger lifts, and emission factors for each. We chose to calculate releases using a bottom-up approach for this source because the prevalence of liquids unloading using plunger lifts and without using plunger lifts and the emission factors for each are highly variable across region. We then applied the prevalence and emission factors to the number of producing gas wells on Federal and Indian lands on January 1, 2014.[102]

What are the differences in gas releases among wells equipped with plunger lifts and those that are not? What is the prevalence of plunger lifts? The 2015 GHG Inventory lists activity data and emission factors, by region, for wells that conduct liquids unloading with plunger lifts and without plunger lifts. The data are informed by the API/ANGA survey, conducted in 2012 and presented in a study by Shires & Lev-On (2012).

The emission factors for venting during liquids unloading are variable among regions and among wells that vent with and without being equipped with plunger lifts. Generally speaking, since the EPA draws heavily upon the API/ANGA survey data, the regional activity data and emission factors are very similar to those presented by Shires & Lev-On. These data are presented in Table 14.

We note that in the Northeast and Midcontinent regions, the emission factors for gas wells with plunger lifts are higher than for gas wells without plunger lifts. Shire & Lev-On note that two respondents (representing 174 gas wells with plunger lifts that vent) from the Midcontinent region reported high frequencies of venting in which the plunger system vented during each plunger cycle for very short durations.

Data presented by Shires & Lev-On (2012) and Allen et al. (2013) provide further insight into the characteristics of the wells that vent to the atmosphere for liquids unloading, including the number of vents per well, the duration of the vents, and the production rates of the wells. From this data, we extrapolated the average cumulative duration of vents for wells, both with and without plunger lifts, for each region. The data are in Table 15.

Another study informing this discussion is Allen et al. (2013), mentioned above. The study measured 9 liquid unloading events and found average emissions that were one-fifth (or 20%) of the value used in the 2015 GHG Inventory. The emissions were highly variable across wells; 4 of the 9 events contributed more than 95% of the total emissions. Due to this variability and the small sample size, the authors caution against extrapolating the results to the larger population.

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[101] GAO 2010, pp. 12, 20.

[102] Simply scaling down the national emissions in the 2015 GHG Inventory according to the share of natural gas production from Federal and Indian lands in 2013 would return an estimate of 2.06 Bcf.

Table 14: Natural Gas Emission Factors for Gas Wells that Vent to the Atmosphere for Liquids Unloading (Mcfy per well)

Source:	**Shires & Lev-On (2012)**		**Allen et al. (2013)***	**EPA 2015 GHG Inventory**	
Region	**Gas wells with plunger lifts that vent (Calculated)**	**Gas wells without plunger lifts that vent (Calculated)**	**Gas wells without plunger lifts that vent (Measured)**	**Gas wells with plunger lifts that vent (Calculated)**	**Gas wells without plunger lifts that vent (Calculated)**
Northeast	315	166	139	315	166
Midcontinent	1,380	230	na	1,380	230
Rocky Mtn	135	2,315	4	154	2,578
Southwest	4	97	na	4	97
West Coast	na	na	na	345	304
Gulf Coast	69	250	569	70	301
National	**323**		**na**		

na = not able to determine from the reports.

*Allen et al. had a small sample size (9 wells: 1 in Northeast, 3 in Rocky Mountain, and 5 in the Gulf Coast) where it measured actual emissions. The authors caution against using these data for larger extrapolations.

The researchers witnessed liquids unloading of one variety, where the operator manually bypasses the well's separator and diverts the flow to an atmospheric (lower) pressure tank. The lower pressure endpoint allows more gas to flow, increasing velocity in the production tubing and lifting the liquids out of the well. Gas is discharged from the tanks through the tank vent, unless tanks have an emissions control system such as a combustor. The researchers did not measure emissions from wells conducting liquids unloading with plunger lifts or wells with uncontrolled well purging.

For all of the well unloading events observed, average methane emissions were 57 Mcf per event (range of 0.95 Mcf to 191 Mcf) and the average number of events per year for a well was 5.9 events (range of 1 to 12).[103] For the 3 well unloading events in the Rocky Mountain region, average methane emissions were lower and about 1.21 Mcf per event (range of 0.95 Mcf to 1.35 Mcf) and the average number of events per year for a well was 2.67 events (range of 2 to 4).[104] Looking at the well characteristics, it appears as though the duration of the blowdown and the volume of the wellbore play important roles in the emissions measured. In both cases, the wells in the Rocky Mountain region were lower than wells in the other regions.

The researchers also discuss the difference between measuring emissions and estimating emissions using a formula. For example, the EPA estimated the emissions based on well characteristics available in the API/ANGA survey. To compare methods, Allen et al. plugged the characteristics of the wells that they observed into the EPA's estimation formula. They found that the equation

[103] This translates to average methane emissions of 300 Mcf per well per year (range of 1.9 Mcf to 1,337 Mcf).
[104] This translates to average methane emissions of 9.88 Mcf per well per year (range of 1.9 Mcf to 5.3 Mcf).

produced estimates that were five times higher than the emissions actually observed. The researchers noted that liquid unloading in the sampled wells occurred infrequently (on average, 5.9 times per year) compared with the API/ANGA survey (on average, 32.57 times per year).

The researchers also noted the emission rate from liquid unloading (ranging from 100 g/min to 30,000 g/min of methane) was much higher than emission rates from completions (typically a few hundred grams per event per minute) and for production sites (typically tens of grams per minute per well). As such, a single unloading event could, during the short period that it occurs, result in emissions that are the equivalent of anywhere from just a few wells up to several thousand wells in routine production.

What is the prevalence of gas wells that require liquids unloading, either with plunger lifts or without plunger lifts? The 2015 GHG Inventory data suggest that 4.95% of all gas wells are equipped with plunger lifts and vent to the atmosphere during liquids unloading. Similarly, the data suggest that 8.25% of all gas wells do not have plunger lifts and vent to the atmosphere during liquids unloading. We note that in the Rocky Mountain region, where most of the gas wells on Federal and Indian Lands are located, the data suggest that most of the gas wells that vent to the atmosphere during liquids unloading are already equipped with plunger lifts.

The API/ANGA survey data, presented by Shires & Lev-On (2012), are similar. The survey included detailed data regarding liquids unloading from operators on 42,681 gas wells. Of the wells for which they received detailed responses, 27% were equipped with plunger lifts and 73% were not equipped with plunger lifts. About 21% of the wells with plunger lifts vented gas to the atmosphere and 9.3% of the wells without plunger lifts vented. Further, of the 42,681 gas wells with detailed data, 5.68% were equipped with plunger lifts and vented to the atmosphere while 6.80% were not equipped with plunger lifts and vented to the atmosphere.

How much gas is lost from liquids unloading activities on Federal and Indian leases? Using the 2015 GHG Inventory data by region, we estimate that about 3.26 Bcf of natural gas was lost during liquids unloading activities on Federal and Indian Lands in 2013. The estimated activity and the associated releases are as follows, and are also presented in Tables 17 and 18:

- About 6,952 wells equipped with plunger lifts that vent, accounting for 1.1 Bcf of natural gas vented; and
- About 1,547 wells not equipped with plunger lifts that vent, accounting for 2.158 Bcf of natural gas vented.

We note that since the majority of gas wells on federal and Indian lands are in the Rocky Mountain region, which has a higher percent of gas wells with plunger lifts than gas wells without plunger lifts, the total estimated number of gas wells with plunger lifts is greater than those without plunger lifts (even though the national percentages in Shires & Lev-On and the 2015 GHG Inventory would indicate otherwise).

Table 15: Other Information about Gas Wells that Vent to the Atmosphere for Liquids Unloading

Metric:	Average vents per well (per year)			Average time per vent (hours)			Average production rate (Mcfd of gas)			Average Cumulative Duration (hours/month)	
Source:	Shires & Lev-On		Allen et al.	Shires & Lev-On		Allen et al.	Shires & Lev-On		Allen et al.	Calculated using Shires & Lev-On data	
Region	with plunger lifts	without plunger lifts	without plunger lifts	with plunger lifts	without plunger lifts	without plunger lifts	with plunger lifts	without plunger lifts	without plunger lifts	with plunger lifts	without plunger lifts
Northeast	259.34	49.70	12.00	0.14	1.72	0.25	24.91	12.34	4,992	3.03	7.12
Midcontinent	2,035.84	10.22	na	0.66	1.76	na	298.63	333.65	na	111.72	1.50
Rocky Mtn	25.41	99.26	2.67	0.93	1.89	0.73	150.97	121.55	6,144	1.98	15.67
Southwest	1.09	2.42	na	0.27	1.03	na	365.38	797.64	na	0.02	0.21
West Coast	na	na	na	na	na	na	na	na	na	na	na
Gulf Coast	5.92	5.04	6.60	0.52	1.52	1.53	633.34	1,482.04	5,586	0.26	0.64
National	**343.72**	**32.57**	**5.90**	**0.11**	**1.90**	**1.00**	**104.30**	**45.90**	**5,760**	**3.15**	**5.16**

na = not able to determine from the reports.

*Allen et al. had a small sample size (9 wells: 1 in Northeast, 3 in Rocky Mountain, and 5 in the Gulf Coast) where it measured actual emissions. The authors caution against using these data for larger extrapolations.

Table 16: Prevalence of Gas Wells that Vent to the Atmosphere During Liquids Unloading (As a Percent of All Gas Wells)

Source:	Shires & Lev-On		2015 GHG Inventory	
Region	Gas wells with plunger lifts	Gas wells without plunger lifts	Gas wells with plunger lifts	Gas wells without plunger lifts
Northeast	nd	nd	4.36%	11.26%
Midcontinent	nd	nd	2.33%	4.14%
Rocky Mtn	nd	nd	12.88%	1.52%
Southwest	nd	nd	3.32%	19.47%
West Coast	nd	nd	7.58%	6.80%
Gulf Coast	nd	nd	2.32%	7.08%
National	**5.68%**	**6.80%**	**4.95%**	**8.24%**

nd = not able to determine from the report.

Table 17: Estimated Emissions from Liquids Unloading on Federal Lands in 2013, by NEMS Region and Well Characteristic

NEMS Region	Number of Gas Wells	CH4 Emissions (Metric Tons)	Raw Natural Gas Releases (Bcf)
Northeast	112	378	0.023
Midcontinent	59	610	0.038
Rocky Mountain	6,697	41,326	2.749
Southwest	662	855	0.055
West Coast	8	45	0.003
Gulf Coast	58	242	0.014
Total	**7,596**	**43,456**	**2.882**
Well Characteristics	**Number of Gas Wells**	**CH4 Emissions (Metric Tons)**	**Raw Natural Gas Releases (Bcf)**
Plunger Lift	6,158	14,581	0.967
Without Plunger Lift	1,438	28,874	1.915
Total	**7,596**	**43,456**	**2.882**

Table 18: Estimated Emissions from Liquids Unloading on Indian Lands in 2013, by NEMS Region and Well Characteristic

NEMS Region	Number of Gas Wells	CH4 Emissions (Metric Tons)	Raw Natural Gas Releases (Bcf)
Northeast	0	0	0.000
Midcontinent	26	262	0.016
Rocky Mountain	877	5,414	0.360
Southwest	0	0	0.000
West Coast	0	0	0.000
Gulf Coast	0	0	0.000
Total	**903**	**5,676**	**0.377**
Well Characteristics	**Number of Gas Wells**	**CH4 Emissions (Metric Tons)**	**Raw Natural Gas Releases (Bcf)**
Plunger Lift	794	2,024	0.134
Without Plunger Lift	109	3,653	0.243
Total	**903**	**5,676**	**0.377**

F. Oil And Condensate Storage Tanks

The GAO estimated that 18 Bcf of natural gas was lost from oil and condensate tanks on onshore federal leases in 2008. According to its findings, that volume represented about 14.3% of the total volume of gas vented and flared from onshore federal leases. It concluded that releases could be reduced by about 13 Bcf per year (a 72% reduction), through the installation of vapor recovery units.[105]

The regulatory landscape has changed since 2010 with action on the federal and state levels. In 2012, the EPA finalized its Oil and Natural Gas Sector NSPS. The NSPS establishes the following requirements[106] for storage vessels constructed, modified, or reconstructed after August 23, 2011 on new and existing well sites:

- Determine the VOC emission rate within 30 days;
- If the uncontrolled VOC emissions are equal to or greater than 6 tpy, the operator must reduce VOC emissions by 95 percent or more within 60 days;
- Operators must equip vessels with a cover that meets specifications;
- If VOC emissions drop below 4 tpy for 12 months and remain below 4 tpy, the operator may vent without controlling emissions.

NTL-4A does not place requirements on operators to capture or flare/combust gas vapors from storage tanks, but some states have requirements to control gas vapor emissions. In Colorado, tanks with uncontrolled emissions equal to or greater than 6 tpy of VOC must have emissions control with 95% efficiency (or 98% efficiency if combusted).[107] The operator must also have a STEM monitoring plan.[108]

California is the only state that we identified that specifies when an operator must recover vapors with a VRU. In California, crude tanks constructed after June 1, 1989 are subject to VOC control requirements, which generally require a vapor recovery system, pressure-vacuum relief value, or internal or external floating roof.[109] California requires a recovery system if the vapor pressure is equal to or greater than 11 pounds per square inch absolute (psia). Small producers with tanks of less than 0.5 psia and a throughput equal to or less than 50 bbl per day are exempt.[110]

How much gas loss is associated with venting from storage tanks on Federal and Indian leases? We estimate that 2.77 Bcf of natural gas was lost in 2013 from storage tank venting on Federal and Indian lands. Of that volume, we estimate that 1.82 Bcf was lost from storage tanks in the natural gas production segment and 0.95 Bcf of gas was lost from storage tanks in the petroleum production segment. These estimates were calculated using data from the 2015 GHG Inventory and the share of natural gas and crude oil production coming from Federal and Indian lands.

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[105] GAO 2010, pp. 12, 20.
[106] Subpart OOOO, Sec. 60.5395
[107] Regulation Number 7, Section XVII.C.1.b
[108] Ibid at Section XVII.C.2.b
[109] Rule 4623, Section 5.5.1
[110] Rule 4623, Section 5.5.2

What is the variability in gas loss from among the storage tanks? The 2015 GHG Inventory lists *potential* methane emission factors according to total volume of throughput in barrels of condensate or crude oil. For the natural gas system, the Inventory lists methane emission factors for condensate tanks without control devices and for condensate tanks with control devices, by region, which we then converted to whole gas emission factors using regional methane concentrations of natural gas ranging from 77.9% to 91.9%. For the petroleum system, the Inventory does not distinguish between tanks with or without control devices or by region, instead listing one methane emission factor which we then converted to a whole gas emission factor using a methane concentration of natural gas of 78.8%. See Table 19.

Table 19: Potential Methane and Natural Gas Emission Factors for Condensate and Crude Storage Tanks (scf/bbl)

NEMS Region	Uncontrolled Emission Factor (scf/bbl condensate)		Controlled Emission Factor (scf/bbl condensate)	
	CH4	Gas (Est.)	CH4	Gas (Est.)
Natural Gas Systems				
North East	21.87	25.67	4.37	5.13
Midcontinent	302.75	366.53	60.55	73.31
Rocky Mountain	21.87	28.22	4.37	5.64
South West	302.75	376.09	60.55	75.22
West Coast	21.87	23.80	4.37	4.76
Gulf Coast	21.87	24.80	4.37	4.95
Petroleum Systems				
No regional distinction	7.39	9.39	NA	NA

Allen et al. used on-site measurements or estimation for each for pneumatic controllers and pumps, fugitives, compressors, and tanks. For sites in the Rocky Mountain region, they found tanks emissions ranging from 0.00 to 4.28 scf/min (equating to about 0.00 to 6.16 Mcf/day). Seven of the sites had tank emissions less than 0.02 scf/min. The other three sites registered tanks emissions of 0.36, 2.82, and 4.28 scf/min. Most of the RM region sites had combustors on the tank vents, resulting in lower emissions. We believe that tanks on the sampled sites are more likely to have combustors than tanks on the average site because they are likely be newer and already complying with the NSPS, and since they are gas wells, operators are more likely to flare due to the methane (and VOC) content in the gas.

We note two characteristics of production on Federal and Indian lands that potentially lead to lower relative releases than that which the 2015 GHG Inventory reports for the U.S as a whole. First and foremost, the vast majority of production on Federal and Indian lands is in areas with lower relative condensate production. Similarly, a small minority of production on Federal and Indian lands is in areas with higher relative condensate production. Table 20 illustrates this concept. According to the 2015 GHG Inventory, Annex 3, condensate production from the Rocky Mountain and Gulf Coast regions represent almost 13% and 51%, respectively, of the total U.S. condensate production.

Meanwhile, in contrast, condensate production from Federal and Indian lands in the Rocky Mountain and Gulf Coast regions represent about 88% and 5%, respectively, of the total production from Federal and Indian lands.

The second characteristic of production on Federal and Indian lands that would lead to lower relative releases is that condensate production is lower in the regions with high emissions factors, again relative to condensate production nationwide. Table 20 illustrates this concept as well. The Midcontinent and Southwest regions are on the higher tier of methane emission factors, while the other 4 regions are on the lower tier. Condensate production on Federal and Indian lands in the Midcontinent and Southwest regions represents a combined 6.5% of the total condensate production on Federal and Indian lands, while U.S. condensate production in those regions represents over 27% of the total U.S. condensate production. Given both of these characteristics, we would expect relatively lower releases from condensate tanks on Federal and Indian lands compared to releases nationwide.

Table 20: Percent of Condensate Production and Methane Emission Factors, by Region

NEMS Region	U.S. - Percent of Condensate Production	Federal and Indian lands - Percent of Condensate Production, 2014	Uncontrolled Methane Emission Factor (scf/bbl condensate)	Controlled Methane Emission Factor (scf/bbl condensate)
North East	1.81%	0.04%	21.87	4.37
Midcontinent	18.77%	2.96%	302.75	60.55
Rocky Mountain	13.00%	88.36%	21.87	4.37
South West	8.66%	3.55%	302.75	60.55
West Coast	6.50%	0.34%	21.87	4.37
Gulf Coast	51.26%	4.76%	21.87	4.37

G. Leaks

How much gas loss is associated with venting from leaks on Federal and Indian leases? We estimate that about 3.2 Bcf of natural gas was lost as leaks in 2013. Of that volume, we estimate that 2.94 Bcf was fugitive gas from production operations in the natural gas production segment and that 0.27 Bcf was fugitive gas from production operations in the petroleum production segment. These estimates were calculated using data from the 2015 GHG Inventory and the share of natural gas and crude oil production coming from Federal and Indian lands.

The data show that roughly 92% of the fugitive losses come from the natural gas production segment and that only 8% come from the pretroleum production segment. Among the sources, fugitive losses from pipelines, separators, and meters/piping represent the largest shares of estimated releases at 42%, 17%, and 16%, respectively.

Table 21: Estimated Fugitive Releases from Federal and Indian Lands in 2013, by Production Segment and Emissions Source

Source	Net Natural Gas Releases from Natural Gas Production Segment (Bcf)	Net Natural Gas Releases from Petroleum Production Segment (Bcf)	Net Natural Gas Releases Total (Bcf)	Percent of Total
Wellheads, Non-associated Gas Wells (less fractured wells)	0.089		0.089	3%
Wellheads, Gas Wells with Hydraulic Fracturing	0.168		0.168	5%
Wellheads, Oil Wells		0.179	0.179	6%
Heaters/Treaters	0.157	0.034	0.191	6%
Separators	0.503	0.032	0.536	17%
Dehydrators	0.153		0.153	5%
Meters/Piping	0.515		0.515	16%
Headers		0.016	0.016	0%
Floating Roof Tanks		0.000	0.000	0%
Battery Pumps		0.001	0.001	0%
Large Reciprocating Stations	0.005		0.005	0%
Pipelines	1.350		1.350	42%
Sales Areas		0.005	0.005	0%
Total	**2.939**	**0.268**	**3.207**	**100%**

Allen et al. 2013 measured methane emissions at 190 onshore natural gas sites across the U.S. The researchers measured leak losses at 150 sites, including 146 sites with wells and 4 sites with separators and other equipment. The measurements, shown in Table 21, include leaks detected from piping, valves, separators, wellheads, and connectors. The researchers concluded that the emissions they observed are comparable to the average values of the potential emission factors listed in the EPA's current GHG Inventory at the time (which the reseachers calculated as 0.072 scf of methane/min/well).

Table 22: Measured Leak Losses from Natural Gas Well Sites

Activity	Unit	Appala-chian	Gulf Coast	Mid-continent	Rocky Mountain	All Facilities
Number of sites with wells visited	count	47	54	26	19	146
Number of wells with leaks detected	count	30	31	19	17	97
Methane emission rate	scf/min/well	0.098 ± 0.059	0.052 ± 0.030	0.046 ± 0.024	0.035 ± 0.026	0.064 ± 0.023
Whole gas emission rate (based on site specific gas composition)	scf/min/well	0.100 ± 0.060	0.058 ± 0.033	0.055 ± 0.034	0.047 ± 0.034	0.070 ± 0.024

Summary of results of Allen et al. 2013 study; Data in chart presented by EPA 2014, p. 23.

How prevalent are leaks from well sites? Not all well sites have detectable leaks. A study by Carbon Limits (2014) analyzed 4,293 surveys from 2 private sector firms that provide contracted services to operators to detect and measure gas losses from oil and gas facilities in the U.S. and Canada. We focus on their findings for well site losses, which included an analysis of 1,764 surveys. Of the surveyed well sites (ranging in size from 1 well to 15 wells), it found that 64% were either leaking or venting gas, while 36% of the well sites and well batteries had no leaks. Twenty-five percent of the well sites and well batteries had leaks with volumes of natural gas of 100 Mcf or more per year per facility, while 38% had leaks with volumes less than or equal to 99 Mcf per year per facility. The data also indicate that gas processing plants tend to leak the most, compressor stations leak the second highest amounts, and well sites and well batteries leak relatively less in comparison.

Table 23: Distribution of Facilities by Category and Leak Rate

Leak Rate (Mcf of gas per facility per year)	Percent of well sites and well batteries	Percent of compressor stations	Percent of gas processing plants
No Leaks	36%	11%	3%
<= 99	38%	30%	17%
100-499	18%	36%	32%
500-1499	5%	15%	25%
>= 1500	2%	9%	23%

Source: Carbon Limits 2014, p. 4

Appendix A-10: Results of BLM Survey of Royalty-Free Flaring Requests

In order to understand the nature of the flaring requests and to estimate the impact of the proposed provisions, we requested that 5 BLM field offices survey their recent flaring applications. We asked for information about the justifications operators provided for royalty-free flaring, the volumes they requested, and the economic data or analysis they submitted to support a determination that the gas is not economic to capture (where such a determination was made). The 5 field offfices were Dickinson (North Dakota), Carlsbad (New Mexico), Tulsa (Oklahoma), Vernal (Utah), and Worland (Wyoming). With the exception of Tulsa, these field offices represent areas where the flaring of associated gas is very prevalent. Tulsa has extensive Indian Lands production, and we wanted to ensure that our sample represented conditions on Indian lands as well as Federal.

The response from Dickinson included 19 applications for royalty-free flaring covering 19 wells. On 10 wells, operators made general requests to flare royalty-free for a year while planning for gas capture. These operators were producing between 24 to 248 bbl/day, and they requested royalty free flaring for between 4 to 221 Mcf/day. An operator on 1 well, producing 73 bbl/day and seeking royalty-free flaring of 3 Mcf/day, indicated that the gas capture was not economic. Operators on 8 wells, producing between 2-216 bbl/day and requesting 1-124 Mcf/day of royalty free gas flaring, cited pipeline capacity issues.

The response from Carlsbad included 20 applications for royalty free flaring covering 235 wells. Operators on 70% of the wells, requesting between 60 – 1,100 Mcf/day of royalty-free flared gas for the wells in the entire application, cited that the gas plant was down or was under maintenance. Operators on 26% of the wells, requesting between 5 – 500 Mcf/day of royalty-free flared gas for the wells in the application, cited pipeline or line capacity issues. Operators on 3% of the wells, requested 16 Mcf/day of royalty-free flaring for wells in the application for exploring gas injection. For 1 well, the operator was waiting on a right-of-way (ROW), producing 522 bbl/day and requesting royalty-free flaring of 756 Mcf/day. For the last well, the operator requested general associated gas flaring and did not provide a production or flaring volume.

The response from Tulsa included 16 applications for royalty-free flaring covering 16 wells. Applications for 14 of the wells indicated that the gas was not economic to capture. Each of those wells had production levels of 2 bbl/day of crude and requested 1 Mcf/day of royalty-free flared gas. For an exploration well, producing about 1,100 bbl/day and 75 Mcf/day, the operator cited a lack of infrastructure. For another exploration well, producing about 3,300 bbl/day and 20 Mcf/day, the operator cited a a lack of infrastructure and that the gas was not economic to capture (presumably the lack of infrastructure was the determining factor in the gas not being economic to capture).

The response from Vernal included 5 applications covering 252 wells. Operators on 70% of the wells requested royalty-free flaring because of gas plant shutdowns, maintenance, etc. The crude production ranged from 400 to 25,000 bbl/day/application and the requested royalty-free flaring was for 400 to 25,000 Mcf/day/application. Operators on the other 30% of wells indicated that they were waiting on a pipeline. The crude production ranged from 700 to 2,000 bbl/day/application and the requested royalty-free flaring was for 270 to 365 Mcf/day/application.

The response from Worland included 12 applicatons covering 12 wells. For 7 of the wells, the operators requested royalty-free flaring (ranging from 4-30 Mcf/day per well) of sour gas during compressor maintenance. For 3 wells, the operators requested royalty-free flaring of 30 Mcf/day each for additional well testing to determine the economic viability of the gas. For 1 of the wells, the operator requested royalty-free flaring of 70 Mcf/day, and cited a lack of infrastructure. For the last well, the operator indicated that gas capture was not economic and requested royalty-free flaring of 5 Mcf/day.

Table 24 shows a summary of the responses to the data call, the justifications for the applications to flare gas royalty-free, the average crude production, and the average volume of royalty-free gas requested to be flared, the average duration of requested royalty-free flaring, and the total volume of gas requested to be flared royalty-free during the application period (note that the flaring durations may vary). In addition, the table shows the percent of gas flared, by justification, and an estimate as to whether those volumes would be royalty-bearing under the proposed requirements.

Table 24: Summary of Responses to Data Call

BLM Field Office	Justification	# of Wells	Average Crude Production (bbld per well)	Average Requested Royalty-Free Gas Flaring (Mcfd per well)	Average Duration of Flaring (days)	Total Gas Flared (Mcf)	Percent of FO Total (%)	Presumed to be Royalty-Bearing under Proposed Rule?	Percent Royalty-Bearing under Proposed Rule (%)
Dickinson (ND)	Installing capture infrastructure	10	98	90	344	310,174	82.6%	Unknown	17%
	Pipeline or line capacity issues or interruptions	8	91	22	365	64,247	17.1%	Yes	
	Not economic to capture	1	73	3	365	1,095	0.3%	No	
Carlsbad (NM)	Installing capture infrastructure (Waiting on ROW)	1	522	756	90	68,040	19.9%	Unknown	80%
	Pipeline or line capacity issues or interruptions	60	NA	19	36	41,580	12.2%	Yes	
	Gas plant shutdown, maintenance, etc.	165	14	25	56	230,923	67.5%	Yes	
	Exploring gas injection	8	NA	2	90	1,440	0.4%	Yes	
	General request to flare casinghead gas	1	NA	NA	90	NA	NA	Unknown	
Tulsa (OK)	Not economic to capture	12	2	1	Indefinite	NA	0.0%	No	0%
	Lack of infrastructure (Exploration wells)	2	2,201	48	NA/ Indefinite	NA	100.0%	No	
Vernal (UT)	Installing capture infrastructure (Waiting on pipeline)	75	55	55	337	1,388,989	64.6%	Unknown	35%
	Gas plant shutdown, maintenance, etc.	177	144	144	30	762,000	35.4%	Yes	
Worland (WY)	Not economic to capture	1	0	5	Indefinite	NA	NA	No	94%
	Compressor or gas plant shutdown, maintenance, etc	7	15	1,239	15	126,334	93.8%	Yes	
	Lack of infrastructure (Wildcat well)	1	0	70	120	8,400	6.2%	No	
	Additional well testing	3	NA	NA	30	NA	NA	Unknown	
								Average	**45%**