

**Bureau of Land Management**

**43 CFR Parts 3100, 3160 and 3170**

**[ 17X.LLWO310000.L13100000.PP0000 ]**

**RIN 1004-AE14**

**Waste Prevention, Production Subject to Royalties, and Resource Conservation**

**AGENCY:** Bureau of Land Management, Interior.

**ACTION:** Final rule.

**SUMMARY:** The Bureau of Land Management (BLM) is promulgating new regulations to reduce waste of natural gas from venting, flaring, and leaks during oil and natural gas production activities on onshore Federal and Indian (other than Osage Tribe) leases. The regulations also clarify when produced gas lost through venting, flaring, or leaks is subject to royalties, and when oil and gas production may be used royalty-free on-site. These regulations replace the existing provisions related to venting, flaring, and royalty-free use of gas contained in the 1979 Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases, Royalty or Compensation for Oil and Gas Lost (NTL-4A), which are over 3 decades old.

**DATES:** The final rule is effective on January 17, 2017.

**FOR FURTHER INFORMATION CONTACT:** Timothy Spisak at the BLM Washington Office, 20 M Street, SE., Room 2134LM, Washington, DC 20003, or by telephone at 202-912-7311. For questions relating to regulatory process issues, contact Faith Bremner at 202-912-7441.

Persons who use a telecommunications device for the deaf (TDD) may call the Federal Relay Service (FRS) at 1-800-877-8339 to contact these individuals during normal business hours. FRS is available 24 hours a day, 7 days a week to leave a message or question with these individuals. You will receive a reply during normal business hours.

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## **II. Executive Summary**

### **A. Background**

This final 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 venting or flaring of the gas, and through equipment leaks. While oil and gas production technology has advanced dramatically in recent years, the BLM’s rules to minimize waste of gas have not been updated in over 30 years. The Mineral Leasing Act of 1920 (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, and that leases include “a provision that such rules . . . for the prevention of undue waste as may be prescribed

by [the] Secretary shall be observed,” *id.* at § 187. The BLM believes there are economical, cost-effective, and reasonable measures that operators can take to minimize gas waste. These measures will enhance our nation’s natural gas supplies, boost royalty receipts for American taxpayers, tribes, and States, reduce environmental damage from venting, flaring, and leaks of gas, and ensure the safe and responsible development of oil and gas resources.

The BLM’s onshore oil and gas management program is a major contributor to our nation’s oil and gas production. The BLM manages more than 245 million acres of land and 700 million acres of subsurface estate, making up nearly a third of the nation’s mineral estate. Domestic production from 96,000 Federal onshore oil and gas wells accounts for 11 percent of the Nation’s natural gas supply and 5 percent of its oil. In Fiscal Year (FY) 2015, operators produced 183.4 million barrels (bbl) of oil, 2.2 trillion cubic feet (Tcf) of natural gas, and 3.3 billion gallons of natural gas liquids (NGLs) from onshore Federal and Indian oil and gas leases. The production value of this oil and gas exceeded \$20.9 billion and generated over \$2.3 billion in royalties, which were shared with tribes, Indian allottee owners, and States.<sup>1</sup> Over the past decade, the United States has experienced a dramatic increase in oil and natural gas production due to technological advances, such as hydraulic fracturing combined with directional drilling. Yet the American public has not benefited from the full potential of this increased production, due to venting, flaring, and leaks of significant quantities of gas during the production process. Federal and Indian onshore lessees and operators reported to the Office of Natural Resources Revenue (ONRR) that they vented or flared 462 billion cubic feet

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<sup>1</sup> Office of Natural Resources Revenue, Statistical Information, <http://statistics.onrr.gov/ReportTool.aspx> using Sales Year - FY2015 – Federal Onshore – All States Sales Value and Revenue for Oil, Natural Gas Liquids (NGL), and Gas products as of September 7, 2016.



(Bcf) of natural gas between 2009 and 2015—enough gas to serve about 6.2 million households for a year, assuming 2009 usage levels.<sup>2</sup>

Venting, flaring, 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 may harm local communities and surrounding areas through visual and noise impacts from flaring, and contribute to regional and global air pollution problems of smog, particulate matter, and toxics (such as benzene, a carcinogen). Finally, vented or leaked gas contributes to climate change, because the primary constituent of natural gas is methane, an especially powerful greenhouse gas (GHG), with climate impacts roughly 25 times those of carbon dioxide (CO<sub>2</sub>), if measured over a 100-year period, or 86 times those of CO<sub>2</sub>, if measured over a 20-year period.<sup>3</sup> Thus, measures to conserve gas and avoid waste may significantly benefit local communities, public health, and the environment.

Congress has directed the BLM to oversee Federal and Indian oil and gas activities under multiple laws, including the 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.<sup>4</sup> In particular, the MLA requires the BLM to

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<sup>2</sup> BLM analysis of ONRR Oil and Gas Operations Report Part B (OGOR-B) data provided for 2009-2015; see Energy Information Administration (EIA), *Trends in U.S. Residential Natural Gas Consumption*, [http://www.eia.gov/pub/oil\\_gas/natural\\_gas/feature\\_articles/2010/ngtrendsresidcon/ngtrendsresidcon.pdf](http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngtrendsresidcon/ngtrendsresidcon.pdf) (reporting that in 2009, U.S. residential consumption was approximately 74 Mcf per household with natural gas service).

<sup>3</sup> See Intergovernmental Panel on Climate Change, *Climate Change 2013: The Physical Science Basis*, Chapter 8, *Anthropogenic and Natural Radiative Forcing*, at 714 (Table 8.7), available at [https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5\\_Chapter08\\_FINAL.pdf](https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf)

<sup>4</sup> 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.

ensure that lessees “use all reasonable precautions to prevent waste of oil or gas developed in the land.”<sup>5</sup> Leases issued by BLM must ensure that operations are conducted with “reasonable diligence, skill, and care” and that lessees comply with rules “for the prevention of undue waste.”<sup>6</sup>

Advancing those mandates, this rule replaces the BLM’s decades-old NTL-4A requirements related to venting and flaring, and to royalty-free use of oil and gas production; amends the BLM’s oil and gas regulations at 43 CFR part 3160 to include requirements for a waste minimization plan; and adds new subparts 3178 and 3179 to 43 CFR part 3170 that address royalty-free use of lease production (subpart 3178) and waste prevention through reduction of venting, flaring and leaks (subpart 3179). This rule will apply to all Federal and Indian (other than Osage Tribe) onshore oil and gas leases as well as leases and business agreements entered into by tribes (including IMDA agreements), as consistent with those agreements and with principles of Federal Indian law.<sup>7</sup>

This rule implements recommendations from several oversight reviews, including reviews by the Office of the Inspector General of the Department of the Interior (OIG) and the Government Accountability Office (GAO). These reviews raised concerns about waste of gas from Federal and Indian production, found that the BLM’s existing requirements regarding venting and flaring are insufficient and outdated, and expressed concerns about the “lack of price flexibility in royalty rates”<sup>8</sup> and about royalty-free use

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<sup>5</sup> 30 U.S.C. 225.

<sup>6</sup> 30 U.S.C. 187.

<sup>7</sup> Key statutes underpinning this proposed regulation contain exceptions for the Osage Tribe. Specifically, the Osage Tribe is exempted from the application of both the Indian Mineral Leasing Act and the Federal Oil and Gas Royalty Management Act, 25 U.S.C. 396f; 43 U.S.C. 1702(3), 1702(4). The leasing of Osage Reservation lands for oil and gas mining is subject to special Bureau of Indian Affairs regulations contained in 25 CFR part 226.

<sup>8</sup> GAO, Oil and Gas Royalties: The Federal System for Collecting Oil and Gas Revenues Needs Comprehensive Reassessment, GAO-08-691, September 2008, 6.

of gas. The GAO also noted that “around 40 percent of natural gas estimated to be vented and flared on onshore Federal leases could be economically captured with currently available control technologies.”<sup>9</sup> The OIG and GAO reports recommended that the BLM update its regulations to require operators to augment their waste prevention efforts, afford the BLM greater flexibility in rate setting, and clarify BLM policies regarding royalty-free, on-site use of oil and gas.

The BLM has engaged in substantial stakeholder outreach in the course of developing this proposal. In 2014, the BLM conducted a series of forums to consult with tribal governments and to solicit stakeholder views to inform the development of this proposed rule, with public meetings (some of which were livestreamed) in Colorado, New Mexico, North Dakota, and Washington, D.C.<sup>10</sup> The BLM continued to consult with stakeholders throughout the rule development process, including holding numerous meetings and calls with State and tribal representatives, individual companies, trade associations, and non-governmental organizations (NGOs). The BLM conducted additional outreach with States and tribes where there is extensive oil and gas production from BLM-administered leases. We issued a proposed rule on January 21, 2016, which was published on February 8, 2016, and accepted public comments through April 22, 2016, after extending the comment period. In addition, we held public meetings during the comment period in Farmington, New Mexico; Oklahoma City, Oklahoma; Denver, Colorado; and Dickinson, North Dakota. We also held separate meetings with tribes at each of these locations, and held further government-to-government consultation

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<sup>9</sup> GAO, 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, (Oct. 2010), 2.

<sup>10</sup> Further information can be found at the BLM oil and gas program’s outreach-events page: [http://www.blm.gov/wo/st/en/prog/energy/public\\_events\\_on\\_oil.html](http://www.blm.gov/wo/st/en/prog/energy/public_events_on_oil.html).

meetings at the request of several tribes. The BLM received approximately 330,000 public comments on the proposed rule, including approximately 1,000 unique comments.

The BLM is not the only regulator with the responsibility to oversee aspects of onshore oil and gas production, and throughout this rulemaking the BLM has focused on potential interactions of this rule with other Federal, State, or tribal regulatory requirements. For example, the U.S. Environmental Protection Agency (EPA) issued rules in 2012 and early 2016 to control emissions of methane and volatile organic compounds (VOCs) from new, modified and reconstructed oil and gas wells and production equipment, and many States and tribes regulate aspects of the oil and gas production process to address safety, waste, production accountability, and/or air quality concerns. Regulatory agencies often have overlapping authority and may adopt very similar measures to realize those complementary goals, such as improving air quality and reducing waste. For example, measures in this rule that aim to avoid the waste of methane gas through venting or leaks will also reduce methane pollution.

The BLM recognizes that overlapping regulatory regimes can create difficulties for operators, and has therefore very carefully considered and minimized potential overlaps with other Federal, State, or tribal regulations. The BLM aligned the requirements of this new rule with similar requirements adopted by the EPA and States, where practicable, and exempted equipment complying with relevant EPA requirements from overlapping requirements of this rule. In addition, this rule includes a provision that authorizes the BLM to grant variances from particular BLM requirements if a State or tribe demonstrates that a State, local, or tribal regulation imposes equally effective requirements.

It is critical to note, however, that neither EPA nor State and tribal requirements obviate the need for this rule. First, the BLM has an independent legal responsibility and a proprietary interest as a land and resource manager to oversee and minimize waste from oil and gas production activities conducted pursuant to Federal and Indian (other than Osage Tribe) leases, as well as to ensure that development activities on Federal and Indian leases are performed in a safe, responsible, and environmentally protective manner. The BLM's existing venting and flaring requirements are over 30 years old and predate significant technological developments. Updating and clarifying those requirements 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 carry out its responsibility, delegated by Congress, to ensure that the public's resources are not wasted and are developed in a manner that provides for long-term productivity and sustainability.

Second, as a practical matter, neither EPA nor State and tribal regulations fully address the issue of waste of gas from BLM-administered leases. The EPA regulations are directed at air pollution reduction, not waste prevention; they cover only new, modified and reconstructed sources; and they do not address wasteful routine flaring of associated gas from oil wells, among other things. Similarly, no State or tribe has established a comprehensive set of requirements addressing all three avenues for waste—venting, flaring, and leaks—and only a few States have significant requirements in even one of these areas. The BLM therefore believes this rule is a necessary step in fulfilling its statutory mandate to minimize waste of the public's and tribes' natural gas resources.

## **B. Summary of Rule**

This rule requires operators to take various actions to reduce waste of gas, establishes clear criteria for when flared gas will qualify as waste and therefore be subject to royalties, and clarifies which on-site uses of gas are exempt from royalties. The rule focuses on several key points or processes in the oil and gas production process where waste-prevention actions are most effective and least costly: venting and flaring of associated gas from development oil wells (routine flaring occurs at oil wells that dispose of gas as a waste product), gas leaks from equipment at the well site or elsewhere on the lease, operation of high-bleed pneumatic controllers and certain pneumatic pumps, gas emissions from storage vessels, downhole well maintenance and liquids unloading, and well drilling and completions. The following discussion summarizes the rule's requirements applicable to each of these aspects of the production process, and also outlines the rule's provisions with respect to royalties, and the interaction between the rule and related EPA and State or tribal regulations.

## **1. Venting and Flaring**

In 2014, operators vented about 30 Bcf and flared at least 81 Bcf of natural gas from BLM-administered leases, totaling 4.1 percent of the total production from those leases in that year, and sufficient gas to supply nearly 1.5 million households with gas for a year.<sup>11</sup> In 2015 operators flared at least 85 Bcf, a 114 percent increase from 2009 levels.<sup>12</sup> Roughly 83 Bcf of this flaring came from oil wells.<sup>13</sup> Analysis of data supplied by the ONRR suggests that most of the flaring was routine flaring of associated gas from development oil wells (as opposed to flaring during exploration, well testing, and

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<sup>11</sup> RIA at 16; see Energy Information Administration (EIA), *Trends in U.S. Residential Natural Gas Consumption*, [http://www.eia.gov/pub/oil\\_gas/natural\\_gas/feature\\_articles/2010/ngtrendsresidcon/ngtrendsresidcon.pdf](http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngtrendsresidcon/ngtrendsresidcon.pdf) (reporting that in 2009, U.S. residential consumption was approximately 74 Mcf per household with natural gas service).

<sup>12</sup> BLM analysis of ONRR OGOR-B data provided for 2009-2015 and EPA GHG Inventory data for 2014.

<sup>13</sup> RIA at 49.

emergencies). Over 88 percent of this flaring occurred in North Dakota, South Dakota, and New Mexico.

This rule prohibits venting of natural gas, except under certain specified conditions, such as in an emergency or when flaring is technically infeasible.<sup>14</sup> With respect to flaring, the rule requires operators to reduce wasteful flaring of gas by capturing for sale or using on the lease a percentage of their gas production. The required capture percentage increases over time, and is also adjusted to provide for a base level of “allowable” flaring that ramps down over time. This capture requirement builds on the proposed rule’s flaring limits, and modifies that approach in response to comments, to make compliance more feasible and less costly, while working towards phasing out routine flaring of associated gas from oil wells by increasing capture. Specifically, beginning one year from the effective date of the final rule, operators must capture 85 percent of their adjusted total volume of gas produced each month. This percentage increases to 90 percent in 2020, 95 percent in 2023, and 98 percent in 2026. An operator’s adjusted total volume of gas produced is calculated based on the quantity of high pressure gas produced from the operator’s development oil wells that are in production, adjusted to exempt a specified volume of gas per well, which declines over time. Beginning one year from the effective date of the final rule, operators are allowed to exempt 5,400 Mcf gas per well per month, and this quantity declines to 3,600 beginning in 2019, 1,800 in 2020, 1,500 in 2021, 1,200 in 2022, 900 in 2024, and 750 from 2025 on.

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<sup>14</sup> See 43 CFR 3179.6.

The final rule gives operators the option to meet their capture targets on a lease-by-lease basis, or an average basis over all of their Federal or Indian production from development oil wells county-by-county or State-by-State. Giving operators the ability to average their rates of gas capture over geographic areas beyond individual leases enhances flexibility and makes the targets less costly to meet. Similarly, the more extended phasing in of the capture targets eases costs and compliance burdens, while allowing appropriate planning and investment by industry to meet more stringent targets in out years. At the same time, the BLM recognizes that it has a statutory responsibility to ensure that operators minimize waste of public resources. Accordingly, the BLM has structured the capture targets to ensure that operators will achieve overall reductions in wasteful flaring that are comparable to, and eventually slightly greater than, what the BLM estimated would have been achieved under the proposed rule.

The BLM estimates that, once fully implemented, the capture targets will reduce flaring by up to 49 percent relative to 2015 levels. Like the proposed rule, the final rule also retains the BLM's discretion to craft alternative requirements for certain operators that cannot meet the baseline flaring reduction obligations. Specifically, the final rule allows the BLM to adjust the capture target for an operator on an existing lease that demonstrates to the BLM that meeting the target would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. In assessing the operator's showing, the BLM will consider the costs of gas capture, and the costs and revenues of all oil and gas production on the lease.

As explained in the proposed rule, the initial flaring limitations were intended to motivate operators to increase their capture of gas associated with oil development, since



a reduction in flaring is achieved most effectively by an increase in capture.

Consequently, flaring limitations and capture requirements are two sides of the same coin. Increasing capture is the BLM's primary goal in imposing these waste prevention requirements, and we concluded that it would be a more direct means of achieving that goal to require capture rather than merely encourage it through the imposition of flaring limits. In modifying the rule in this way, we have determined that both approaches are expected to achieve comparable results, in terms of both increasing capture and reducing wasteful flaring.

In addition, this rule finalizes the proposal to require operators to submit a Waste Minimization Plan when they apply for a permit to drill a new development oil well. Preparation of a Waste Minimization Plan ensures that the operator carefully considers and plans for how it will capture the gas that will be produced, before the operator drills a well. While the provisions of a plan will not be enforceable against the operator, plan submission is mandatory, and the plan must include specific elements listed in the regulations. As in the proposed rule, failure to submit a complete and adequate plan could be grounds for denial of an application for permit to drill (APD).

## **2. Leaks**

Based on our estimates, leaks are the second largest source of vented gas from Federal and Indian leases, accounting for about 4 Bcf of the natural gas lost in 2014.<sup>15</sup> Our analysis indicates that Leak Detection and Repair (LDAR) programs are a cost-effective means of reducing waste in oil and gas production, and multiple studies have

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<sup>15</sup> RIA at 3.

found that once leaks are detected, the vast majority can be repaired with a positive return to the operator.<sup>16</sup>

Like the proposed rule, the final rule requires operators to use an instrument-based approach to leak detection. The final rule allows operators to use optical gas imaging equipment, portable analyzers deployed according to the protocol prescribed in EPA's Method 21,<sup>17</sup> or an alternative leak detection device approved by the BLM. In response to comments on the proposed rule, the final rule was revised to be consistent with the EPA's final requirements under 40 CFR part 60 subpart OOOOa, requiring operators to conduct semi-annual inspections at well sites and quarterly inspections at compressor stations. Operators may also request BLM approval of an alternative instrument-based leak detection program; the BLM may approve such a program if it finds that the program would reduce leaked volumes by at least as much as the BLM program. Operators must repair a leak within 30 days of discovery, absent good cause, and verify that the leak is fixed. Operators must also keep records documenting the dates and results of leak inspections, repairs, and follow-up inspections.

### **3. Reducing Venting from Equipment and Practices**

Like the proposed rule, the final rule includes requirements to update old, inefficient equipment and to follow best practices to minimize waste through venting. These provisions address gas losses from pneumatic controllers and pumps, storage vessels, liquids unloading, and well drilling and completions.

#### **a. Pneumatic Controllers and Pumps**

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<sup>16</sup> RIA at 27.

<sup>17</sup> See 40 CFR part 60, appendix A-7.

We estimate that on BLM-administered leases in 2014, operators lost about 14.9 Bcf of natural gas from pneumatic controllers and about 2.3 Bcf from pneumatic pumps.<sup>18</sup> A recent study by the consulting firm ICF International (ICF) identified replacement of high-bleed pneumatic controllers (those with bleed rates higher than 6 standard cubic feet (scf)/hour) with low-bleed pneumatic controllers (those with bleed rates of 6 scf/hour or less) as one of the most inexpensive options for reducing methane losses, estimating that replacing these devices would actually save industry \$2.65 per Mcf of avoided methane emissions.<sup>19</sup> Like the proposed rule, the final rule requires operators to replace high-bleed pneumatic controllers with low-bleed or no-bleed pneumatic controllers within one year of the effective date of the final rule. This requirement tracks existing requirements in Colorado and Wyoming (in part of the State), and it applies only to pneumatic controllers that are not covered by EPA regulations.

For pneumatic pumps, the final rule requires the operator to replace pneumatic diaphragm pumps that operate 90 or more days per year with zero-emissions pumps, or route the pump exhaust gas to processing equipment. If use of a pneumatic pump is required based on the function the pump must serve, and the operator determines that routing the exhaust gas to processing equipment would be technically infeasible or unduly costly, the operator must route the pneumatic diaphragm pump to a combustor or flare, if one is located on the site.

The BLM modified the requirements in the proposed rule for pneumatic pumps in response to comments and to better align with the EPA's final subpart OOOOa requirements. For example, the BLM eliminated the proposed requirements for chemical

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<sup>18</sup> RIA at 4.

<sup>19</sup> ICF International, Economic Analysis of Methane Emission Reduction Opportunities in the U.S. in the Onshore Oil and Natural Gas Industries, 4-4 (Mar. 2014), available at [https://www.edf.org/sites/default/files/methane\\_cost\\_curve\\_report.pdf](https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf) (ICF 2014 Study) (base case assumed \$4/Mcf price for recovered gas and a 10 percent discount rate/cost of capital).

injection pumps and diaphragm injection pumps that operate relatively infrequently, as we believe that these pumps vent relatively small quantities of gas. Like the proposed rule, the final rule does not apply to pneumatic pumps that are subject to EPA regulations.

The final rule provides that an operator can receive an exemption from the requirements for pneumatic controllers or pumps if the operator demonstrates and the BLM concurs that replacing the pneumatic pump(s) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. In making this determination, the BLM will consider the costs of capture, and the costs and revenues of all oil and gas production on the lease.

b. Storage Vessels

We estimate that 2.94 Bcf of natural gas was lost in 2014 from storage tank venting on Federal and Indian lands.<sup>20</sup> Of that volume, we estimate that 1.54 Bcf was lost from storage vessels used in natural gas production and 1.4 Bcf of gas was lost from storage vessels used in oil production.<sup>21</sup> Tank vapors can be controlled by installing a vapor recovery unit (VRU) or by routing them to a flare or combustor. New, modified and reconstructed vessels used in oil and gas production are already subject to EPA emissions limits, which require that individual storage vessels with VOC emissions equal to or greater than 6 tons per year (tpy) achieve at least a 95 percent reduction in VOC emissions from baseline levels. Colorado and part of Wyoming have similar, somewhat more stringent requirements for storage vessels.<sup>22</sup>

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<sup>20</sup> RIA at 17.

<sup>21</sup> RIA at 17.

<sup>22</sup> Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001-9, Sections XII.D-F; XVII.C; Wyoming, Nonattainment Area Regulations Ch. 8, Section 6(c) (June 2015), available at <http://soswy.state.wy.us/Rules/RULES/9868.pdf>.

Like the proposed rule, this final rule includes requirements to reduce gas losses from existing storage vessels, which are not covered by the EPA standards. Using the same applicability threshold as EPA and Colorado (6 tpy of VOCs, which the BLM is using as a proxy for natural gas losses since the VOCs in this context are coming from the natural gas from storage vessels), the rule requires operators to route storage vessel vapor gas to a sales line, if the storage vessel has the potential to emit at least 6 tpy of VOCs. If an operator determines that compliance with this requirement is technically infeasible or unduly costly, the operator may instead route the tank vapor gas to a combustor or flare. Like the proposed rule, this final rule allows operators to request an exemption from these requirements if the operator demonstrates, and the BLM concurs, that complying with the requirements would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. In making this determination, the BLM will consider the costs of compliance, and the costs and revenues of all oil and gas production on the lease.

c. Well Maintenance and Liquids Unloading

We estimate that 3.26 Bcf of natural gas was lost in 2014 during liquids unloading operations on Federal and Indian lands.<sup>23</sup> There are a wide variety of methods for liquids unloading, and technological developments, such as automated well controls and plunger lift systems, now allow liquids to be unloaded with minimal loss of gas. The BLM expects prudent operators to use available technologies and practices to minimize gas losses, and we believe that the failure to use such technologies and practices during liquids unloading constitutes waste.

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<sup>23</sup> RIA at 3.

The final rule does not adopt the provision from the proposed rule that would have prohibited manual well purging from new wells, due to concerns about the technical feasibility of such a ban. Instead, the final rule requires an operator to: (1) minimize gas vented to unload liquids, consistent with safe operations; (2) optimize the operation of the plunger lift or automated well control system, at wells equipped with such a system, to minimize gas losses from the system to the extent possible; (3) consider other methods for liquids unloading and determine that they are technically infeasible or unduly costly, prior to manually purging a well for the first time; and (4) comply with specified procedures and document venting events when unloading liquids by manual well purging.

d. **Reduction of Waste from Drilling, Completion, and Related Operations**

We estimate that in 2014, 1.12 Bcf of natural gas was lost during drilling, completion, and refracturing (sometimes referred to by the broader term “workover”) operations on BLM-administered leases.<sup>24</sup> The EPA requires new hydraulically fractured and refractured oil or gas wells to capture or flare gas that otherwise would be released during drilling and completion operations. The BLM final rule also includes provisions to minimize the waste of gas during these operations by requiring operators to capture, use, flare, or inject the gas. While we do not expect that these provisions will obligate operators to take any additional actions beyond what they must do to comply with the EPA requirements, we believe it is appropriate for the BLM to adopt its own provisions governing operator conduct, to fulfill its independent statutory obligation to minimize waste of oil and gas resources on BLM-administered leases.

**4. Royalty Provisions Governing New Competitive Leases**

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<sup>24</sup> RIA at 3.

The final rule revises 43 CFR 3103.3-1, which governs royalty rates applicable to onshore oil and gas leases, to make the rule text parallel to the BLM’s statutory authority, which specifies that competitively-issued BLM-administered leases “shall be conditioned upon the payment of a royalty at a rate of *not less than* 12.5 percent in amount or value of the production removed or sold from the lease.” 30 U.S.C. 226(b)(1)(A). The final version of 43 CFR 3103.3-1 thus makes clear that for competitive leases issued after the effective date of this rule, the BLM has the flexibility to set rates at or above 12.5 percent. This change finalizes this provision as it was proposed, and responds to findings and recommendations in audits from the GAO. The final rule does not, however, set a new rate for competitively-issued leases.

Like the proposed rule, the final rule specifies the fixed, statutory rate of 12.5 percent for all noncompetitive leases issued after the effective date of the rule, as required by statute.<sup>25</sup> In addition, the final rule makes clear that the royalty rate on all existing leases remains the rate prescribed in the lease or in regulations applicable at the time of lease issuance.

## **5. Unavoidable Versus Avoidable Losses of Gas**

Like the proposed rule, the final rule also updates the pre-existing royalty provisions in NTL-4A to more clearly and specifically define when a loss of gas is considered “unavoidable” and royalty-free, and when it is considered “avoidable” and subject to royalties. A loss of gas is deemed unavoidable when an operator has complied with all applicable requirements and taken prudent and reasonable steps to avoid waste, and the gas is lost from one of the operations or sources specified in this final regulation, subject to certain limitations. The specified operations and sources include emergencies;

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<sup>25</sup> 30 U.S.C. 226(c)(1).

well drilling, completions, and tests; normal operations of pneumatic devices and storage vessels; liquids unloading; leaks; equipment or pipeline maintenance requiring depressurization; and residual gas after stripping of natural gas liquids. A loss of gas is also deemed unavoidable when gas is flared from a well that is not connected to a gas pipeline, provided the BLM has not otherwise determined that the loss of gas is avoidable. All other losses of gas, as well as any gas flared in violation of the capture requirement (regardless of whether the well is connected to a pipeline), are deemed avoidable and subject to royalties. By establishing clear-cut categories for unavoidable and avoidable losses, the final rule will dramatically reduce the large number of requests for approval to flare royalty-free that operators have had to file and the BLM has had to process each year.

## **6. Interaction with EPA and State Regulations**

Like the proposed rule, this final rule seeks to minimize regulatory overlap. Thus, if EPA and/or States or tribes have adopted requirements that are at least as effective as and would potentially overlap with the provisions of this rule, the final rule provides a means for operators to comply with the EPA, State, local or tribal requirements in lieu of the BLM requirements. Specifically, in cases in which EPA rules limit venting from equipment or require leak inspections and repairs, those operators that are in compliance with those EPA requirements are deemed, under this rule, to be in compliance with the comparable BLM requirements. With respect to State, local, or tribal rules, the final rule allows a State or tribe to request a variance from a particular BLM regulation. If the variance is granted, the BLM has the authority to enforce the specific provisions of the State, local, or tribal rule for which the variance was granted, in lieu of the comparable



provisions of the BLM rule. As clarified in the final rule, the BLM may grant a State or tribal variance request only if the BLM determines that the State, local, or tribal rule would perform at least as well as the BLM provision to which the variance would apply, in terms of reducing waste of oil and gas, reducing environmental impacts from venting and/or flaring of gas, and ensuring the safe and responsible production of oil and gas.

## **7. Other Provisions**

Like the proposed rule, the final rule includes provisions that update and clarify pre-existing BLM requirements regarding when operators may use oil or gas from a lease for production activities without owing royalties on the oil or gas used. In addition, like the proposed rule, the final rule includes provisions specifying when operators must measure the volumes of gas vented or flared, and requiring operators to report to ONRR volumes of gas vented or flared.

## **8. Summary of Costs and Benefits**

Overall, the BLM estimates that the benefits of this rule would outweigh its costs by a significant margin. Under certain assumptions, for example, the rule is expected to produce net benefits ranging from \$46 million to \$199 million per year (annualizing capital costs using a 7 percent discount rate) or from \$50 million to \$204 million per year (annualizing capital costs using a 3 percent discount rate).<sup>26</sup>

### **a. Costs**

The BLM estimates that this rule will pose costs ranging from \$114 – \$279 million per year (using a 7 percent discount rate to annualize capital costs) or \$110 - \$275 million per year (using a 3 percent discount rate to annualize capital costs) over the next

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<sup>26</sup> BLM, Economic Impact and Regulatory Threshold Analysis for 43 CFR 3178 (Royalty Free Use of Production) and 43 CFR 3179 (Venting and Flaring Requirements) (2015) (hereinafter RIA) at 6.

10 years.<sup>27</sup> These costs include engineering compliance costs and the social cost of minor additions of carbon dioxide to the atmosphere, resulting from the on-site or downstream use of gas that is newly captured as a result of this rule.<sup>28</sup> The engineering compliance costs presented do not include potential cost savings from the recovery and sale of natural gas (those savings are shown in the summary of benefits).

In some areas, operators have already undertaken, or plan to undertake, voluntary actions to address gas losses. To the extent that operators are already in compliance with the requirements of this final rule, the above estimates overstate the likely impacts of the rule.

We expect that cost impacts on individual operators would be small, even for businesses with less than 500 employees. In the Regulatory Impact Analysis (RIA), we estimate that average costs for a representative small operator would increase by about \$55,200, which would result in an average reduction in profit margin of 0.15 percentage points.<sup>29</sup>

b. Benefits

We measure 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 methane (a potent GHG) and other air pollutants released into the atmosphere. As with the estimated costs, we expect benefits on an annual basis. The BLM estimates that this rule would result in monetized benefits of \$209 – \$403 million per year (using model averages of the social cost of methane with a 3 percent discount

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<sup>27</sup> RIA at 4.

<sup>28</sup> Some gas that would have otherwise been vented would now be combusted on-site or presumably downstream to generate electricity. As described in the RIA, the estimated value of these carbon additions would not exceed \$30,000 in any given year.

<sup>29</sup> RIA at 129. These estimates rely on 2014 company data, and use a 7 percent discount rate.

rate).<sup>30</sup> We estimate that the final rule would reduce methane emissions by 175,000-180,000 tpy, roughly a 35% reduction in methane emissions from the 2014 estimates, and which we estimate to be worth \$189 - \$247 million per year (this social benefit is included in the monetized benefit above).<sup>31</sup>

Adoption of the final rule will also have numerous ancillary benefits. These include improved quality of life for nearby residents, who note that flares are noisy and unsightly at night; reduced release of VOCs, including benzene and other hazardous air pollutants; and reduced production of nitrogen oxides (NOx) and particulate matter, which can cause respiratory and heart problems.

c. Net Benefits

Overall, the BLM estimates that the benefits of this rule outweigh its costs by a significant margin. The BLM expects net benefits ranging from \$46 – \$199 million per year (using a 7 percent discount rate to annualize capital costs) or \$50 – \$204 million per year (using a 3 percent discount rate to annualize capital costs). Specifically, assuming a 7 percent discount rate to annualize capital costs, we estimate the following annual net benefits in selected years:

- \$99 – \$115 million in 2018;
- \$51 – \$93 million in 2022; and
- \$120—\$189 million in 2026.

Assuming a 3 percent discount rate to annualize capital costs, we estimate the annual net benefits would be:

- \$103 – \$119 million in 2018;

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<sup>30</sup> RIA at 5.

<sup>31</sup> RIA at 110. We also estimate that the final rule would have an incidental benefit of reducing VOC emissions by 250,000-267,000 tpy (this benefit is not monetized in our calculations).

- \$55 – \$97 million in 2022; and
- \$125 – \$193 million in 2026.<sup>32</sup>

d. Influence on Production

The final rule has a number of requirements that are expected to influence the production of natural gas, NGLs, and crude oil from onshore Federal and Indian oil and gas leases. We estimate the following incremental changes in production, noting the representative share of the total U.S. production in 2015 for context. We estimate additional natural gas production, ranging from 9 – 41 Bcf per year (representing 0.03 – 0.15 percent of the total U.S. production), and a reduction in crude oil production ranging from 0.0 – 3.2 million bbl per year (representing 0 – 0.07 percent of the total U.S. production). We also expect 0.8 Bcf of gas to be combusted on-site that would have otherwise been vented. Combined, the rule will reduce venting by about 35 and reduce flaring by 49%, depending on the year.<sup>33</sup>

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

e. Royalties

We estimate that this final rule will produce additional royalties of \$3-\$10 million per year (discounted at 7 percent) or \$3-\$14 million per year (discounted at 3 percent).<sup>34</sup>

### III. Background

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<sup>32</sup> RIA at 111.

<sup>33</sup> RIA at 5.

<sup>34</sup> RIA at 143.

The BLM's onshore oil and gas management program is a major contributor to the nation's oil and gas production. The BLM manages more than 245 million acres of land and 700 million acres of subsurface estate, comprising nearly a third of the nation's mineral estate. Domestic production from over 96,000 Federal onshore oil and gas wells accounts for 11 percent of the Nation's natural gas supply and 5 percent of its oil supply. In FY 2015, the ONRR reported that operators produced 183.4 million bbl of oil, 2.6 Tcf of natural gas, and 3.3 billion gallons of NGLs from onshore Federal and Indian oil and gas leases. The production value of this oil and gas exceeded \$20.9 billion and generated over \$2.3 billion in royalties.<sup>35</sup>

Over the past decade, the United States has experienced a dramatic increase in oil and natural gas production due to technological advances, such as hydraulic fracturing combined with directional drilling. This boost in production has brought many benefits in the form of expanded and more secure domestic supplies, lower prices, increased economic activity in certain regions of the country, and greater royalty revenues for Federal, State, and tribal governments.

At the same time, the American public has not benefited from the full potential of this increased production, as the increase in oil production has been accompanied by significant and growing quantities of wasted natural gas. Between 2009 and 2015, operators on BLM-administered leases wasted enough natural gas to serve over 6.2 million homes for 1 year, according to data reported to ONRR.<sup>36</sup>

#### **A. Impacts of Waste and Loss of Gas**

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<sup>35</sup> Office of Natural Resources Revenue, Statistical Information, <http://statistics.onrr.gov/ReportTool.aspx> using Sales Year - FY2015 – Federal Onshore – All States Sales Value and Revenue for Oil, NGL, and Gas products as of September 21, 2016.

<sup>36</sup> Office of Natural Resources Revenue, Statistical Information, <http://statistics.onrr.gov/ReportTool.aspx> using Sales Year - FY2015 – Federal Onshore – All States Sales Value and Revenue for Oil, NGL, and Gas products as of September 7, 2016.

As explained in the proposed rule preamble section IV.B, natural gas is a limited and valuable public resource, which is critical to U.S. energy security and national security. Natural gas also provides significant economic benefits as an energy source for electricity generation and industrial and residential use, and as a feedstock for manufacturing. Royalty payments on natural gas sales provide Federal, State, and tribal governments with over \$3 billion in revenues each year.

Venting, flaring, and leaks of natural gas from production on BLM-administered sites waste this limited natural resource and deprive the American public and tribes of the security and economic benefits that this resource, which belongs to the public and tribes, would otherwise provide. In addition to the economic and security losses, the waste of natural gas also imposes public health and environmental costs, in the form of air pollution, such as smog and regional haze; emissions of hazardous air pollutants, some of which are carcinogenic; and emissions of methane, a powerful contributor to global warming and a primary target for reduction under the President's Climate Action Plan.<sup>37</sup> Absent stronger provisions to reduce natural gas waste on Federal lands, the avoidable loss of gas will continue to threaten climate stability and undermine respiratory and cardiovascular health.

## **B. Purpose of the Rule**

### **1. Overview**

The purpose of this rule is to reduce waste of natural gas owned by the American public and tribes, which occurs during the oil and gas production process. While the BLM already regulates venting and flaring of natural gas during oil and gas production

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<sup>37</sup> The President's Climate Action Plan (June 2013) (<https://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>).

on Federal and Indian (other than Osage Tribe) leases, the current requirements are over 30 years old and do not reflect modern technologies, practices, and understanding of the harms caused by venting, flaring, and leaks of gas. Oversight reviews have also suggested that the current requirements are insufficiently clear in their directives, which complicates implementation for BLM staff and creates uncertainty for oil and gas operators. Today's rule updates the existing provisions to direct operators to take reasonable and common-sense measures to prohibit routine venting, minimize the quantities of natural gas routinely flared, reduce natural gas losses through leaks, and deploy up-to-date technology to reduce routine losses from production equipment.

## **2. Issues Addressed by Rule**

### **a. Large Quantities of Natural Gas Are Wasted on Federal and Indian Leases**

As explained in the proposed rule preamble section IV.H.1, while there is some uncertainty regarding the total volume of natural gas lost during production on public and tribal lands, the volume is unacceptably high.

There is no single definitive source for the total volume of natural gas losses from oil and gas production on Federal Lands. BLM efforts to estimate the total volume are informed by the Oil and Gas Operations Report Part B (OGOR-B) filed with the ONRR, the EPA Greenhouse Gas Inventory,<sup>38</sup> data from the EPA Greenhouse Gas Reporting Program,<sup>39</sup> and numerous studies discussed in the preamble to the proposed rule and provided by commenters. Each data set, however, has limitations. The ONRR data rely on self-reporting, and there is substantial variation in the types of losses that different operators report (and certain types of losses, such as most leaks, are not reported at all).

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<sup>38</sup> U.S. EPA, *U.S. Greenhouse Gas Inventory Report: 1990-2014* ), available at <https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-main-text.pdf> ("2016 GHG Inventory").

<sup>39</sup> U.S. EPA, *Greenhouse Gas Reporting Program; Petroleum and Natural Gas Systems*. Available at <https://www.epa.gov/ghgreporting/ghgrp-petroleum-and-natural-gas-systems>.

The EPA data are based on emissions factors that are representative rather than actual.<sup>40</sup> Even though data in these programs have recently been updated, they are still incomplete, and recent studies suggest actual emissions may be somewhat, or even substantially, higher than the emissions factors suggest.<sup>41</sup> Thus, we believe that the estimates of losses used to support today's rule, while substantial, are conservative. For purposes of this final rule, ONRR provided the BLM with data evidencing 7 years of vented and flared volumes reported on the OGOR-Bs. The data analyzed included gas flared and vented from both oil and gas wells from 2009 through 2015. During this period, operators reported that they vented or flared a total of 462 Bcf of natural gas, or about 2.7 percent of the 16.8 Tcf of natural gas that was produced from BLM-administered leases from 2009 through 2015.<sup>42</sup> This is enough natural gas to supply over 6.2 million households – or every household in the States of Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming – for 1 year.<sup>43</sup>

These data are reported by operators on BLM-administered leases, but the production is actually derived from lands with various ownership patterns. Of the vented and flared gas reported to ONRR, 15 percent came from wells extracting only Federal minerals; 8.8 percent came from wells extracting only Indian minerals, and 76.2 percent from wells extracting minerals with mixed ownership (some combination of Federal, Indian, fee (private) and State minerals).

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<sup>40</sup> EPA, *2016 GHG Inventory Report: 1990-2014*. Available at <https://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2016-Main-Text.pdf>.

<sup>41</sup> Env't'l Def. Fund, *New EPA Stats Confirm: Oil & Gas Methane Emissions Far Exceed Prior Estimates* (Apr. 15, 2016), <https://www.edf.org/media/new-epa-stats-confirm-oilgas-methane-emissions-far-exceed-prior-estimates>.

<sup>42</sup> BLM analysis of ONRR OGOR-B data provided for 2009-2015.

<sup>43</sup> Using US Energy Information Administration Natural Gas Consumption by End Use for 2015 found at [http://www.eia.gov/dnav/ng/ng\\_cons\\_sum\\_a\\_EPG0\\_vrs\\_mmcf\\_a.htm](http://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vrs_mmcf_a.htm).



Finally, the BLM notes that available data suggest the problem of natural gas loss on BLM-administered leases is growing. The total amounts of annual reported flaring from Federal and Indian leases increased by over 1000 percent from 2009 through 2015.<sup>44</sup> During this period, reported volumes of flared oil-well gas increased by 318 percent, while reported volumes of flared gas-well gas decreased by 86 percent.<sup>45</sup> The reduction in flaring at gas wells coincides with the adoption of EPA 40 CFR part 60 subpart OOOO (“subpart OOOO”) air pollution requirements, which limit emissions from gas wells hydraulically fractured after August 23, 2011.<sup>46</sup>

Another indicator of the increase of flaring on Federal and Indian lands is the increased number of applications to vent or flare royalty-free that the BLM has received from operators. In 2005, the BLM received just 50 applications to vent or flare gas. In 2011, the BLM received 622 applications, and this doubled again within 3 years to 1,248 applications in 2014. BLM field offices indicate that most of the additional applications were for flaring of associated gas from oil wells in New Mexico, Montana, the Dakotas, and, to a lesser extent, Wyoming.

b. Recent Studies of Venting and Leaks

The proposed rule preamble section IV.H.2 discussed recent efforts to improve our understanding of the quantities of natural gas lost through venting and leaks during the production process, and it highlighted a number of recent studies. These include both “bottom up” studies, which attempt to improve the accuracy and understanding of current estimates by conducting site-specific intensive measurements of losses during the

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<sup>44</sup> BLM analysis of ONRR OGOR-B data provided for 2009-2015.

<sup>45</sup> BLM query of AFMSS database for the number of Flaring Sundry Notices filed on Federal and Indian lands between 2009 and 2015 on November 4, 2011.

<sup>46</sup> 79 FR 49490 (Aug.16, 2012).

production process, and “top down” studies, which use aircraft and tracers to quantify atmospheric methane levels and attribute them to oil and gas production activities.

Several of these recent studies by government, industry, and environmental organizations suggest that emission levels are higher than those estimated using the DOI and EPA data, and in particular, some studies highlighted emissions levels two to three times higher than those based on EPA data. They also provided information on the distribution of gas leaks, which are heavily concentrated at “super-emitter” facilities, and highlighted the challenges in predicting which sites will experience super-emitter conditions.

Commenters on the proposed rule pointed to additional studies, some issued after the proposal, that further demonstrate significant gas loss, the potential to reduce such waste through various technologies and practices, and the need for widespread leak detection and repair.

Commenters pointed to both bottom up and top down studies that suggest BLM’s estimate of natural gas waste is conservative. For example, EPA’s 2016 GHG Inventory was released in April 2016 (after BLM issued its proposed rule), and provides estimates of methane loss from the oil and gas sector that are significantly greater than previous estimates.<sup>47</sup> EPA updated its method for estimating emissions using the latest peer-reviewed science published over the last several years. The data also revealed that emissions had grown by more than 10 percent between 2010 and 2014.

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<sup>47</sup> EPA, *U.S. Greenhouse Gas Inventory Report: 1990-2014* at 3-69, Table 3-46 (2016), available at <https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-main-text.pdf> (“2016 GHG Inventory”); EPA, *U.S. Greenhouse Gas Inventory Report: 1990-2013* at 3-70, Table 3-44 (2016), available at <https://www.epa.gov/sites/production/files/2016-03/documents/us-ghg-inventory-2015-main-text.pdf> (“2015 GHG Inventory”). See also Env’t Def. Fund, *New EPA Stats Confirm: Oil & Gas Methane Emissions Far Exceed Prior Estimates* (Apr. 15, 2016), <https://www.edf.org/media/new-epa-stats-confirm-oilgas-methane-emissions-far-exceed-prior-estimates>; A.R. Brandt et al., *Methane Leaks from North American Natural Gas Systems*, 343 *Science* 733 (2014), available at <http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf>; Gina McCarthy, *Remarks on Climate Action at CERA in Houston, Texas* (Feb. 24, 2016), available at <https://yosemite.epa.gov/opa/admpress.nsf/8d49f7ad4bbcf4ef852573590040b7f6/5c432a7068e191e985257f630054fea8!OpenDocument>.

Commenters also referenced a 2013 top-down study led by the National Oceanic and Atmospheric Administration (NOAA) that estimated emissions from an oil and natural gas production field in Uintah County, Utah, using atmospheric measurements in a mass balance approach. The measurements, published in *Geophysical Research Letters*, suggested an emission rate between 6.2 and 11.7 percent of production, allowing for uncertainties in gas composition and gas production.<sup>48</sup> This is significantly higher than estimates from bottom up inventories, such as the 1.4 percent of production assumed in the 2012 EPA Greenhouse Gas Inventory, and further suggests that natural gas waste is likely underestimated in commonly cited inventories.

In meetings pursuant to E.O. 12866, stakeholders referenced a new study published in *Nature* on October 5, 2016, entitled “Upward revision of global fossil fuel methane emissions based on isotope database.”<sup>49</sup> The research was conducted by scientists from NOAA and the Cooperative Institute for Research in Environmental Sciences at the University of Colorado, Boulder. The study relied on the largest isotopic methane source signature database ever assembled to estimate total global methane emissions and identify the sources of emissions. It finds that methane emissions from fossil fuel production are 20% to 60% greater than previous estimates, and that they represent 20% to 25% of global methane emissions. The study also highlights that methane emissions by microbial sources (e.g., cows, agriculture, landfills, and wetlands)

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<sup>48</sup> Anna Karion et al., Methane Emissions Estimate from Airborne Measurements Over a Western United States Natural Gas Field, 40, *Geophysical Research Letters* 4393, 4393 (2013) (<http://onlinelibrary.wiley.com/doi/10.1002/grl.50811/full>).

<sup>49</sup> Schwietzke, Stefan et al. “Upward Revision of Global Fossil Fuel Methane Emissions Based on Isotope Database.” *Nature*, 88 Vol. 538. (Oct. 5, 2016) (<http://www.nature.com/nature/journal/v538/n7623/full/nature19797.html>); U.S. Department of Commerce, National Oceanic and Atmospheric Administration. *Study Finds Fossil Fuel Methane Emissions Greater Than Previously Expected* (2016) (<http://www.noaa.gov/media-release/study-finds-fossil-fuel-methane-emissions-greater-than-previously-estimated>).

are responsible for 58% to 67% of total methane emissions each year, and that these sources drove most of the global increase in methane emissions observed between 2007 and 2013. Thus, the study affirms the potential for methane mitigation from fossil fuel production, while indicating that significant further reductions may be available from expanding mitigation efforts to other sectors as well.

There have also been recent and ongoing studies of so-called “super-emitters,” which account for a disproportionate quantity of the losses. One of these is a study by Zavala et al., published on July 7, 2015, in *Environmental Science and Technology*. The study used data collected from gas wells in the Barnett Shale region in Texas to identify unusually high emitters—that is, emissions outliers—by focusing on a site’s absolute methane emissions divided by production rate. The study referred to this metric as the proportional loss rate, and demonstrated that sites with “high proportional loss rates have excess emissions resulting from abnormal or otherwise avoidable operating conditions such as improperly functioning equipment.” The study then concluded that these sources’ “reduction potential”—that is, their ability to reduce their losses—is likely greater than that suggested by emission-factor based estimates. The study also found that the losses and abnormal operating conditions that characterize these super-emitters are not specific to a given set or type of sources, but can and do occur at different sources over time.<sup>50</sup>

In 2015, a team of scientists at Colorado State University published studies based on direct measurements of emissions from 114 gathering facilities at sixteen different processing plants. The study found that 30 percent of facilities were responsible for

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<sup>50</sup> Zavala-Araiza, et al., (2015) “Toward a Function Definition of Methane Super-Emitters: Application to Natural Gas Production Sites,” *Environ. Sci. Technol.*, 49, at 8167-8174 (“Zavala-Araiza (2015)”), available at <http://pubs.acs.org/doi/abs/10.1021/acs.est.5b00133>

approximately 80 percent of the venting. Substantial venting occurred at liquid storage tanks at approximately 20 percent of the facilities where emission rates were four times the average rate. Moreover, the high emitting facilities were generally capable of immediate emission reductions through operating adjustments, such as adjusting the operating pressure of the separation equipment.<sup>51</sup>

In 2012, the City of Fort Worth, Texas, sponsored a study of 375 oil and gas production facilities. It found that thief hatches were the largest source, and pneumatic controllers were the most frequent source, of fugitive emissions at well pads and compressor stations. These leaks were often due to operator error or inadequate maintenance.<sup>52</sup>

Commenters also pointed to the largely random nature of significant leaks. A recent study, authored by Lyon et al., used optical gas imaging to survey 8,220 oil and gas well pads through aerial surveys. The study found only a small correlation between the probability of detection of a leak and site characteristics, such as well count, well age, gas production, oil production, and water production. The stochastic and diverse nature of the sites with leaks, along with the level of waste observed, provides further support for broadly applicable leak detection and repair programs.<sup>53</sup>

Both the Zavala and Lyon studies observed that leak rates are not strongly correlated with well production rates—that is, higher and lower producing wells can both have significant levels of natural gas waste. Specifically, the Zavala study found small producing sites (10-100 Mcf/day) were twice as likely as those sites an order of

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<sup>51</sup> Mitchell, A.L., et al, (2015) “Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants,” *Environ. Sci. Technol.*, 2015, 49 (5), pp 3219–3227, available at <http://pubs.acs.org/doi/abs/10.1021/es5052809>.

<sup>52</sup> Eastern Research Group and Sage Environmental Consulting, City of Fort Worth Natural Gas Air Quality Study (Final Report) 3-99 (2011), available at [http://fortworthtexas.gov/uploadedFiles/Gas\\_Wells/AirQualityStudy\\_final.pdf](http://fortworthtexas.gov/uploadedFiles/Gas_Wells/AirQualityStudy_final.pdf)

<sup>53</sup> David R. Lyon et. al, Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites, 1 *Envtl. Sci. Tech.* (2016)

magnitude larger (100-1,000 Mcf/day) to be among the 5% of sites with the highest emissions. The Lyon study found that well pad characteristics, such as oil production levels, could only collectively explain about 14% of the variation in observed emissions. While a statistically significant correlation between size and leaks is observed, both studies note that it is a weak linear correlation and that leak occurrence is largely stochastic. The Lyon study found that over 15 percent of the high-emitting sites detected in its survey were low production sites, producing 15 barrel of oil equivalent (BOE) per day or less.<sup>54</sup>

Another recent study by the Colorado Air Pollution Control Division surveyed oil and gas wells over two years using optical gas imaging. The research revealed a significant number of leaks, but also highlighted that it is possible to achieve immediate reduction or minimization of waste from production facilities with timely identification and repair of leaks. The survey spanned from July 2013 through June of 2015 and covered over 4,400 facilities. The optical gas imaging technology identified gas lost through leaks or vents at more than 25 percent of the facilities, with the majority of these leaks or vents occurring at storage tanks.<sup>55</sup>

c. Existing BLM Regulations Need to Be Updated

As discussed in detail in the proposed rule preamble at section IV.E, venting, flaring, and royalty-free uses of oil and natural gas on BLM-administered leases are currently governed by NTL-4A. This “Notice to Lessees” was issued by the U.S.

Geological Survey on December 27, 1979, before the BLM assumed oversight

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<sup>54</sup> David R. Lyon et. al, *Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites*, 1 *Envtl. Sci. Tech.* (2016) available at <http://pubs.acs.org/doi/abs/10.1021/acs.est.6b00705>. See supporting information “Site-level parameter data for well pads in the surveyed areas and basins” file columns M and N in the “Surveyed Well Pads” worksheet.

<sup>55</sup> Colorado Department of Public Health and Environment Air Pollution Control Division Colorado Optical Gas Imaging Infrared Camera Pilot Project: Final Assessment July 11, 2016 Author: Tim Taylor

responsibility for onshore oil and gas development and production. NTL-4A places limitations on venting or flaring of gas-well or oil-well gas, unless approved in writing by BLM. NTL-4A also specifies the circumstances under which an operator owes royalties on oil or gas that is lost from a lease.

In the past 37 years since NTL-4A was issued, oil and gas production technologies and practices have advanced considerably, particularly with the development of modern hydraulic fracturing techniques and directional drilling. Technologies for capturing and using gas on-site, detecting leaks, powering equipment, controlling vapors from storage vessels, removing liquids from gas wells, and many other aspects of the production process have also advanced. Not surprisingly, NTL-4A neither reflects today's best practices and advanced technologies, nor is particularly effective in minimizing waste of public minerals, as the previously described data and studies show. In addition, as discussed in the preamble to the proposed rule, ambiguities have arisen regarding how NTL-4A is interpreted and implemented by various BLM offices and industry entities. There is a compelling need to update these requirements to make them clearer, more effective, and reflective of modern technologies and practices.

d. Concerns Identified Through Oversight

External oversight reviews strongly support the BLM's conclusion that the current NTL-4A requirements need to be updated, and many of the changes made in this rule implement recommendations from relevant oversight reviews. As discussed in the proposed rule, key oversight reviews that influenced the development of this rule include: (1) a December 2007 Royalty Policy Committee (RPC) report, *Mineral Revenue Collection from Federal and Indian Lands and the Outer Continental Shelf*, which

recommended that the BLM update its rules and identified many specific actions to improve production accountability; (2) a March 2010 report by the OIG, *BLM and MMS Beneficial Use Deductions*, which recommended that the BLM clarify its requirements for royalty-free use of natural gas; and (3) an October 2010 GAO report, *Federal Oil and Gas Leases – Opportunities Exist to Capture Vented and Flared Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases*, which recommended that the BLM update its regulations to take advantage of opportunities to capture economically recoverable natural gas using available technologies.

In July 2016, the GAO issued another report relevant to this rule. The 2016 report entitled, “*OIL AND GAS--Interior Could Do More to Account for and Manage Natural Gas Emissions*,” reviewed the DOI’s provisions to account for and manage natural gas emissions. The GAO found that DOI agencies, including the BLM and ONRR, have historically focused on determining the volume of natural gas production and accounting for the percent of that volume that is royalty-bearing, but have not focused enough on providing operators clear guidance on how to determine, account for, and report the volumes of natural gas that are *not* royalty bearing. The GAO suggested that lack of specific guidance in these areas has resulted in substantial variation in how operators obtain and report the data, and may result in inaccuracy in the DOI’s data on natural gas emissions. The GAO recommended that the BLM provide operators with specific instructions regarding how to estimate natural gas emissions, which the GAO suggests would improve emissions data and better ensure that, when appropriate, royalties are collected on these lost quantities of natural gas. The GAO also addressed recommendations to the ONRR that are closely related to provisions of this rule. For



example, the GAO recommended that the ONRR provide additional guidance on how to report royalty-free and royalty-bearing flaring, and how to report unreported or underreported emissions from sources such as tanks. Some of the changes made in today's rule will help clarify the regulatory requirements that relate to some of these reporting concerns.

### **3. Relationship to Other Federal, State, and Industry Activities**

Understanding that other Federal, State and tribal rules also apply to aspects of onshore oil and gas production, the BLM has aimed to ensure that this rule will complement other regulatory requirements. As noted earlier, for example, the EPA issued rules in 2012 and May of 2016 to control emissions of methane and VOCs from new, modified and reconstructed oil and gas wells and production equipment, and many States and tribes also regulate aspects of the production process to address safety, waste, production accountability, and/or air quality concerns.

In updating the BLM regulations, the BLM carefully considered and accounted for these potentially overlapping regimes. Thus, to the maximum extent possible, today's rule aligns its requirements with similar requirements adopted by the EPA or the States, exempts equipment and processes covered by EPA requirements, and authorizes the BLM to grant variances from particular rule provisions if a petitioner State or tribe can show that a State, local, or tribal requirement is at least as effective as the corresponding provision of this rule. The BLM is also committed to working with the EPA to ensure that any future EPA regulations align to the extent possible with the BLM requirements. To the extent that additional State or tribal regulations are adopted in the future, the State and tribal variance provisions in section 3179.401 provide a mechanism

for the BLM to approve compliance with those regulations in lieu of the BLM regulations, where the State or tribal regulations meet the criteria for a variance.

As noted earlier, even though EPA, State, and tribal requirements address some gas waste, there is still a clear need for this rule. For one thing, the BLM has independent legal and proprietary responsibilities to prevent waste in the production of Federal and tribal minerals, as well as to ensure the safe, responsible, and environmentally protective use of BLM-managed lands and resources. This rule will update the BLM's decades-old venting and flaring requirements, and represents an important element of BLM's larger effort to ensure that its oil and gas regulations are effective, transparent, and easy to understand and administer, and that the provisions of those regulations adequately account for significant recent technological advances in the industry.

The BLM also notes that this regulation covers a range of sources and activities that are not adequately addressed by existing BLM, State, or tribal regulations. Further, EPA regulations cover only new, modified, and reconstructed sources, not the many existing and unmodified sources on BLM-administered leases. EPA regulations also do not address flaring or activities such as liquids unloading. Finally, State and tribal regulations are effective only within the jurisdiction of the relevant State or tribe, and State and tribal regulations do not consistently address all the sources of waste BLM seeks to prevent via this rule. Indeed, no State or tribe has requirements covering all the sources of waste addressed by this rule.

In the proposed rule preamble section IV.I.2., the BLM also discussed the commendable efforts that some oil and gas operators have made to reduce waste of gas through venting, flaring, and leaks. While steps in the right direction, these voluntary

efforts are insufficient by themselves, given the large and growing volumes of waste. Moreover, for the one specific activity area for which industry has identified a reduction in gas losses over the past few years – well completions at hydraulically fractured gas wells – the decreases appear to be largely driven by the adoption of the EPA subpart OOOO requirements for green completions at those wells.

The following sections provide a brief overview of EPA and State regulations that are particularly relevant to this rulemaking.

a. EPA Regulations

The EPA regulates air pollution from oil and gas production, and since measures to reduce emissions tend to limit releases of natural gas, the EPA’s air pollution regulations to reduce emissions from the oil and gas sector have the co-benefit of reducing waste of natural gas and increasing gas capture. BLM very carefully coordinated the waste prevention requirements under today’s rule with EPA requirements applicable to some of the same sources, to minimize compliance burdens for operators and to avoid unnecessary duplication.

As explained in section IV.I.3 of the proposed rule preamble, the EPA adopted new source performance standards (NSPS) in 2012 (subpart OOOO) that require new, modified, or reconstructed sources to limit the release of VOCs by requiring that operators use “green completions” at hydraulically fractured natural gas wells.<sup>56</sup> The EPA’s NSPS also imposed requirements at gas processing plants and boosting stations.<sup>57</sup>

On September 18, 2015, EPA proposed NSPS standards that would update the 2012 standards to limit methane in addition to VOCs, as described in the BLM proposed

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<sup>56</sup> 79 FR 49490, August 16, 2012.

<sup>57</sup> Subpart OOOO imposed emission standards for pneumatic controllers, centrifugal compressors and storage vessels, and required work practices for reciprocating compressors and equipment leaks at gas processing plants. Subpart OOOO also imposed a sulfur dioxide emission standard for sweetening units at gas processing plants.

rule, to be codified in proposed 40 CFR part 60 subpart OOOOa.<sup>58</sup> This rule also proposed to limit methane and VOC emissions from additional sources not covered under the 2012 subpart OOOO rule. EPA finalized 40 CFR part 60 subpart OOOOa on May 12, 2016, after receiving over 900,000 public comments and holding three public hearings, and the rule went into effect in August 2016. As with the subpart OOOO standards, subpart OOOOa applies only to new, modified, or reconstructed sources, and not to existing equipment and operations. The final OOOOa rule regulates greenhouse gases through limits on methane emissions that owners and operators can meet using readily available and cost-effective technologies.<sup>59</sup> It also requires leak detection and repair at new, modified, and reconstructed sources, and it covers additional new, modified, and reconstructed equipment and activity in the oil and gas production sector not addressed in the subpart OOOO standards, such as hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations. The final 40 CFR subpart OOOOa rule includes several changes from the EPA's proposed rule that are particularly noteworthy with respect to the BLM's rulemaking, including: (1) it establishes a fixed semi-annual schedule for monitoring leaks from well sites; (2) it does not adopt a proposed exemption from the LDAR requirements for low-production wells; and (3) it does not adopt proposed requirements to limit emissions from pneumatic piston pumps.

On May 12, 2016, EPA also announced the availability of Control Technique Guidelines (CTGs) to help States reduce VOC emissions from *existing* sources in certain ozone nonattainment areas. Although reducing methane emissions is not the purpose of CTGs,

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<sup>58</sup> 80 FR 56593, Sept. 18, 2015.

<sup>59</sup> 81 FR 35823, June 3, 2016.

control of VOC emissions also results in co-control of methane emissions. These CTGs identify many of the same types of measures required by the OOOOa standards, but the guidelines are not legally binding. Rather, the CTGs are a set of recommendations that State and local air pollution control agencies must consider when evaluating what they will identify as Reasonably Available Control Technology (RACT) for existing sources covered under State ozone nonattainment plans to implement Clean Air Act requirements, known as State Implementation Plans (SIPs). States are only required to include RACT measures in their SIPs for ozone nonattainment areas whose air quality levels violate the Clean Air Act air quality standard for ozone and are classified as moderate nonattainment or higher.<sup>60</sup> In October of 2015, EPA revised the health-based ambient air quality standard for ozone pollution to 70 parts per billion. The changes to SIPs required to address that pollution would be due to EPA within two years after the ozone classifications are published in the Federal Register, which is projected to be no later than Jan. 21, 2021.<sup>61</sup> It appears that few, if any, areas with significant Federal or Indian oil and gas production are likely to be classified as moderate nonattainment or above for the most recent ozone standard. Moreover, even if some areas with significant Federal or Indian oil and gas production are identified as having ozone pollution problems, the changes to SIPs required to address that pollution would not likely be due to EPA for a number of years.

The EPA has also taken the first steps to gather information to promulgate regulations that would require subsequent State regulation of existing sources under Clean Air Act (CAA) section 111(d). When the EPA establishes NSPS for new sources

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<sup>60</sup> *I.e.*, nonattainment areas designated “moderate” or above.

<sup>61</sup> These are the attainment dates for areas designated as moderate nonattainment or above.

in a particular source category, as it did for the oil and gas sector in its OOOOa regulations promulgated in May 2016, the EPA is also required, under CAA section 111(d)(1), to prescribe regulations for States to submit plans establishing emissions performance standards for existing sources in that source category. Acting under this CAA mandate, in March of 2016 the EPA announced its intention to regulate existing oil and gas sources for methane and VOC emissions.<sup>62</sup> To begin this process, the EPA issued a draft information collection request (ICR) on May 12, 2016, and a second draft ICR on September 23, 2016.<sup>63</sup> Once the ICR is approved by the Office of Management and Budget, the ICR is expected to gather a broad range of information on the oil and gas industry regarding emission control efficacy, costs, and timing requirements.<sup>64</sup> The EPA then expects to use this information in developing regulations to guide State plans to reduce emissions from existing sources. This rulemaking would then be followed by State development and adoption of State plans containing enforceable performance standards for sources, State plan approvals by EPA, and subsequent implementation by industry to meet compliance deadlines established in the State plans. Given the length of this process and the uncertainty regarding the final outcomes, and in light of the BLM's independent statutory mandate to prevent waste from Federal and Indian oil and gas leases based on information currently available, the BLM has determined that it is necessary and prudent to update and finalize this regulation at this time.

#### b. State Regulations

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<sup>62</sup> McCarthy, Gina. "EPA Taking Steps to Cut Methane Emissions from Existing Oil and Gas Sources". March 10, 2016. Available at <https://blog.epa.gov/blog/2016/03/epa-taking-steps-to-cut-methane-emissions-from-existing-oil-and-gas-sources>.

<sup>63</sup> 81 FR 35763 and 81 FR 66692.

<sup>64</sup> On September 23, 2016, EPA issued a second draft ICR, and public comments are due October 31, 2016. Once all of the public comments are reviewed and incorporated, and the ICR is approved by the Office of Management and Budget, the EPA will issue a final ICR, using its authority under CAA Section 114. Industry will have at least 30 days to complete the operator survey and 120 days to respond to the facility survey.

<https://www.gpo.gov/fdsys/pkg/FR-2016-09-29/pdf/2016-23463.pdf>

In developing this rule, the BLM consulted with State regulators and reviewed analogous State requirements related to waste of oil and gas resources. Specifically, the BLM reviewed requirements from Alaska, California, Colorado, Montana, North Dakota, Ohio, Pennsylvania, Utah, and Wyoming. Most of these State requirements were discussed in the preamble to the proposed rule, which also explained that these State requirements, and the outcomes they produce, vary widely.<sup>65</sup> As noted in the preamble to the proposed rule, of the States with extensive oil and gas operations on BLM-administered leases, only one has comprehensive requirements to reduce flaring, and only one has comprehensive statewide requirements to control losses from venting and leaks.<sup>66</sup> Furthermore, State regulations do not apply to BLM-administered leases on Indian lands, and States do not have a statutory mandate or trust responsibility to reduce the waste of Federal and Indian oil and gas. Finally, because State laws and regulations are subject to change, BLM reliance on State standards risks additional waste of public resources and adverse environmental impacts to Federal and Indian lands should the State standards change to allow for additional waste and environmental impacts. There is therefore a need for uniform, modern waste reduction standards for oil and gas operations on public and Indian lands across the country. Nonetheless, the BLM did look to some of the most effective State approaches as models. In particular, we have drawn on approaches that Colorado, Wyoming and North Dakota adopted to address rising rates of flaring, waste of minerals, and pollution impacts in those states.

The BLM also notes that at least two States have recently expressed an intent to further reduce methane emissions through regulatory action. On February 1, 2016,

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<sup>65</sup> 81 Fed. Reg. at 6633–34.

<sup>66</sup> 81 Fed. Reg. at 6636.

California's Air Resources Board proposed new rules to reduce emissions of methane through venting and leaks during oil and gas production, processing, and storage.<sup>67</sup>

These proposed rules would require the use of vapor collection systems and the control of vapors with 95 percent efficiency. The rules would limit the use of combustion; however, if a combustion control device must be used, the rules would require the use of a low-emissions incinerator. In January 2016, the Pennsylvania Department of Environmental Protection also announced that it would pursue an enhanced strategy for reducing methane emissions.<sup>68</sup> Importantly, though, neither of these proposed regimes nor any existing State regimes cover the full suite of oil and gas activities addressed by this rule.

### **C. Legal Authority**

Pursuant to a delegation of Secretarial authority, the BLM is authorized to regulate oil and gas activities on Federal and Indian lands under a variety of statutes, including the MLA, the MLAAL, FOGRMA, FLPMA, the IMLA, the IMDA, and the Act of March 3, 1909.<sup>69</sup> These statutes authorize the Secretary of the Interior to promulgate such rules and regulations as may be necessary to carry out the statutes' various purposes.<sup>70</sup>

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<sup>67</sup> State of California Air Resources Board Staff Report: Statement of Reasons, available at: <http://www.arb.ca.gov/cc/oil-gas/Oil%20and%20Gas%20ISOR.pdf>.

<sup>68</sup> Pennsylvania Department of Environmental Protection, A Pennsylvania Framework of Actions for Methane Reductions from the Oil and Gas Sector, available at: <http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Methane/DEP%20Methane%20Strategy%201-19-2016%20PDF.pdf>.

<sup>69</sup> 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.

<sup>70</sup> 30 U.S.C. § 189 (MLA); 30 U.S.C. § 359 (MLAAL); 30 U.S.C. § 1751(a) (FOGRMA); 43 U.S.C. § 1740 (FLPMA); 25 U.S.C. § 396d (IMLA); 25 U.S.C. § 2107 (IMDA); 25 U.S.C. § 396.



The MLA rests on the fundamental principle that the public should benefit from mineral production on public lands.<sup>71</sup> A primary instrument for public benefit is the requirement that a lessee return a portion of the proceeds from production to the public through the payment of royalties to Federal, State, and/or tribal governments. For competitively issued leases, the MLA requires the payment of a royalty “at a rate *not less than* 12.5 percent in amount or value of the production removed or sold from the lease”; for non-competitive leases, the MLA sets the royalty “at a rate of 12.5 percent in amount or value of the production removed or sold from the lease.”<sup>72</sup> The BLM is responsible for specifying royalty rates and determining the quantity of produced oil and gas that is subject to royalties under the terms and conditions of a Federal lease.

Another important means of ensuring that the public benefits from mineral production on public lands is minimizing and deterring the waste of oil and gas produced from the Federal mineral estate. To this end, the MLA requires oil and gas lessees to “use all reasonable precautions to prevent waste of oil or gas developed in the land, . . .”<sup>73</sup> The MLA requires lessees to exercise “reasonable diligence, skill, and care” in their operations and also requires oil and gas lessees to observe “such rules . . . for the prevention of undue waste as may be prescribed by [the] Secretary.”<sup>74</sup> Lessees are not only responsible for taking measures to prevent waste, but also responsible for making royalty payments on wasted oil and gas when waste does occur. In FOGRMA, Congress expressly made lessees “liable for royalty payments on oil or gas lost or wasted from a lease site when such loss or waste is due to negligence on the part of the operator of the

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<sup>71</sup> See, e.g., *California Co. v. Udall*, 296 F.2d 384, 388 (D.C. Cir. 1961) (noting that the MLA was “intended to promote wise development of . . . natural resources and to obtain for the public a reasonable financial return on assets that ‘belong’ to the public”).

<sup>72</sup> 30 U.S.C. § 226(b)(1)(A) (emphasis added); 30 U.S.C. §226(c)(1); see also 30 U.S.C. § 352 (applying that requirement to leases on acquired land). The same royalty provision is included in the lease instruments for leases of Indian tribal and allotted lands under applicable regulations, although that rate is set at no less than 16-2/3%, absent approval of the Secretary. 25 CFR 211.41, 212.41.

<sup>73</sup> 30 U.S.C. § 225.

<sup>74</sup> 30 U.S.C. § 187.

lease, or due to the failure to comply with any rule or regulation, order or citation issued under [FOGRMA] or any mineral leasing law.”<sup>75</sup>

In addition to ensuring that the public benefits from oil and gas production from public lands, the BLM is also tasked with regulating the physical impacts of oil and gas development on public lands. The MLA directs the Secretary to “regulate all surface-disturbing activities conducted pursuant to any lease” and to “determine reclamation and other actions as required in the interest of conservation of surface resources.”<sup>76</sup> The MLA requires oil and gas leases to include provisions “for the protection of the interests of the United States . . . and for the safeguarding of the public welfare,” which includes lease terms for the prevention of environmental harm.<sup>77</sup> The Secretary may suspend lease operations “in the interest of conservation of natural resources,” a phrase that encompasses not just conservation of mineral deposits, but also preventing environmental harm.<sup>78</sup> The Secretary also may refuse to lease lands in order to protect the public’s interest in other natural resources and the environment.<sup>79</sup> BLM’s regulations governing oil and gas operations on the public lands have always required operators to avoid damaging other natural resources or environmental quality.<sup>80</sup>

The MLA additionally requires oil and gas leases to contain “a provision that such rules for the safety and welfare of the miners . . . as may be prescribed by the Secretary shall be observed . . . .”<sup>81</sup> This rule helps to ensure safety of workers engaged in the production of oil and gas on Federal and Indian lands by requiring, except in special

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<sup>75</sup> 30 U.S.C. § 1756.

<sup>76</sup> 30 U.S.C. § 226(g).

<sup>77</sup> See *Natural Resources Defense Council, Inc. v. Berkland*, 458 F. Supp. 925, 936 n.17 (D. D.C. 1978).

<sup>78</sup> 30 U.S.C. § 209; *Copper Valley Machine Works v. Andrus*, 653 F.2d 595, 601 & nn.7-8 (D.C. Cir. 1981); *Hoyle v. Babbitt*, 129 F.3d 1377, 1380 (10th Cir. 1997); *Getty Oil Co. v. Clark*, 614 F. Supp. 904, 916 (D. Wyo. 1985).

<sup>79</sup> *Udall v. Tallman*, 380 U.S. 1, 4 (1965); *Duesing v. Udall*, 350 F.2d 748, 751-52 (1965).

<sup>80</sup> See 43 C.F.R. § 3162.5-1 to .5-2 (1983-2014).

<sup>81</sup> 30 U.S.C. § 187.

circumstances, the combustion of natural gas loosed from wells and equipment during production.

FLPMA further authorizes BLM to “regulate” the “use, occupancy, and development” of the public lands via “published rules.”<sup>82</sup> FLPMA also mandates that the Secretary, “[i]n managing the public lands . . . shall, by regulation or otherwise, take any action necessary to prevent unnecessary or undue degradation of the lands.”<sup>83</sup> And FLPMA authorizes BLM to “promulgate rules and regulations to carry out the purposes of this Act and of other laws applicable to the public lands.”<sup>84</sup> FLPMA expressly declares that the BLM should balance the need for domestic sources of minerals against the need to “protect the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resources, and archeological values; . . . [and] provide for outdoor recreation and human occupancy and use.”<sup>85</sup>

FLPMA requires the BLM to manage public lands under principles of multiple use and sustained yield.<sup>86</sup> The statutory definition of “multiple use” explicitly includes the consideration of environmental resources. Multiple use is a “combination of balanced and diverse resource uses that takes into account the long-term needs of future generations for renewable and nonrenewable resources . . . .”<sup>87</sup> Multiple use also requires resources to be managed in a “harmonious and coordinated” manner “without permanent impairment to the productivity of the land and the quality of the environment.”<sup>88</sup>

Significantly, FLPMA admonishes the Secretary to consider “the relative values of the

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<sup>82</sup> 43 U.S.C. § 1732(b).

<sup>83</sup> 43 U.S.C. § 1732(b).

<sup>84</sup> 43 U.S.C. § 1740.

<sup>85</sup> 43 U.S.C. § 1701(a)(8).

<sup>86</sup> 43 U.S.C. §§ 1702(c), 1732(a).

<sup>87</sup> 43 U.S.C. § 1702(c).

<sup>88</sup> 43 U.S.C. § 1702(c).

resources and not necessarily . . . the combination of uses that will give the greatest economic return or the greatest unit output.”<sup>89</sup>

Finally, the promulgation of this rule helps to meet the Secretary’s statutory trust responsibilities with respect to the development of Indian oil and gas interests. The Secretary’s management and regulation of Indian mineral interests carries with it the duty to act as a trustee for benefit of the Indian mineral owners.<sup>90</sup> The Congress has directed the Secretary to “aggressively carry out [her] trust responsibility in the administration of Indian oil and gas.”<sup>91</sup> In furtherance of her trust obligations, the Secretary has delegated regulatory authority for administering operations on Indian oil and gas leases to the BLM,<sup>92</sup> which has developed specialized expertise through regulating the production of oil and gas from public lands administered by the Department. In choosing from among reasonable regulatory alternatives for Indian mineral development, the BLM is obligated to adopt the alternative that is in the best interest of the tribe and individual Indian mineral owners.<sup>93</sup> What is in the best interest of the tribe and individual Indian mineral owners is determined by a consideration of all relevant factors, including economic considerations as well as potential environmental and social effects.<sup>94</sup> The BLM believes that this rule is in the best interest of Indian mineral owners because it will prevent unnecessary and excessive losses (“waste”) of natural gas from Indian lands. In so doing, this rule will help ensure that the extraction of natural gas from Indian lands results in the payment of royalties to Indian mineral owners, rather than the waste of the owners’

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<sup>89</sup> 43 U.S.C. § 1702(c).

<sup>90</sup> See *Woods Petroleum Corp. v. Department of Interior*, 47 F.3d 1032, 1038 (10th Cir. 1995) (*en banc*).

<sup>91</sup> 30 U.S.C. § 1701(a)(4).

<sup>92</sup> 235 DM 1.1.K.

<sup>93</sup> See *Jicarilla Apache Tribe v. Supron Energy Corp.*, 728 F.2d 1555, 1567 (10th Cir. 1984) (Seymour, J., concurring in part and dissenting in part), adopted as majority opinion as modified *en banc*, 782 F.2d 855 (10th Cir. 1986).

<sup>94</sup> See 25 C.F.R. § 211.3.

mineral resources.<sup>95</sup> Additionally, the BLM believes tribal members and individual Indian mineral owners who live near Indian oil and gas development will realize environmental benefits as a result of this rule's reductions in flaring and air pollution from Indian oil and gas development. During public comment hearings, the BLM heard from a number of tribal members who raised concerns about the impacts of vented and leaked gas on their health, highlighting in particular increases in ozone pollution and air toxics. Tribal members also detailed the impacts of living near numerous large flares, noting the resulting noise and light pollution. The BLM believes that this rule will help to reduce some of these impacts on tribal members.

In short, the BLM has the authority to manage public and tribal oil and gas resources to reduce waste and ensure environmentally responsible development. In response to the notice of proposed rulemaking, the BLM received many comments asserting a range of different arguments regarding the BLM's exercise of its legal authority in promulgating this rule. The most salient of these arguments are addressed later in this preamble, but the BLM did not make any changes to this rule based on comments about the BLM's authority.

#### **D. Stakeholder Outreach**

In 2014 and again in in 2016, the BLM conducted a series of forums to consult with tribal governments<sup>96</sup> and solicit stakeholder views to inform the BLM's development of the proposed and final rules. In 2014, the BLM held public meetings in Denver, Colorado (March 19, 2014), Albuquerque, New Mexico (May 7, 2014),

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<sup>95</sup> The remainder of this preamble refers to this analysis as the BLM's determination that, as a result of its trust obligations, it has an obligation or mandate to reduce waste from Indian lands, just as it does to reduce waste from BLM-administered Federal Lands.

<sup>96</sup> In developing this rule, the BLM consulted with tribal stakeholders in compliance with 25 U.S.C. § 2107, 512 DM 4, and 512 DM 5.

Dickinson, North Dakota (May 9, 2014), and Washington, D.C. (May 14, 2014).<sup>97</sup> On each of those days, the BLM held a tribal outreach session in the morning and a public outreach session in the afternoon. In advance of the tribal outreach sessions, the BLM sent letters to over 200 tribal leaders that have previously expressed interest in oil and gas related matters. These letters explained generally the proposed rulemaking, invited the tribal leaders to attend the outreach sessions, provided contact persons for further information, and provided an e-mail address for submitting comments. At the 2014 Denver, Colorado, and Washington, D.C. sessions, the tribal and public meetings were live streamed to allow for the greatest possible participation by interested parties. The tribal outreach sessions also served as initial consultation with Indian tribes to comply with Executive Order 13175, Consultation and Coordination with Indian Tribal Governments.

As part of our pre-proposal outreach efforts, the BLM accepted informal comments generated as a result of the public/tribal outreach sessions through May 30, 2014. A total of 29 unique comments were received: 12 from the oil and gas industry and trade associations, 6 from NGOs representing 37 organizations, 2 from government officials or elected representatives, and 9 from private citizens. Two hundred and sixty comments from private citizens were part of an email campaign.

After the proposed rule was published on February 8, 2016, we conducted a second series of paired outreach meetings, with a tribal meeting each morning and a public meeting each afternoon. We held these meetings at four locations: Farmington, New Mexico (February 16, 2016), Oklahoma City, Oklahoma (February 18, 2016),

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<sup>97</sup> See the BLM oil and gas program's outreach-events page: [http://www.blm.gov/wo/st/en/prog/energy/public\\_events\\_on\\_oil](http://www.blm.gov/wo/st/en/prog/energy/public_events_on_oil).

Denver, Colorado (March 1, 2016), and Dickinson, North Dakota (March 3, 2016).

Again, in advance of the tribal outreach sessions, the BLM sent letters to over 200 tribal leaders that have previously expressed interest in oil and gas related matters. These letters explained generally the proposed rule, invited the tribal leaders to attend the outreach sessions, provided contact persons for further information, and provided an e-mail address for submitting comments. The public outreach sessions included a telephone conference call-in number to allow members of the public who could not attend in person to listen live to the proceedings.

In addition, the BLM conducted outreach to States with extensive oil and gas production on BLM-administered leases. Prior to the proposal, the BLM reviewed State regulations and guidance, and contacted State regulatory bodies that oversee aspects of oil and gas production to discuss their requirements and practices. After issuing the proposal, the BLM conducted seven online meeting sessions with State regulators from Alaska, Colorado, New Mexico, North Dakota, Utah (two meetings), and Wyoming.

In response to the proposed rule and these outreach meetings, the BLM received approximately 330,000 total comment submissions from Federal, State, and local governments and agencies, tribal organizations, industry representatives, non-governmental organizations, individuals, and other stakeholders. Of the approximately 330,000 comment submissions, approximately 1,000 were unique comments, with the remaining comments coming from mass-mailing campaigns from several organizations. The BLM closely reviewed and analyzed the comments we received, and made revisions to the proposed rule based on the information, data, analysis, insights, and viewpoints provided in the comments. The final rule reflects the very extensive input that the BLM

gathered from these public meetings, discussions with States and tribes, and the public comment process.

#### **IV. Summary of Final Rule**

Like the proposed rule, the final rule focuses on key areas in the oil and gas production process where waste-prevention actions are most effective and least costly. Specifically, we are adopting requirements to reduce waste from the following: venting or flaring of associated gas from producing oil wells; gas leaks from equipment and facilities located at the well site, as well as from compressors located on the lease; operation of high-bleed pneumatic controllers and certain pneumatic pumps; gas emissions from storage vessels; well maintenance and liquids unloading; and well drilling and completions. Based on the available data regarding methane emissions and the numbers and types of sources of gas losses from Federal and Indian leases, we believe that these aspects of the production process offer the best opportunities for reducing waste.

Like the proposed rule, the final rule requires operators to flare gas rather than vent it, except in specified circumstances, such as emergencies, the routine operation of certain equipment, and when flaring is technically infeasible. The final rule then requires operators to avoid wasteful flaring of gas by capturing for sale or using on-site specified percentages of their adjusted total gas production. Beginning one year from the effective date of the final rule, operators must capture 85 percent of their adjusted total gas production each month, and this gradually increases to 98 percent by 2026. An operator's adjusted total gas production is based on the quantity of high pressure gas produced from the operator's development wells that are in production, adjusted to exempt a specified



volume of gas per well. The exempted or “flaring allowable” volume declines over time. Beginning one year from the effective date of the final rule, operators are allowed to exempt 5,400 Mcf gas per well per month, and this quantity gradually declines to 750 Mcf by 2025.

With respect to leaks, the final rule largely follows the proposed rule, except that the required frequency of inspection is set at two times a year, and does not vary according to the number of leaks found. Operators must use optical gas imaging equipment or portable analyzers deployed according to Method 21, and leaks must be repaired and retested within specified time frames. The final rule clarifies the approval process for alternative leak detection devices and for operators’ individual alternative leak inspection programs.

Like the proposed rule, the final rule includes requirements to update old and inefficient equipment, and to follow best practices to minimize waste through venting. Thus, operators must replace high-bleed pneumatic controllers and certain pneumatic pumps with less wasteful controllers and pumps, and capture or flare any high volumes of gas that would otherwise be vented from tanks. In addition, the final rule requires operators to capture, flare, use, or reinject gas produced during well drilling and well completions, and it limits the quantities of gas that may be vented royalty-free during well testing.

The final rule continues to address whether and when lost oil or gas is royalty-bearing, based on whether the loss is deemed unavoidable (royalty-free) or avoidable (royalty-bearing). Relative to the proposed rule, and after our evaluation of public comments, the final rule somewhat expands the list of circumstances in which a loss of

oil or gas is deemed unavoidable (thereby expanding the circumstances under which the loss of gas is considered royalty-free), and retains the proposed approach that all oil or gas that is not specifically defined as unavoidably lost is deemed to be avoidably lost and subject to royalties. Unavoidable losses include oil or gas lost in emergencies, losses from normal equipment operation when the operator is in compliance with all requirements to update equipment, and gas that is flared from wells not connected to a gas pipeline (unless the operator has not met applicable gas capture requirements). Because the BLM believes that it is reasonable to expect operators to reduce waste in order to comply with the final rule's capture percentage requirements, any quantities of flared gas that cause the operator to violate the applicable capture requirements are deemed avoidable losses and subject to royalties.

In addition, the BLM is finalizing the proposed change to the royalty provisions, to align the provisions with the BLM's statutory authority and allow the BLM to set royalties for competitive leases at or above 12.5 percent. At this time, however, the BLM is not setting the royalty rate above 12.5 percent in this regulation.

Like the proposed rule, the final rule aligns the requirements of this rule to the extent practicable with EPA and State requirements. It also avoids potential regulatory overlap by exempting certain equipment covered by relevant EPA rules, and deeming the operator's compliance with relevant EPA requirements to satisfy the BLM requirements as well.

The final rule also allows a State or tribe to request a variance from particular BLM requirements. If the variance is granted, the BLM has authority to enforce the specific provision(s) of the State, local, or tribal rule for which the variance was granted,

instead of the comparable provision(s) of the BLM rule. As clarified in the final rule, the BLM may grant a State or tribal variance request if the BLM determines that the State, local, or tribal rule would perform at least as well as the affected BLM regulatory provision in reducing waste of oil and gas, reducing environmental impacts from venting and or flaring of gas, and ensuring the safe and responsible production of oil and gas.

## **V. Major Changes from Proposed Rule**

Based on information that has become available since the proposed rule, and the extensive material BLM received through public comments, the BLM has made changes and adjustments to the proposed regulatory text. This section of the preamble summarizes the most significant of those changes and addresses some of the key public comments.

This section only addresses a few substantive areas in which the BLM made significant changes from the proposed rule. Section VI discusses significant comments received on other aspects of the rule. The final text of all of the rule provisions, and changes made in light of all public comments, are discussed in Section VII, Section by Section. Finally, additional public comments are addressed in the separate Response to Comments document, which is available to the public on the BLM website and is part of the rule-making record.

### **A. Venting Prohibition and Capture Targets**

As discussed in section III.B.2.a of this preamble, routine venting and flaring of gas from oil or gas wells waste significant volumes of natural gas. In 2014, for example, operators vented about 30 Bcf and flared at least 81 Bcf from BLM-administered leases – 4.1 percent of the total production from those leases in that year, and sufficient gas to

supply nearly 1.5 million households with gas for a year.<sup>98</sup> The final rule aims to reduce this waste using a two-pronged approach: a prohibition on venting, and capture targets to reduce flaring.

## **1. Venting Prohibition**

### **a. Requirements of Final Rule**

First, final rule § 3179.6 prohibits venting from oil and gas wells, except under certain enumerated conditions. The circumstances in which venting is permissible include: when flaring is technically infeasible, such as when the gas is not readily combustible or the volumes are small; when the gas is vented during normal operation of an on-site, gas-activated pneumatic pump or controller; when the gas is vented from a storage vessel, provided that § 3179.203 does not require flaring of the gas; when the gas is vented during downhole well maintenance or liquids unloading, provided those operations are conducted in accordance with § 3179.204 of the final rule; and when gas is vented through a leak, provided that the operator is complying with the rule's LDAR provisions in §§ 3179.301 – 3179.305. Venting is also permissible during “emergencies,” which final rule § 3179.105 defines as situations in which the loss of gas is “uncontrollable,” and venting or flaring is “necessary to avoid risk of an immediate and substantial adverse impact on safety, public health, or the environment.” In addition, venting is allowed if necessary to allow facility or pipeline non-routine maintenance to be performed. Any venting of gas from oil or gas wells that does not fit within one of the circumstances listed in § 3179.6 is a violation of this rule and could result in enforcement actions. In addition, gas vented in violation of this rule will be deemed “avoidable” under final rule § 3179.4, and thus subject to royalties under final rule § 3179.5.

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<sup>98</sup> BLM analysis of ONRR OGOR-B data provided for 2009-2015 and EPA GHG Inventory data for 2014.

b. Changes from Proposed Rule and Significant Comments

The final venting prohibition largely tracks proposed section § 3179.6, although the BLM modified a few provisions and added additional express exemptions in response to comments received. First, proposed § 3179.6(a)(3), which exempted gas vented from storage vessels subject to conditions specified in § 3179.203, has been renumbered § 3179.6(b)(4) and reworded for clarity. Second, proposed § 3179.6(a)(4), which exempted gas vented during normal operations of natural gas-activated pneumatic controllers and pumps, has been renumbered § 3179.6(b)(3). Third, the BLM added a provision, final rule § 3179.6(b)(5), to clarify that gas may be vented during downhole well maintenance or liquids unloading activities, provided those activities are performed in compliance with § 3179.204. This change responds to comments noting that while this rule requires operators to use best practices to minimize venting from liquids unloading operations, these operations will still release some quantity of gas, and it is not practical to capture and flare that gas regardless of whether the operator uses plunger lifts, manual purging, or another method to unload liquids. Fourth, in response to comments noting that there are additional losses through venting not listed in the proposed provision, the BLM added § 3179.6(b)(6) to the final rule, to clarify that an operator is not required to flare gas that is lost due to leaks, provided the operator is in full compliance with the leak detection and repair requirements in final rule §§ 3179.301-305. Fifth, the BLM added § 3179.6(b)(7) to the final rule, to respond to commenters' concern that some gas is released when pressurized equipment must be depressurized for maintenance, and their assertion that it is difficult and costly to route such infrequent, low-volume emissions to capture or a flare. This exemption from the venting prohibition is limited to venting associated with

non-routine maintenance activities. In justifying their request for an exemption for venting associated with maintenance activities, commenters emphasized that these activities release only small quantities of gas in total because they occur infrequently and each incidence involves a relatively small volume of gas. The BLM is aware, however, that activities such as pigging a gathering line may release a not insignificant volume of gas, and, under some circumstances, operators conduct pigging routinely, such as monthly, weekly, or even several times a day. Under those circumstances, the BLM expects that a prudent operator would configure its operations or deploy capture or flaring equipment so as to avoid routine venting, and the final rule requires operators to avoid such routine venting. Finally, the BLM added § 3179.6(b)(8) to the final rule in response to commenters' observations that it may be necessary to vent gas when applicable laws, regulations, or permit terms prohibit flaring in particular areas or at particular times, such as flaring prohibitions that may be imposed in permafrost areas or during an extreme fire hazard.

## 2. Capture Targets

### a. Requirements of Final Rule

The second prong of the final rule's approach to routine venting and flaring is laid out in final rule §§ 3179.7 and 3179.8, which together target routine flaring of associated gas from "development" oil wells.<sup>99</sup> These final rule provisions are based on proposed rule §§ 3179.6(b) and 3179.7, respectively, but the provisions have been renumbered and revised in the final rule in response to numerous comments received during the public

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<sup>99</sup> As defined in final rule § 3179.3, a "development" oil or gas well is a well "drilled to produce oil or gas, respectively, from an established field in which commercial quantities of hydrocarbons have been discovered and are being produced." The BLM retains the authority to determine whether the well in question is a development oil or gas well. *Id.*

comment period. This discussion first describes the approach taken in the final rule, and then, in part b., details how this modified approach responds to comments received.

First, in response to comments, the final rule shifts from numerical limits on per-well flaring volumes (the approach taken in proposed rule § 3179.6(b)) to a more flexible approach modeled in part on existing North Dakota rules. The new approach sets targets for the percent of associated gas from development oil wells that must be captured in a given month, either on a per lease/unit/communitized area basis or averaged over a county or state. The capture targets do not, however, apply to the full volume of gas that an operator flares. Instead, like the proposed rule, the final rule allows operators to flare a specified volume of gas that declines over time. In the final rule, however, this allowed flaring has been recast as a “flaring allowable” volume that operators can subtract from their total flaring volume *prior* to calculating their capture percentage. Overall, then, the final rule’s approach to flaring has three parts: capture targets, which increase over time; averaging provisions that allow operators to choose whether to comply with the capture targets one lease/unit/communitized area at a time, or instead on an area-wide average basis; and finally, a flaring allowable volume that declines over time, which operators can subtract from their total flaring prior to assessing their compliance with the capture targets.

The mechanics of implementing this approach are as follows. First, final rule § 3179.7 establishes required capture targets that incrementally increase over the first nine years of rule implementation. The schedule for the capture targets is provided in § 3179.7(b)(1)-(4) and reproduced in Table 1:

Table 1

<b>Date Range</b>	<b>Required Monthly Capture Target (Percent of associated gas captured per month)</b>
1/17/2018 through 12/31/2019	85
1/1/2020 through 12/31/2022	90
1/1/2023 through 12/31/2025	95
Beginning 1/1/2026	98

Section 3179.7(c)(3) of the final rule then provides that, in order to demonstrate compliance with the relevant monthly capture target, operators must choose the “relevant area” over which they intend to assess their capture percentage(s). An operator may choose whether to comply with the capture targets on each of the operator’s leases, units, or communitized areas (the “lease-by-lease approach,” see final rule § 3179.7(c)(3)(i)), or instead to comply on a county-wide or state-wide basis (the “averaging approach,” see final rule § 3179.7(c)(3)(ii)). An operator that chooses the lease-by-lease approach must demonstrate that *each* lease, unit, or communitized area is *individually* in compliance with the relevant capture target each month. An operator that chooses the averaging approach must notify the BLM by Sundry Notice of its choice by January 1 of the relevant year, and may then demonstrate monthly compliance with the relevant capture target on an area-wide average basis.



The second step to demonstrating compliance with the capture targets, detailed in final rule § 3179.7(c), is for an operator to determine its total volume of gas produced from development oil wells in the relevant area, subtract the flaring allowable volume, and then divide the result of that calculation into the total volume of gas that the operator sold or used, to determine the operator's actual capture percentage. The operator must then compare its actual capture percentage to the required gas capture percentage for the applicable period, to determine whether the operator meets or exceeds the required capture target for the given month.

More specifically, the volume of gas that the operator sold or used is the volume of gas that the operator sold over the month from all of the operator's development oil wells in the relevant area plus the volume of gas that the operator used on lease, unit, or communitized area across the relevant area. The volume of gas flared is the volume that the operator flared from high pressure flares over the month in the relevant area. The flaring allowable concept derives from the flaring limits introduced in proposed rule § 3179.6(b), and it represents the volume of flared gas that is exempt from the capture target. Flaring allowable equals the total number of development oil wells "in production"<sup>100</sup> in the relevant area multiplied by the relevant flaring allowable quantity, which is specified in final rule § 3179.7(c)(2)(i) through (iv) and reproduced in Table 2. The final rule allows an operator to choose whether to calculate each of these volumes – the volumes of gas sold, used, or flared, and the flaring allowable volume – for each BLM-administered lease, unit, or communitized area (under the lease-by-lease approach),

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<sup>100</sup> As defined in § 3179.7(c)(4), a well is considered "in production" after "a completion, a completion report, or a notice of first production, whichever occurs first, and only during a month in which it produces gas (that is sold or flared) for 10 or more days."

or instead to calculate them on an area-wide average basis for all BLM-administered leases, units, and communitized areas in the county or State (under the averaging approach).

Table 2

<b>Date Range</b>	<b>Monthly Flaring Allowable Per Well (Mcf)</b>
1/17/2018 through 12/31/2018	5,400 Mcf
1/1/2019 through 12/31/2019	3,600 Mcf
1/1/2020 through 12/31/2020	1,800 Mcf
1/1/2021 through 12/31/2021	1,500 Mcf
1/1/2022 through 12/31/2023	1,200 Mcf
1/1/2024 through 12/31/2024	900 Mcf
Beginning 1/1/2025	750 Mcf

If the operator’s actual capture percentage for a given lease, unit, or communitized area (lease-by-lease approach), or for the county or State (averaging approach), falls short of the required capture target for the given month, then the operator may face enforcement action, and must pay royalties on the excess flared gas, which is considered avoidably lost. The excess flared gas is the volume of gas by which the operator missed its required capture target, and it is calculated as follows:

Excess flared gas =

(Required capture target \* (total volume of produced gas – flaring allowable)) –  
(volume of gas sold or used).

Royalties on the excess flared gas would be prorated across an operator’s leases, units or communitized areas that reported high-pressure flaring during the month.

Alternatively, an operator may request that the BLM establish an alternative capture target under final rule § 3179.8, if three conditions are met: (1) the operator has chosen to comply with the capture target using the lease-by-lease basis rather than the averaging approach; (2) the potentially noncompliant lease was issued before the effective date of this final rule; and (3) the operator demonstrates via Sundry Notice, and the BLM agrees, that the applicable capture percentage under final rule § 3179.7 “would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.”

b. Changes from Proposed Rule and Significant Comments

Proposed rule § 3179.6(b) would have imposed a monthly limit on flaring, beginning on the effective date of the final rule, with the specific limit decreasing over the first three years of the final rule. Specifically, the proposed rule would have established a flaring limit of 7,200 Mcf/month per development oil well in production on the lease, unit, or communitized area, for the first year the rule was in effect (proposed rule § 3179.6(b)(1)); 3,600 Mcf/month per development oil well in production on the lease, unit, or communitized area for the second year the rule was in effect (proposed rule § 3179.6(b)(2)); and 1,800 Mcf/month per development oil well in production on the

lease, unit, or communitized area for every month beginning in year three and thereafter (proposed rule § 3179.6(b)(3)).

The proposed rule included a broad request for comments on a range of issues relating to this section, including: the feasibility and costs of imposing a long-term limit on routine flaring of associated gas from development oil wells; whether the specific long-term flaring limit should be lower or higher than 1,800 Mcf/month/well, to further reduce flaring or reduce compliance costs, respectively; operators' likely operational response(s) to the imposition of a flaring limit; the feasibility and costs of the proposed three-year timeline for decreasing the flaring limit from 7,200 to 1,800 Mcf/month/well; and the effectiveness of the proposed method and conditions in § 3179.7 for allowing operators to obtain an alternative flaring limit.

The BLM developed the capture target approach in final rule § 3179.7, and the alternative capture target provisions in final rule § 3179.8, after careful consideration of the many comments received on the flaring limit approach set forth in proposed rule §§ 3179.6(b) and 3179.7. In particular, the BLM gave careful consideration to operators' assertions that the numerical values of the proposed flaring limits, the proposed schedule for meeting those limits, and the prescriptive nature of the limits would make it prohibitively expensive – and, in some areas of the country, technically impossible – for operators to comply with the terms of the proposed rule. After reviewing the flaring data provided by these commenters, obtaining additional updated and more detailed data from ONRR, and reanalyzing these provisions, the BLM determined that the final rule should phase in its approach to routine flaring over a longer period of time, and provide

operators with more flexibility to take better account of variable conditions on different leases, units, and communitized areas in different parts of the country.

The BLM remains committed to requiring operators to significantly reduce routine flaring of associated gas from development oil wells on BLM-administered leases, thereby increasing gas capture. We have structured final rule §§ 3179.7 and 3179.8 to achieve a comparable volume of flaring reductions as proposed rule §§ 3179.6(b) and 3179.7, although over a somewhat longer timeframe, and then to achieve additional reductions in later years.

The final rule's capture targets and the proposed rules flaring limits operate in a similar manner, with the latter approach a refinement of the former to enhance opportunities for compliance. For example, the long-term flaring limit of 1,800 Mcf/month/well in proposed rule § 3179.6(b)(3) is *exactly* equivalent to a capture target of 100 percent, with a flaring allowable volume of 1,800 Mcf/month/well, applied on a lease-by-lease basis. The final rule phases in a 98 percent (rather than 100 percent) capture target over nine years, and converts the proposed volumetric flaring limits from the proposed rule into declining allowances against the capture target. The differences between proposed rule § 3179.6(b) and final rule § 3179.7(b) are therefore more a matter of form than function, with the final rule designed to achieve flaring reductions comparable to the reductions that the BLM expected from the proposed rule, but to allow operators more compliance flexibility.

That said, the proposed and final approaches to reducing routine flaring do differ in certain key respects, as a result of public comments. The five most significant differences are as follows.

First, the final rule uses specified capture targets, rather than requiring that operators capture 100 percent of their associated gas above fixed volumetric limits as initially proposed, in response to comments indicating that, in some states (notably North Dakota and New Mexico), gas volumes are so high and the availability of capture infrastructure so variable that it is extremely difficult to identify a fixed volumetric limit on flaring that would both be achievable and also provide meaningful reductions in all States. Commenters asserted that given the high gas-to-oil ratios (GOR) in the Bakken basin, there are certain areas where an operator could exceed the proposed flaring limit of 1,800 Mcf/month/well in a period of hours. Commenters argued that even after averaging over a month and across a lease, as the proposed rule would have allowed, the 1,800 Mcf/month/well limit would significantly impact future development in the Bakken and Permian basins. Operators in these areas suggested that allowing averaging of flaring volumes across multiple leases, units, or communitized areas—or even across counties or across a State—would enable operators to use high capture rates in areas with low GOR and/or significant gas capture capability to offset lower capture rates in other areas, and thereby avoid having to curtail production.

Based on these concerns, the BLM restructured the fixed flaring limits as capture targets both to better take account of geographically varying volumes of associated gas and to allow operators some greater flexibility to absorb the impacts of intermittent interruptions or reductions in capture capacity. Final rule § 3179.7, therefore, requires capture of a specified percentage of gas above the flaring allowable volume; this specified capture target incrementally increases from 85 percent in year two (e.g., one year after the effective date of the final rule) to 98 percent in year nine. As noted, this

flexible capture target approach is modeled in large part on North Dakota's regulations, which also impose an escalating capture target, as described in the preamble to the proposed rule.<sup>101</sup>

Second, the BLM extended the compliance dates in response to commenters' concern that coming into compliance with a long-term flaring limit of 1,800 Mcf/month/well would take longer than the three years that the BLM had proposed. The final rule postpones the effective date of any capture requirements for one full year after the effective date of the rule. Thereafter, the final rule incrementally increases the required capture targets over a nine year period and incrementally decreases the flaring allowable volumes over an eight year period. Final rule § 3179.7(b) extends the time an operator has to meet the flaring allowable volume of 1,800 Mcf/month/well until calendar year 2021, about four years after the effective date of the final rule (and about two additional years after the 1,800 Mcf/month/well fixed flaring limit would have taken effect under § 3179.6(b)(3) of the proposed rule).

Third, and conversely, the BLM has reduced the long-term flaring allowable volumes that apply once the final rule is fully phased in, in response to other commenters' concerns that the proposed approach allowed significant quantities of wasteful flaring to continue unabated from 2020 on and did not provide sufficient incentives for industry to continue to decrease flaring over time. Natural gas is a valuable resource that should be put to productive use, and the MLA requires that we minimize the waste of public resources, consistent with existing lease obligations. In addition, if the only changes the BLM made to the final rule were to allow averaging over a broad geographic area and to impose capture targets that never ramp up to 100%, the final rule

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<sup>101</sup> 81 Fed. Reg. at 6634.

would achieve far less of a reduction in wasteful flaring than the proposed rule. While providing operators more flexibility to reduce flaring at lower costs by shifting from the proposed rule's fixed flaring limits to the final rule's capture targets and allowable flaring volumes, the BLM strived to ensure that the final rule still achieves meaningful flaring reductions, comparable to the reductions that the BLM expected from the proposed rule. The key change necessary to meet that goal was the shift from a fixed long-term flaring limit of 1,800 Mcf/month/well (proposed rule § 3179.6(b)(3)) over three years to a flaring allowable volume that decreases over time to 750 Mcf/month/well in year 2025 (final rule § 3179.7(c)(2)(iv)).

Fourth, the final rule allows greater flexibility in how operators may comply with the capture targets. Commenters indicated that leases, units, and communitized areas vary greatly in both the volumes of associated gas produced from oil wells and the availability of gas capture infrastructure, and asserted that complying with a single flaring limit that applies uniformly to every lease, unit, and communitized area would be prohibitively expensive or even, in some areas of the country, technically impossible. Commenters contended that as a result, they would be forced to submit numerous Sundry Notices under proposed rule § 3179.7 to request alternative flaring limits. Commenters asserted that North Dakota's approach, which allows operators to comply with capture targets on a statewide average basis, would reduce the need to request alternative limits and thus achieve comparable overall flaring reductions at significantly lower cost. The BLM agrees, and has in response to these comments structured the final rule to provide operators with greater discretion in how they choose to comply. Specifically, final rule § 3179.7(c)(3) allows an operator to choose whether to comply with the capture targets on



a county- or state-wide average basis, or instead to comply on each lease, unit, or communitized area. This flexibility, too, is modeled on North Dakota's regulations, which allow for compliance on a well-, field-, county- or state-wide basis, as described in the preamble to the proposed rule.<sup>102</sup>

Fifth and finally, the final rule makes certain changes to the alternative flaring provisions (proposed rule § 3179.7, renumbered as final rule § 3179.8) in part to address some commenters' concerns that the proposed renewable 2-year exemption (proposed rule § 3179.7(d)) would allow too many operators to evade the flaring limits and should therefore be eliminated. The changes also account for the change in the final rule from flaring limits to capture targets, and for the BLM's decision to allow operators to choose to demonstrate compliance with the capture targets on an area-wide average basis. Specifically, the BLM deleted the proposed 2-year exemption provision and restyled proposed rule § 3179.7 as an alternative capture target rather than an alternative flaring limit. The change to a capture target approach and the decision to allow operators to choose to comply by averaging their flaring over an entire county or State significantly reduce the risk that a single remote lease, unit, or communitized area with high levels of flaring and little or no access to capture infrastructure will make it impossible for an operator to comply. Under the averaging approach, such leases, units, or communitized areas need not receive a blanket exemption from the capture target. Rather, an operator concerned about the ability of a lease, unit, or communitized area to comply with the capture target can either (a) reduce its flaring at other sites in the relevant area to compensate for the high levels of flaring at that remote lease, or (b) apply for an alternative capture target for that lease under final rule § 3179.8 (if the predicate

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<sup>102</sup> 81 Fed. Reg. at 6634.

conditions are met). Because fewer leases are likely to raise such concerns under the final rule's capture target approach than under the proposed rule, the BLM anticipates receiving fewer requests for alternative capture targets and having an increased capacity to process such requests on a case-by-case basis.

To set the capture targets and flaring allowable volumes in the final rule, the BLM conducted a detailed analysis of 2015 data submitted to ONRR of sales, on lease use and flaring volumes month-by-month for operators within a state. These data go substantially beyond what was available to BLM in preparing the proposed rule, and while the results show that the proposed rule would have reduced flaring less than we initially estimated, we have higher confidence in the updated estimates. Using the new data to reanalyze the likely flaring reductions from the proposed rule, the BLM estimates that the proposed rule would have reduced the quantity of flared gas in 2020 by 42 percent relative to 2015 levels.

Using the same data and assumptions, the BLM estimates that the final rule's approach, which allows operators to average over their statewide production and establishes a capture target of 98% over time, will reduce the quantity of flared gas in 2020 by roughly 26 percent relative to 2015 levels. With the additional time and flexibility provided in the final rule, operators will be able to plan for and build out the additional infrastructure necessary to capture and transport greater volumes of gas in later years. Thus, the final rule further steps down the allowable flaring volumes after 2020, and likewise steps up the required capture percentages, to achieve almost a 50% reduction in flaring by 2025, 8 years after the rule comes into effect.

Thus, the BLM expects that the final rule’s schedule and targets for reducing flaring will achieve a total volume of flaring reductions somewhat greater than the proposed rule, and at lower cost, though over a longer timeframe. Moreover, the final rule establishes a structure in § 3179.7 for reducing routine flaring that could be adapted to achieve more ambitious flaring reductions, if and when the BLM deems those reductions to be technologically feasible and cost effective. The BLM has only specified capture targets and flaring allowable volumes out to 2026. As additional data on flaring become available, and capture technologies improve, the BLM could choose to increase the capture targets further over time, and/or decrease the flaring allowable volumes, through future rulemakings in order to continue to reduce routine flaring of associated gas from BLM-administered leases, units, and communitized areas, consistent with the United States’ March 2016 endorsement of the World Bank’s Zero Routine Flaring by 2030 Initiative.<sup>103</sup>

**B. Leak Detection and Repair**

**1. Requirements of Final Rule**

As discussed in detail in the RIA, we estimate using data from the EPA GHG Inventory that about 4.01 Bcf of natural gas was lost in 2014 as a result of leaks or other fugitive emissions from various components, including valves, fittings, pumps, storage vessels and compressors on well site operations on BLM-administered leases.<sup>104</sup> This quantity of gas would supply nearly 55,000 homes each year.<sup>105</sup>

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<sup>103</sup> “Zero Routine Flaring by 2030” is a voluntary initiative introduced by the World Bank in 2015 and endorsed by multiple governments, oil companies, and development institutions. The initiative focuses on the phase-out of routine, high-pressure flaring of the type addressed by the BLM’s capture targets in § 3179.7 of the final rule, not flaring for safety and other non-routine reasons. For more information and a list of endorsers, see <http://www.worldbank.org/en/programs/zero-routine-flaring-by-2030>.

<sup>104</sup> RIA at 17.

<sup>105</sup> Based on an estimate of 74 Mcf of gas used per household per year. See footnote 2.

LDAR programs are a cost-effective means of reducing waste of gas in the oil and gas production process, as indicated by the studies and State programs discussed in the proposed rule, as well as additional information provided since the proposal, which is discussed in the background section III. Provisions in §§ 3179.301 through 3179.305 of the final rule require operators to carry out leak inspections and repairs at their well sites and associated equipment, meeting specified standards for leak detection methodology and frequency, and for the timing of repairs. Within one year of the effective date of the rule (or within 60 days of beginning production, for new sites), operators must use an instrument-based approach to conduct semi-annual inspections at well sites and quarterly inspections at compressor stations. Operators may also request BLM approval of an alternative instrument-based leak detection program, which the BLM may approve if it finds that the program would reduce leaked volumes by at least as much as the BLM program. Operators must repair a leak within 30 days of discovery, absent good cause, and verify that the leak is fixed. Operators must also keep records documenting the dates and results of leak inspections, repairs, and follow-up inspections, and submit annual reports with this information.

Section 3179.301 provides that the leak detection requirements in the final rule apply to sites<sup>106</sup> and associated equipment that is used to produce, process, compress, treat, store, or measure natural gas from or allocated to a Federal or Indian lease (or from a unit or communitized area that includes such a lease), where such sites are upstream of or contain the approved royalty point of measurements. These requirements also apply to each site located on a Federal or Indian lease, and all associated equipment operated by

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<sup>106</sup> A “site” is defined as a discrete area containing a wellhead, wellhead equipment, or other equipment used to produce, process, compress, treat, store, or measure natural gas or store, measure, or dispose of produced water, which is suitable for inspection in a single visit.

the operator, which is used to store, measure, or dispose of produced water. An operator is not required to inspect sites that contain only a wellhead or wellheads and no other equipment, nor is the operator required to inspect the “leak components”<sup>107</sup> that are not accessible

In response to multiple requests from industry and NGO commenters, the final rule provides greater specificity on what constitutes a “leak”, which includes releases not associated with the normal operation of the component (e.g., releases from equipment designed to vent that exceed the quantities and frequencies expected during normal operation of the equipment). Similarly, releases due to operator error or equipment malfunctions, or from control equipment that does not meet the level of control required by this or other regulations, are also considered leaks. These types of leaks include releases from: a thief hatch left open; a vapor recovery unit that is not operating properly; a tank or combustor that is inadequately sized to handle the throughput of gas; or an intermittent controller that actuates continuously.

Section 3179.301(j) and (k) integrate the final rule with EPA NSPS requirements for operators to conduct a fugitive emissions inspection and repair program. Section 3179.301(j) provides that for new, modified or reconstructed equipment, an operator will be deemed to be in compliance with the BLM LDAR requirements if the operator is in compliance with the EPA subpart OOOOa requirements applicable to the equipment. Paragraph (k) further allows an operator to choose to comply with the EPA fugitive emissions monitoring requirements in subpart OOOOa and apply those requirements to all sites and equipment on a lease not already deemed in compliance with the BLM

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<sup>107</sup> Under the definitions in the final rule, “leak component” means any component that has the potential to leak gas and can be tested in the manner described in sections 3179.301 through 3179.305 of this subpart, including, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems, thief hatches or other openings on a storage vessel, compressors, instruments, and meters.

LDAR provisions, in lieu of complying with the BLM LDAR provisions. This provision allows an operator with new, modified or reconstructed facilities (which must comply with subpart OOOOa) as well as existing facilities (which are not subject to subpart OOOOa) to apply a single leak detection regime to all of their facilities, rather than complying with subpart OOOOa for some facilities and the BLM requirements for others.

The final BLM LDAR provisions also apply to a few specific types of equipment that EPA addresses under requirements that are separate from EPA's subpart OOOOa fugitive emissions program – specifically, certain covers and closed vent systems, and thief hatches or other openings on controlled storage vessels, which are covered under 40 CFR §§ 60.5411a or 60.5395a, rather than under the fugitive emissions requirements in subpart OOOOa. The final rule provides that if an operator chooses to comply with the EPA subpart OOOOa fugitive emissions requirements in lieu of the BLM LDAR requirements for all equipment on a lease, the operator must apply the EPA fugitive emissions requirements to sources covered under 40 CFR §§ 60.5411a or 60.5395a as well.<sup>108</sup> Absent this requirement, these equipment covers, closed vent systems, and openings on controlled storage vessels would not be subject to the BLM's LDAR requirements or the EPA's subpart OOOOa fugitive emission inspection requirements if the operator chose to comply with the EPA requirements in lieu of the BLM requirements.

The final rule requires operators to use an instrument-based approach to leak detection. This is consistent with the proposed rule, and with EPA, Colorado, and Wyoming leak detection requirements. Under final rule § 3179.302, operators must use

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<sup>108</sup> See Section VII, Section by Section, for discussion of treatment of sources exempt from the EPA fugitive emissions program specified in section 43 CFR 60.5397a.

an optical gas imaging device (also commonly referred to as an infrared camera), or a portable analyzer device capable of detecting leaks and used according to the specifications of Method 21, a protocol prescribed by EPA for effectively using these devices.<sup>109</sup> Use of a portable analyzer device must also be assisted by audio, visual, and olfactory (AVO) inspection, as these devices have much more narrowly-focused leak detection capabilities compared to optical gas imaging, which can be used to scan across broad arrays of equipment. The final rule includes specifications for acceptable optical gas imaging equipment, requires all instruments to be used according to the manufacturer's specifications, and requires the operator of any leak detection instrument to be adequately trained in its proper use.

Final section 3179.302 also allows any person to request and the BLM to approve the use of an alternative monitoring device, accompanied by a monitoring protocol, and, in response to comments, this section also details the information that must be included in a request. The BLM may approve an alternative leak detection device and inspection protocol, if the BLM finds that the alternative would achieve equal or greater reduction of gas lost through leaks, compared with optical gas imaging used as required. The BLM may approve the device for use for all or most applications, or may approve use on a pilot project or demonstration basis. Finally, the BLM will provide public notice of a request for approval of an alternative monitoring device and will post on the BLM website a list of each approved monitoring device and protocol, along with any limitations on its use. The BLM intends that the decision to approve the use of an alternative monitoring device would be made only at the national level, by the Director, Deputy Director, or an

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<sup>109</sup> See 40 CFR part 60, appendix A-7.

Assistant Director, as, once approved, the alternative monitoring device could be used anywhere in the country.

Section 3179.303 specifies the required frequency for inspections, which is fully aligned with the requirements of Subpart OOOOa. Operators must inspect each well site at least semi-annually, with consecutive inspections spaced at least four months apart. Operators must inspect each compressor station at least quarterly, with consecutive inspections spaced at least 60 days apart.

In addition to alternative monitoring devices, the final rule allows for BLM approval of alternative monitoring programs. Specifically, like the proposed rule, the final rule allows an operator to request the BLM to approve an alternative instrument-based leak detection program in place of the program specified in the regulations. The BLM may approve the alternative program if it finds that the alternative program would achieve equal or greater reduction of gas lost through leaks compared with the approach specified in the regulations. Because approval of inadequate alternative programs could unintentionally but significantly undermine the effectiveness of the LDAR requirements, the BLM intends that the decision to approve an alternative program would be made only by the relevant BLM State Director, or, with respect to requests that cover operations in more than one State, at the national level by the BLM Director, Deputy Director, or an Assistant Director. In addition, the BLM will post approved alternative programs online both to provide public transparency and to allow other operators to see examples of alternative programs that the BLM believes will be effective.

Section 3179.304 requires operators to repair the leaks that they find. Operators must repair a leak as soon as practicable, and within 30 days of discovery, unless there is



good cause to delay the repair. When an operator repairs a leak, the operator must verify that the repair was effective within 30 days of the date of the repair using optical gas imaging, a portable analyzer using Method 21, or a soap-bubble test.

Section 3179.305 requires operators to keep records related to leak detection inspections and repairs, make them available to the BLM upon request, and submit an annual summary report on the previous year's inspection activities.

## **2. Changes from Proposed Rule**

The final rule provisions on leak detection and repair largely track the proposal, however, we adjusted the frequency of inspections, based upon public comments along with a desire to align these requirements with EPA's final rule, and made other minor adjustments. The BLM had proposed an approach in which the initial required frequency of inspection was semi-annual, but then the frequency varied for each site according to the number of leaks found. An operator that found more than three leaks in each of two inspections would have been required to increase its inspection frequency to quarterly, while an operator that found fewer than three leaks in each of two inspections would have been allowed to drop its inspection frequency to annually. A broad swathe of commenters opposed this approach in the proposed rule (as well as in the EPA's proposed OOOOa). The final rule replaces this approach with a fixed semi-annual rate of inspections for all sites other than compressor stations, and a quarterly inspection rate for compressor stations, consistent with the final OOOOa as well.

Another change from proposed to final rule concerns the effective date of the leak detection requirements. The proposed rule would have imposed the leak detection requirements as of the effective date of the rule, with the first inspection required within

six months of that date. In response to comments, the final rule extends the time for initial compliance to give operators one year from the effective date of the rule to make their first inspection.

The BLM made several other changes that adopt commenters' suggestions. We added a provision allowing approval of an alternative, potentially less effective, leak detection program for an operator that demonstrates that compliance with the LDAR requirements would impose such costs as to cause the operator to cease production and abandon significant recoverable oil or gas reserves. We also added a requirement that operators provide an annual summary report on the results of their leak inspections. Consistent with the final subpart OOOOa, the final rule also includes a new exemption from LDAR requirements for sites that contain only a wellhead(s), and no other equipment.

In addition, the BLM made various smaller changes to enhance the clarity of the final rule. The final rule has refined and clarified the specific sites and equipment subject to the leak inspection requirements. The final rule applies to all equipment handling Federal or Indian gas, upstream of and including the site where the royalty measurement point is located—whether the equipment is on or off the lease and regardless of the ownership of the equipment. The final rule also specifies that with respect to equipment associated with the storage, measurement, or disposal of produced water, the leak detection requirements apply only to such equipment operated by the operator and located on the Federal or Indian lease.

The final rule retains and refines the proposed rule's provision allowing an operator to satisfy the leak detection requirements by complying with the EPA leak

detection requirements under 40 CFR Part 60, Subpart OOOOa. First, the final rule provides that for new, modified and reconstructed equipment, an operator that is in compliance with the EPA fugitive emissions requirements will be deemed to be in compliance with the BLM LDAR requirements, without any requirement to file a Sundry Notice and demonstrate compliance, as the BLM had proposed. Second, it clarifies that that an operator who chooses to comply with the EPA fugitive emissions monitoring requirements in subpart OOOOa in lieu of the BLM LDAR requirements must apply the EPA requirements to all sites and equipment on a lease not already deemed in compliance with the BLM LDAR provisions.

The final rule includes this change because leaks from some types of new, modified and reconstructed equipment, such as covers and closed vent systems, and thief hatches on controlled storage vessels, are not covered by the fugitive emissions requirements under subpart OOOOa, but instead are addressed through specific provisions for storage vessel affected facilities and any associated covers and closed vent systems in subpart OOOOa—namely 40 CFR 60.5395a and 60.5411a. These provisions establish comprehensive control programs for storage vessel affected facilities, including separate and distinct inspection regimes. This final rule ensures that if an operator elects to comply with the EPA fugitive emissions requirements in lieu of the BLM leak detection requirements for equipment on a given lease, the operator must apply the EPA fugitive emissions requirements to all equipment covered by the BLM leak detection requirements, including equipment such as covers, closed vent systems, and thief hatches. Absent this provision, operators could potentially avoid any leak detection program with respect to existing sources in these categories.

The final rule also modifies the requirement in the proposed rule that operators who choose to comply with the EPA requirements in lieu of the BLM requirements must file a Sundry Notice demonstrating compliance with the EPA rule. The final rule provides that the operator need only notify the BLM through a Sundry Notice that it is complying with the EPA rule in lieu of the BLM requirements for equipment on a lease. While the BLM needs to know for oversight purposes if an operator has elected not to comply with the BLM requirements, we agree with commenters that requiring a “demonstration” of compliance with the EPA requirements is unnecessary.

As noted earlier, the final rule also contains a more detailed definition of a “leak” than the proposed rule, as well as more detailed specifications of approved leak detection instruments and methods. In addition, the final rule separates approval of an alternative monitoring device and protocol from approval of an operator’s alternative leak detection program, and it adds specificity on what is required for each of these. The final rule also adds a required minimum interval between inspections, which was not specified in the proposal, but is consistent with final subpart OOOOa. Other minor changes that align the rule with final subpart OOOOa include: a 30- rather than 15-day period for repair and follow-up inspections; additional detail on what constitutes good cause for delay of repair; and a new, two-year outer limit on the timeline for completing repairs delayed for good cause. In addition, while the proposal had required operators to verify the effectiveness of repair using the same method used to identify the leak, in response to comments, the final rule allows operators to use any approved monitoring instrument or the soap bubble test to verify the effectiveness of repair.

### **3. Significant Comments**

Commenters provided many detailed comments on numerous aspects of the leak detection program. This section highlights the most significant comments; additional comments are addressed in Section V. and the Response to Comments document. Comments addressed here include: coverage of the program (i.e., which types of operations and equipment should be included in the program); program structure (how inspection frequency is to be determined, and the required frequency of inspection); the instruments and methods to be used for leak detection; opportunities for use of new instruments and methods; requirements for repairs; and potential exemptions from the requirements.

a. Coverage

*Comments:* Many commenters addressed the coverage of the program. Some commenters supported applying the program broadly to catch as many leaks as possible, while others urged the BLM to use risk-based or other approaches to target the program more narrowly to exclude certain types of sites and equipment and/or to focus on the most likely sources of significant leaks and improve the program's cost-effectiveness.

Some commenters urged the BLM to exclude sites where the commenters asserted that there is less likelihood of leaks and/or smaller leaks. For example, they suggested excluding oil or gas low production wells (also commonly called "marginal" or "stripper" wells) that produce less than 15 barrels of oil equivalent per day; oil well sites that produce crude oil with either an API gravity less than 18° or a GOR less than 300 scf/bbl; and sites that have just wellheads without co-located production equipment.

Some commenters alleged that wells producing less than 15 BOE per day do not have the potential to emit at the same rate as larger producing facilities or enough

production to have significant waste from leaks. Hence, they argued, the costs of LDAR for a marginal well far outweigh any benefits in terms of recovery of lost gas. One commenter stated that sites with marginal wells have less equipment on-site, fewer components that could leak, and thus a smaller likelihood of leaks. Commenters also noted that the EPA proposed to exclude low production wells from its fugitive emissions program, and argued that the BLM should do the same. Some asserted that these wells are only marginally profitable to begin with, and the costs of LDAR could make these wells uneconomical, leading to premature shut-in and a loss of mineral resources. Commenters also recommended that, at minimum, these low production wells should be subject to more relaxed LDAR requirements, such as one-time or annual instrument-based inspections, possibly in combination with AVO inspections, rather than semi-annual instrument-based inspections.

Commenters also asserted that the requirement to inspect for leaks should be limited to certain specified facilities or components because those facilities or components are more likely to leak, and to have higher leak rates. Various commenters recommended that the rule focus on valves, open-ended lines, pumps, or components with potential to operate at or above sales line pressure. Other commenters suggested limiting the LDAR requirements to facilities with components that tend to vibrate or are in thermal operation, and specifically those with controlled storage vessels, compressors, and/or vapor recovery units. Commenters also asserted that the 2013 Carbon Limits Study and the 2014 CAPP study show that compressor stations leak more than well sites, and that components tend to have greater average emissions when subjected to frequent thermal cycling, vibrations or cryogenic service.

In addition, commenters urged the BLM to exclude from the LDAR requirements storage vessels that would not be required to have emission controls under the proposed BLM and final EPA rules (i.e., tanks with the potential to emit less than 6 tpy of VOCs), and equipment designed to vent, such as pneumatic pumps and pneumatic controllers, as well as other types of equipment and sites discussed in Section V.

On the other hand, other commenters strongly opposed narrowing the applicability of the LDAR program, and in particular, excluding low production wells from that program. These commenters cited recent peer-reviewed studies concluding that the occurrence of leaks is fairly random; the probability of a production site being among the highest emitting sites does not increase uniformly with production volumes; and relatedly, both high- and low-producing sites can be associated with high-emitting events. These commenters provided estimates of calculated methane emissions from low production and non-low production wells nationwide based on data reported to EPA and the EPA GHG Inventory, finding that 83 percent of the total methane emissions from oil and gas wells was attributable to low production wells, while only 17 percent was attributable to other wells. The commenters also provided calculations based on an EPA estimate of the cost of semi-annual inspections. These calculations showed, the commenters argued, that even for low production wells, the cost of LDAR compliance would on average be only a small fraction of the annual revenue per well. These commenters further argued that the majority of all existing wells, including those on public lands, meet the definition of “marginal,” and that excluding such wells from the LDAR requirements would allow large amounts of gas waste to continue unabated.

*Response:* The final rule covers largely the same types of sites and equipment as the proposed rule, with a few small exceptions. As discussed above, natural gas leaks during the oil and gas production process are wasteful and can cause significant environmental harm. The BLM is adopting a broadly applicable LDAR requirement to reduce leaks as much as reasonably possible.

The BLM carefully considered numerous and varied approaches that might improve the program's cost-effectiveness by narrowing the coverage of the LDAR program while maintaining its benefits. In evaluating suggestions to exclude certain types of sites from the LDAR requirements, the BLM looked for evidence indicating that the frequency of leaks, size of leaks, and overall amounts of gas lost through leaks relate to the type of site being inspected. In requesting comments on this topic, the BLM had urged commenters to present data or other information to support their assertions, and specifically requested "information regarding the relationship between well production and levels of leaked methane from a site."<sup>110</sup>

With respect to suggestions that the BLM exclude low production wells from the LDAR requirements, we note that roughly 85 percent of wells on Federal and Indian leases are classified as low production wells (i.e., produce 15 barrels of oil equivalent per day or less). Thus, unless these wells are, in fact, unlikely to leak significant volumes of gas, a decision to exclude these wells from the LDAR program would have a significant negative effect on the waste reduction benefits of this rule.

The information submitted by commenters on low production wells does not support their exclusion from the LDAR requirements. As discussed above, some commenters suggested, without providing supporting data, that sites with low production

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<sup>110</sup> Proposed Rule at \_\_\_.



would be expected to lose smaller quantities of gas overall from leaks. However, others disagreed, pointing to the Zavala-Araiza study. As discussed in section III, this study showed that the probability of a production site being among the highest emitting sites does not increase uniformly with production volume, and it found significant opportunities to reduce losses by finding and fixing leaks at lower production wells. These commenters noted that the Lyon et al. study also demonstrates that both high- and low-production sites can be associated with high-emitting events with roughly 15 percent of the identified high-emissions sites in that study being associated with low production wells. Commenters urging an exclusion for low production wells did not provide data refuting these findings. Without additional data on this issue, the BLM simply cannot conclude that low-production sites pose low leak risks and therefore merit exclusion from semi-annual LDAR.

As commenters noted, the EPA had proposed to exclude wells with less than 15 barrels a day oil-equivalent production from the OOOOa fugitive emissions requirements. In the final OOOOa rule, however, the EPA reached the same conclusion as the BLM and dropped the proposed exemption. EPA found that the record for the final rule did not support excluding these wells from the fugitive emissions requirements. In the preamble to the final rule, EPA stated: “We did not receive data showing that low production well sites have lower GHG (principally as methane) or VOC emissions other [sic] than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites because the type of equipment and the well pressures

are more than likely the same.”<sup>111</sup> Thus, including low production wells under the BLM requirements also maintains consistency between the BLM and EPA rules.

In addition, the BLM does not anticipate a significant number of individual well shut-ins or any lease-wide shut-ins as a result of the LDAR requirements, even with respect to low production wells. As discussed in the RIA, third-party providers offer LDAR services at a relatively modest cost, and operators may recoup some of the costs of the program through the saved gas. Also, operators have the option to design and request approval of an alternative LDAR program that is less costly for their particular circumstances, provided they can demonstrate that their alternative program is equally effective. Finally, an operator may request approval of an alternative leak detection program that is *not* as effective as the BLM’s requirements, if the operator demonstrates that compliance with the BLM’s LDAR requirements or an equally effective alternative would be so costly as to cause the operator to cease production and abandon significant recoverable oil or gas reserves under a lease.

With respect to oil well sites that produce crude oil with either an API gravity less than 18° or a gas-to-oil ratio (GOR) less than 300 scf/bbl, as with low production wells, the BLM does not have data to be able to conclude that these oil well sites are likely to be responsible for a sufficiently small quantity of gas lost through leaks that they should be excluded from the LDAR requirements or subject to less stringent requirements.

The BLM does, however, agree with commenters that the risk of leaks is substantially lower at sites with only a wellhead, compared to sites with one or more pieces of production equipment, such as a tank, compressor, dehydrator, or vapor

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<sup>111</sup> 81 Fed. Reg. at 35856.

recovery unit. Industry commenters asserted that there is a greater likelihood of leaks from moving or vibrating equipment, or from equipment in thermal operation, because a valve may stick open, vibrations may cause a connection to loosen, or heat may cause a seal to degrade. While the BLM does not have data about the likelihood and/or size of leaks in these circumstances, the BLM's experience in the field supports the general point. In addition, studies have identified many leaks from the identified equipment, including tanks, compressors, and dehydrators.<sup>112</sup> At a wellhead without co-located production equipment, there are significantly fewer components capable of leaking. Exempting these sites from the LDAR requirements will provide some cost savings for operators, and based on the information available, the BLM believes that realizing those savings will have only a minimal impact on the overall benefits of the LDAR program. Moreover, excluding wellhead-only sites is directionally consistent with some of the other suggestions for narrowing program applicability, such as focusing on sites with tanks or compressors. In the final OOOOa rule, the EPA reached the same conclusion and exempted wellhead-only sites from its fugitive emissions requirements.

Other than the exclusion for sites with only a wellhead, the BLM is not limiting the LDAR requirement to covering only certain specified types of equipment or equipment components. BLM does not believe that it has sufficient information to appropriately distinguish between types of production equipment or equipment components on the basis of the likely quantity of gas lost through leaks. In addition, once an operator is at a site conducting a leak detection inspection, inspecting all of the on-site equipment should add little time and cost, particularly when the operator is using optical

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<sup>112</sup> See, e.g., Warneke, C., Geiger, et.al.: Volatile organic compound emissions from the oil and natural gas industry in the Uintah Basin, Utah: oil and gas well pad emissions compared to ambient air composition, *Atmos. Chem. Phys.*, 14, 10977-10988, doi:10.5194/acp-14-10977-2014, 2014.

gas imaging. The BLM believes that trying to identify and exclude specific types of equipment from inspection adds complexity to the inspection system and introduces the likelihood of errors that would allow leaks to escape detection. It is simpler and more effective for operators simply to inspect all of the equipment located at a site. If, however, an operator has data that show it is possible to conduct an equally effective LDAR monitoring program while excluding certain types of equipment, or sites that only have that type of equipment, the operator may submit a proposed alternative monitoring protocol to BLM for review and potential approval.

Some commenters pointed out that pneumatic controllers are designed to vent and argued that these releases should not be considered leaks. The BLM agrees, and has excluded normal operation of this equipment from the final rule's leak definition. The BLM notes, however, that pneumatic controllers can and do malfunction, such as getting stuck in an open position, which can lead to unnecessary losses of gas. Additionally, as other commenters stated, these malfunctions can be identified through leak inspections. The BLM, therefore, believes it would be inappropriate to exclude this equipment from the rule's LDAR requirements.

Commenters make similar arguments with respect to uncontrolled storage vessels (i.e., tanks that are not required to capture or flare their releases), which are allowed to release up to 6 tons per year of VOCs. Commenters argued that venting from an uncontrolled tank is necessary for proper relief of overpressure. Again, the BLM believes that the commenters' concerns should be addressed through the definition of a "leak," which now excludes releases due to normal operation of a storage vessel or

pressure relief valve, rather than by removing uncontrolled storage vessels from coverage under the LDAR program.

As an initial point, uncontrolled tanks are not open to the atmosphere – rather, they are typically vapor tight, slightly pressurized, and equipped with a thief hatch to allow measurement of production and a pressure relief valve to allow gas release of overpressure. This standard industry practice, which preserves the product and prevents unlimited release of vapors, was recently reinforced in the BLM’s oil measurement rule, 43 CFR subpart 3174. The oil measurement rule requires oil storage tanks, hatches, connections, and other access points to be vapor tight, and it sets specifications for pressure relief valves. Using leak inspections to ensure that thief hatches are closed, seals are sound, and pressure relief valves are operating properly will reduce waste of gas.

Moreover, as discussed in section III., recent studies indicate that tanks are a very significant source of lost gas. As noted earlier, the Lyon et al. study, a helicopter survey of over 8,000 oil and gas wells, reported that over 90 percent of the detected emission incidences were from tanks. Similarly, the Colorado State University studies found substantial venting at tanks, and the City of Fort Worth study found that thief hatches are the largest source of fugitive emissions. The BLM believes that including both controlled and uncontrolled storage tanks in the LDAR program will allow operators to identify leaks and malfunctions that allow significant quantities of gas to be lost.

b. Definition of a leak

*Comments:* Many commenters noted that the proposed rule did not define a “leak,” and they asserted that this would cause confusion, variations in interpretations, and inequitable implementation of these provisions, as well as potentially requiring

repairs for very small releases. Some commenters also urged the BLM to define a leak to distinguish it from normal, intended operation (e.g., pneumatic device actuation, crank case ventilation, etc.).

Many commenters suggested that BLM identify the quality or quantity of a release that would trigger repair requirements under the leak detection program. Commenters generally supported defining a leak as any visible hydrocarbon emission detected by use of an optical gas imaging instrument, or the formation of visible bubbles when equipment is tested with soap solution. With respect to portable analyzers, commenters generally supported setting a numeric threshold, but differed on the number. Some commenters urged the BLM to use 10,000 ppm of hydrocarbon as the threshold for a “leak,” while others recommended using 500 ppm, stating that this is protective and consistent with the Colorado requirements.

*Response:* The BLM agrees that the rule should define what constitutes a “leak” and has included a definition in the final rule. As noted earlier, the definition excludes losses due to normal operation of equipment intended to vent, provided the releases do not exceed the quantities and frequencies expected during normal operations. The definition further clarifies that “leaks” include releases due to operator errors or equipment malfunctions.

The purpose of a leak detection program is to find and fix losses of gas that are not part of normal operations. A prudent operator should conduct reasonable levels of monitoring, staff training, and preventative maintenance to minimize the occurrence and duration of such losses. We are adopting a definition of “leak” sufficiently broad in coverage to give operators the incentive to avoid wasteful losses, whether they occur due

to aging equipment or due to operator error, including errors in appropriately sizing equipment to handle the quantities of production. As found in multiple recent surveys, all of these types of unnecessary losses occur and they are frequently identified using leak detection methods.

The BLM has also slightly modified the definition of “leak component,” and clarified that the inspection requirement applies to leak components at a covered site. Industry commenters had requested that the BLM limit the inspection requirement to specific components on a site. For the reasons previously discussed, the BLM believes it is reasonable to require operators to inspect all pieces of equipment that have the potential to leak gas and that can be tested for leaks. Moreover, as discussed in the proposed rule, repairing leaks generally pays for itself over a reasonably short time-frame through gas savings. To provide additional clarity, the BLM has added to the definition of “leak component” examples of specific types of components that are covered, including but not limited to: valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems, thief hatches or other openings on a storage vessel, compressors, instruments, and meters.

With respect to leak thresholds, and consistent with the proposed rule, EPA and State provisions, and commenters’ suggestions, the BLM is defining “leak” as including “a visible hydrocarbon emission” detected using optical gas imaging, or a release of gas forming visible bubbles with soap solution. Including soap solution allows operators to deploy an additional detection methodology that is inexpensive and effective in confirming that leak repairs have worked. The BLM agrees with commenters that portable analyzers can detect extremely small releases, so the rule needs to specify a

threshold for the size of leak that requires repair. The final rule identifies 500 ppm as the appropriate threshold. This threshold is consistent with both the Colorado and EPA fugitive emissions programs, and aligning the BLM and other Federal, State and tribal programs is important to enhance clarity and consistency and reduce confusion and costs. Additionally, the BLM does not believe that this threshold is too burdensome for operators because once a leak is identified, repairs are generally cost-effective. On average, many repairs pay for themselves in terms of gas savings, and even if some smaller leaks may cost more to repair than they return in gas savings, we generally expect that the benefits to the public exceed the costs of repair.<sup>113</sup>

c. Inspection frequency

*Comments:* Numerous commenters opposed the BLM's proposed approach to the frequency of inspections, under which the frequency would initially be semi-annual, but then could increase or decrease depending on the number of leaks found. Commenters stated that this approach: is not consistent with Colorado and Wyoming leak detection programs; is confusing, overly complicated, and burdensome; inappropriately relies on past performance, which is not indicative of future performance due to the random nature of leaks; creates an incentive for operators not to find leaks; and incorrectly assumes that loss through leaks is homogeneously distributed, rather than heterogeneously distributed, which means that just one leak can be responsible for the majority of the waste.

While commenters generally supported fixed frequency inspections, different commenters supported different frequencies. Some called for quarterly inspections, while others preferred annual. Still others suggested an approach like Colorado's, which

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<sup>113</sup> Carbon Limits AS report entitled, *Improving utilization of associated gas in US tight oil fields* by Anders Pederstad, April 2015 found on the internet at: [http://www.catf.us/resources/publications/files/Flaring\\_Report.pdf](http://www.catf.us/resources/publications/files/Flaring_Report.pdf)



requires different frequencies, from monthly to once, depending on the estimated uncontrolled VOC emissions from the highest emitting storage tank at a site.

Commenters supporting a requirement for quarterly inspections asserted that: the costs are reasonable (and lower than calculated by the BLM); Colorado, Wyoming, and other states already require quarterly inspections for many sites; and optical gas imaging is most effective when performed frequently, which can make up for its tendency to miss smaller leaks compared to other leak detection methods. Commenters who recommended annual inspections asserted that: the costs of LDAR programs outweigh the benefits (and are higher than calculated by the BLM); operators find far fewer leaks after the initial inspection, so repeated inspections produce diminishing returns; and even requiring annual inspections will likely cause operators to prematurely shut-in some wells. Commenters also objected to inspection frequencies that differ from EPA and State requirements.

*Response:* Upon review of the comments, the BLM agrees that requiring leak inspections at a fixed frequency will make the program easier to implement, less burdensome for operators, and more effective. The BLM has concluded that requiring semi-annual inspections is a reasonable approach that balances the leak-detection advantages of more frequent inspections against the associated costs. Further discussion of the cost-effectiveness of this approach is provided in the RIA.

Requiring semi-annual inspections also aligns the BLM and EPA requirements. The BLM notes that it is not possible to align the BLM program's inspection frequency with both EPA requirements and all State requirements because the EPA and States have different inspection frequencies, and frequencies differ even among the States and among

different EPA leak detection programs for different sources. The BLM expects that States with comprehensive and effective LDAR requirements that differ from the requirements of this rule are likely to obtain variances under section 3179.401, which would eliminate conflict concerns. Also, as a legal matter, operators on a Federal or Indian lease, unit, or communitized area will be subject to EPA fugitive emissions requirements for their new, modified and reconstructed facilities and BLM LDAR requirements for their existing facilities. By aligning the timing of the BLM and EPA requirements, and separately allowing operators to comply with EPA requirements in lieu of BLM requirements, the rule provides operators with options for implementing a single leak inspection program across all of their facilities on a lease, unit, or communitized area.

d. Instruments/methods for leak detection

*Comments:* Commenters generally supported allowing the use of optical gas imaging for leak detection, but differed on whether also to allow portable analyzers, or portable analyzers deployed according to Method 21, as an alternative instrument for leak detection. In addition, most commenters opposed the BLM's proposal to allow operators with less than 500 wells within the jurisdiction of a BLM field office to use portable analyzers in lieu of optical gas imaging. Some argued that Method 21 should be an option for all operators, while others argued that the BLM should only allow the use of optical gas imaging, stating that portable analyzers are less effective. Some commenters urged the BLM also to allow use of AVO inspections as the method of leak detection.

*Response:* Upon reviewing the comments, the BLM has concluded that portable analyzers, if used appropriately and supplemented by AVO inspection, can be as effective

as optical gas imaging for leak detection. Thus, the BLM has revised the proposed approach to allow operators to use optical gas imaging, or to use portable analyzers according to Method 21 and supplemented by AVO inspection. The BLM believes that concerns about the accuracy of portable analyzers are ameliorated by requiring the use of Method 21, Determination of Volatile Organic Compounds Leaks, which is a procedure established by the EPA for detecting VOC leaks from process equipment using a portable detecting instrument.<sup>114</sup> Method 21 contains requirements for equipment specifications, performance, calibration, and use to ensure that the analyzers are used properly and will identify leaks that are occurring. The BLM agrees with commenters that allowing the use of portable analyzers according to Method 21 will reduce costs by aligning with existing EPA, State, and local requirements. The BLM did not receive information supporting some commenters' contention that AVO inspections can be as effective as a technology-based program, and thus the final rule does not allow operators to inspect for leaks only using AVO.

e. Approval of alternative leak detection instruments/methods and alternative leak detection programs

*Comments:* Many commenters strongly supported the provisions allowing the BLM to approve additional technologies and methods for leak detection when they are found to be effective, and they urged the BLM to establish clear criteria for rapid approval of alternative monitoring devices and new technology. Some commenters included alternative monitoring programs in their comments on this topic. Commenters noted ongoing research and development investment in new monitoring technologies and

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<sup>114</sup> U.S. EPA, *Leak Detection and Repair, A Best Practices Guide* (Oct. 2007) (<https://www.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf>). 40 CFR part 60, Appendix A-7.

methods, such as the DOE's ARPA-E MONITOR program and the Environmental Defense Fund's Methane Detectors Challenge,<sup>115</sup> and they stated that several new technologies for continuous or periodic monitoring may become commercially available within the next 2 years.

Many commenters urged the BLM to detail the information that must be included in an application for approval of alternative technologies, as well as the process and criteria that the BLM would use to respond to an application. Various commenters emphasized that the process should be rapid, efficient, transparent, predictable, consistent, and rigorous. In addition, commenters suggested that any person should be able to submit an application, and that any operator should be able to use an approved technology.

*Response:* The BLM agrees on the need for a clear, consistent, and rigorous process and criteria for approval of alternative leak instruments and methods, and we have modified the regulations accordingly. The final rule provides that any person may request approval of an alternative monitoring device and protocol for using that device by submitting a Sundry Notice to the BLM that contains information that the BLM would need to evaluate the effectiveness of the alternative device compared to the base program.

Once a device is approved for general use, any operator may use it without the need for additional notification or approval. Because an approved device could potentially be used by an operator on any Federal or Indian lease, unit, or communitized area, the BLM intends that the request will be evaluated by the BLM Director, Deputy Director, or Associate Director. The BLM may approve the device if the BLM finds that

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<sup>115</sup> American Petroleum Institute (API). Comments on the "Waste Prevention, Production Subject to Royalties, and Resource Conservation" Proposed Rule. Submitted April 22, 2016. Docket ID BLM-2016-0001-9073: Available at [regulations.gov](https://www.regulations.gov).

the device would achieve equal or greater reduction of gas lost through leaks compared to optical gas imaging used in a leak detection program that meets the rule requirements.

The BLM believes that this is an appropriate criterion for approval because it ensures that the program will achieve its leak reduction goals regardless of the type of leak detection device used. The BLM understands that different types of devices may achieve equivalent results. For example, a device that monitors continuously, but is less sensitive than optical gas imaging, might achieve results equivalent to optical gas imaging due to the gas savings from early detection. The information submitted must be sufficient to support such a finding, however. Finally, the rule states that the BLM will post online each approved alternative monitoring device and protocol, along with any limitations on its use.

The BLM also clarified the distinction between alternative leak detection devices or methods and alternative leak detection programs, which are both included in the proposed and final rules. Separate from the provisions for approval of an alternative device, the final rule allows an operator to request BLM approval of an alternative leak detection program that uses optical gas imaging, a portable analyzer or another approved device according to approved specifications. As with an alternative device, the final rule spells out the information that an operator would need to submit to request approval of an alternative program. The BLM intends that the request would be reviewed and potentially approved by the BLM State Director (or Director, if the request covers operations in more than one State). The BLM could approve an alternative leak detection program if the BLM finds that the alternative program would achieve equal or greater reduction of gas lost through leaks compared to the leak detection program required

under the rule. The rule does not allow other operators to use an alternative leak detection program requested by and approved for a specific operator, as the results may not be transferable. The BLM expects each operator to make a detailed showing, specific to their particular circumstances, that an alternative program would be equally or more effective. For example, an operator might propose a program that included more frequent inspections for some sites and less frequent for others, compared to the final rule requirements, or an operator may be able to deploy an alternative leak detection device or system, approved by the BLM, on a continuous basis and achieve results that would allow for less frequent inspections using optical gas imaging.

f. Timing

*Comments:* Several commenters recommended that the BLM extend the phase-in period for the proposed LDAR program. They stated that operators or contractors will need time to ramp up LDAR efforts, including acquiring the necessary equipment and hiring and training inspectors. Commenters variously recommended phase-in periods of one year or three years.

*Response:* The BLM agrees and has modified the final rule to allow for a one year phase-in period. Thus, the first round of leak detection inspections must be completed by January 17, 2018. The BLM notes that equipment manufacturers, service providers, and operators are already taking action to produce and procure leak detection equipment and establish programs in response to EPA's OOOOa requirements published on June 3, 2016. Under those requirements, all operators with new, modified or reconstructed facilities will already be conducting leak detection inspections as of June 3, 2017. Expanding such programs to cover additional well sites should take less time than

the initial development and deployment. The BLM also believes that one year from the effective date of the rule will provide ample time to manufacture the needed equipment, given the number of additional sources that will be covered by this rule .

g. Repair requirements

*Comments:* Commenters raised several primary concerns. First, many commenters opposed the BLM’s proposal to require that an operator verify a repair using the same method used to detect the leak. They noted that it may be more efficient to allow the operator to test a repair using, for example, a soap bubble test than to bring the leak surveyor back to the site to check the repair.

Second, some commenters urged the BLM to allow 30 rather than 15 days for leak repair. Commenters stated that some leaks require more time to repair due to safety issues, availability of personnel or replacement parts, hostile weather conditions, or other logistical issues related to sites being remote, dispersed, unmanned, and un-electrified. One commenter argued that if an operator contracts with a consultant to perform the monitoring, the consultant will not be able to make the repair at the time the leak is detected, thus requiring more time to complete the repairs.

Third, commenters requested more clarification on what would constitute “good cause” for delay of repair, noting that where the operator must blowdown (depressurize) the equipment before making the repair, this could release more gas than would be released by the leak prior to the next scheduled equipment blowdown.

*Response:* The BLM modified the final rule to address each of these concerns, as well as align the rule with the final subpart OOOOa. The BLM agrees that optical gas imaging, portable analyzers using Method 21, and the soap bubble test are all effective

means to identify whether a leak has been repaired, and providing operators the flexibility to select a verification method should minimize costs.

The BLM also has modified the final rule to provide operators up to 30 days to make a repair, although the rule still requires operators to repair leaks as soon as practicable. We recognize that some State LDAR programs require repairs to be made sooner – within 5 to 15 days of finding a leak. The requirement to repair leaks as soon as practicable means that many leaks will be repaired upon discovery or within a shorter timeframe than 30 days, as many leaks can be repaired on the spot or as soon as a maintenance technician can get out to the site. However, according to industry commenters, allowing up to 30 days will meaningfully reduce the time and costs involved in filing Sundry Notices for leaks that could not be fixed in 15 days but could be fixed in 30.

The final rule also provides additional detail regarding what constitutes “good cause” for delay of repair beyond 30 days. Good cause for delay exists if repair within 30 days is technically infeasible; would require a pipeline blowdown, a compressor station shutdown, or a well shut-in; or would be unsafe to conduct during operation of the unit. In addition, the operator must complete the repair at the earliest opportunity, and in no case may the repair be delayed beyond two years. Technical infeasibility includes a need to order parts, in which case the operator must complete the repair as soon as the parts are available. Where the cause for delay is the need to blowdown or shut-down equipment, the operator must complete the repair during the next equipment blowdown or shutdown that occurs after the leak is found.



h. Interaction with EPA fugitive emission requirements and State LDAR requirements

*Comments:* Many commenters argued that the proposed BLM LDAR program overlaps and in some ways conflicts with the EPA fugitive emissions requirements under OOOOa and various State LDAR requirements. These commenters urged the BLM to drop the LDAR program altogether or, at minimum, align the BLM requirements with the EPA and State requirements and/or allow operators to comply with EPA or State requirements in lieu of the BLM requirements.

*Response:* While the BLM cannot abdicate its statutory responsibility to ensure safe, responsible, and nonwasteful production of public oil and gas resources, the BLM has worked closely with the EPA and consulted with States to align the regulations as much as possible, consistent with the agencies' separate statutory authorities. In final form, the EPA and BLM programs use the same criteria to identify what constitutes a leak that must be repaired, and they require operators to use the same types of leak detection equipment, inspect the same types of sources at the same frequencies, and repair leaks within the same timeframes. In addition, the final rule provides that operators complying with EPA requirements for new, modified and reconstructed equipment are deemed in compliance with the BLM requirements for such equipment, eliminating the possibility of overlap where both regulations apply. Also, the final rule gives operators the option to comply only with the EPA requirements at existing facilities as well.

The BLM notes that there are a few small differences between the BLM and EPA programs, but these should not increase compliance burdens for operators. First, while

the programs both cover largely the same sources, the programs differ somewhat in their coverage. The BLM LDAR provisions apply to all covers, closed vent systems, and storage vessels, while the EPA fugitive emissions requirements only apply to covers and closed vent systems not subject to § 60.5411a, and thief hatches or other openings on a controlled storage vessel not subject to §60.5395a. Subpart OOOOa has a separate, detailed set of requirements in § 60.5411a for sources covered by that section, and another set of requirements in § 60.5395a for storage vessel affected facilities, and section 60.5416a prescribes a separate and different leak inspection regime for these sources.

For waste reduction purposes, the BLM did not believe it was necessary to adopt separate requirements for storage vessels, covers and closed vent systems. Instead, the BLM elected to require controls for storage vessels with high levels of gas loss and to include storage vessels, covers, and closed vent systems under the LDAR program. Thus, the final rule provides that operators that choose to comply with the EPA fugitive emissions program in lieu of the BLM leak detection program for both new and existing equipment on a lease must apply the EPA fugitive emissions requirements to all equipment covered by the BLM requirements, including storage vessels, covers and closed vent systems, to ensure that these types of equipment are covered by at least one of the agencies' leak detection requirements.

Second, a few elements of the BLM LDAR requirements are less prescriptive than the EPA requirements, but again, the BLM does not believe that these differences would impose any additional burdens on operators. The BLM regulations do not require operators to develop a monitoring plan or specify their walking path for inspections, nor

do they include requirements for scheduling inspection of components that are difficult-to-monitor or unsafe-to-monitor. The BLM record-keeping requirements are also less specific than the EPA requirements. The BLM regulations do not provide specific direction to operators on the proper calibration and use of leak detection instruments, instead simply requiring operators to operate the instruments according to the manufacturer's specifications. Also, the BLM requirements define "leak component" slightly more broadly than the EPA definition of "fugitive emissions component." For existing equipment that is not also subject to the EPA requirements, the final rule provides operators the choice of complying with the EPA or the BLM requirements, allowing operators to comply with a single set of requirements for all of their sources if they so choose, or to comply with the somewhat less prescriptive BLM requirements with respect to their existing sources.

With respect to State leak detection requirements, the BLM notes that because requirements differ both among the individual States and between the EPA and the individual State rules, it is not possible to align the BLM requirements with all of the other potentially applicable requirements. In addition, the BLM does not believe it is appropriate to exempt operators from the BLM requirements if they are subject to any State requirement relating to leak detection, as some commenters suggested. That approach would not ensure achievement of an equivalent reduction in gas losses. Instead, the final rule has a variance provision that allows State or local requirements to substitute for any of the BLM requirements under these rules, upon a showing that the State or local requirement at issue would perform at least equally well in terms of reducing the waste of

oil and gas, reducing environmental impacts from venting and or flaring of gas, and ensuring the safe and responsible production of oil and gas.

**C. Liquids Unloading at New Wells**

**1. Requirements of Final Rule and Changes from Proposed Rule**

The requirements to reduce venting from liquids unloading activities at natural gas wells are generally discussed in Section VII. Section by Section. This section highlights one significant change to those provisions from the proposed rule. In the final rule, liquids unloading activities at new wells are subject to the same best practices and reporting requirements as those at existing wells. The BLM had proposed to prohibit liquids unloading through manual well purging at new wells drilled after the effective date of the rule, but we are not carrying this proposal forward into the final rule.

**2. Significant Comments**

*Comments:* Many commenters opposed the proposed well purging prohibition for wells drilled after the effective date of the rule. These commenters stated that even with optimized liquids unloading management and a highly sophisticated automated system, some purging would still be necessary. One commenter asserted that there are a large number of different technologies, tools, and practices for liquids unloading that are matched to an individual well's characteristics at each stage of its lifecycle (e.g., wellbore design, tubular design and condition, use of packers, and the frequency of unloading needed to maintain or increase production), and that no single technique will be adequate or appropriate across the full lifecycle of a well. Others argued that it is inappropriate to have different standards apply to similar wells depending on the date on which they are drilled.

Several commenters apparently assumed that the prohibition on well purging would effectively require operators to install a plunger lift system during initial well construction, and these commenters provided multiple reasons that would not be appropriate. First, they asserted that new wells are not likely to require liquids unloading until later in the life of the well. Second, they argued that the characteristics of the well at the time that deliquification is needed impact the technical feasibility and cost of using methods other than purging for liquids unloading, and that operators are not likely to know during initial construction which option is optimal. Third, commenters contended that installing plunger lift systems at initial construction would also "lock in" technology choices that may preclude the use of more appropriate or improved technology when deliquification is needed. Lastly, commenters asserted that even if equipment was installed on new wells to accommodate plunger lifts, by the time liquids unloading is required, the equipment may need to be fixed or replaced.

Other comments supported BLM's proposal to prohibit purging during liquids unloading activities at new wells. They stated that operators could effectively design wells and deploy mitigation technologies in a way that would eliminate emissions, and that these technologies are cost effective. Citing datasets showing that a small minority of wells are responsible for a large amount of venting during liquids unloading events, these commenters also argued that the BLM should address this issue by applying the purging prohibition to these high-emitting existing wells as well.<sup>116</sup>

*Response:* Upon reviewing the information provided by the commenters, the BLM has determined that it is not appropriate to prohibit manual well purging at new

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<sup>116</sup> See EDF, *Comments on Proposed Regulation Order Article 3: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities: Part II of Comments 8* (May 22, 2015), available at [http://www.arb.ca.gov/cc/oil-gas/meetings/EDF\\_5-22-15.pdf](http://www.arb.ca.gov/cc/oil-gas/meetings/EDF_5-22-15.pdf).

wells. It is often less expensive to design in performance specifications (such as no purging) than to retrofit an existing source. However, in this case, the BLM agrees with commenters that there is no single technology or set of technologies that could appropriately be deployed at all new gas wells to avoid manual purging later in the well's life. The BLM did not intend the proposed purging prohibition to force all new wells to install plunger lift systems, and we do not believe that would be a cost-effective way to minimize venting from liquids unloading activities.

#### **D. Variances Related to State and Tribal Regulations**

##### **1. Requirements of Final Rule**

Like the proposed rule, the final rule provides a variance procedure to allow an equally or more effective State, local government, or tribal requirement to substitute for the comparable BLM requirement under this subpart. The BLM may grant a variance request submitted by a State or tribe if the BLM State Director finds that the State, local government, or tribal rule or regulation would perform at least as well as the relevant provision of the BLM rule in terms of reducing waste of oil and gas, reducing environmental impacts from venting and/or flaring of gas, and ensuring the safe and responsible production of oil and gas.

The rule identifies what a State or tribe would need to include in a request for a variance. The request must identify the provision or provisions of the BLM requirements from which the State or tribe is requesting a variance, and must identify the State, local, or tribal provisions that would substitute for the BLM provision or provisions. The variance request must also explain why the variance is needed, and demonstrate how the

State, local or tribal rules would perform at least as well as the BLM provisions they would replace.

## **2. Changes from Proposed Rule**

The variance provisions in the final rule largely track the proposed rule, with a few additions and clarifications. The criterion for approval of a variance request in the proposed rule was a determination that the State or tribal regulation “meets or exceeds the requirements of the provision(s) from which the State or tribe is requesting the variance.” The final rule requires instead a finding that the State or tribal rule “would perform at least equally well in terms of reducing waste of oil and gas, reducing environmental impacts from venting and/or flaring of gas, and ensuring the safe and responsible production of oil and gas, compared to the particular provision(s) from which the State or tribe is requesting the variance.” The final rule changes the phrase “any individual provision of this subpart” to “any provision(s) of this subpart,” to make clear that a variance request can apply to a specific provision or a group of provisions.

The final rule also: allows local government requirements, in addition to State and tribal requirements, to support a variance request and substitute for BLM requirements; adds a requirement that the State or tribe must notify the BLM of any substantive changes to the State, local government, or tribal rules to be applied under the variance; and clarifies that a variance allows State, local government, or tribal rules to apply in place of the BLM requirements, but does not eliminate Federal enforcement of waste prevention requirements on Federal or Indian leases, units, or communitized areas. Rather, under a variance, the BLM has the authority to enforce the rules identified by the State, locality, or tribe as if the requirements were BLM regulations. The final rule

further clarifies that State, local, and tribal enforcement of their own regulations would not be affected by the BLM's approval of a variance.

### **3. Significant Comments**

#### **a. Criteria for Variance Approval and Scope of Variance**

*Comments:* Several commenters expressed concerns with the proposed criteria for BLM approval of a variance request. Many commenters stated that a patchwork of State, Federal, and tribal regulations could cause compliance difficulties and confusion for both the regulators and the regulated entities. These commenters requested that the variance approval criterion be less restrictive, and opposed the proposed language stating that the State or tribal regulation must “meet or exceed” the requirements of this rule. Stating that many of the State and tribal regulations that limit venting and flaring are qualitative, not quantitative, commenters asserted that determining what “meets or exceeds” the BLM's requirements would be arbitrary. Instead, some commenters suggested that the BLM change the language to “is consistent with the intent of,” stating that this would allow State regulations that meet the intent of the proposed rule, and are adequate and complete in achieving similar goals, to meet the variance criterion.

Other commenters suggested changes to make the variance application and approval process more restrictive, or opposed allowing variances altogether. One commenter supported the proposed criteria for approval but suggested strengthening this requirement by specifying how the BLM would evaluate the relative effectiveness of the State program, for example by requiring additional data or modeling to support a variance request. Commenters also requested that variance requests be made publicly available, and that there be an opportunity for the public to comment on the requests.



Several commenters suggested that variances should be allowed for all provisions and for entire State programs, stating that this approach would eliminate an involved process requiring variance requests for specific provisions. Others raised concerns about allowing a programmatic variance, and urged the BLM to limit variances to specific provisions of the rule or allow for a variance only when the State and BLM requirements are duplicative. They noted that in many cases State regulations do not address all of the areas covered by the BLM rule – i.e., venting, flaring, and leaks – and State and tribal regulations may also not cover the same specific sources of these losses as the BLM rule.

*Response:* The BLM agrees that it could be helpful to add further detail to the proposed criteria for approving a variance. In addition, the BLM agrees that it could be helpful to clarify whether several provisions could be considered together and be found, in combination, to meet the criteria for approving a variance. The BLM has revised the variance provisions to address both of these issues.

First, the goal of the variance provision is to allow State, local, or tribal regulations to substitute for the BLM requirements where they will produce benefits at least equivalent to the expected benefits of the BLM regulations. The final rule spells out this criterion by identifying three key benefits of the BLM rules: (1) reducing waste of oil and gas; (2) reducing environmental impacts from venting and/or flaring of gas; and (3) ensuring the safe and responsible production of oil and gas. To replace provisions of the BLM rule with a State or tribal requirement, the State or tribe must demonstrate that their rules would perform at least as well in achieving these benefits.

The final rule would allow States and tribes to request variances for specific sets of provisions, as well as individual provisions. For example, a State that had a leak

detection program similar to the BLM program, but with a different required inspection frequency, might request a variance for the frequency provisions or for the whole leak detection program. The State would need to demonstrate that even if the State or local program would identify a different set of leaks compared to the BLM program, overall the State or local program would be at least as effective as the BLM program in reducing an equivalent quantity of gas losses—which would, in turn, reduce waste, reduce the environmental impacts of venting, and enhance safe and responsible production.

The final rule provisions are not, however, structured to support a broad approval of a variance for an entire State, local, or tribal oil and gas production oversight program, and the BLM agrees with the commenters who raised concerns about such an approach. The BLM recognizes that all States and many tribes regulate various aspects of oil and gas production, but different States and tribes focus on different aspects of the production process and aim for different goals. For example, one State may primarily regulate flaring, while another aims primarily to reduce methane emissions from tanks. The focus on at least equivalent performance requires a specific look at the results achieved from a particular provision or set of provisions, and it would not allow approval of, for example, a stringent flaring regime to substitute for leak prevention requirements.

The final rule does not require that variance requests be made publicly available or that there be an opportunity for the public to comment on the requests. In the past, the BLM has not made individual variance requests publicly available or provided an opportunity for public comment.

b. Enforcement under an Approved Variance

*Comments:* Commenters requested clarification on who would be responsible for enforcement if a variance were approved. Commenters stated variously that: the State or tribe should enforce the applicable State, local or tribal requirements; States and the BLM should establish memoranda of understanding for enforcement; or the BLM should retain authority to enforce any State, local, or tribal provision for which a variance is granted (noting that States or tribes might lack resources to operate effective enforcement programs).

*Response:* The final rule clarifies that the variance provisions allow operators to comply with State, local, or tribal requirements in lieu of BLM provisions where a variance has been approved, but the BLM is still responsible for enforcing those requirements insofar as they would replace the BLM requirements. As a practical matter, the BLM and States, localities, or tribes will likely enter into memoranda of understanding to coordinate enforcement activities and efficiently deploy enforcement resources, avoiding overlap or redundancy. Ultimately, however, the BLM remains responsible for ensuring that operators comply with Federal requirements, or in this case, State, local, or tribal requirements that the BLM deems to be an acceptable substitute for the Federal requirements.

This is in contrast to situations in which a Federal agency is authorized by law to formally delegate administration and enforcement of a regulatory program to a State agency. Here, the BLM is not delegating its regulatory or enforcement authority to the State, locality, or tribe. Rather, the BLM is recognizing that, in the absence of a variance, an operator would be required to comply with overlapping requirements. Where States, localities, or tribes have regulations in place that are different from, but at least as

effective as, the BLM requirements, applying two sets of requirements is burdensome for operators and would not generate additional benefits. The variance process avoids the potential duplication and inefficiencies that could otherwise occur in this situation, while still holding the BLM responsible for ensuring that operators meet the requirements and produce the benefits for the public that would have been provided under the BLM regulations.

## **VI. Additional Significant Comments and Responses**

This section summarizes and responds to some additional comments on the proposed rule, that, while significant, did not lead to major changes in the final rule, and that are more cross-cutting in nature than the provision-specific comments addressed in the Section VI. Section-by-Section. These include comments on: the interaction between the BLM rule and EPA regulations; the BLM's authority to require flaring of vented gas; when gas should be considered "avoidably lost"; application of these requirements to units and communitized areas; delays in permitting for natural gas pipeline rights of way; and the interplay between this rule and the BLM's land use planning activities.

### **A. Interaction with EPA Regulations**

*Comment:* Many commenters raised concerns about how the proposed BLM regulations would interact with EPA regulations on oil and gas production. Some commenters urged the BLM not to finalize some or all of the provisions of this rule, arguing that its provisions regulate air pollution, and that task should be left to EPA. Some of these commenters further suggested that if the BLM does regulate waste from oil and gas production, the BLM should exempt sources covered by the EPA regulations, and align its requirements with the EPA requirements where they overlap, to avoid

duplication and inconsistencies. Some commenters highlighted specific provisions that could potentially overlap with EPA's requirements, and expressed concern about differences or conflicts between the two agencies' regulatory regimes.

*Response:* We discuss the necessity for BLM regulations to reduce waste from oil and gas production in section III.B.3.a of this preamble, and the BLM's legal authority for the rule in section III.C. The BLM agrees with commenters, however, that in those areas covered by both this rule and EPA requirements, the two sets of regulations should align to the maximum extent possible. We have addressed comments raising potential inconsistencies between the proposed BLM text in specific provisions and corresponding EPA text in sections VI.A of this preamble, and in the Section by Section discussion in section VII, where those specific provisions are discussed. The remainder of this section addresses comments on the generalized potential for duplication and overlap.

We do not believe that the final BLM and EPA rules impose conflicting requirements on operators, and we further believe that we have addressed issues of regulatory overlap. First, much of this rule regulates activities or areas that are not regulated by EPA. This includes the rule's provisions on routine flaring during the oil and gas production process, well maintenance and liquids unloading, well drilling, well testing, emergencies, royalties due on lost gas, royalty rates, measurement and reporting of lost gas, and operators' royalty-free use of gas. Second, where both EPA and the BLM regulate an activity, the rules largely apply to different sources. In particular, the BLM requirements on venting from pneumatic controllers, pneumatic pumps, and storage vessels all explicitly apply to existing sources that are *not* subject to EPA's subpart OOOOa, but would be subject to that rule if they were new, modified, or reconstructed

sources. In addition, even where the BLM and EPA requirements address the same type of activity, but apply to different sources (existing (BLM) versus new, modified, or reconstructed (EPA)), the agencies have worked together to align the text and substance of the requirements as closely as practicable.

Third, in those few instances in which both agencies regulate an activity and could potentially cover the same source – specifically well completions and leak detection – the BLM final rule provides that an operator can comply with just one set of requirements. Specifically, the rule aligns the BLM’s requirements with the corresponding EPA requirements to a substantial degree, and also provides that an operator will be deemed to be in compliance with the BLM rules if the operator complies with the applicable requirements of subpart OOOOa.

*Comment:* Commenters noted that in addition to the existing EPA regulations of new, modified, and reconstructed air pollution sources at oil and gas facilities, EPA announced in March 2016 its intention to regulate *existing* oil and gas sources under CAA section 111(d), and EPA is currently developing an information collection request (ICR) as the first step in that process. Commenters argued that this EPA action negates any argument that the BLM rule is necessary to address emissions from the existing sources that subpart OOOO and subpart OOOOa do not cover.

*Response:* The ICR and EPA’s intention to conduct a rulemaking under CAA section 111(d) are discussed in detail in section III.B.3.a of this preamble. In summary, establishing emission reduction requirements for existing sources under the CAA would entail the following steps:

- EPA issues a final ICR;

- Industry submits the required information;
- EPA develops and proposes a rule under CAA section 111(d);
- EPA reviews public comment on that proposal and finalizes the CAA section 111(d) rule;
- Because rules under section 111(d) do not have independent effect but are implemented by States, States then develop and submit to EPA State plans to implement the 111(d) rule (a process that generally requires State rulemaking and may require State legislation);
- EPA approves the State Plan (or prescribes a Federal implementation plan where the State fails to submit a satisfactory plan); and
- Industry implements the requirements in time to meet compliance deadlines established in the State plans.

Clearly, it will be many years before existing sources in this sector are subject to binding requirements under CAA section 111(d), and it is not yet evident what shape those requirements will take. Given the substantial uncertainty surrounding the timing and content of any EPA regulation of existing oil and gas sources, the BLM has both the authority and the obligation to act now to rein in the ongoing waste of large quantities of public and Indian natural gas.

## **B. Authority to Require Flaring of Gas**

Citing several specific provisions of the proposed rule that would require operators to flare rather than vent gas that is not captured for sale or use, including the venting prohibition and provisions on storage tanks, several industry commenters asserted that the BLM lacks the authority to require flaring instead of venting of Federal

and tribal gas. These commenters argued that the BLM's sole authority is to prevent waste, and a provision that requires flaring rather than venting does not aim at waste prevention because shifting from venting to flaring does not conserve the gas. The sole purpose of such provisions, these commenters asserted, is to regulate air pollution and GHG emissions. Commenters further asserted that regulation of air pollution and GHG emissions is the exclusive province of the EPA, and by extension, the BLM may not regulate in this arena.

For several reasons, the provisions of the rule that require flaring instead of venting are within the BLM's statutory authority. First, as noted above, the MLA grants the BLM the authority to promulgate rules for the prevention of undue waste or for safety purposes.<sup>117</sup> As explained further in the Section by Section analysis in Preamble Section VII, each provision of this rule that requires flaring rather than venting is a waste prevention and/or a safety measure. For instance, the requirement to flare and not vent high-pressure associated gas constitutes waste prevention because any flaring at a given well will likely cause the operator to capture more gas at its other wells in order to stay within the capture percentage under § 3179.7. These provisions therefore fall comfortably within the BLM's waste prevention and safety authority under the MLA, irrespective of the BLM's environmental mandate.

Second, as discussed above, the MLA and FLPMA grant BLM the authority to regulate oil and gas development on the public lands, including to protect the public's interest in other natural resources and the quality of the environment.<sup>118</sup> In its traditional role as manager of the public lands and steward of publically owned resources, BLM

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<sup>117</sup> The BLM has acted on the latter authority since DATE: longstanding rules promulgated under the MLA require the operator to "perform operations and maintain equipment in a safe and workmanlike manner" and "take all precautions necessary to provide adequate protection for the health and safety of life and the protection of property." 43 CFR § 3162.5-3.

<sup>118</sup> See 30 U.S.C. §§ 187, 189; 43 U.S.C. §§ 1732(b), 1740.



must regulate the development of federally owned oil and gas deposits pursuant to principles of multiple use and sustained yield.<sup>119</sup> Under those principles, BLM may consider air quality and GHG emissions when deciding how to regulate mineral-development operations. FLPMA expressly declares that BLM should balance the need for domestic sources of minerals against the need to protect the quality of “air and atmospheric” resources.<sup>120</sup> Furthermore, as part of its resource management plans, the BLM has recently exercised its authority under FLPMA to include emission mitigation standards for oil and gas operations.<sup>121</sup>

Third, the rule’s provisions requiring flaring rather than venting further the BLM’s trust responsibilities with respect to Indian oil and gas development because they will prevent the waste of gas and will reduce the environmental impacts to Indian lands from oil and gas development. The BLM believes that these provisions, like all the provisions in this rule, are in the best interest of Indian mineral owners and that the extension of these provisions to oil and gas production from Indian lands is therefore justified.

Finally, while the CAA indeed delegates responsibility for implementing its air pollution and GHG emissions control program to EPA, nothing in the Act bars the BLM from considering air pollution and GHG emissions when deciding how to regulate the development of federally owned oil and gas deposits. The EPA and the Department of the Interior have distinct statutory authorities and missions that may, in some cases, result in overlapping policy goals. This rule does not infringe on EPA’s prerogative to regulate

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<sup>119</sup> 43 U.S.C. § 1732(a).

<sup>120</sup> 43 U.S.C. § 1701(a)(8), (a)(12).

<sup>121</sup> See, e.g., BLM Tres Rios Field Office, *Resource Management Plan and Record of Decision* at II-63 (Feb. 27, 2015), available at [http://www.blm.gov/style/medialib/blm/co/field\\_offices/san\\_juan\\_public\\_lands/land\\_use\\_planning/approved\\_lrmplp.Par.66402.File.dat/Part%20II%20-%20RMP%20Chapter%202.pdf](http://www.blm.gov/style/medialib/blm/co/field_offices/san_juan_public_lands/land_use_planning/approved_lrmplp.Par.66402.File.dat/Part%20II%20-%20RMP%20Chapter%202.pdf) (setting forth specific standards to mitigate oil and gas emissions that will apply to all approved site-specific projects, including NOx limits for engines, use of “green completions technology,” storage tank controls designed to achieve 95% emission reduction, and use of low or no-bleed pneumatics).

air quality through source-specific performance standards and cooperation with State partners. Nor does EPA’s authority infringe on or otherwise restrict the BLM’s mandate to prevent waste from and manage the environmental impacts of activities on public lands and using public resources. The CAA does not displace other Federal agencies’ Congressionally-granted authority to address environmental and climate change concerns.<sup>122</sup> Congress may grant agencies overlapping spheres of authority, and such agencies merely have a responsibility to coordinate with each other.<sup>123</sup> The BLM has worked closely with EPA to ensure that this rule and EPA’s subpart OOOO and subpart OOOOa regulations harmonize to the maximum extent practicable.

### C. “Avoidably Lost” Oil or Gas

As noted above, the MLA requires royalties on oil and gas to be paid as a “percent in amount or value of the production removed or sold from the lease.”<sup>124</sup> As interpreted in a judicial decision addressing waste prevention regulations issued by the Department in the 1970’s,<sup>125</sup> production “removed or sold from the lease” does not include oil or gas that is “unavoidably lost” during production. “Avoidably lost” oil or gas, on the other hand, constitutes waste and is subject to royalties. As explained in the preamble to the proposed rule, NTL-4A distinguished between “avoidably lost” and “unavoidably lost” oil and gas, though it defined those terms in a general way that was

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<sup>122</sup> See, e.g., 42 U.S.C. § 7610 (“Except as provided in subsection (b) of this section, this chapter shall not be construed as superseding or limiting the authorities and responsibilities, under any other provision of law, of the Administrator or any other Federal officer, department, or agency.”).

<sup>123</sup> See, e.g., *Massachusetts v. EPA*, 549 U.S. 497, 531-32 (2007) (finding overlap but no conflict between EPA’s authority to regulate greenhouse gases from new motor vehicles under the CAA section 202(a) and the authority of the National Highway Transportation Safety Administration (NHTSA) under the Energy Policy and Conservation Act (EPCA) to promote energy efficiency by setting mileage standards); see also *Green Mt. Chrysler Plymouth Dodge Jeep v. Crombie*, 508 F. Supp. 2d 295, 350 (D. Vt. 2007) (concluding that “the preemption doctrines do not apply to the interplay between” EPA’s responsibilities under the Clean Air Act and NHTSA’s duties under the EPCA, and noting that “[s]hould a conflict between [the two agencies’ processes] become apparent, the federal agencies involved—EPA and NHTSA— are capable of and even encouraged to cooperate in a joint accommodation or resolution”).

<sup>124</sup> 30 U.S.C. §§ 226(b)(1)(A), 226(c)(1) (emphasis added).

<sup>125</sup> See *Marathon Oil Co. v. Andrus*, 452 F. Supp. 548, 552–53 (D. Wyo. 1978).

subject to inconsistent application.<sup>126</sup> In § 3179.4, this rule clarifies the distinction between “avoidable” and “unavoidable” losses by limiting “unavoidable” losses to specific circumstances in which the operator has not been negligent and has complied fully with applicable laws, lease terms, and regulations. Industry commenters objected to this approach on the ground that whether a loss of oil or gas is “avoidable,” and therefore royalty-bearing under the MLA, requires a case-by-case evaluation of a lessee’s reasonableness in light of the economic circumstances. That is, they argued that a loss of oil or gas should be deemed “unavoidable” if taking measures to avoid the loss would have been “uneconomic” from the operator’s perspective.

For several reasons, the BLM did not change the final rule based on these comments. As an initial matter, there is no statutory or jurisprudential basis for the commenters’ position that the BLM must conduct an inquiry into a lessee’s economic circumstances before determining a loss of oil or gas to be “avoidable.” Although the BLM’s practice under NTL-4A has generally been to engage in case-by-case economic assessments before making avoidable/unavoidable loss determinations, the BLM has not always done so<sup>127</sup> and is not legally required to do so. Furthermore, in the absence of clear statutory language or legislative history delineating what should be considered “avoidably lost” oil or gas under the MLA, the BLM’s past practice does not prohibit it from revising its interpretation of that term. Finally, FOGRMA provides BLM with an independent statutory authorization to impose royalties on oil or gas lost as a result of an operator’s negligence or failure to comply with any rule or regulation issued under the

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<sup>126</sup> 81 Fed. Reg. at 6665.

<sup>127</sup> Compare *Ladd Petroleum Corp.*, 107 IBLA 5, 7 (1989) (requiring opportunity for operator to show that gas capture would be “uneconomic” before flaring is deemed avoidable), with *Lomax Exploration Co.*, 105 IBLA 1, 7 (1988) (flaring without prior approval constitutes per se avoidable loss under NTL-4A).

mineral leasing laws, without further economic analysis. Specifically, section 308 of FOGRMA, provides that “[a]ny lessee is liable for royalty payments on oil or gas lost or wasted from a lease site when such loss or waste is due to negligence on the part of the operator of the lease, or due to the failure to comply with any rule or regulation, order or citation issued under this Act or any mineral leasing law.”<sup>128</sup>

Some commenters argued that the BLM’s existing interpretation of what constitutes an “avoidable loss” has become a “fundamental term” of the BLM’s existing oil and gas lease contracts upon which lessees relied in entering into the contracts and making subsequent business decisions. Citing *Mobil Oil Exploration & Producing Southeast, Inc. v. United States*, 530 U.S. 604 (2000), commenters argued that the proposed rule would substantially impair the value of their lease contracts and therefore subject the BLM to contract damages or takings claims.

On the contrary, in promulgating this final rule the BLM is acting within its authority under the MLA and thus within the terms of existing leases. First, the MLA requires lessees to “use all reasonable precautions to prevent waste of oil or gas,”<sup>129</sup> and provides the Secretary with the continuing authority to “prescribe necessary and proper rules and regulations” in order to carry out the purposes of the MLA.<sup>130</sup> The MLA further requires that each lease contain a provision “that such rules . . . for the prevention of undue waste as prescribed by [the] Secretary shall be observed.”<sup>131</sup> The BLM’s standard form lease makes clear that the rights granted to the lessee are “subject to . . . the Secretary of the Interior’s regulations and formal orders in effect as of lease issuance, *and to regulations and formal orders hereafter promulgated* when not inconsistent with the

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<sup>128</sup> 30 U.S.C. § 1756.

<sup>129</sup> 30 U.S.C. § 225.

<sup>130</sup> 30 U.S.C. § 189.

<sup>131</sup> 30 U.S.C. § 187.

lease rights granted or specific provisions of [the] lease.”<sup>132</sup> Both the plain meaning of this language and the BLM’s longstanding interpretation of it extend to “incorporat[ing] future regulations, even though inconsistent with those in effect at the time of lease execution, and even though to do so creates additional obligations or burdens for the lessee.”<sup>133</sup> The BLM’s legal and contractual authority to update its regulations governing oil and gas leases should thus foreclose successful breach of contract claims based on this rule.

The *Mobil Oil* decision cited by commenters is not pertinent. In that case, a permitting delay mandated by a subsequently enacted statute constituted a breach of the lease because the terms of the lease did not subject it to the burdens of such later-enacted statutes.<sup>134</sup> Today’s rule constitutes a “hereafter promulgated” regulation to which Federal oil and gas leases are expressly subject. The application of this rule to existing lessees, therefore, does not breach their contract rights because their existing leases incorporate the rule by reference.

That said, the BLM is cognizant that some of the requirements of this rule may pose more substantial burdens for existing lessees than for future lessees, because future lessees can take account of the requirements of the rule in making their leasing decisions. Accordingly, certain sections of the rule, including sections 3179.8 and 3179.201, are structured to reduce the burden on existing lessees. For further discussion of these provisions, see Section VII, Section by Section.

#### **D. Application to Units and Communitized Areas**

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<sup>132</sup> BLM Form 3100-11 (emphasis added).

<sup>133</sup> *Coastal Oil & Gas Corp., et al.*, 108 IBLA 62, 66 (1989).

<sup>134</sup> *Mobil Oil Exploration & Producing Southeast v. United States*, 530 U.S. 604, 613-20 (2000).

Some commenters objected to the application of this rule to operations on State and private tracts that are committed to a Federally-approved unit or communitized area. These commenters admit that the BLM has the authority under FOGRMA to regulate oil and gas activities on such tracts for the purposes of royalty accountability, but fail to recognize the various royalty-accountability purposes of this rule, including identifying and imposing royalties on wasteful losses of oil and gas, clarifying the circumstances under which production may be used royalty free, and setting measurement standards for venting and flaring (some of which is royalty bearing). More to the point, though, these commenters did not explain why the BLM's waste prevention authority under the MLA does not extend to the waste of Federal oil and gas that occurs on non-Federal tracts in a Federally-approved unit or communitized area. Commenters cited the BLM's decision not to apply Onshore Oil and Gas Order No. 1 ("Order 1") to operations on non-Federal lands in units and communitized areas<sup>135</sup> as evidence that the BLM lacks authority to apply this rule to such lands. However, the cited passage from the preamble to Order 1 did not address the scope of the BLM's regulatory authority with respect to non-Federal tracts in Federally-approved units and communitized areas; rather, the passage addressed what was "appropriate" in light of the jurisdictional limitations contained in 43 CFR. § 3161.1.

Commenters also asserted that because the regulation of State and private minerals is under the jurisdiction of the States, the BLM lacks the authority to apply its waste prevention regulations to units and communitized areas in a manner that would affect the production of State and private minerals unitized or communitized with Federal minerals. While the BLM agrees that the regulation of State and private minerals is

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<sup>135</sup> 72 Fed. Reg. 10308, 10313 (March 7, 2007).

under the jurisdiction of the States, the BLM does not agree that States' jurisdiction over State and private minerals precludes the BLM from promulgating a waste prevention regulation that has incidental impacts on State and private minerals unitized or communitized with Federal or Indian minerals. The purpose of this rule is to ensure that operators take reasonable precautions to prevent the waste of Federal and Indian oil and gas, a matter that BLM has the authority to regulate pursuant to its statutory and trust responsibilities described in Section III.C.

The fact that States and private parties have chosen to enter into unitization or communitization agreements whereby State or private oil or gas is commingled with Federal or Indian oil or gas, and produced concurrently with Federal or Indian oil or gas, does not deprive the BLM of its authority to impose reasonable waste prevention requirements on operators producing Federal or Indian oil or gas.

#### **E. ROW Permitting**

Under section 28 of the MLA, the BLM is responsible for granting most of the ROWs for oil and natural gas gathering, distribution, and transportation pipelines and related facilities on public lands. Specifically, the BLM has ROW approval authority for ROWs that cross lands administered by the BLM, or lands administered by two or more Federal agencies,<sup>136</sup> except lands in the National Park System or lands held in trust for Indians or Indian tribes.<sup>137</sup>

Several commenters expressed concern that they have experienced significant delays in obtaining ROW approvals for gathering lines, and that these delays impede producers' ability to capture and sell gas. These commenters stated that the BLM should

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<sup>136</sup> 43 CFR 2881.11.

<sup>137</sup> Mineral Leasing Act section 28(b)(1) (definition of "Federal lands" excluding lands in the National Park system or lands held in trust for Indians or Indian tribes).

streamline the ROW approval process. They asserted that accelerating the permitting process for pipeline ROWs would allow energy producers to more easily capture and market gas that might otherwise be flared due to a lack of infrastructure. Some commenters further asserted that the BLM could quickly and easily reduce flaring by processing ROWs in a timely manner, and that streamlining ROW permitting would provide a more cost-effective solution to the problem of gas waste than imposing the requirements in the proposed rule.

Commenters suggested several ways in which the BLM could increase permitting speed for gas gathering lines on Federal land. One commenter stated, for example, that the BLM should expand the use of categorical exclusions under the National Environmental Policy Act (NEPA) when permitting gas gathering lines, and another suggested using a ROW “corridor” approval approach, so that small adjustments in a project footprint would not delay the full approval process.

The BLM’s experience is that while processing time for ROW applications can sometimes be an issue, particularly in a handful of offices where staff retention has been difficult over the past few years, processing time is not the primary cause of the large volume of current flaring. For example, BLM data indicate that many applications to flare gas come from wells that are already connected to pipeline infrastructure, or for which operators are not seeking ROWs to build new pipelines. For instance, in Dickinson, North Dakota, large volumes of gas are being flared from over 1,700 Federal and Indian oil wells,<sup>138</sup> yet the local BLM field office currently has just four ROW applications pending.

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<sup>138</sup> Based on internal BLM analysis of North Dakota activity from AFMSS queried on April 16, 2015.



While the BLM data indicate that the current speed of the BLM's ROW processing is not a significant factor in the rate of flaring at most wells, the BLM recognizes the importance of timely ROW approvals and continues to make improvements aimed at increasing the efficiency of the ROW permitting process. A variety of factors, some in the BLM's control but some beyond the BLM's control, can impact the timely approval of ROWs and other actions that may be needed to construct a pipeline or gas processing facility. For example, fee land owners may delay or block a pipeline project that crosses both public and private lands, even when the Federal portion of the ROW is permitted. The time period for permitting ROWs may also be extended if, for example: the ROW grant is pending consultation or concurrence from another agency, e.g., pursuant to the Endangered Species Act or Section 106 of the National Historic Preservation Act; the ROW application is incomplete; the corresponding APD has not yet been processed; or a high volume of applications is submitted in a short period of time.

Last year, the BLM instituted key program changes to more quickly process pending oil- and gas-related ROW applications, and we have seen progress as a result of these efforts. These steps included using strike teams to add additional permit-processing resources at high-volume offices, working with the Office of Personnel Management to identify pay strategies to address staff shortages in key offices, and increasing formal training for critical staff. Additionally, particular field offices are actively pursuing other actions to decrease permitting times, including: 1) coordinating aspects of the pipeline ROW and corresponding APD reviews, so that they occur concurrently rather than consecutively; 2) working with project proponents to minimize surface disturbance to help expedite environmental reviews; 3) fully and consistently utilizing applicable

Categorical Exclusions to NEPA to streamline reviews; 4) encouraging project proponents to develop oil and gas Master Development Plans and Master Leasing Plans as well as right-of-way Master Agreements, which are negotiated with a single applicant for processing and monitoring multiple applications covering facilities within a specific geographic area; 5) encouraging unitization to help streamline permitting by avoiding the need for multiple ROWs (or potentially for any ROW at all, if the gas can be gathered and transmitted without crossing Federal or Indian land); and 6) working closely with proponents to determine which projects are priorities.

#### **F. Planning**

Finally, many stakeholders requested that the BLM address waste reduction through requirements under the MLA relating to the BLM's land use planning and environmental review processes. Commenters stated that the BLM should use its authority to reduce waste by proactively using all available planning, analysis and permitting tools including Applications for a Permit to Drill (APDs); lease stipulation decisions in resource management plans (RMP); master leasing plans (MLPs); waste minimization plans (WMPs); and unitization agreements. Commenters also stated that the proposed rule fails to exercise the BLM's full authority at the planning and leasing stages, and further, that land-use planning should be used to support well-planned fossil fuel development that would, for example, limit the leasing of lands where infrastructure constraints are expected to be significant, so as to minimize the need for venting or flaring of associated gas.

Commenters asserted that if the BLM conducted more robust NEPA reviews prior to oil and gas development, the reviews would identify additional waste reduction

opportunities. Commenters further requested that the rules governing development of RMPs be modified to support the intended purpose of the rule to capture gas and prevent venting or flaring. These commenters also asserted that detailed, site-specific MLPs can support methane capture and waste minimization once an RMP is in place.

Commenters disagreed with the BLM's decision not to propose changes to the BLM land use planning regulations as part of this rulemaking. They suggested that the BLM's failure to link the proposed rule to the BLM's foundational planning and management framework misses opportunities to foster orderly and efficient development of oil and gas that would prevent methane pollution and waste. Some commenters suggested that although changes to the BLM's land use planning rules are not required to enhance the use of planning mechanisms available to the BLM when developing RMPs and MLPs, referencing these tools in the final rule would emphasize their importance.

While the BLM is not making changes to the BLM land use planning regulations or NEPA review processes as part of this rulemaking, as stated in the preamble to the proposed rule, the BLM agrees that the land use planning and NEPA processes are critical to achieving our simultaneous goals of responsible oil and gas development, land stewardship and resource conservation, and protection of air quality on (and reduction of air emissions from) Federal lands.

The BLM already has land use planning and NEPA tools and processes in place that can be used to help achieve the specific goals of this rulemaking – to reduce the wasteful and environmentally harmful loss of gas through venting, flaring, and leaks. The BLM conducts NEPA analyses for both regional planning decisions and project level decisions. These analyses take a hard look at the direct effects, indirect effects, and

cumulative effects of the proposed federal action on various resources during the land use planning or project approval process, such as the effects on wildlife, air quality, or recreation opportunities. The BLM's NEPA analyses also quantify GHG emissions associated with the proposed planning decision alternatives under consideration. In particular, the land use planning and NEPA processes for new RMPs and MLPs provide important opportunities to consider the effects of oil and gas development over a larger area and to optimize planned development to minimize impacts from venting and flaring, among other activities. The planning process gives the BLM the opportunity to consider how a specific land management plan could address the timing and location of development of oil and gas and related infrastructure, such as pipelines, and the projected consequences of such decisions in terms of the quantities of vented and flared gas and the impacts associated with those emissions.

Thus, the BLM already has the NEPA processes and tools in place to evaluate the effects of the gas that would be flared, vented, and leaked from proposed oil and gas production, including impacts to wildlife and air quality, as well as GHG emissions, which contribute to climate change. The NEPA analyses can also identify ways to minimize such effects, such as evaluating alternative options for siting and timing of development that would maximize the opportunities for gas capture in lieu of flaring.

In addition, the BLM is in the process of completing a comprehensive update to its land use planning regulations, which should further enhance the opportunities to address gas waste in new oil and gas production approvals. The BLM proposed its new planning regulations in February 2016. The proposed changes would boost public participation and facilitate earlier stakeholder engagement in the planning process. For

example, the new planning regulations would provide for a planning assessment at the initiation of an RMP, which would involve stakeholders and other agencies in identifying key issues and obtaining better data early in the process. These new regulations would also enhance the existing opportunities for stakeholders to highlight options to reduce waste from proposed oil and gas production in BLM land use planning.

**G. Exemptions through Sundry Notices**

Some commenters expressed concerns that because the rule provides for operators to request various exemptions through submission of Sundry Notices to the BLM, these provisions could impose a paperwork burden on operators and the requests could be difficult for the BLM staff to process in a timely manner. The BLM believes that the number of requests for exemptions will be fairly limited, as the BLM's analysis does not indicate that the costs of these provisions will be substantial for the vast majority of operators. Nevertheless, the BLM recognizes that these are valid concerns, and is committed to minimizing unnecessary paperwork burdens on operators and continuing to streamline its own operations.

Thus, the BLM is providing here some additional information regarding how we expect operators to submit requests and how we may process them, and we will provide additional guidance as we move forward to implement the final rule. Concerns have been raised in this regard with respect to requests for exemption from multiple requirements of the rule for a lease. Specifically, operators have asked whether they could submit a single request for an exemption from multiple provisions of the rule, and how the BLM would evaluate it. The final rule requires an operator to make a demonstration that each requirement for which the operator is requesting an exemption would itself cause the

operator to cease production and abandon significant recoverable reserves on the lease. An operator could not simply add up the costs of compliance with multiple requirements of the rule to show that the cumulative costs of the requirements would cause the operator to cease production and abandon significant recoverable reserves under the lease, and thereby obtain an exemption from all of those requirements. In making the showing for a specific requirement, however, the operator could take into account as part of the baseline costs any requirements of the rule for which an exemption is not being requested. In addition, to the extent that there is common data supporting multiple exemption requests, such as the data on production and revenues from a given lease, the BLM intends that an operator would be able to provide that data once on a single submission containing a separate showing for each of the specific requests, rather than providing multiple separate submissions.

## **VII. Section by Section**

This section discusses the final rule provisions, substantial changes from the proposed rule, and some of the most significant comments received. Public comments not addressed in this section or elsewhere in this preamble are addressed in the separate Response to Comments document, which is available on the BLM website and is part of the rule-making record.

### **Part 3100**

#### **Section 3103.3-1 Royalty on production**

The final rule's amendments to existing 43 CFR 3103.3-1 focus on existing § 3103.3-1 (a)(1), and do five things: (1) remove two provisions of the existing regulations that are no longer necessary (§ 3103.3-1(a)(1)(i) and (ii)); (2) add a new § 3103-1(a)(2);

(3) specify that the royalty rate on all leases existing at the time the rule becomes effective will remain at the rate “prescribed in the lease or in applicable regulations at the time of lease issuance”; (4) specify the statutory rate of 12.5 percent for all noncompetitive leases issued after the effective date of the final rule; and (5) conform the regulatory regime for competitive leases issued after the effective date of the rule to the regime envisioned by the MLA, which specifies that the royalty rate for all new competitively issued leases be set “at a rate of not less than 12.5 percent.”<sup>139</sup> All of these changes were in the proposed rule.

The final rule also renumbers existing § 3103–1(a)(2) and (a)(3) as § 3103–1(a)(3) and (a)(4) and makes minor changes to existing § 3103–1(a)(3) (final § 3103–1(a)(4)) for clarity.

Additionally, the final rule reprints existing §§ 3103–1(b) and (c), for clarity. Finally, the BLM made a minor revision to § 3103.3–1(d) from the proposed rule. To improve the clarity of this provision, final § 3103–1(d) adds the language “from the gas stream” in two places that address any helium component that is not conveyed with the mineral estate in a Federal oil and gas lease.

Several commenters stated that a new royalty rate above the current rate of 12.5 percent would create uncertainty in the leasing process, and would disadvantage Federal leases compared with State and private leases and disincentivize investments on Federal lands. One commenter objected to the proposed rule’s use of the term “base rate,” because the BLM did not provide a definition of that term. The commenter also noted that the proposed rule does not describe the process by which the rate will be determined,

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<sup>139</sup> Note that the rule renumbers current 43 CFR 3103.3–1 (a)(2) and (3) but does not otherwise change the content of those provisions. Further, the rule does not alter 43 CFR 3103.3–1(b), (c), or (d). Those provisions are reprinted in this rule solely to clarify the numbering of the revised § 3103.3–1, and for ease of reference.

to whom it will apply, or how and when it will be reevaluated and reset. One commenter noted that under the BLM's recent regulatory revision of Onshore Oil and Gas Order Number 3, the BLM proposes to authorize commingling allocations and approvals (CAAs) for properties with identical fixed royalty rates. The commenter suggested that a variable royalty rate would have the unintended consequence that most CAAs would not be approved.

Other commenters supported the BLM's proposal to ensure that the royalty rate of 12.5 percent represents a floor and not a ceiling. The commenters contended that this would allow the American public to receive a fair market return on their resources. Some commenters suggested that the royalty rate be raised to 18.75 percent to be in line with the royalty rate assessed on Federal offshore leases. Commenters also noted that the current rate is far below several state rates. One commenter suggested that the increase in royalty rate should be informed by the social and environmental costs of oil and gas production, including the social cost of methane emissions. Another commenter stated that if the BLM were to increase the royalty rate, it should be a constant rate, rather than a sliding scale, as this would reduce administrative and reporting burdens. Some commenters requested that the BLM set the royalty rate at least 60 - 90 days prior to any lease sale and publish notice in the Federal Register and the BLM website for public comment.

The BLM did not revise the rule in response to these comments. As stated in the proposed rule preamble, the BLM is not currently proposing to raise the base royalty rate for new competitively issued leases above 12.5 percent; rather, we are conforming the regulatory provisions governing royalty rates for new competitive leases to the



corresponding rate provisions in the MLA. The BLM would engage in additional process before raising the rate.

### **Section 3160.0-5 Definitions**

This amendment to § 3160.0-5 deletes the definition of “avoidably lost” that by its terms applies to part 3160. A definition of “avoidably lost” is no longer needed for part 3160, and this definition is superseded by the provisions in new subpart 3179, particularly § 3179.4, governing when the loss of oil or gas is deemed avoidable or unavoidable. The BLM did not receive comments on removing this definition and is finalizing this deletion as proposed.

### **Section 3162.3-1 Drilling applications and plans**

This section describes the requirements for drilling applications and plans, including the information that an operator must provide with an APD. The BLM is amending this section to add paragraph 3162.3-1(j), which requires that when submitting an APD for an oil well, an operator must also submit a waste minimization plan. Submission of the plan is required for approval of the APD, but the plan will not itself become part of the APD, and the terms of the plan will not be enforceable against the operator.

The purpose of the waste minimization plan is for the operator to set forth a strategy for how the operator will comply with the requirements of subpart 3179 regarding the control of waste from venting and flaring. The waste minimization plan must include information regarding: the anticipated completion date(s) of the proposed well(s); a description of anticipated production from the well(s); certification that the operator has provided one or more midstream processing companies with information

about the operator's production plans, including the anticipated completion dates and gas production rates of the proposed well or wells; and identification of a gas pipeline to which the operator plans to connect.

Based on comments received requesting that the information required in the plans be streamlined, the final rule provides that certain kinds of information are only required if an operator cannot identify a gas pipeline with sufficient capacity to accommodate the anticipated production of the proposed well(s). This conditionally-required information includes: a gas pipeline system location map showing the proposed well(s); the name and location of the gas processing plant(s) closest to the proposed well(s); all existing gas trunklines within 20 miles of the well, and proposed routes for connection to a trunkline; the total volume of produced gas, and percentage of total produced gas, that the operator is currently venting or flaring from wells in the same field and any wells within a 20-mile radius of that field; and a detailed evaluation, including estimates of costs and returns, of potential on-site capture approaches.

Some commenters requested that waste minimization plans required by other states, such as North Dakota and New Mexico, should be allowed to satisfy the requirements set forth in this section. The BLM recognizes that some States have similar waste minimization plan requirements under State law. To the extent that an operator is already preparing, under State requirements, a waste minimization plan that meets all or most of the requirements for a waste minimization plan under section 3162.3-1, the BLM requirements should impose little additional burden on the operator. The operator would be able to submit the same plan to the BLM, supplemented as necessary to meet each of the requirements of section 3162.3-1.

Other commenters stated that the preparation and review of the waste minimization plans would be a burden both on applicants and the BLM, because in the commenters' view, the proposed rule significantly underestimated the number of plans that would be required and the time required to prepare them. The commenters asserted that the BLM can be slow in approving APDs, and argued that the review of the additional waste minimization plans could slow the process further. Other commenters suggested that the requirement to prepare a waste minimization plan be limited only to wells that anticipate flaring a high volume of associated gas after completion. The BLM disagrees with these comments and believes that requiring operators to prepare a waste minimization plan for all wells is a reasonable, low cost, and effective way to encourage operators to consider and plan for capturing gas before the development of every new well. As stated previously, however, the final rule streamlines some of the elements required in the plan. Further, the BLM presently plans to review the effectiveness of the plan requirement within 3 years after the final rule's effective date, to assess the costs to operators of preparing the plans, the costs to the BLM of reviewing the plans, and the effectiveness of the plans in driving flaring reductions at new wells.

Commenters also expressed concern that the waste minimization plan requirement could trigger the need for additional analysis under NEPA for non-federal/non-Indian wells within a unit or communitized area. Under existing regulations, wells that are not located on federal or Indian surface and do not pierce federal or Indian minerals are not required to obtain BLM's approval of an APD, even if those wells are within a unit or communitized area from which federal or Indian minerals are produced. Commenters

were concerned that the requirement for a waste minimization plan would somehow require those wells to file APDs or subject them to NEPA.

The BLM believes these concerns are unfounded. Operators would be required to submit waste minimization plans only for wells that already require an APD under part 3160 – i.e., for wells that are located on federal or Indian surface or pierce federal or Indian minerals. Operators may need to incorporate information in their waste minimization plans regarding wells on a unit or communitized area that do not require APDs (*see, e.g.*, § 3162.3-1(j)(2)(ii), requiring anticipated production information for all wells on a multi-well pad). Also, to the extent that gas from a nonfederal mineral estate is mixed with federal or Indian gas, the waste minimization plan may effectively minimize waste of both federal or Indian and non-federal or non-Indian gas. However, nothing under this provision requires operators to file an APD for any well, much less extends the APD requirements under part 3160 to wells that are not located on federal or Indian surface and do not pierce federal or Indian minerals. Moreover, waste minimization plans are not enforceable, and BLM will only review and approve them in the course of acting on an APD. While the BLM will analyze potential indirect impacts of execution of the waste minimization plan as part of its NEPA analyses for APDs submitted after the rule takes effect, there is no independent federal action here that would trigger NEPA for a waste minimization plan separate from an APD. Other commenters stated that the BLM should strengthen the requirements of the waste minimization plans and make them enforceable. The BLM declined to do so. The BLM believes that waste minimization plans, like the environmental analyses performed under the National Environmental Policy Act, can drive significantly better outcomes by

ensuring that the operator and midstream companies have more information at an earlier stage, to allow for better planning and coordination. To achieve that result, however, the plans must be quite detailed and contain all relevant information. The BLM believes that the plan's unenforceability helps achieve that outcome: because the terms of the plans cannot be enforced against the operator, the BLM avoids creating an incentive for operators to develop very general plans with few specific details. Additionally, the BLM is concerned that circumstances could change between when the plan is developed and when well production begins, making strict adherence to the plan difficult. In such a circumstance, the existence of the plan would still be useful, because operators would have information at their fingertips that would enable them respond nimbly to the changed circumstance, but operators would not be held to the specific terms of the now outdated plan.

Commenters also requested that the BLM make the waste minimization plans publicly available. The BLM already publicly posts APDs for a period prior to approval, and we plan to post the waste minimization plans accompanying the APDs in the same manner, subject to any protections for confidential business information.

## **Subpart 3178—Royalty-Free Use of Lease Production**

### **Section 3178.1 Purpose**

This section states that the purpose of the subpart is to address circumstances in which oil and gas produced from Federal and Indian leases may be used royalty-free. This subpart supersedes those parts of NTL-4A pertaining to oil or gas used for “beneficial purposes.”

The BLM received a comment on this section requesting that the BLM clarify whether the rule will replace all of NTL-4A, or just those parts “pertaining to use of oil or gas for beneficial purposes.” The BLM notes that Subpart 3178 replaces the portion of NTL-4A pertaining to the use of oil or gas for beneficial purposes and Subpart 3179 replaces the portion of NTL-4A pertaining to venting and flaring of produced gas, unavoidably and avoidably lost gas, and waste prevention. Together, the combined revisions to Subparts 3178 and 3179 supersede NTL-4A in its entirety. The BLM disagrees that the regulatory text requires clarification beyond what is stated here, and did not revise this section in response to this comment.

#### **Section 3178.2 Scope of this subpart**

This section specifies which leases, agreements, wells, and equipment are covered by this subpart. The section also states that the term “lease” in this subpart includes IMDA agreements, unless specifically excluded in the agreement or unless the relevant provisions of this subpart are inconsistent with the agreement. In the final rule, in response to comments, the BLM edited proposed paragraph (a)(5) to clarify the list of items to which this subpart applies. Paragraph (a)(5) in the final rule provides that this subpart applies to wells and production equipment, and also, under specified circumstances, compressors. Additionally, the final rule omits proposed paragraph (a)(6) relating to coverage of gas lines, as the BLM has determined that gas lines do not “use” production for purposes of this subpart.

One commenter suggested replacing “other facilities” with “production equipment,” and suggested distinguishing compressors that promote production at the wellhead from those that promote pipeline flow. The BLM agrees that these suggested

changes improve the clarity of the rule, and we have revised the text accordingly. The text now refers to “production equipment” and limits coverage to compressors that both are located on a lease, unit or communitized area and compress production from the same lease, unit or communitized area.

Commenters also suggested distinguishing among flow lines, gathering lines and transmission lines, and requested revisions to highlight the limits of the BLM’s authority over gas lines. We believe that these comments are no longer applicable with the elimination of proposed paragraph (a)(6).

### **Section 3178.3 Production on which royalty is not due**

This section sets forth the general rule that royalty is not due on oil or gas that is produced from a lease or communitized area and used for operations and production purposes (including placing oil or gas in marketable condition) on the same lease or communitized area without being removed from the lease or communitized area. This section also treats oil and gas produced from unit PAs—that is, the productive areas on a unit—and used for operating and production purposes on the unit, for the same PA, in the same way. Units often include different PAs composed of multiple leases with varied ownership. This section therefore limits royalty-free use of gas from a particular PA to uses that are made on the same unit, to support production from the same unit PA. The reason for this limitation is to prevent excessive use of royalty-free gas by prohibiting a unit operator from using royalty-free production from one PA to power operations on, or treat production from, another PA on the same unit, to the benefit of different owners and to the detriment of the public interest.

As discussed below, § 3178.5 qualifies the general provisions of § 3178.3 by listing specific operations for which prior written BLM approval will be required for royalty-free use.

The BLM received a few relatively technical comments on § 3178.3, which are addressed in the Response to Comments document. The BLM did not make any changes to this section from the proposed rule.

**Section 3178.4 Uses of oil or gas on a lease, unit, or communitized area that do not require prior written BLM approval for royalty-free treatment of volumes used**

This section identifies uses of produced oil or gas that will not require prior written BLM approval for royalty-free treatment. The uses listed in this section involve routine production and related operations. In addition, paragraph (b) clarifies that even when a use is authorized, the royalty-free volume is limited to the amount of fuel reasonably necessary to perform the operation on the lease using appropriately sized equipment. This ensures that royalty-free on-site use remains subject to the requirement to avoid waste of the resource.

While the royalty-free uses described here are generally similar to the uses identified as “beneficial purposes” in NTL-4A, this rulemaking further clarifies which uses warrant royalty-free treatment.

In addition, this section clarifies that hot oil treatment is an accepted on-lease use of produced crude oil that does not require prior approval to be royalty-free. In this treatment, oil is not consumed as fuel. Rather, after the oil is pumped back into the well to stimulate production, it is produced again. Although the use of produced crude oil for



hot oil treatments on the producing lease, unit, or communitized area has historically been understood by the BLM and by operators as a royalty-free use, it is not specifically addressed in NTL-4A but is now included in this final rule.

As mentioned above, the BLM received comments requesting that other uses of oil or gas be identified as royalty-free, including fuel for power generation, pilot and assist gas, fuel for heating, fuel for ancillary equipment, fuel to treat gas to remove impurities, fuel to run completion and work over equipment, and gas used for gas lift. The BLM agrees that these uses are routine, and therefore should not require prior approval to be royalty-free.

Regarding using oil as a circulating medium in drilling operations, or injecting gas produced from a lease, unit PA, or communitized area into the same lease, unit, PA, or communitized area to increase the recovery of oil or gas, the BLM had proposed to include these uses in the list in § 3178.5 of uses requiring prior approval. As operators are already required to report the use of oil as a circulating medium in drilling operations under Onshore Order Number 1, and the use of gas for injection under applicable regulations in parts 3100, 3160 and 3180 of this title, however, the BLM has decided not to require prior approval for these uses. In addition to the injection of gas for the purpose of increasing the recovery of oil or gas, the BLM has added the injection of gas “for the purpose of conserving gas” as a royalty-free use that does not require prior written BLM approval under the final rule. Often, gas injection is used to enhance resource recovery by maintaining or slowing the reservoir pressure decline which leads to higher oil recovery. The BLM also understands that, in some circumstances, excess gas that cannot be captured and sold or used on lease may be injected in order to conserve the

gas. This practice occurs in Canada's Bakken field. While not all reservoirs are conducive to gas injection, the BLM believes it important to provide that as an option to conserve any gas that can't be sold immediately.

Finally, this rule does not address some uses that are already defined as royalty-free under ONRR provisions, such as the royalty-free use of residue gas to fuel gas plant operations, as provided in 30 CFR 1202.151(b).

Overall, in response to comments received, the BLM made the following changes in the final rule:

- Modified paragraph (a)(1) to more broadly address the use of fuel to generate power, including the use of fuel to operate "combined heat and power," which is a particularly efficient means of generating power from gas;
- Combined and modified proposed paragraphs (a)(2) and (a)(3) to include artificial lift equipment and completion and workover equipment;
- Renumbered the remaining paragraphs accordingly;
- Added use of gas as a pilot fuel or as assist gas for a flare, combustor, thermal oxidizer, or other control device, as paragraph (a)(5);
- Added treatment of gas to paragraph (a)(6); and
- Added two uses that will not require prior written BLM approval for royalty-free treatment, which were identified in § 3178.5 in the proposed rule as requiring prior approval: (1) using oil as a circulating medium in drilling operations (paragraph (a)(8)), and (2) injecting gas produced from a lease, unit PA, or communitized area into the same lease, unit PA, or communitized area to for the

purposes of conserving gas or increasing the recovery of oil or gas (paragraph (a)(9).

- Added injection of gas that is cycled in a contained gas-lift system, as paragraph (a)(10).

**Section 3178.5 Uses of oil or gas on a lease, unit, or communitized area that require prior written BLM approval for royalty-free treatment of volumes used**

This section identifies uses of oil or gas that will require prior written BLM approval to be deemed royalty-free. The aim of this section is three-fold: (1) to ensure that the BLM retains discretion to grant royalty-free use where the BLM deems the use to be consistent with the MLA's royalty requirement for oil or gas that is produced and then removed from the lease and sold; (2) to increase uniformity in the administration of the royalty provisions by specifying circumstances that warrant particular BLM attention; and (3) to ensure the BLM's awareness of unusual uses that risk the loss or waste of oil and gas.

For all of the identified uses, operators will be required to submit a Sundry Notice requesting BLM approval to conduct royalty-free activities.

The potentially royalty-free uses identified in this section are as follows:

- *Using oil or gas that was removed from the pipeline at a location downstream of the approved facility measurement point (FMP).* The BLM anticipates that these situations will be quite rare because the tap that operators use to extract and measure gas is generally upstream of the FMP.
- *Using produced gas for operations on the lease, unit PA, or communitized area, after it is returned from off-site treatment or processing to address a particular physical*

*characteristic of the gas.* Physical characteristics that might preclude initial use of gas in lease operations and necessitate off-lease treatment or processing include an unusually high concentration of hydrogen sulfide, or the presence of inert gases or liquid fractions that limit the gas's utility as a fuel. The operator will bear the burden of establishing the necessity of off-lease treatment.

- *Any other types of use for operations and production purposes which are not identified in § 3178.4.* This provision clarifies that the BLM retains discretion to consider approving royalty-free use under circumstances that are not now anticipated.

In response to comments described below, the BLM made the following three changes to the proposed rule requirements: (1) Removed proposed paragraphs (a)(1) and (a)(2) from this section and moved them to § 3178.4 (royalty-free without prior approval); (2) Added language to paragraph (2) (paragraph (4) in the proposed rule) to clarify that the provision applies to the physical characteristics of the gas “that require the gas to be treated or processed prior to use”; and (3) Removed proposed paragraph (c) and added language to paragraph (b)(1) that indicates that royalties must be paid on volumes when the BLM disapproves a request for royalty-free treatment under this section, and that any approvals for royalty-free treatment will be effective from the date the request was filed. Each change is discussed below along with a summary of the comments that lead to the change.

Several commenters indicated that some of the activities in proposed § 3178.5 should not require prior approval. The BLM agrees and, in response to this and other comments on § 3178.4, moved some provisions to § 3178.4, as described previously.

Additionally, some commenters stated that operators should not be required to seek prior approval for the following two royalty-free uses: gas removed from a pipeline at a location downstream of the FMP and gas initially removed from a lease, unit participating area, or communitized area for treatment or processing where the gas is returned to the lease, unit, or communitized area for lease operation. The BLM disagrees with these comments and retained these paragraphs in paragraphs (a)(1) and (a)(2) of this section. Gas that is removed from a lease, unit participating area, or communitized area would normally be royalty-bearing. Inclusion of these uses in this section allows the BLM the discretion to approve royalty-free uses under the unique circumstances in which gas is removed and returned to the same lease, unit participating area, or communitized area.

Several commenters also stated that the BLM did not adequately explain why operators must ever receive agency approval for royalty-free use of production. Commenters stated that the BLM must specify the standard or criteria used to evaluate requests for approval. The BLM has determined that royalty-free uses requiring prior approval are uses that do not typically occur, that are not likely to apply to a large number of operators, and that have a higher risk of loss of gas depending on the individual circumstances surrounding the use. These factors warrant individual approval by the BLM on a case-by-case basis, and are not situations in which development of standard approval criteria is appropriate.

Some commenters argued that the BLM should remove the limitation, included in the proposed rule, that gas removed from the lease may only be used on the lease royalty-free if it was removed for treatment or processing “to address a particular characteristic of

the gas.” The commenters stated that the operator should not have the burden of establishing the necessity of off-lease treatment. In response to this comment, the BLM revised paragraph (a)(2) (paragraph (a)(4) in the proposed rule) to clarify that the provision applies to particular physical characteristics of the gas “that require the gas to be treated or processed prior to use.”

Some commenters suggested that an identified use should be royalty-free until the BLM denies it, rather than having to wait for the BLM to approve it. In addition, one commenter suggested that if the BLM does not, within 30 days, respond to a Sundry Notice requesting approval, the Notice should be deemed approved. Another commenter requested that approvals should go into effect when the request is filed. In response to these comments, the BLM revised § 3178.5(b)(1) to indicate that approvals will be effective from the date the request was filed. However, if the BLM disapproves a request, the operator must pay royalties on all volumes used, including those used while the request was pending.

Several commenters stated that exceptions for royalty-free use should not be considered, that the rule allows too much royalty-free venting and flaring, or that the rule does not sufficiently restrict royalty-free use that results in emissions to the environment. As stated in the proposed rule preamble, however, royalty-free on-site use is limited to reasonable uses that are not wasteful. The BLM does not intend to grant prior approval of royalty-free uses under § 3178.5 unless it determines, in light of available technology, that the requested use is reasonable and not wasteful. As a result, the BLM did not revise this section in response to these comments.

**Section 3178.6 Uses of oil or gas moved off the lease, unit, or communitized area that do not require prior written approval for royalty-free treatment of volumes used**

This section identifies two circumstances in which royalty-free use of oil or gas that has been moved off the lease, unit, or communitized area would be permitted without prior BLM approval. The first situation is where an individual lease, unit, or communitized area includes non-contiguous areas, and oil or gas is piped directly from one area of the lease, unit, or communitized area to another area where it is used, and no oil or gas is added to or removed from the pipeline, even though the oil or gas crosses lands that are not part of the lease, unit, or communitized area. Under this section, the BLM will consider such production as not having been “removed from the lease.” This will provide the lessee or operator the same opportunity for royalty-free use as if the lease, unit, or communitized area were one contiguous parcel.

The second situation is where a well is directionally drilled, and the wellhead is not located on the producing lease, unit, or communitized area, but produced oil or gas is used on the same well pad for operations and production purposes for that well. In such situations, the rule allows for royalty-free use at the well pad, without prior approval.

Use at off-lease well heads is an established royalty-free use.<sup>140</sup>

Commenters asserted that the language in proposed paragraph (a) that described reasons why oil or gas would be moved off the lease, unit, or communitized area was ambiguous. In response to this comment, the BLM simplified the language in this paragraph to clarify the original intent discussed above. Paragraph (a) of the final rule

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<sup>140</sup> *Plains Exploration & Production Co.*, 178 IBLA 327, 341 n.16 (2010).

now states: “The oil or gas is transported from one area of the lease, unit, or communitized area to another area of the same lease, unit, or communitized area where it is used, and no oil or gas is added to or removed from the pipeline while crossing lands that are not part of the lease, unit, or communitized area; . . . .”

**Section 3178.7 Uses of oil or gas moved off the lease, unit, or communitized area that require prior written approval for royalty-free treatment of volumes used**

This section addresses the royalty treatment of oil or gas used in operations conducted off the lease, unit, or communitized area. When production is removed from the lease, unit, or communitized area, it becomes royalty-bearing unless otherwise provided. This principle is reflected in paragraph (a) of this section, which provides that with only limited exceptions, royalty is owed on all oil or gas used in operations conducted off the lease, unit, or communitized area.

Existing NTL-4A does not include a provision that specifically addresses approving off-lease royalty-free use. Such approval is required, however, under ONRR regulations, which provide, “All gas (except gas unavoidably lost or used on, or for the benefit of, the lease, including that gas used off-lease for the benefit of the lease when such off-lease use is permitted by the BOEMRE or BLM, as appropriate) produced from a Federal lease to which this subpart applies is subject to royalty.”<sup>141</sup> New § 3178.6 will add clarity and consistency in implementation of that ONRR regulation.

Paragraph (b) of this section identifies circumstances in which, despite the general rule articulated in paragraph (a), the BLM will consider approving off-lease royalty-free use (referred to here as “off-lease royalty-free uses”). These include situations in which the operation is conducted using equipment or at a facility that is located off the lease,

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<sup>141</sup> 30 CFR 1202.150(b).



unit, or communitized area (under an approved permit or plan of operations, or at the agency's request) because of engineering, economic, resource protection, or physical accessibility considerations. For example, a compressor that otherwise would have been located on a lease may be sited off the lease because the topography of the lease is not conducive to equipment siting. To be approved for off-lease royalty-free use, the operation would also have to be conducted upstream of the approved FMP. This paragraph reflects the BLM's policy to encourage operators to reduce the amount of surface disturbance associated with oil and gas exploration and development projects. In some cases, centralizing production facilities at a location off the lease may serve that objective.

Paragraph (c) requires the operator to obtain BLM approval for off-lease royalty-free use via a Sundry Notice containing the information required under proposed § 3178.9 of this subpart. In response to a comment described below, in the final rule the BLM added the following provision to paragraph (c) of this section: "If the BLM disapproves a request for royalty-free treatment for volumes used under this section, the operator must pay royalties on the volumes. If the BLM approves a request for royalty-free treatment for volumes used under this section, such approval will be deemed effective from the date the request was filed."

Paragraph (d) of this section clarifies that approval of off-lease measurement or commingling under other regulatory provisions does not constitute approval of off-lease royalty-free use. An operator or lessee must expressly request, and submit its justification for, approval of off-lease royalty-free use. The BLM anticipates that generally such approval would be appropriate only in some of the situations in which the BLM has

approved measurement at a location off the lease, unit, or communitized area, or has approved commingling production off the lease, unit, or communitized area and allocating production back to the producing properties.

Paragraph (e) of this section addresses circumstances in which equipment located on a lease, unit, or communitized area also treats production from other properties that are not unitized or communitized with the property on which the equipment is located. An operator is allowed to report as royalty-free only that portion of the oil or gas used that is properly allocable to the share of production contributed by the lease, unit or communitized area on which the equipment is located, unless otherwise authorized by the BLM.

A commenter proposed that an identified use should be royalty-free until the BLM denies an application for prior approval, rather than requiring an operator to wait for the BLM to approve the use. As stated above, in response to these comments, the BLM revised § 3178.7(c) to indicate that approvals will be effective from the date the request was filed. However, if the BLM disapproves a request, the operator must pay royalties on all volumes used, including those volumes used during pendency of the request.

Commenters also suggested that the proposed language in paragraph (e) was inconsistent with the BLM's goal of encouraging operators to reduce the amount of surface disturbance because this provision would discourage production from multiple leases. The BLM disagrees. This section indicates that only the portion of the oil or gas used as fuel that is properly allocable to the lease, unit, or communitized area on which the equipment is located (on-lease) is royalty-free; however, the proportion of the oil or

gas used from off-lease production may be approved by the BLM for off-lease royalty-free use. The BLM recognizes both the operating efficiency and resource conservation advantages of locating production equipment from multiple wells on a common site. The BLM did not revise this paragraph in response to these comments.

Another commenter suggested that the BLM should approve all requests unless it can demonstrate that particular circumstances related to lease operations justify disallowing royalty-free use. The BLM disagrees with this comment and did not modify the rule in response to this comment. The MLA exempts from royalties production that is used on the lease for lease operations. This rule allows for royalty-free off-lease uses in some cases, including those specified in § 3178.6 as not requiring prior approval. The circumstances described in § 3178.7 give the BLM the flexibility to approve additional off-lease royalty-free uses where the BLM believes those uses are reasonable and not wasteful.

**Section 3178.8 Measurement or estimation of volumes of oil or gas that are used royalty-free**

This section specifies that an operator must measure or estimate the volume of royalty-free gas used in operations upstream of the FMP. In general, the operator is free to choose whether to measure or estimate, with the exception that the operator must in all cases measure the following volumes: (1) royalty-free gas removed downstream of the FMP and used pursuant to sections 3178.4 through 3178.7; and (2) royalty-free oil used pursuant to sections 3178.4 through 3178.7. When royalty-free oil or gas is removed downstream of the FMP and used pursuant to sections 3178.4 through 3178.7, the

operator must apply for a new FMP under section 3173.12 to measure the gas that is removed for use.

If oil is used on the lease, unit or communitized area, it is most likely to be removed from a storage tank on the lease, unit or communitized area. Thus, paragraph (c) also requires the operator to document the removal of the oil from the tank or pipeline.

Paragraph (e) requires that operators use best available information to estimate gas volumes, where estimation is allowed. For both oil and gas, the operator must report the volumes measured or estimated, as applicable, under ONRR reporting requirements. As revisions to Onshore Oil and Gas Orders No. 4 and 5 have now been finalized as 43 CFR subparts 3174 and 3175, respectively, the final rule text now references § 3173.12, as well as §3178.4 through §3178.7 to clarify that royalty-free use must adhere to the provisions in those sections. The BLM received few, highly technical comments on this section, which are addressed in the Response to Comments document.

### **Section 3178.9 Requesting approval of royalty-free treatment when approval is required**

This section describes how to request BLM approval of royalty-free use when prior-approval is required under § 3178.5 or § 3178.7. The operator must submit a Sundry Notice containing specified information, which is necessary for the BLM to determine if approval is appropriate. The information includes a description of the operation to be conducted, the measurement or estimation method, the volume expected to be used, the basis for an estimate (if applicable), and the proposed use of the oil or gas. This section was finalized as proposed, with minor wording changes to improve clarity.

The BLM received few, highly technical comments on this section, which are addressed in the Response to Comments document.

### **Section 3178.10 Facility and equipment ownership**

This section clarifies that although the operator is not required to own or lease the equipment that uses oil or gas royalty-free, the operator is responsible for all authorizations, production measurements, production reporting, and other applicable requirements. The BLM did not receive significant comments on this section and did not revise this section from the proposed rule.

## **Subpart 3179 – Waste Prevention and Resource Conservation**

### **Section 3179.1 Purpose**

As in the proposed rule, this section states that the purpose of subpart 3179 is to implement statutes relating to prevention of waste from Federal and Indian (other than Osage Tribe) leases, conservation of surface resources, and management of the public lands for multiple use and sustained yield. The section also provides that subpart 3179 supersedes those parts of NTL-4A that pertain to venting and flaring of produced gas, unavoidably and avoidably lost gas, and waste prevention.

One commenter stated that BLM should clarify whether subpart 3179 replaces NTL-4A and that NTL-4A is no longer applicable, or if subpart 3179 only supersedes part of NTL-4A. As stated previously, subpart 3178 replaces the portion of NTL-4A pertaining to the use of oil or gas for beneficial purposes, and subpart 3179 replaces the portion of NTL-4A pertaining to flaring and venting of produced gas, unavoidably and avoidably lost gas, and waste prevention. Together, the combined revisions to subparts 3178 and 3179 supersede NTL-4A in its entirety.

### **Section 3179.2 Scope**

This section specifies which leases, agreements, tracts, facilities, and gas lines are covered by this subpart. The section also states that the term “lease” in this subpart includes IMDA agreements, unless specifically excluded in the agreement or unless the relevant provisions of this subpart are inconsistent with the agreement. The BLM did not revise this section from the proposed rule.

Some commenters stated that the scope of the rule is too broad. Some commenters suggested limiting its scope to leases with more than 51 percent Federal interest, while others suggested that the BLM clarify that this subpart does not apply to exploration, wildcat, or delineation wells. The BLM disagrees that the scope of the rule is too broad, and did not revise this section based on these comments. As discussed earlier in this Preamble, the BLM has both the authority to ensure that operators take reasonable precautions to prevent the waste of Federal and Indian oil and gas. The fact that this final rule may impact some leases with minority Federal or Indian interest does not deprive the BLM of its authority to impose reasonable waste prevention requirements on operators producing Federal or Indian oil or gas.

Finally, the BLM notes that the rule generally applies to all oil and gas wells, including exploratory, wildcat, and delineation wells. Provisions of the rule that apply more narrowly explicitly indicate the narrower scope; for example, the gas capture requirements in section 3179.7 apply only to “development oil wells.”

### **Section 3179.3 Definitions and acronyms**

This section contains definitions for terms that are used in subpart 3179: “accessible component”; “automatic ignition system”; “capture” and “capture

infrastructure”; “compressor station”; “continuous bleed”; “development oil well” or “development gas well”; “gas-to-oil ratio”; “gas well”; “high pressure flare”; “leak”; “leak component”; “liquid hydrocarbon”; “liquids unloading”; “lost oil” or “lost gas”; “pneumatic controller”; “storage vessel”; and “volatile organic compounds.” Some defined terms have a meaning particular to this rule. Other defined terms may be familiar to many readers, but are defined in the regulatory text to enhance the clarity of the rule.

In response to comments, the final rule adds several definitions that were not included in the proposed rule, including “automatic ignition system”; “continuous bleed”; “high pressure flare”; “leak” and “leak component” (which replaced the term “component” from the proposed rule); and “pneumatic controller.” The final rule also adds a definition of “compressor station” that is consistent with the definition in subpart OOOOa, as the final rule leak detection provisions and the subpart OOOOa leak detection provisions both refer to compressor stations. In addition, the definition of “storage vessel” has been expanded to clarify the types of vessels covered by section 3179.203. The definitions of “development oil well” and “development gas well” include minor wording changes for clarity.

Some commenters expressed concerns that the proposed definition of a storage vessel in § 3179.3 does not match the definition provided in subparts OOOO and OOOOa. Commenters asserted that the definition proposed by the BLM applies the 6 tpy VOC threshold for applicability to a whole tank battery, as well as to a single tank, making the proposed rule significantly more stringent than the EPA OOOOa rule, which only applies if an individual storage vessel exceeds the threshold. Commenters also noted that the EPA definition of storage vessel excludes portable tanks temporarily

located at the well site, and they recommended that the BLM take the same approach as the EPA by aligning the BLM's definition with the EPA definition. Other commenters supported the BLM's proposed definition of storage vessel, as it could apply the requirements for storage vessels to a collection of low-emitting single tanks that would not otherwise meet the threshold.

Based on input from commenters, the BLM has revised its definition of storage vessel to be largely consistent with the EPA subpart OOOO and subpart OOOOa definitions. The BLM removed the reference to a "battery of tanks" and added provisions excluding temporary tanks from the definition of a storage vessel. The BLM believes that this is a reasonable approach. The 6 tpy threshold identifies a quantity of lost gas that is reasonably cost-effective to address at an individual tank, without regard to the type of vessel or fluid stored. Avoiding the same quantity of lost gas from a battery of tanks would effectively lower the tank size threshold for coverage and would be considerably less cost-effective, as the same type of equipment would have to be installed on multiple tanks with smaller releases.

The BLM has also excluded from the definition of storage vessel tanks storing hydraulic fracturing fluid prior to implementation of an approved permanent disposal plan under Onshore Oil and Gas Order No. 7. This revision ensures that the final rule will not overlap with BLM rules governing hydraulic fracturing activities.

Commenters also suggested that the BLM adopt definitions for "pneumatic controllers" and "continuous bleed" that are consistent with the definitions in subpart OOOOa. The BLM agrees that aligning the definitions in the BLM and EPA rules to the extent possible will reduce the potential for confusion. Accordingly, § 3179.3 includes



definitions for “pneumatic controllers” and “continuous bleed” that are consistent with the definitions of these terms in subpart OOOOa.

In order to provide clarity, BLM has included definitions of “automatic ignitor system” and “high pressure flare” in the final rule. The final rule defines an “automatic ignition system” as an automatic ignitor and, where needed to ensure continuous combustion, a continuous pilot flame. A “high pressure flare” is defined as an open-air flare stack or flare pit designed for the combustion of natural gas leaving a pressurized production vessel (such as a separator or heater-treater) that is not a storage vessel.

#### **Section 3179.4 Determining when the loss of oil or gas is avoidable or unavoidable**

This section describes the circumstances under which lost oil or gas is classified as “unavoidably lost.” “Avoidably lost” oil or gas is then defined as oil or gas that is not unavoidably lost. The descriptions in the rule enhance clarity and consistency by listing specific circumstances under which oil and gas may be “unavoidably lost” when the operator has not been negligent, has not violated laws, regulations, lease terms or orders, and has taken prudent and reasonable steps to avoid waste.

The rule also defines as “unavoidably lost” any produced gas that is vented or flared from a well that is not connected to gas capture infrastructure, if the BLM has not determined that the loss of gas through such venting or flaring is otherwise avoidable.

Finally, this section defines “avoidably lost” oil or gas as lost oil or gas that does not meet this section’s definition of “unavoidably lost.” Also included in the “avoidably lost” category is any “excess flared gas,” which § 3179.7 defines as the quantity of flared gas by which the operator fell short of the applicable capture requirement specified in that section.

In response to comments received, the final rule added two new items to the list of operations and sources that are considered unavoidably lost: (1) gas lost during facility and pipeline maintenance, such as when an operator must blow-down and depressurize equipment to perform maintenance and repairs, which includes “pigging” of lines to remove liquids, and (2) flaring of gas from which at least 50 percent of natural gas liquids have been removed and captured for market, if the operator has notified the BLM through a Sundry Notice that the operator is conducting such capture.

The final rule also makes the following four clarifications to items that were included on the proposed list of operations and sources that are considered unavoidably lost, and that remain on that list in the final rule: (1) normal operating losses from a natural gas-activated pneumatic controller or pump are considered unavoidable, provided the controller or pump complies with §§ 3179.201 and 3179.202; (2) normal operating losses from storage vessels and other low pressure production vessels are considered unavoidable provided the vessels are in compliance with §§ 3179.203 and 3174.5; (3) losses from well venting in the course of downhole well maintenance and/or liquids unloading are considered unavoidable provided those operations are conducted in compliance with § 3179.204; and (4) leaks are considered unavoidable, provided the operator has complied with the leak detection and repair requirements of §§ 3179.301 through 3179.305.

The BLM also modified the proposed treatment of gas that is lost from a well that is not connected to a pipeline to align this provision with the revised approach in the final rule that addresses flaring through capture targets instead of flaring limits. The BLM had proposed that gas flared in excess of the applicable flaring limit would be considered

avoidable. The final rule deems avoidable any gas that is “excess” relative to the capture target. The term “excess flared gas” is defined in § 3179.7.

The principle underlying both the proposed and final regulatory text with respect to excess flared gas is that a prudent and reasonable operator will not routinely flare an unlimited quantity of natural gas from a development oil well. In this rulemaking, the BLM is modernizing and clarifying the criteria for determining when incidental and necessary disposal of gas accompanying oil production crosses the line into unreasonable waste of public gas resources, and the final rule expresses these criteria in the form of a gas capture target. When an operator is not meeting the applicable gas capture target, specified in § 3179.7 the BLM deems the excess flared gas volume—that is, the volume that caused the operator to fall short of the capture target—to be waste, avoidable, and subject to royalties.

Several commenters disagreed with BLM's proposed definitions of “waste” and “avoidably lost.” Many commenters felt that the BLM should maintain the definitions used in NTL-4A, including applying an economic test to determine what degree of capture is economical for the operator. These comments are addressed in section V.C of this preamble.

Some commenters stated that the BLM should consider gas lost during force majeure events as unavoidably lost. The BLM does not agree that all losses during force majeure events should be considered unavoidable. Such events may be out of the control of operators, but they are often expected and operators can therefore plan for them. The final rule does include as justifications for unavoidable loss some specific events that are generally considered force majeure events, such as emergencies. However, the gas

capture requirements in the final rule are structured to provide operators substantial flexibility to meet the capture targets without providing a blanket exemption for all events that the operator does not directly control. For example, scheduled maintenance of downstream pipeline or processing plants is neither unexpected nor unusual, and the BLM believes an operator should be able to plan ahead to address those events—for example, by identifying alternative capture approaches or planning to temporarily reduce production or shut in the well to address these circumstances.

Moreover, as described in Preamble Section V.A, Venting Prohibition and Capture Targets, the final rule allows operators to meet the capture target on average over a month at all of the wells on a lease, unit, or communitized area, or alternatively, on average over a month at all of the operator’s wells in a county or state. A prudent and reasonable operator will be able to take advantage of this flexibility to ensure that it has captured enough gas over the month, somewhere in the averaging area, to provide itself a sufficient buffer in meeting the gas capture targets to accommodate force majeure events that may not be within its control, but are common and predictable.

Relatedly, some commenters requested that gas lost because of ROW delays should be considered unavoidably lost. This preamble addresses the issue of ROW delays in Section VI.E. For the reasons discussed there, the BLM declines to make this change, which goes to the central premise of the gas capture requirement. The BLM has determined that it is not reasonable for operators to develop oil wells and plan to use flaring as the primary and routine disposal method for the associated gas. Rather, these rules require oil well operators, over time, to plan to capture an increasing percentage of their associated gas. In the near-term, the BLM believes that the gas capture targets,

combined with the quantities of allowable flaring and the ability to average, are sufficiently generous to allow operators to manage short-term delays in planned gas pipeline infrastructure with little difficulty, using production deferment and on-site capture at some wells where necessary. Over the longer term, a reasonable operator can continue to use those tools as well as working with the midstream companies to ensure that there is adequate pipeline capacity available to support transport of associated gas prior to building out large well developments.

Many commenters requested that the BLM grandfather all existing determinations of royalty-free flaring. Again, this change would undercut a key goal of this rulemaking: gradually, over time, to require operators to reduce routine flaring of associated gas from development oil wells. With the generous phase-in schedule for the gas capture targets and the quantities of allowable flaring, this rule requires only modest near-term reductions in flaring from existing wells. The BLM believes that it is entirely reasonable to expect operators to work, over time, to reduce flaring from their existing wells, as well as from new developments. Moreover, for this rule to have any meaningful effect on flaring, it must cover both existing and new development. Allowing all current determinations of royalty-free flaring to persist in perpetuity is unnecessary and would substantially undercut the effectiveness of this rule.

#### **Section 3179.5 When lost production is subject to royalty**

This section provides that royalties are due on all avoidably lost oil or gas, but not on unavoidably lost oil or gas. We received no significant comments on this section, and the final rule is very similar to the proposed rule with minor wording changes to improve clarity.

## **Section 3179.6 Venting and flaring from gas wells and venting prohibition**

This section expressly prohibits all venting and flaring from gas wells, except where the gas is unavoidably lost pursuant to section 3179.4(a). In addition, this section requires operators to flare rather than vent all gas that is not captured, except under certain limited circumstances. Operators will be allowed to vent gas in the following situations: (1) when flaring is technically infeasible – for example if the volumes of gas are too small to operate a flare (such as so-called bradenhead gas), or if the gas is not readily combustible; (2) under emergency conditions, when the loss of gas is uncontrollable or venting is necessary for safety; (3) when the gas is vented through normal operation of a natural gas-activated pneumatic controller or pump; (4) when the gas is vented from a storage vessel, provided that § 3179.203 does not require the combustion or flaring of the gas; (5) when the gas is vented during downhole well maintenance or liquids unloading activities performed in compliance with § 3179.204; (6) when the gas is vented through a leak where the operator is in compliance with § 3179.301-305; (7) when venting the gas is necessary to allow non-routine facility and pipeline maintenance to be performed, such as when an operator must, upon occasion, blow-down and depressurize equipment to perform maintenance or repairs; and (8) when release of gas is unavoidable and flaring is prohibited by Federal, State, local or Tribal law, regulation, or enforceable permit term.

The BLM made the following changes to the proposed rule requirements: (1) changed the title of this section; (2) added a new section (a) that expressly prohibits venting or flaring gas from gas wells, except where the gas is unavoidably lost pursuant to section 3179.4(a); (3) renumbered paragraphs (a)(1) and (2) paragraphs (b)(1) and (2);

(4) moved discussion of venting from a storage vessel from proposed paragraph (a)(3) to paragraph (b)(4) and added language clarifying that such venting is permitted when § 3179.203 does not require combustion or flaring of the gas; (5) renumbered proposed paragraph (a)(4) as paragraph (b)(3) and qualified that venting from a natural gas-activated pneumatic controller or pump is permitted during normal operation and when the pump is in compliance with § 3179.201 and § 3179.202; (6) Added paragraphs (b)(5) through (b)(8) that describe additional cases when venting of gas is permitted (situations 4-8 in the previous paragraph); (7) Removed all of proposed paragraph (b) describing venting or flaring volume limits, because flaring limits are now addressed in a new § 3179.7; and (8) Added a new paragraph (c), which requires that all flares or combustion devices be equipped with an automatic ignition system.

Section 3179.6(a) carries forward NTL-4A's express prohibition on venting and flaring from gas wells. Section IV.A of NTL-4A prohibits the venting or flaring of gas well gas, except for unavoidable losses and short-term venting and flaring during emergencies, well purging and evaluation tests, initial production tests, and wells tests (circumstances now defined as unavoidable in section 3179.4(a)). Similar restrictions on venting and flaring from gas wells were implied in the proposed rule; the BLM has chosen to state this explicitly in the final rule in order to avoid confusion.

Key comments received on this section are discussed in Section III.B.1.b of this preamble. Additional substantial comments received on the venting prohibition provisions are discussed below.

The BLM received comments asserting that the BLM lacked the statutory authority to require operators to flare rather than vent gas that is not captured.

Commenters argued that such a requirement does not fall within the BLM's waste-prevention authority under the MLA because shifting from venting to flaring does not prevent waste as the gas is lost in either case. These commenters then argued that the only possible justification for the requirement to flare rather than vent is control of GHGs and other air pollutants, which commenters assert is exclusively within the EPA's domain.

The BLM disagrees with these comments for several reasons. First, the requirement in this section to flare rather than vent does result in waste prevention, because it is paired with provisions that limit total flaring – namely, the gas capture requirements in § 3179.7. Under § 3179.7(c), the denominator in the gas capture percentage calculation is “the total volume of gas captured over the month plus the total volume of gas flared over the month from high-pressure flares from all of the operator's development oil or gas wells in the relevant area, minus” a declining “flaring allowable” volume.. By requiring that operators shift from venting to flaring, the BLM is effectively increasing operators' flared volume in a given month, which in turn increases the total volume of gas that the operators must capture in that month.

Second, directing associated gas to a flare rather than allowing operators to vent it improves waste accounting because under final rule § 3179.9, operators must measure volumes above 50 Mcf per day that are flared from a high pressure flare stack or manifold. By shifting operators from venting to flaring, § 3179.6 will likely increase the number of operators that must measure their flared gas volumes under § 3179.9. This will, in turn, improve operators' (and the BLM's) waste accounting. Better waste accounting is itself a waste prevention measure, because it gives the BLM and operators a



better sense of how much gas is being wasted—and thus how much could be made available for productive use and/or sold to offset the costs of waste prevention equipment.

Third, this requirement constitutes waste prevention when applied to operator flaring during activities regulated under §§ 3179.102, 3179.103, and 3179.104. Under §§ 3179.102 and .103, flaring during well completion and initial production testing that exceeds 20 MMcf/well is treated as avoidably lost gas subject to royalties under § 3179.4(a)(1)(C). The BLM believes that in many instances, the venting prohibition in § 3179.6 may result in operators reaching the 20 MMcf/well royalty flaring threshold sooner, thereby providing an additional financial incentive for operators to reduce waste. Under § 3179.104, all flaring during subsequent well tests that exceeds 24 hours is treated as avoidably lost gas subject to royalties under § 3179.4(a)(1)(D).

Fourth, as discussed above, the requirement to flare rather than vent associated gas is justified as a safety measure under the MLA. It is generally safer to combust methane gas than allow it to vent uncombusted into the surrounding air due to concerns over methane's explosiveness and the risks to workers of hypoxia and exposure to various associated pollutants.<sup>142</sup> Fifth, and as also discussed above, even if the venting prohibition were purely an air quality control measure, the BLM does have the authority to regulate air quality and GHG impacts on and from the public lands, pursuant to FLPMA and the MLA, as discussed in Section III.C of this Preamble.

Several commenters stated that operators should be required to capture *all* natural gas from all wells, with no exceptions, or that if flaring is allowed, combustion devices should be required to have a design destruction efficiency of at least 98%, that enclosed

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<sup>142</sup> NIOSH-OSHA Hazard Alert entitled, "Health and Safety Risks for Workers Involved in Manual Tank Gauging and Sampling at Oil and Gas Extraction Sites," February 2016, [www.osha.gov](http://www.osha.gov).

flares should be required, and that flares should be required to be equipped with a continuous pilot light and an auto-ignition system. As discussed in Section III.B.2 of this preamble, the BLM does not believe that it is feasible to eliminate all venting and flaring, but we have revised both the flaring requirements and the circumstances when venting is permitted in response to comments. The BLM also is not adding a requirement for flares to have a design destruction efficiency of 98%. Many existing flares have a design combustion efficiency of 95%, rather than 98%.

The BLM has added a requirement in the final rule that flares must be equipped with an automatic ignition system, which will provide the flare system with an effective method of ignition in the case of interruption. The term “automatic ignition system” implies the concept of maintaining an ignition source without specifying a particular type of device, and the BLM believes that operators will utilize devices that are appropriate for the circumstance. The BLM does not believe that requiring a specific device, such as a continuous pilot, would necessarily result in reduced waste relative to a more general requirement for an automatic ignition system.

Some commenters requested that the BLM allow venting when flaring is not economically feasible. The BLM believes that this change is unnecessary, would add substantial ambiguity to the rule, and could significantly weaken the requirement to flare rather than vent. Flaring rather than venting gas that is not being captured is widespread industry practice, due in large part to safety concerns. While there are situations where the quantities of gas are too small or difficult to allow for flaring, the rule explicitly allows venting in lieu of flaring in those situations. It is not clear to the BLM what other

circumstances would render flaring “economically infeasible,” or what specific concerns the commenter is trying to address.

A commenter seeking to minimize exceptions to the venting prohibition asked the BLM to define the term “technically infeasible.” Given the wide variety of situations that are likely to occur on a lease that inform an operator’s determination of technical feasibility, the BLM does not believe that it is appropriate to add further specificity to this term. If there is a dispute about the term in a specific case, the BLM has the final say in determining whether flaring is, in fact, technically infeasible.

### **Section 3179.7 Gas capture requirement**

Final rule § 3179.7 houses a modified version of the flaring requirements that were in proposed rule s 3179.6. As discussed in Section III.B.2.a, the final rule alters how the proposed rule constrained the quantities of gas lost through flaring, but achieves similar flaring reductions by requiring operators to meet specified monthly capture targets (subject to shrinking flaring allowances), rather than setting per well numeric flaring limits.

Final rule § 3179.7 establishes capture targets that increase over the first nine years of rule implementation. Paragraphs (a) and (b) describe the capture percentage requirements. The schedule for the capture targets is provided in § 3179.7(b)(1)-(4) and is reproduced in Section III.B.2.a of this preamble. Paragraph (c) defines “capture percentage,” “total volume of gas captured,” “adjusted total volume of gas produced,” and “relevant area.” Under § 3179.7(c)(3), an operator may choose whether to comply with the capture targets on each of the operator’s leases, units or communitized areas, or on a county-wide or state-wide basis. Section 3179.7(c)(4) defines when an oil or gas

well is considered “in production” and therefore subject to the capture targets in this section. Section 3179.7(d) establishes an equation for determining the quantity of “excess flared gas”—that is, the volume of flared gas that causes an operator to fall short of the applicable capture target in a given month, and that is therefore subject to royalties. Section 3179.7(e) requires operators to prorate the excess flared gas to each lease, unit, or communitized area that reported high-pressure flaring, for purposes of calculating royalties.

As discussed in Section III.B.2 of this preamble, the BLM developed the capture target approach in final rule § 3179.7 after careful consideration of the many comments received on the flaring limit approach taken in proposed rule § 3179.6(b). The key comments received on § 3179.7 and BLM’s response to these comments are also discussed in Section III.B of this preamble. Additional substantive comments received on the proposed flaring provisions are discussed below.

Several commenters asserted that the ability to avoid flaring depends on the capacity of gathering lines, and that operators must prove production for a new oil play and initiate larger scale development before gathering and/or processing companies are willing to invest in infrastructure. These comments informed the revisions to the flaring revisions made in the final rule. The BLM also recognizes that currently the optimal mechanism to capture gas is through connecting to a pipeline, which may take time to achieve in some areas due to lagging infrastructure and capacity constraints. As a result, the final rule provides additional time and flexibility for industry to plan and better coordinate development of production wells with development of pipelines to transport the production. As discussed in section III.B.2, the final rule provides an option for

operators to comply with the capture targets on a lease-by-lease, county-wide, or state-wide basis, and also phases in the capture targets over a longer period of time. These changes will allow sufficient time and flexibility to enable industry to better align oil development with gas infrastructure over time.

On the other hand, given the BLM's statutory obligation to reduce waste of gas, the clear technical capability of operators to capture gas, the economic value of the gas, and the environmental impacts of not capturing it, the BLM has determined that it is not reasonable to allow operators to dispose of large quantities of associated gas from development oil wells using routine flaring. The final rule therefore structures the capture targets in a way that the BLM estimates will achieve slightly greater flaring reductions than the proposed rule, albeit over a longer timeframe.

Many commenters asserted that on-site capture technologies are not technically feasible and/or economically viable. In the proposed rule, we discussed research indicating that LNG stripping, CNG, and gas-to-power are commercially mature technologies that are portable, scalable, and have been utilized economically at well sites.<sup>143</sup> Moreover, MJ Bradley released a re-analysis of the economic analysis in the proposal, which suggests that for over 500 of the leases in the BLM data set, the CNG trucking option would have total net benefits that exceed total lessee costs by approximately \$56.5 million over a 10 year period.<sup>144</sup> The BLM agrees with the commenter's assertion that these remote-site capture technologies may not be viable at all well sites. However, they are viable and currently used at some sites. The final rule's option allowing operators to average compliance across all of their wells in a county or

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<sup>143</sup>81 FR 6641. See also Carbon Limits. *"Improving Utilization of Associated Gas in US Tight Oil Fields"*. 2015. Available at [http://www.catf.us/resources/publications/files/Flaring\\_Report.pdf](http://www.catf.us/resources/publications/files/Flaring_Report.pdf).

<sup>144</sup>M.J Bradley and Associates. *"Re-analysis of Proposed BLM Flaring Reduction Rule; Projected Costs and Benefits"*. September 9, 2016. Pages 13-14

State accommodates this heterogeneity in site/technology compatibility: operators can deploy on-site capture technologies where it is most cost-effective, and use the increased capture rates at those sites to offset continued flaring at other sites. The BLM also notes that leasing on-site capture equipment during the earlier periods of well production, when associated gas levels and corresponding potential revenues are highest, can enhance the cost-effectiveness of the technologies. Leasing allows operators to avoid upfront capital costs associated with purchasing equipment, making it easier to use such equipment only for periods in the well's life when it is most economic to do so. This strategy also allows operators to match equipment size to expected associated gas production volumes at different stages of well production. Finally, on-site capture technology capital costs may continue to decline as the market further matures and achieves greater economies of scale.

Several commenters expressed concern about delays in approvals of ROWs for gas pipelines, and asserted that such delays will prevent operators from complying with the capture targets. These comments are addressed in Section VI.E of this preamble.

### **Section 3179.8 Alternative capture requirement**

Section 3179.8 (§ 3179.7 in the proposed rule) describes an alternative process that is available to an operator that cannot meet the capture targets described in final rule § 3179.7. Under § 3179.8, an operator that cannot meet the capture targets may request that the BLM establish an alternative capture target if three conditions are met: (1) the operator has chosen to comply with the capture target using the lease-by-lease, unit-by-unit, or communitized area-by-communitized areas basis rather than the averaging approach; (2) the potentially noncompliant lease was issued before the effective date of

this final rule; and (3) the operator demonstrates via Sundry Notice, and the BLM agrees, that the applicable capture percentage under final rule § 3179.7 “would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.”

As discussed in Section V.B.2.b of this preamble, § 3179.8 was revised in the final rule to reflect the shift to gas capture targets in final rule § 3179.7. Section 3179.8(a) was also revised to reflect the three conditions discussed above. Section 3179.8 (b) describes the information an operator must submit in the Sundry Notice. The final version of this paragraph makes minor modifications relative to the proposed version, including: adding the phrase, “to the extent that the operator is able to obtain this information,” to the requirements to include pipeline capacity and the operator’s projections of the cost associated with installation and operation of gas capture infrastructure; adding cost projections for alternative methods of transportation that do not require pipelines; specifying that the cost projections required in final § 3179.8(b)(5)(i) must be based on the next 15 years or the life of the lease, unit, or communitized area, whichever is less; and dropping the requirement to provide the depths and names of producing formations. Section 3179.8(c) remains similar to the proposed rule (§ 3179.7(c)), with flaring limits changed to capture percentages. The final rule also does not contain the renewable 2-year exemption in proposed § 3179.7(d).

The key comments received on this section and BLM’s response to these comments are discussed in Section III.B.2.b of this preamble. Additional substantive comments received on the proposed flaring provisions are discussed below.

Some commenters asserted that the proposed alternative capture and related Sundry Notice requirements were overly burdensome and required submission of confidential information. These commenters contended that oil and gas price and production volume forecasts and pipeline and gas capture costs are considered confidential business information. Commenters also claimed that operators do not have access to information on pipeline capacity.

The BLM does not agree that the Sundry Notice requirements for a request for an alternative capture requirement are unduly burdensome, although the BLM has streamlined the proposed requirements in the final rule where it was possible to do so without losing information that would be necessary to evaluate a request. Commenters did not explain how the BLM would be able to determine whether a request met the criteria for approval absent the required information. Also, operators routinely provide information to the BLM that they consider confidential; if they indicate on the Sundry Notice that the information is considered confidential, the BLM will handle the information in accordance with applicable regulations in 43 CFR Part 2. In response to statements that commenters may not have access to information on pipe capacity, the BLM revised the final rule to state that data on pipeline capacity and the operator's projections of the cost associated with installation and operation of gas capture infrastructure is required to the extent that the operator is able to obtain such information.

Some commenters requested that the BLM clarify what "significant" means with regard to recoverable oil reserves in § 3179.8(c), while another recommended that the criteria should be based on an economic test that would grant an alternative limit if the return on investment would be too low for a prudent operator to proceed with



compliance. Another commenter stated that new wells should also be allowed to apply for alternative limits. Other commenters asserted that the BLM should eliminate or substantially narrow the approval of alternative limits, with one commenter stating that the BLM should determine approval of alternative limits based on a cost-benefit analysis that includes the consideration of environmental benefits.

The BLM did not revise the rule based on these comments, but we are providing here additional clarification on the BLM's interpretation of this standard. The BLM believes that requiring the operator to demonstrate that the applicable capture percentage under § 3179.7 would "impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves" is an appropriate threshold for granting alternative capture requirements. The BLM recognizes that the term "significant" is a qualitative rather than quantitative metric. The BLM considered development of a quantitative metric, but determined that setting a quantitative threshold, such as number of days of production lost, might be arbitrary and ineffective. Moreover, the BLM has a history of reviewing and effectively evaluating requests based on similar qualitative criteria. While we do not expect there to be a significant change in the review of these requests from prior practice, as discussed in the preamble to the proposed rule, we do expect that spelling out the requirements and qualitative criteria more clearly in today's rule will ensure a more consistent review and approval process.

The BLM notes that the phrase "cease production and abandon significant recoverable oil reserves" is not intended to require an operator to demonstrate that the lease could never be developed under any future circumstances. Yet nor would it be sufficient for an operator to show that compliance with the capture targets would cause

the operator to shut in the wells on a lease for a limited period of time. Rather, the operator must make a showing that the cost of complying with the capture requirements would cause the operator to shut in the wells on the lease under current market conditions and for the reasonably foreseeable future, taking into account uncertainty regarding the long-term recoverable potential of the lease and reservoir. In other words, the showing should illuminate whether compliance would cause the operator to be deprived of the value of the lease, not simply cause a reduction in profit. For example, depending on the specific economic circumstances of the lease, it may be sufficient for an operator to show that it would have to shut in the wells on a lease for a time period on the order of a year or two. The BLM notes, however, that it is not uncommon for operators to shut in and restart production due to market conditions, and a showing under this exemption should demonstrate a more significant impact that is clearly distinguishable from such normal fluctuations.

With respect to the request to allow an alternative capture target to apply to new wells, the BLM notes that the alternative is limited to existing leases, not existing wells. Thus, the alternative capture target is potentially available with respect to an existing lease with new wells. Moreover, the BLM believes that with the extended phase-in of the capture targets and the state- and county-wide averaging option, operators have ample flexibility to take the capture targets into account as they develop new production wells. Indeed, this rule encourages such planning by requiring operators to submit waste minimization plans with their APDs. Further, the BLM does not believe that the opportunity to request an alternative capture target should be extended to new leases.

Operators have broad flexibility to plan to meet the capture targets at the time that they bid on new leases.

Some commenters requested that the Sundry Notices be processed in a timely manner, and that the BLM provide a schedule for applying for and being granted an alternative capture percentage. One commenter suggested that the BLM should align the phase-in of the rule with the time it would take to for the BLM to approve the requests for alternate capture targets. Given that the final rule phases in the capture targets over a longer period of time, the BLM expects that operators will have sufficient time to prepare their Sundry Notice requests for alternative capture targets if needed. Additionally, the BLM does not anticipate receiving a large number of Sundry Notice requests for alternative capture targets, and therefore anticipates that it will have adequate time to review them in a timely manner.

### **Section 3179.9 Measuring and reporting volumes of gas vented and flared**

This section (which was § 3179.8 in the proposed rule) requires operators to estimate (using estimation protocols) or measure (using a metering device) all flared and vented gas, whether royalty-bearing or royalty-free. This section further provides that specific requirements apply when the operator is flaring 50 Mcf or more of gas per day from a high pressure flare stack or manifold, based on estimated volumes from the previous 12 months, or based on estimated volumes over the life of the flare, whichever is shorter. Beginning one year from the effective date of the rule, when this volume threshold is met, the operator must measure the volume of the flared gas, or must calculate the volume of the flared gas based on the results of a regularly performed GOR test, so as to allow the BLM to independently verify the volume, rate, and heating value

of the flared gas. This section also requires operators to report all volumes vented or flared under applicable ONRR reporting requirements.

This section allows operators that are flaring gas across multiple leases, unit PAs, communitized areas, or non-Federal or non-Indian leases to measure or calculate the flared volumes at a single point. To mitigate environmental impacts, commingling to a single flare may be approved even though the relevant royalty interests may differ. The BLM recognizes that the additional costs of requiring individual flaring measurement and meter facilities for each lease, unit PA, or communitized area are not necessarily justified by the incremental royalty accountability afforded by the separate meters and flares. However, to ensure proper production accountability, the method of allocating the flared volumes to each lease, unit PA, or communitized area must be approved by the BLM where the flared volumes exceed the 50 Mcf/day threshold.

The BLM made the following changes from the proposed rule: the final rule clarifies that (1) this section applies to gas vented and flared from wells, facilities, and equipment on a lease, unit PA, or communitized area, rather than just referencing gas vented and flared from wells; (2) the 50 Mcf/day threshold triggering the requirement to measure is determined by averaging the estimated volumes from a high pressure flare stack or manifold over the previous 12 months, or the life of the flare, whichever is shorter; (3) when the 50 Mcf/day threshold is met, operators have the choice of measuring or calculating the volume of the gas, rather than being required to measure only; (4) the requirement to measure or calculate volumes applies beginning one year from the effective date of the rule; and (5) under new paragraph § 3179.9(c), operators may measure or calculate commingled gas at a single measurement point at the flare, but

they must use an allocation method approved by the BLM to allocate the quantities of flared gas across the leases, unit PAs, or communitized areas that can contribute production to a flare that is above the 50 Mcf /day threshold.

The BLM received a range of comments on § 3179.9 (§ 3179.8 in the proposed rule). Some commenters recommended that the BLM disallow estimation of flared or vented gas and requested that gas be measured in all cases or that the threshold for measurement be lowered from 50 Mcf /day. Commenters asserted that requiring measurement and monitoring rather than allowing operators to estimate flared gas volumes will provide the co-benefits of assisting the BLM with compliance assurance, allowing accurate determination of when royalties are due, and further reducing methane emissions.

Other commenters argued that the threshold for measurement should be raised or that the measurement requirement should be eliminated from the rule altogether. One commenter contended that metering simply adds costs and logistical difficulties without providing environmental benefit or reducing waste. Several commenters asserted that metering technology is not available that can accurately or reliably estimate flare gas volumes over the extreme range of pressures and rates typically encountered on producing wells, and that the measurement equipment and methods in Onshore Order 5 and its successor regulations are not applicable to flares. Arguing that there is no current technology that can reliably measure low pressure, low volume, fluctuating gas flow, several commenters recommended that the BLM remove the requirement to measure gas at low-volume flow rates and allow the operator to continue to use the estimation requirements and GOR methodology in NTL-4A. Another commenter asserted that

operators would need to install meters on any site where vented and flared gas could potentially exceed the threshold. Several commenters requested clarification on the period over which the flaring must exceed the 50 Mcf/day threshold, with one suggesting that the threshold be based on an average value over a production month.

Like the proposed rule, the final rule maintains the 50 Mcf/day threshold for triggering more specific standards for determining the volume of flared gas, however, the BLM has modified the standards that apply when a flare stack or manifold exceeds that threshold to allow either metering or a rigorous GOR-based approach. The final rule also clarifies that exceedance of the 50 Mcf/day threshold will be determined based on the average quantity of flaring per day over the life of the flare or over the previous 12 months of flaring activity, whichever is shorter. The BLM agrees that the rule should specify the measurement period for exceeding the threshold, and believes that limiting the averaging period of 12 months (or the life of well) provides a good indication of ongoing, current levels of flaring that are high enough to warrant measurement.

Although the BLM received comments arguing for both higher and lower thresholds, the BLM ultimately concluded that a change in the threshold is not warranted. The 50 Mcf /day threshold represents a level of activity of high-pressure flares that can be measured or calculated with a reasonable degree of accuracy. In addition, particularly when measured or calculated on average over a period of time at a single flare stack or manifold, 50 Mcf/day is a sufficiently high level of flaring that it could reasonably be expected to lead to royalty obligations on flared volumes considered “avoidably lost” under the final rule. When an operator exceeds this threshold, the operator needs to be able to account accurately for the amount of flaring that occurs and validate its

compliance with the capture target, particularly as the “flaring allowable” level decreases and the capture target increases in future years.

The BLM has modified the standards that apply to flares that exceed the 50 Mcf/day threshold, however, to allow for either metering or a GOR-based calculation of flare volumes in circumstances where a GOR-based approach would allow the BLM to independently verify the volume, rate, and heating value of the flared gas. As noted above, many commenters argued that metering technology is not available to measure gas volumes at many flares, and they asserted that using GOR-based methods provides sufficient information to accurately calculate flared gas volumes. Other commenters argued that all flared gas volumes should be directly metered.

The BLM believes that technology exists to measure flared volumes, especially on higher-volume flares, and that meters would not be prohibitively expensive to install. For example, the gas measurement requirements in recently adopted subpart 3175 contain standards applicable to metering gas at very-low volume FMPs. These are the BLM’s least stringent measurement requirements for gas measurement, and they allow operators to use alternative methods for measuring highly fluctuating gas flows, provided only that the measurements meet the performance goals of section 3175.31. While the specific standards in subpart 3175 are geared to orifice plate measurement, the performance goals for very-low volume FMPs only require that the measurement be verifiable and they do not require the operator to achieve any set level of uncertainty or maintain measurement free of statistically-significant bias. Therefore, the BLM may approve alternate devices for purposes of subpart 3175, such as thermal mass meters, ultrasonic meters, or other technology that industry develops that can provide verifiable measurement, which could

also be applicable to measuring flared volumes under this provision. In addition, provisions in newly adopted subparts 3170 and 3175 establish a production measurement team, which will approve technologies for gas metering. Technologies approved by the production measurement team could also be used to comply with the requirements of this section.

Nevertheless, the BLM is sensitive to the performance limitations of many commonly used meters, and the BLM believes that a properly designed GOR-based approach can also produce adequately accurate results. A GOR-based method for calculating volumes of flared gas would use a known GOR and measured volumes of oil production and sold gas. The GOR itself is determined based on a test that directly measures in a controlled manner all of the oil and gas produced by the well over a given period of time. Calculating the volumes of flared gas based on GOR can be quite accurate, if the GOR value used is accurate and the well conditions are relatively stable. Since the GOR will vary as well conditions change, the accuracy of the GOR value for a well can be enhanced by more frequent GOR testing, either on a set frequency and/or in response to changes in the well's production. The BLM expects that to meet the standards of §3179.9, GOR tests would need to be performed at least monthly for most wells.

Commenters also contended that the rule does not clearly specify the type of gas that must be estimated or measured, and they recommended that the rule not apply to "unavoidably lost" gas volumes. The BLM does not agree that measurement should be required only when the volume of avoidably flared gas exceeds the threshold. As a first step to reducing waste through flaring, it is important for both the operator and the BLM



to have an accurate understanding of the total quantity of gas that is being flared. While the BLM agrees that estimation techniques can provide a ballpark volume estimate, the BLM believes that direct measurement methods authorized under subpart 3175 more consistently and accurately identify the actual volume of the losses. Furthermore, the BLM notes that if an operator is flaring high pressure gas at a rate of more than 50 Mcf/day, it becomes more likely that the operator is failing to meet capture requirements. If an operator fails to meet capture requirements, then at least a portion of the flared gas is deemed avoidably lost, and therefore royalty bearing.

Several commenters noted that the rule does not provide methods for estimating vented or flared volumes. One commenter asserted that the BLM must require operators to use estimation techniques that provide accurate and reliable estimates of releases, while others recommended that methods currently allowed under NTL-4A should continue to be allowed for estimating associated gas and royalty-free volumes. The BLM does not believe that it is necessary to specify estimation methods, as the BLM expects the industry to continue to use well-understood and generally accepted engineering practices for estimating quantities of flared gas below the 50 Mcf/day threshold.

Commenters also requested that the BLM make public the data on volumes of gas reported by operators as flared or vented. The BLM agrees that this is important information for the public, and the BLM plans to make this information available, subject to any protections for confidential business information.

#### **Section 3179.10 Determinations Regarding Royalty-Free Flaring**

This section (which was § 3179.9 in the proposed rule) provides for a transition period for operators that are operating under existing approvals for royalty-free flaring, as of the effective date of the rule. Further, this section clarifies that nothing in this subpart alters the royalty-bearing status of flaring that occurred prior to January 17, 2017, nor the BLM's authority to determine that status and collect appropriate back-royalties.

Commenters asserted that the rule represents a change in what is considered "avoidable loss" and therefore cannot be applied to existing leases. Commenters also requested that the BLM permanently grandfather existing approvals for royalty-free flaring and only apply the rule requirements to wells drilled after the effective date of the rule, arguing that 90 days is too little time to design and construct gas capture infrastructure.

As discussed in Preamble Section III.C, the BLM's legal and contractual authority to update its regulations governing existing oil and gas leases is well established. The BLM has the authority to revise its interpretation of what constitutes "avoidably lost" oil and gas and may impose this interpretation on existing leases. The BLM revised the rule, however, to extend the grace period for preexisting approvals to flare royalty free from the 90 days specified in the proposed rule to one year after the final rule becomes effective. After one year, those operators with preexisting royalty-free flaring approvals will become subject to all the provisions of the final rule.

#### **§ 3179.11 Other waste prevention measures**

This section clarifies that nothing in this subpart alters the BLM's existing authority under applicable laws, regulations, permits, orders, leases, and unitization or communitization agreements to limit the volume of production from a lease, or to

delay action on an APD to minimize the loss of associated gas. Specifically, if production from a new well would force an existing producing well already connected to the pipeline to go offline, then notwithstanding the requirements in 3179.7 and 3179.8, the BLM may limit the volume of production from the new well while gas pressures from the well stabilize. In addition, this section clarifies that, consistent with existing authority, the BLM may delay action on an APD or approve it with conditions related to gas capture and production levels, and can suspend the lease under 43 CFR 3103.4-4 if the lease associated with the APD is not yet producing.

In the final rule, the BLM revised both paragraphs §3179.11(a) and (b) to add additional specificity regarding the sources of the BLM's existing authority. Specifically, the BLM added to both paragraphs (a) and (b) language to the effect that the BLM may exercise its existing authority "under applicable laws and regulations, as well as its authority under the terms of applicable permits, orders, leases, and unitization or communitization agreements."

The BLM received a number of comments on this section. While some commenters expressed support for BLM's authority on this matter, other commenters expressed concern that the BLM could delay approval of APDs due to infrastructure limitations that are out of the control of the operator (e.g., third-party pipeline capacity). One commenter suggested that the proposed requirements would result in curtailment of new production, potentially causing reservoir damage during initial production operations. Another commenter asked the BLM to (1) clarify that this portion of the rule applies to Federal minerals only and (2) explain implementation of the rule for special

cases, such as long reach horizontal wells that produce from Federal and non-Federal leases within the same wellbore.

The BLM did not revise this section based on comments received. As stated in the regulatory text, the BLM is exercising existing authority and this section does not expand upon that authority. The intent of this section is to address operators' concerns that gas from their existing wells could be forced offline by new Federal gas production, and to clarify that the BLM already has the authority to remedy such circumstances when appropriate to minimize waste of oil and gas on BLM-administered leases. If implementation of this section could result in the incidental curtailment of non-Federal production, the BLM will coordinate on a case-by-case basis with the relevant State regulatory authorities pursuant to Section 3179.12. As noted in Preamble Section VI.D, the fact that a regulatory provision aimed at Federal and Indian production may have incidental impacts on State or private production does not impinge on the BLM's authority to ensure that operators take reasonable steps to minimize waste of Federal and Indian minerals.

#### **Section 3179.12 Coordination with State regulatory authority**

This section addresses certain "mixed ownership" situations, in which a single well may produce oil and gas from both Federal and/or Indian mineral interests and non-Federal, non-Indian mineral interests. This section provides that to the extent any BLM action to enforce a prohibition, limitation, or order under this subpart might adversely affect production of oil or gas from non-Federal and non-Indian mineral interests, the BLM will coordinate on a case-by-case basis with the State regulatory authority with jurisdiction over that non-Federal and non-Indian production. This is consistent with

current practice, in which the BLM and State regulators coordinate closely in regulating and enforcing requirements that apply to operators producing from Federal or Indian interests and from non-Federal, non-Indian mineral interests. The BLM did not revise this section from the proposed rule.

Some commenters asserted that that the propose rule did not indicate what constitutes coordination, and separately, that state-Federal coordination would not reduce duplicative requirements for operators. This provision is aimed at coordinating enforcement of BLM requirements, not intended to address issues related to overlapping state and Federal requirements. The BLM anticipates that its level of coordination will vary by state, and may involve entering into (or revising existing) memoranda of understanding with the relevant State parties.

#### **Section 3179.101 Well drilling**

This section requires that gas reaching the surface as a normal part of drilling operations be used or disposed of in one of four specified ways: (1) captured and sold; (2) directed to a flare pit or flare stack; (3) used in the operations on the lease, unit, or communitized area; or (4) injected. The final rule specifies that gas may not be vented except under the circumstances specified in § 3179.6(b) or when it is technically infeasible to use or dispose of the gas in one of the ways specified above.

This section also states that gas lost as a result of a loss of well control will be classified as avoidably lost if the BLM determines that the loss of well control was due to operator negligence, in which case it will be subject to royalties.

Several commenters asserted that the proposed requirement that all gas that reaches the surface during drilling be captured and sold, flared, used on-site, or injected is

not always technically feasible because such gas can be low pressure, low volume, and intermittent. Commenters also stated that achieving a no-venting standard is not feasible particularly when gas reaches the surface through unplanned gas kicks. Commenters asserted that in these situations, venting the gas can sometimes be the only safe solution.

In response to these comments, in addition to the exceptions described in § 3179.6(b), the final rule states that operators also do not have to use or dispose of gas that reaches the surface in one of the ways specified in § 3179.101(a) if it is technically infeasible to do so. The BLM believes that a technical infeasibility option is necessary to address the situations described by commenters, which we expect to occur rarely, where the operator cannot use or dispose of the gas as specified in § 3179.101(a).

The BLM also received comments asserting that it lacks the authority to require that gas reaching the surface during drilling operations be flared if not captured, used on the lease, or injected. Commenters argued that such a requirement does not fall within the BLM's MLA authority because it is not waste prevention, as the gas is lost whether it is vented or flared. These commenters then argued that the only possible justification for the requirement was control of GHGs and other air pollutants, which commenters assert is exclusively within the EPA's domain.

The BLM disagrees with these comments. Flaring during drilling does not count toward an operator's capture target, so the requirement to flare rather than vent this gas does not achieve waste reduction in that way. Nevertheless, the requirement falls squarely within the BLM's authority because, as discussed in connection with § 3179.6, a requirement to flare rather than vent associated gas is a safety measure under the MLA. It is generally safer to combust methane gas than to allow it to vent uncombusted into the

surrounding air due to concerns over methane's explosiveness and the risk of hypoxia and exposure to various associated pollutants. In addition, also as discussed in connection with § 3179.6, the BLM has the authority to regulate air quality and GHG impacts on and from public lands pursuant to FLPMA and the MLA.

### **Section 3179.102 Well completion and related operations**

This section addresses gas that reaches the surface during well completion, post-completion, and fluid recovery operations, after a well has been hydraulically fractured or refractured. It requires the gas to be used or disposed of in one of four specified ways: (1) captured and sold; (2) directed to a flare pit or stack, subject to a volumetric limitation in section 3179.103; (3) used in the lease operations; or (4) injected. The final rule specifies that gas may not be vented except under the narrow circumstances specified in proposed § 3179.6(b) or when it is technically infeasible to use or dispose of the gas in one of the four ways specified above. It also provides that an operator will be deemed to be in compliance with the gas capture and disposition requirements of § 3179.102(a) if the operator is in compliance with the requirements for control of gas from well completions established under subpart OOOO or subpart OOOOa, or if the well is not a "well affected facility" under either of these subparts.

The final rule also allows an exemption from the requirements of §3179.102(a) if the operator submits a Sundry Notice to the BLM demonstrating that compliance with these requirements would impose such costs as to cause the operator to cease production and abandon significant oil reserves under the lease.

In response to comments described below, we have made several changes to the proposed rule requirements. Specifically, the final rule: (1) clarifies that sources subject

to, and in compliance with, subpart OOOO and subpart OOOOa are deemed to be in compliance with this section, without filing a Sundry Notice (as the proposed rule would have required); (2) limits coverage of this section to hydraulically fractured or refractured well completions; (3) adds text to clarify that a well that does not meet the definition of a “well affected facility” under either subpart OOOO or subpart OOOOa, will nevertheless be deemed to be in compliance with this section, since the NSPS provides that existing wells that are refractured and follow the well completion procedures in the NSPS are not affected facilities; (4) adds an exemption for technical infeasibility; and (5) adds an exemption from the requirements of this section when the operator can demonstrate that compliance would cause the operator to cease production and abandon significant recoverable oil reserves under the lease due to the cost of compliance.

Several commenters asserted that the requirements for well completions are duplicative with EPA requirements contained in 40 CFR part 60 subpart OOOO and subpart OOOOa. These EPA rules address emissions from flowback operations following completion of new gas and oil wells using hydraulic fracturing treatment. Commenters asserted that the EPA rules effectively cover all wells, because most new wells utilize hydraulic fracturing, and existing wells that undergo “recompletion” hydraulic fracturing will be covered as well, as they are considered a “modified” source post-recompletion. Commenters further argued that the BLM should allow for exemptions for wells that comply with either 40 CFR part 60, subpart OOOO or subpart OOOOa, rather than limiting the exemption to wells that comply with subpart OOOOa as the proposed rule would have done. Commenters asserted that several issues related to controlling emissions from well completion operations have already been worked out in



detail with the EPA, and these issues would apply to the BLM's rule as well. These issues include inadequate well pressure or gas content during the well completion to operate surface equipment, and the need for an exemption for wells with less than 300 scf of gas per stock tank barrel of oil produced. Other commenters noted that the EPA's well completion requirements in subpart OOOOa do not cover conventional wells because of their low methane and VOC emissions, but that the proposed BLM rule would apply to conventional wells. Commenters also argued that the Sundry Notice requirement to document EPA compliance was an additional and unnecessary burden for sources already regulated elsewhere.

Although we believe that new wells will generally be subject to subpart OOOOa, after considering these comments, we have added language in the final rule stating that wells that are in compliance with either subpart OOOO or subpart OOOOa are deemed to be in compliance with the requirements of this section. We also agree with commenters that filing a Sundry Notice to this effect is unnecessary, and we have not included that proposed requirement in the final rule. We also revised the text to limit the coverage of this section to fractured and refractured wells. Upon consideration of the comments, the BLM agrees that the loss of gas from conventional well completions is very small and that regulating conventional well completions is not a particularly cost-effective way to reduce waste. We also revised the text to clarify that a well that does not meet the definition of a "well affected facility" under either subpart OOOO or subpart OOOOa, and is exempt from those subparts on that ground, is deemed to be in compliance with this section. This change aligns the coverage of the BLM requirements with the coverage of the EPA requirements, and it ensures that a well that the EPA exempted from the

subpart OOOO and subpart OOOOa requirements would not become subject to the BLM requirements by virtue of that exemption.

The BLM is including requirements for well completions in this rulemaking to satisfy its statutory obligations to prevent waste of oil and gas on Federal lands. The well completion requirements are a key part of a comprehensive regulatory regime reducing waste from development of the public's oil and gas resources. The BLM requirements do not require any additional action from an operator that is in compliance with subparts OOOO and OOOOa. Thus, without imposing any burden on an operator, the BLM requirements provide a backstop in the unlikely event that subparts OOOO or OOOOa are no longer in effect. The BLM does not in any way question the validity of the EPA regulations, but we note that some of the same commenters that claim the BLM regulations are unnecessarily duplicative are separately challenging EPA's subpart OOOOa in court.

Commenters also questioned the technical feasibility of the proposed requirement that all gas that reaches the surface during well completion and post completion, drilling fluid recovery, or fracturing or refracturing must be captured and sold, flared, used on-site, or injected. These commenters contended that gas releases during these stages of development, especially immediately following drilling, may involve small quantities, or gas with low BTU or high contaminant concentrations. As a result, the commenters stated, the compliance options in the proposed rule are cost prohibitive and not technically feasible. They further argued that capturing low quantities of gas requires significant compression capacity to enter a sales line, that gas that does not meet pipeline specifications for sales is unlikely to burn (without makeup gas) or be appropriate for

beneficial use, and that reinjection of small volumes produced for a limited time is cost prohibitive.

In response to these comments, the final rule includes an exemption from the requirements for handling gas from a well completion when it is technically infeasible to use or dispose of the gas using any of the four identified options. Commenters also asserted that under the proposed rule, absent an exemption, if using any of the four identified compliance options was technically infeasible, the operator would have been forced to abandon the well. While we do not believe that the requirements for well completions are likely to impose such costs as to cause an operator to abandon the lease, the final rule also includes an exemption from § 3179.102(a) when the operator can demonstrate that compliance would cause the operator to cease production and abandon significant recoverable oil reserves under the lease due to the cost of compliance.

The BLM also received comments asserting that it lacks the authority to require that gas reaching the surface during well completions be flared if not captured, used on the lease, or injected. Commenters argued that such a requirement does not fall within the BLM's MLA authority because it is not waste prevention—i.e., the gas is lost whether it is vented or flared. These commenters then argued that the only possible justification for the requirement was control of GHGs and other air pollutants, which commenters assert is exclusively within the EPA's domain.

The BLM disagrees with these comments for several reasons. First, the requirement in this section to flare rather than vent constitutes waste prevention because (a) all flaring covered by this section and § 3179.103 is subject to a volumetric royalty-free flaring limit of 20 MMcf/well; and (b) flared gas from well completions that exceeds

this volumetric limit is treated as avoidably lost gas subject to royalties under § 3179.4(a)(1)(B). This royalty trigger provides an incentive for operators to stay under the 20 MMcf/well flaring limit—and thus to limit their waste. Second, as discussed in connection with § 3179.6, a requirement to flare rather than vent associated gas is a safety measure under the MLA. It is generally safer to combust methane gas than to allow it to vent uncombusted into the surrounding air due to concerns over methane’s explosiveness and the risk of hypoxia and exposure to various associated pollutants. In addition, also as discussed in connection with § 3179.6, the BLM has the authority to regulate air quality and GHG impacts on and from public lands pursuant to FLPMA and the MLA.

### **Section 3179.103 Initial production testing**

This section clarifies when gas may be flared royalty-free during a well’s initial production test. It provides that gas may be flared royalty-free during initial production testing until the first of the following events: (1) the operator determines that it has obtained adequate reservoir information for the well; (2) 30 days have elapsed; (3) 20 MMcf of gas have been flared (as measured in combination with volumes flared during well completion under section 3179.102); or (4) the beginning of well production. Under any of these scenarios, royalty-free flaring allowed by this section ends when production begins.

Paragraph (b) of this section allows the BLM to approve royalty-free flaring for up to an additional 60 days, if there are well or equipment problems or a need for additional testing to develop adequate reservoir information. Paragraph (d) allows a 90-day period for royalty-free flaring during dewatering and initial evaluation of an

exploratory coalbed methane well, and the BLM may approve up to two extensions of 90 days each. This approach recognizes that it generally takes substantially more than 30 days to dewater a coalbed methane well, but the time required can vary considerably between different coalbed methane resources. The operator is required to submit a Sundry Notice to BLM if it wishes to request a longer test period under paragraph (b) or (d) of this section.

In response to comments described below, the final rule includes a new provision in paragraph (c) of this section that allows the BLM to increase the 20 MMcf royalty-free flaring limit by up to an additional 30 MMcf of gas for exploratory wells in remote locations where additional testing is needed in advance of development of pipeline infrastructure. The operator is required submit a Sundry Notice to BLM if it wishes to request this higher limit.

Under any of these circumstances, notwithstanding an extension of the test period, the well will still be subject to the royalty-free flaring limit of 20 MMcf limit or, upon approval through a Sundry Notice, the higher limit specified in paragraph (c) of this section. Volumes vented or flared under this section must be reported to ONRR as directed in § 3179.9 of this subpart.

Several commenters argued that the proposed royalty-free flaring limit of 20 MMcf was too low, and that higher limits are needed due to higher production rates being achieved through advancements in hydraulic fracturing. They further requested that the rule state that the duration and maximum gas volumes for initial production testing do not include the duration of flowback operations and gas volumes produced during those operations. In response to these comments, the BLM added new paragraph (c) of this

section (discussed above), which allows the BLM to increase the 20 MMcf royalty-free flaring limit by up to an additional 30 MMcf of gas for exploratory wells in remote locations where additional testing is needed in advance of the development of pipeline infrastructure. While the BLM believes that for established fields, adequate testing to determine a well's production capacity can be conducted with no more than 20 MMcf of flared gas (including flaring from flowback operations), we recognize that a higher amount of flaring may be necessary for exploratory wells that are located in remote areas where no existing infrastructure exists. To the extent that an operator chooses to conduct additional testing beyond the royalty-free limits established in this section, the operator is free to do so, but the operator is responsible for paying royalties on the flared gas, rather than being able to shift the associated royalty losses to the public.

#### **Section 3179.104 Subsequent well tests**

The requirement in this section is essentially the same as NTL-4A's requirement regarding subsequent well tests. This section limits to 24 hours any royalty-free flaring during production tests conducted after the initial production test, unless the BLM approves or requires a longer test period. The operator must submit via Sundry Notice its request for a longer test period. Volumes vented or flared under this section must be reported to ONRR as directed in proposed § 3179.9 of this subpart. The BLM received few comments on this provision and made no substantive changes to this provision from the proposed to final rule.

#### **Section 3179.105 Emergencies**

This section allows operators to flare (or in some cases vent) royalty-free during an emergency, which is a temporary, infrequent, and unavoidable situation in which the

loss of gas is uncontrollable or necessary to avoid immediate and substantial adverse impacts to safety, public health, or the environment. Paragraph (a) further limits royalty-free emergency venting or flaring to a maximum of 24 hours per incident, unless the BLM agrees that the emergency conditions necessitate flaring—and possibly venting—for a longer period. In addition, paragraph (b) clarifies situations that do not constitute an emergency for purposes of royalty assessment, including: more than three failures of the same equipment within any 365-day period; failures from improperly sized, installed, or maintained equipment; failure to limit production when the production rate exceeds the capacity of related equipment or other infrastructure; scheduled maintenance; a situation caused by operator negligence; and when a lease, unit, or communitized area has already experienced three or more emergencies within the past 30 days, except when the BLM determines such emergencies were unanticipated and beyond the operator’s control. Volumes vented or flared under this proposed section must be reported to ONRR as directed in § 3179.9 of this subpart.

Based on a number of comments requesting additional clarification, the BLM has added a definition of “emergency” to the final text. Additionally, in response to comments stating that certain emergency situations may necessitate flaring beyond 24 hours, the final rule allows operators to flare or vent royalty-free beyond the 24-hour limit, but only when necessary and with BLM approval. While the BLM asserts that in most cases, 24 hours is a sufficient timeframe to address an emergency and/or make an appropriate business decision, we acknowledge that venting or flaring beyond 24 hours might be necessary in a limited number of cases, such as a natural disaster that prevents access to the site.

Some commenters asserted that the BLM was being too strict in limiting royalty-free flaring in emergencies to 3 emergencies in a 30-day period. BLM believes that after multiple incidents in a short timeframe, operators should identify and correct any maintenance or operational issues, and that repetitive, systemic events do not constitute an emergency situation. Commenters also recommended that the BLM remove the provisions listing improper installation and scheduled maintenance as events that do not constitute emergencies. The BLM did not revise the rule based on these comments, as scheduled maintenance is not an unanticipated disruption and improper installation can be avoided through good work practices.

The BLM notes that the provisions on downhole well maintenance in § 3179.204 cover well maintenance activities.

#### **Section 3179.201 Equipment requirements for pneumatic controllers**

This section addresses gas losses from pneumatic controllers. Paragraph (a) establishes that this section applies to pneumatic controllers that use natural gas produced from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or Indian lease, if the controllers (1) have a continuous bleed rate greater than 6 scf/hour (“high-bleed” controllers); and (2) are not covered by EPA regulations that prohibit the new use of high-bleed pneumatic controllers (40 CFR 60, subpart OOOO or subpart OOOOa), but would be subject to those regulations if the controllers were new, modified, or reconstructed sources.

Paragraph (b) of this section requires pneumatic controllers subject to the requirement to be replaced with controllers (including, but not limited to, continuous or intermittent pneumatic controllers) having a bleed rate of no more than 6 scf/hour, subject



to the exceptions described below. Paragraph (c) is discussed below, in connection with the exceptions. Under paragraph (d), operators are required to replace such controllers within 1 year from the effective date of the final rule, or within 3 years from the effective date of the rule if the well or facility served by the controller has an estimated remaining productive life of 3 years or less. Under paragraph (e), operators are also required to ensure that pneumatic controllers are functioning within the manufacturers' specifications.

This section provides several exceptions to the replacement requirement in paragraph (b). First, an operator is not required to replace a controller if a high-bleed controller is necessary to perform the needed function. For example, replacement might not be required if a low-bleed controller would not provide a timely response, which would lead to greater waste or create a safety hazard. To avail themselves of this exception, operators must submit a Sundry Notice to the BLM that describes the functional needs requiring the use of higher-bleed controllers. Second, replacement is not required if the controller was routed to a flare device or low-pressure combustor as of the effective date of this rule, and continues to be so-routed. Third, an operator is not required to replace its pneumatic controller if it chooses to route the pneumatic controller exhaust to processing equipment for capture and sale. Fourth, an operator may be exempted from the replacement requirement if it demonstrates through a Sundry Notice (described in paragraph (c)), and the BLM concurs, that replacing the pneumatic controllers on the lease would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

In response to comments and to further clarify the section, the BLM made the following four changes to the proposed rule requirements: (1) clarified that a pneumatic controller is subject to this section if it is not subject to 40 CFR part 60, subparts OOOO or OOOOa, but would be subject to either of those subparts if it were a new, modified, or reconstructed source; (2) clarified that the operator may replace a high-bleed pneumatic controller with a continuous pneumatic controller, an intermittent pneumatic controller, or a non-pneumatic device, as long as the replacement has a bleed rate no greater than 6 scf per hour; (3) clarified that an operator may be exempted from replacement if it was routing the controller exhaust to a flare or a low-pressure combustor device at the time the rule was effective, so long as the operator continues to do so; (4) allowed an operator to be exempted from replacement if it routes the controller exhaust to processing equipment; and (5) included in paragraph (c) the information that must be included in the Sundry Notice to demonstrate that the costs of replacing a pneumatic controller would cause the operator to cease production and abandon significant recoverable oil reserves.

Several commenters requested that the final rule clarify perceived conflicting regulatory coverage between the proposed rule and the EPA's subparts OOOO and OOOOa. Based on these comments, we revised § 3179.201(a)(2) to further qualify that a pneumatic controller is subject to this section if it "[i]s not subject to any of the requirements of 40 CFR part 60, subpart OOOO or subpart OOOOa, but would be subject to one of those subparts if it were a new, modified, or reconstructed source." This change ensures that the BLM requirements do not inadvertently apply to existing equipment that would not be covered by the EPA requirements. We believe this change properly

conveys our original intent to cover the same types of pneumatic controllers that EPA rules cover.

Some commenters stated that pneumatic controller exhaust should be allowed to be routed to processing equipment, such as a vapor recovery unit, on-site fuel line, or a control device (in addition to a flare), noting that Wyoming's recent regulation for existing pneumatic controllers in the Upper Green River Basin allow operators this flexibility. The BLM agrees with these comments and as stated previously, revised the rule to state that operators may route the pump to processing equipment. However, the final rule clarifies that with respect to routing pneumatic controller exhaust to a flare or low-pressure combustor, an operator may only be exempted from replacement of the controller if it is already routing such exhaust in this manner as of the effective date of the rule, and continues to do so. The BLM believes that given the low cost and high return on pneumatic controller replacement, spending capital to route controller exhaust to a flare or low-pressure combustor is unlikely to make sense from an economic, practical and waste prevention perspective.

Some commenters stated that the BLM should require the use of zero-bleed devices on leases where on-site electrical grid power is used, or that the BLM should require bleed gas to be routed to a flare or other control device. The final rule does not require the use of zero-bleed pneumatic controllers. Many sites using pneumatic controllers are not connected to the electric grid, and the BLM believes that requiring operators to route gas from pneumatic controllers would impose considerable costs on them and involve technical complications which could impact the cost effectiveness of the replacement requirement. The BLM did clarify in the final rule that operators using

pneumatic controllers that have a bleed rate greater than 6 scf per hour have the option to route the exhaust to processing equipment rather than replace the controller.

Many commenters stated that one year is insufficient to replace high-bleed pneumatic controllers and requested that requirements be extended to two or three years. The BLM believes that one year is a sufficient time period for operators to replace high-bleed pneumatic controllers, given the relatively low cost and rapid pay-back period of these replacements, as discussed in section V. Discussion of the Proposed Rule of the preamble to the proposed rule. In addition, as included in the proposed rule, if the well or facility that the pneumatic controller serves has an estimated remaining productive life of three years or less from the effective date of the rule, the operator has three years from the effective date of the rule to replace the pneumatic controller, provided that the operator notifies the BLM through a Sundry Notice.

Several commenters argued that operators should not have to submit a Sundry Notice and wait for BLM approval, if they meet one of the exemptions to the requirements. These commenters also asserted that the requirement for submission of a Sundry Notice (and hence, they assumed, BLM approval) set a higher standard for retaining a high-bleed controller based on functional need than the requirements in 40 CFR Part 60, subpart OOOOa, under which they claimed EPA only requires recordkeeping to document why a high bleed pneumatic controller is needed.

As provided in the proposed rule, operators seeking exemptions based on a functional need for the equipment need only notify the BLM of that need and do not have to get the BLM's approval. Further, if the exhaust from the pneumatic controller was already being routed to a flare or other control device on the effective date of the rule, or

if the operator chooses to route the exhaust to processing equipment, no notice is required. The BLM only requires a Sundry Notice and approval for exemptions based on the cost of replacing the equipment.

The BLM also received comments asserting that it lacks the authority to require operators who opt not to install low-bleed pneumatic controllers to route their existing pneumatic controllers to a flare device (rather than venting). Commenters argued that such a requirement does not fall within the BLM's MLA authority because it is not waste prevention-- i.e., the gas is lost whether it is vented or flared. These commenters then argued that the only possible justification for the requirement was control of GHGs and other air pollutants, which commenters assert is exclusively within the EPA's domain.

The BLM disagrees with these comments. The final rule does not require flaring in lieu of venting as a means of compliance with this section. The primary means of compliance is replacement with a low-bleed pneumatic controller, which prevents waste by reducing the amount of gas diverted to the pneumatic controllers—which, in turn, makes more gas available for capture. An operator is exempted from this requirement if a high-bleed pneumatic controller is required based on functional needs, if the operator directs its controller exhaust to processing equipment for capture, or if the operator is *already* directing the exhaust from the controller to a flare (or low-pressure combustor). The rule therefore imposes no new or additional flaring requirements.

### **Section 3179.202 Requirements for pneumatic diaphragm pumps**

This section establishes requirements for operators with pneumatic diaphragm pumps that use natural gas produced from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or Indian lease. It applies to such pumps if

they are not covered under EPA regulations at 40 CFR part 60, subpart OOOOa, but would be subject to that subpart if they were a new, modified, or reconstructed source. It does not apply to pneumatic diaphragm pumps that vent exhaust gas to the atmosphere or that operated fewer than 90 days in the prior calendar year (as documented in a Sundry Notice).

For covered pneumatic pumps, this section requires that the operator either replace the pump with a zero-emissions pump or route the pump exhaust to processing equipment for capture and sale. Alternatively, an operator may route the exhaust to a flare or low pressure combustion device if the operator makes a determination (and notifies the BLM through a Sundry Notice) that replacing the pneumatic diaphragm pump with a zero-emissions pump or capturing the pump exhaust is not viable because (1) a pneumatic pump is necessary to perform the function required, and (2) capturing the exhaust is technically infeasible or unduly costly. If an operator makes this determination and has no flare or low-pressure combustor on-site, or routing to such a device would be technically infeasible, the operator is not required to route the exhaust to a flare or low-pressure combustion device. Further, an operator that is required to replace a pump or route the exhaust gas from a pump either for capture or to a flare or combustion device may be exempt from the requirement if the operator demonstrates through a Sundry Notice, and the BLM concurs, that the cost would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

Operators must comply with these requirements no later than one year after the effective date of the rule. In addition, similar to the requirements for pneumatic

controllers and based on the same rationale, this section provides that if the estimated remaining productive life of the well or facility is three years or less, the operator is allowed to notify BLM through a Sundry Notice and replace the pneumatic pump no later than three years from the effective date of this section, rather than within one year. The section also requires that pneumatic pumps function within manufacturers' specifications.

The final rule makes five changes to the proposed rule requirements. First, it restructures the requirements as discussed above to require that operators either replace pneumatic diaphragm pumps with zero emission pumps or capture the exhaust for sale. As explained above, the operator may route the exhaust to a flare or low pressure combustor device if it makes a determination that replacing the pump with a zero-emissions pump is not viable because (a) a pneumatic pump is necessary to perform the function required, and (b) capturing the pneumatic pump exhaust is technically infeasible or unduly costly. If an operator makes this determination and has no flare or low pressure combustor on-site (or flaring to such a device would be technically infeasible), the operator is not required to route the exhaust to a flare or low pressure combustion device. Second, in response to comments and as discussed below, the final rule removes chemical injection pumps from inclusion in this section. Third, it adds paragraph (b) stating that an operator is not required to replace a pump if the pump does not vent exhaust gas to the atmosphere (e.g., already is routed to a flare or to capture equipment) or if the operator submits a Sundry Notice to the BLM documenting that the pump(s) operated fewer than 90 individual days in the prior calendar year. Fourth, the final rule clarifies that a pneumatic diaphragm pump is subject to this section if it is not subject to any of the requirements of 40 CFR part 60, subpart OOOOa, but would be subject to that

subpart if it were a new, modified, or reconstructed source. Fifth, it adds paragraph (d), which includes information that must be included in the Sundry Notice specified in § 3179.202(f).

Some commenters suggested that the BLM require the use of zero-bleed pumps in all cases except where technically infeasible, while other commenters stated that routing pump exhaust to a flare offers no product recovery potential and does not minimize loss or waste. The BLM agrees that the installation of zero-bleed pumps is technically feasible in many cases. In response to these comments, and to require operators to employ waste minimization practices when feasible, the final rule is restructured to require operators, when feasible, to install zero-bleed pumps or route the pump exhaust to process equipment for capture and sale. However, in making this revision, the BLM does not intend to require operators to replace pumps that are already routed to flare or capture equipment (i.e., pumps that do not currently vent exhaust gas to the atmosphere), and we have added clarifying language to avoid this result. As discussed below, the compliance mechanisms in this section are structured to encourage the prevention of waste.

Some commenters stated that chemical injection and temporary use pumps should be exempt because they have low aggregate emissions and operate intermittently. The BLM agrees that chemical injection pumps release substantially lower quantities of gas than diaphragm pumps. The BLM also recognizes that some diaphragm pumps are used very intermittently or only for a short portions of the year, and that low usages result in low quantities of lost gas. In the final rule, the BLM has specified that the rule does not apply to chemical injection pumps or to diaphragm pumps that operated fewer than 90 individual days in the prior calendar year. This change also aligns the requirements of



this section with the requirements for pneumatic pumps under 40 CFR part 60 subpart OOOOa.

Several commenters requested that the final rule clarify perceived conflicting regulatory coverage between the proposed rule and 40 CFR part 60 subpart OOOOa. In addition to the change to chemical injection pumps, we revised § 3179.202(a)(2) to further qualify that a pneumatic diaphragm pump is subject to this section if it “[i]s not subject to any of the requirements of 40 CFR part 60, subpart OOOOa, but would be subject to that subpart if it were a new or modified source.” This change ensures that the BLM requirements do not inadvertently apply to existing equipment that would have been exempted under the EPA requirements. We believe this change properly conveys our original intent to cover the same types of pneumatic pumps that EPA rules cover.

Similar to comments received on pneumatic controllers, some commenters stated that pneumatic pumps should be allowed to be routed to processing equipment, such as a vapor recovery unit, on-site fuel line, or a control device (in addition to a flare). The BLM agrees with these comments and revised the rule to state that operators may route the pneumatic pump exhaust to processing equipment for capture and sale, or, under certain conditions described above, to either a low-pressure combustor device or a flare.

Several commenters stated that 1 year is insufficient to replace covered pneumatic pumps and requested that the replacement requirements be extended to 3 years. The BLM believes that one year is a sufficient time period for operators to replace pneumatic diaphragm pumps, or route them to a flare that is already installed on-site, given the relatively low cost and rapid pay-back period of these replacements, as discussed in the preamble to the proposed rule, and the relatively low cost of connecting a pump to a pre-

existing on-site flare. Moreover, because the BLM is not including chemical injection pumps in this final rule, operators will need to address far fewer pneumatic pumps than the proposed rule would have required. In addition, as included in the proposed rule, if a well or facility that the pneumatic pump serves has an estimated remaining productive life of three years or less from the effective date of the rule, the operator has three years from the effective date of the rule to complete the replacement, provided that notification is filed through a Sundry Notice.

The BLM also received comments asserting that it lacks the authority to require operators who opt not to install zero-emission pneumatic pumps to route their existing pneumatic pumps to a flare device (rather than venting). Commenters argued that such a requirement does not fall within the BLM's MLA authority because it is not waste prevention—i.e., the gas is lost whether it is vented or flared. These commenters then argued that the only possible justification for the requirement was control of GHGs and other air pollutants, which commenters assert is exclusively within the EPA's domain.

The BLM disagrees with these comments for several reasons. First, the requirement in this section to flare rather than vent associated gas constitutes waste prevention. Requiring operators to (at minimum) direct associated gas that bleeds from their pneumatic pumps to a flare device eliminates the lowest cost method of handling such gas (that is, venting). This, in turn, provides a greater incentive for operators to upgrade to a zero-emission pneumatic pump or capture pump exhaust gas. Upgrading to a zero-emission pneumatic pump prevents waste by reducing the amount of gas diverted to the pneumatic pumps—which, in turn, directs more gas to either a capture line or the

high-pressure flare. If an operator chooses to capture, upgrading the pneumatic pump will directly prevent waste by causing more gas to be sold.

Second, as discussed in connection with § 3179.6, a requirement to flare rather than vent associated gas is a safety measure under the MLA. It is generally safer to combust methane gas than to allow it to vent uncombusted into the surrounding air due to concerns over methane's explosiveness and the risk of hypoxia and exposure to various associated pollutants. In addition, also as discussed in connection with § 3179.6, the BLM has the authority to regulate air quality and GHG impacts on and from public lands pursuant to FLPMA and the MLA.

Some commenters raised concerns about differences between the proposed BLM and EPA requirements for pneumatic pumps, asserting that the BLM proposed rules are different and more stringent. First, they asserted that the EPA rule limits "affected facilities" to sites with a control device already on-site, while the proposed BLM requirements would apply to pneumatic pumps regardless of whether a control device is present. Second, commenters asserted that the EPA rule only requires operators to route pump emissions to a control device if one already exists on site, while the BLM proposed rule may require replacement with a zero emission pump in such a circumstance.

Some of these concerns were addressed by the EPA's final subpart OOOOa regulations, while other differences are appropriate given the different authorizing statutes and primary foci of the two sets of regulations. As an initial matter, the BLM requirements apply only to pumps that are not subject to subparts OOOO or OOOOa (but would be if the pump was new, modified, or reconstructed), so no pump will be subject to both regulations.

With regard to the first issue described above, the final BLM and EPA rules apply to the same types of pneumatic pumps. In its final rule, EPA noted that there was some confusion regarding the proposed definition of affected facility, and stated that it had modified the regulatory text to clarify that “all natural gas-driven diaphragm pumps at natural gas processing plants or well sites are affected facilities, except for pumps at well sites that operate less than 90 days per calendar year.”<sup>145</sup> The final subpart OOOOa text requires operators to maintain records on the control status of all pneumatic pump affected facilities and to include them all in the operators’ annual reports. The final BLM rule aligns with the scope and requirements of the final EPA rule in these respects.

With regard to the second issue, the BLM final rule does apply somewhat different requirements to pumps covered by the BLM rule as compared to pumps covered by the EPA rule, due to differences between the two agencies’ legal authorities. The legal authority for subpart OOOOa is section 111 of the Clean Air Act, which requires the EPA to set standards of performance for new sources and requires a “standard of performance” to be based on the best system of emission reduction (BSER) “adequately demonstrated.”<sup>146</sup> As noted in the proposed subpart OOOOa preamble, the EPA did not require zero emissions pumps at facilities other than gas processing plants because the availability of consistent, reliable electrical power at all affected facilities could not be reasonably assumed.<sup>147</sup> The BLM, however, has flexibility to require waste reduction measures at any site where such measures would work, without specifically defining such sites, even if the measures may not be available at all sites. Zero emission pumps are feasible where solar power is adequate to power the pump for its intended function and at

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<sup>145</sup> 81 FR 35851.

<sup>146</sup> 81 FR 35884.

<sup>147</sup> 80 FR 56625.

sites where other sources of electric power are available. Where they are feasible, our analysis indicates that the cost of replacing a gas-driven pneumatic pump with a zero emission pump is modest and would be at least partially offset by the value of the saved gas.

Additionally, the BLM final rule establishes a preference for operators who do not replace their pumps with a zero-emissions pump to route exhaust gas to capture in lieu of routing to a flare. This emphasis on either replacement or capture is a function of the BLM's waste prevention focus. Thus, unlike subpart OOOOa, the final BLM rule requires operators with a gas-driven pneumatic pump that is currently venting to the atmosphere to replace it with a zero emission pump, if a zero-emission pump would work at that site to perform the function required, or route the exhaust gas to capture. If a zero-emission pump is not viable at that site and routing the exhaust gas to capture is technically infeasible or unduly costly, however, then the operator must comply with a requirement that tracks the requirement under subpart OOOOa—the operator must route the exhaust gas from the pneumatic pump to a flare, if there is already a flare on-site. While the BLM rule establishes an additional requirement on operators, it does not conflict in any way with the EPA rule or increase an operator's burden to comply with both rules. Any pump that is already routed to a flare in compliance with the EPA rule will also be in compliance with the BLM rule. For pumps without a flare on-site, the EPA rule requires no further action, while the BLM rule requires replacement or routing to capture, absent the listed conditions.

The third potential difference that commenters highlighted between the BLM and EPA requirements for pneumatic pumps is the level of documentation required to show

that routing to a flare is technically infeasible. To clarify a possible misunderstanding by the commenters, a requirement to notify the BLM through a Sundry Notice, as specified in this section, is not a requirement to obtain approval from the BLM. Sundry Notices may be used simply for notification purposes, or to obtain approval from the BLM for an action. The final rule specifies the purpose of each requirement to file a Sundry Notice.

Here, the BLM final rule requires an operator to notify the BLM through a Sundry Notice if the operator is not replacing the pump for one of the reasons specified. The operator must also notify the BLM if the operator is not routing the pump to a flare because there is no flare on site or routing to a flare would be technically infeasible. Subpart OOOOa establishes requirements for an engineering evaluation of whether routing to a flare would be technically infeasible, requires the evaluation and determination of technical infeasibility to be certified by a qualified professional engineer, and requires this information to be included in the operator's annual report. Thus, while the specific documentation requirements for pumps covered by the BLM requirements differ from those established by the EPA, both rules require the operator, under specified circumstances, to either route the pump exhaust to a flare or notify the respective agency that the pump meets the criteria for an exemption. The BLM notification requirements are less specific than the EPA requirements, which the BLM believes will make compliance less burdensome for an operator.

### **Section 3179.203 Storage vessels**

This section addresses gas vented from crude oil, condensate, intermediate hydrocarbon liquid, or produced water storage vessels that contain production from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or

Indian lease, and are not subject to 40 CFR part 60, subparts OOOO or OOOOa, but would be if they were new, modified, or reconstructed sources. If such storage vessels have the potential for VOC emissions equal to or greater than 6 tpy, the final rule requires operators to route all gas vapor from the vessels to a sales line. Alternatively, the operator may route the vapor to a combustion device if it determines that routing the vapor to a sales line is technically infeasible or unduly costly. The operator also may submit a Sundry Notice to the BLM that demonstrates that compliance with the above options would cause the operator to cease production and abandon significant recoverable oil reserves under the lease due to the cost of compliance. Operators must meet this requirement no later than one year after the rule becomes effective, or three years after the rule becomes effective if the operator needs to replace the storage vessel in order to comply.

Operators must determine the rate of VOC emissions from the storage vessel within 60 days after this rule is effective, and within 30 days after adding a new source of production to a storage vessel. This determination is based on the maximum average daily throughput for a 30-day period of production, and may take into account any legally and practically enforceable limits in an operating permit or other requirements applicable to the storage vessel. This section no longer applies to a storage vessel whose total uncontrolled VOC emissions rate declines to 4 tpy in the absence of controls for 12 consecutive months.

In response to comments, the BLM has made the following changes to the requirements in the proposed rule: (1) clarified the exemption for sources subject to 40 CFR part 60, subparts OOOO or OOOOa; (2) extended the initial compliance period

from 6 months to 1 year; (3) added a 3-year initial compliance period for operators that must replace storage vessels to comply with the requirements; (4) required gas to be routed to a sales line when that option is neither technically infeasible nor unduly costly, as determined by the operator; (5) added a requirement that operators must determine whether the storage vessel has the potential for VOC emissions equal to or greater than 6 tpy based on the maximum average daily throughput for a 30-day period of production, which may take into account legally and practically enforceable limits applicable to the storage vessel; (6) added a requirement that storage vessels subject to the final rule must be adequately sized to accommodate the operator's production levels and equipped to meet any applicable regulatory requirements for tank vapors; and (7) added a requirement that storage vessels subject to the final rule may only vent through properly functioning pressure relief devices. Each change is discussed below along with a summary of the relevant comments and responses.

Several commenters expressed concerns about differences between the types of new storage vessels that are subject to subparts OOOO or OOOOa and the types of existing storage vessels that would have been subject to the proposed rule. The BLM agrees that applying the requirements of this section, as proposed, to storage vessels "not subject to 40 CFR part 60, subparts OOOO or OOOOa" could encompass storage vessels that neither the EPA nor the BLM intended to cover. In the final rule, § 3179.203(a)(2) covers a storage vessel if it "[i]s not subject to any of the requirements of 40 CFR part 60, subparts OOOO or OOOOa, but would be subject to that subpart if it were a new, modified, or reconstructed source."



Several commenters argued that the proposed initial period of 6 months to comply with the emission reduction provisions was too short. Commenters stated that it would take longer than 6 months to complete engineering studies of existing storage vessels; design, order and construct the control device; and then install the control device. Commenters recommended various time periods ranging from 1 to 3 years. We believe a 1-year initial compliance period is adequate to perform the tasks necessary to install a control device, and we have modified §3179.203(c) accordingly.

Commenters also stated that in some cases they would likely have to replace an existing tank in order to meet the emission limitations. In such cases, commenters stated that even more time would be needed to obtain capital funding approval and purchase the new storage vessel. In response, we further amended § 3179.203(c) to provide a 3-year initial compliance period when the operator must replace a storage vessel in order to comply with the rule requirements.

In the proposed rule, § 3179.203(c) allowed the operator to choose between routing emissions from storage vessels subject to the rule to a combustion control device, a continuous flare, or a sales line. Some commenters opposed these provisions because they believe BLM should focus on preventing loss of natural resources. The BLM agrees that this rule should focus on gas capture and use whenever possible, and in the final rule, §3179.203(c) first requires the operator to route tank vapor gas from a storage vessel to a sales line. If the operator determines that routing the emissions to the sales line is technically infeasible or unduly costly, the operator may route the gas to a combustion device.

We also received numerous comments requesting that we align the final rule as much as possible with the requirements finalized by the EPA in subparts OOOO and OOOOa. As stated in the preamble to the proposed rule, the BLM and the EPA understand that aligning our requirements to the extent possible, provides common standards that ease implementation and reduce confusion for both the regulated industry and regulatory agencies.<sup>148</sup> Several small changes in the final rule help clarify the rule and better align it with the final requirements in subparts OOOO and OOOOa. In § 3179.203(b), the rule provides additional guidance to operators on how to make the threshold determination that a storage vessel has the potential for VOC emissions equal to or greater than 6 tpy. Changes to the definition of “storage vessel” in § 3179.3 also synchronize the coverage between the two sets of rules, such that these provisions cover the same types of storage vessels that would be covered by subparts OOOO or OOOOa if they were new, modified, or reconstructed.

One commenter suggested that the BLM make it clear that venting from access points or pressure relief devices during normal operation is prohibited. The commenter stated that to account for those instances where venting may be necessary, the BLM could adopt the approach taken by Colorado by specifying those instances where venting is reasonably required, such as for “maintenance, gauging or safety of personnel and equipment.” The commenter also recommended that the BLM add a requirement that operators certify that their storage tank facilities are adequately sized in order to capture, convey, and control emissions. They stated that this is required in Colorado and is a direct response to the Air Pollution Control Division and EPA investigations that revealed significant leaks and venting from controlled facilities.

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<sup>148</sup> See, e.g., 81 FR 6647.

In response to this comment, final rule § 3179.203(f) provides that storage vessels subject to this section must be adequately sized to accommodate production levels and equipped to meet any applicable regulatory requirements for emissions. Also, §3179.203(g) requires that storage vessels subject to this section may only vent through properly functioning pressure relief devices. We believe both of these provisions embody good engineering practices and should be common practice when operating a storage vessel.

The BLM also received comments asserting that it lacks the authority to require operators who opt not to capture tank vapor gas to route such gas to a flare device (rather than venting). Commenters argued that such a requirement does not fall within the BLM's MLA authority because it is not waste prevention—i.e., the gas is lost whether it is vented or flared. These commenters then argued that the only possible justification for the requirement was control of GHGs and other air pollutants, which commenters assert is exclusively within the EPA's domain.

The BLM disagrees with these comments for several reasons. First, the requirement in this section to flare rather than vent tank vapor gas constitutes waste prevention. Requiring operators to (at minimum) direct tank vapor gas to a flare device eliminates the lowest cost method of handling such gas (i.e., venting), and thereby provides a higher baseline for operators to calculate whether it would be economical to install a VRU to capture the tank vapor gas for sale. The BLM anticipates that this higher baseline may encourage more operators to install VRUs.

Second, as discussed in connection with § 3179.6, a requirement to flare rather than vent associated gas is a safety measure under the MLA. It is generally safer to

combust methane gas than to allow it to vent uncombusted into the surrounding air due to concerns over methane's explosiveness and the risk of exposure to various associated pollutants. In addition, also as discussed in connection with § 3179.6, the BLM has the authority to regulate air quality and GHG impacts on and from public lands pursuant to FLPMA and the MLA.

Some commenters requested that the BLM require storage vessel vapors to be combusted at an efficiency of 98%. Storage vessel vapors can be combusted at an efficiency of 98% using an enclosed combustor. However, the BLM has determined that requiring the operator to install an enclosed combustor on a location with an existing flaring system would be relatively costly compared to the benefit of modestly higher combustion efficiency applied to a comparatively small volume of vapor coming from storage vessels flares. The BLM believes that in those instances where storage vessel vapors must be controlled on a site that does not have an existing flare system, the operator will likely elect to install an enclosed combustor rather than a flare, because it will more effectively combust the lower volumes of vapor associated with storage vessels.

#### **Section 3179.204 Downhole well maintenance and liquids unloading**

This section establishes requirements for venting and flaring during downhole well maintenance and liquids unloading. It requires the operator to use practices for such operations that minimize vented gas and the need for well venting, unless the practices are necessary for safety. The rule also requires that for wells equipped with a plunger lift system or an automated well control system, the operator must optimize the operation of the system to minimize gas losses.

For all wells, before the operator manually purges a well for the first time after the effective date of this section, the operator must document in a Sundry Notice that other methods for liquids unloading are technically infeasible or unduly costly. In addition, during any liquids unloading by manual well purging, the person conducting the well purging is required to be present on-site to minimize to the maximum extent practicable any venting to the atmosphere. This section also requires the operator to maintain records of the cause, date, time, duration and estimated volume of each venting event associated with manual well purging, and to make those records available to the BLM upon request.

The operator must notify the BLM by Sundry Notice within 30 days after the first liquids unloading by manual or automated well purging after the effective date of the rule. Additionally, operators must notify the BLM by Sundry Notice within 30 days after the following conditions are met: (1) the cumulative duration of manual well purging events for a well exceeds 24 hours during any production month; or (2) the estimated volume of gas vented in the process of conducting liquids unloading by manual well purging for a well exceeds 75 Mcf during any production month. The final rule also defines “well purging” for purposes of this section and requires operators to report to ONRR gas volumes vented during manual and automated downhole maintenance and liquids unloading, including through the operation of plunger lifts.

In response to comments on the proposed rule, we removed the proposed prohibition on well purging for wells drilled after the effective date of this section, as discussed in above in section III.D.3., and made several smaller changes in the final rule: (1) removing the proposed requirement to flare unrecovered gas during downhole well maintenance and liquids unloading operations; (2) clarifying recordkeeping and reporting

requirements and increased the length of time operators have to submit reports; and (3) revising the definition of “well purging.”

The BLM is aware, and many commenters observed, that flares are not always feasible control options for downhole well maintenance and liquids unloading activities, and we recognize that there may be difficulties separating liquids from the purged gases. For these reasons, we proposed the use of flares where other recovery or gas loss reduction technologies cannot be used, and only then when flaring is not technically infeasible or unduly costly (see proposed §3179.204(a)). Although we attempted in the proposed rule to narrow the use of flares to situations in which they are more likely to be feasible, and provided an option for operators to document those situations where flaring is infeasible, commenters raised several concerns related to safety, cost and feasibility. Upon further review of the information provided by the commenters, we believe there is uncertainty in the ability of operators to be able to consistently and safely operate a flare during these operations.

For these reasons, we did not finalize the proposed flaring requirement. Instead, the final rule requires operators to minimize vented gas during downhole well maintenance and liquids unloading operations, and it specifies best management practices that operators must follow. For wells equipped with a plunger lift system or an automated well control system, these practices include optimizing the operation of the system to minimize gas losses.

Proposed § 3179.204(a) would have required the operator to use best practices to maximize the recovery of gas from downhole well maintenance and liquids unloading operations. Commenters expressed concern that the word “maximize” could be construed

to imply that the operator must use the technology that provides the absolute highest amount of gas recovery, regardless of other concerns. This is not our intent, as evidenced by our discussion of the proposed requirements in the preamble to the proposed rule. For example, we discuss that some technologies are less costly than others, and that some technologies make more sense to install early in the life of a well rather than later. We also state that we expect most new wells to use plunger lifts, and that the proposed rule would not require (though it would encourage) the use of automated systems.<sup>149</sup> We expect the operator to make an informed and reasoned decision on which technology makes the most sense for each well based on the conditions and economics of the well. To further clarify this, rather than requiring operators to maximize recovery of gas, the final rule requires operators to minimize vented gas and the need for well venting associated with downhole well maintenance and liquids unloading operations.

Several commenters objected to the extent and content of the proposed recordkeeping requirements, but did not identify changes that could be made without compromising the information needed for effective implementation of the rule. The BLM believes the recordkeeping and reporting requirements are essential to verify compliance and to more accurately assess the amount of gas lost through liquids unloading events, including for the purposes of royalty calculations. In response to commenters' concerns, however, the final rule extends the time to submit a Sundry Notice of large quantity liquids unloading events from 14 days to 30 days, to allow operators more time to gather information. Similarly, we have extended the time to submit a Sundry Notice after the first liquids unloading event from 10 days to 30 days.

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<sup>149</sup> 81 FR 6655-6656.

Some commenters contended that recordkeeping and reporting requirements related to each well purging event are unnecessary, but the BLM does not agree. Large quantities of gas are lost through well purging that cannot be used to supply the country's energy needs and provide no royalty revenues to taxpayers. Building a historical record of the amount of gas lost is key to determining proper management of these events in the future. For example, more accurate knowledge of the amount of gas lost to well purging events will allow operators to make better-informed decisions on the financial viability of each liquids unloading technology. Also, the BLM will be able to better estimate the cost of lost royalties associated with vented gas from well purging activities. We believe these important benefits justify the expenditures related to obtaining and reporting the required records.

A number of commenters asserted that BLM should withdraw the proposed downhole well maintenance and liquids unloading provisions of the rule because of the complexity of the issue. They argued that the BLM does not understand the impacts of the proposed requirements. In particular, they noted EPA's decision not to regulate liquids unloading.

The BLM has engaged numerous stakeholders throughout the rulemaking process to better inform its final rule decisions, and has coordinated closely with the EPA in sharing technical information and expertise.<sup>150</sup> This is an area where differences between the two agencies' approaches stem in large part from their different statutory authorities. As noted above in connection with § 3179.202, the legal authority for 40 CFR part 60 subpart OOOOa is section 111 of the Clean Air Act, which requires the EPA to set a

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<sup>150</sup> 81 FR 6617-6618.



standard of performance for new sources and defines a “standard of performance” as to be based on the best system of emission reduction (BSER) “adequately demonstrated.”<sup>151</sup>

In explaining its decision not to regulate liquids unloading at this time, the EPA stated that although it had received valuable information from the public on technologies to reduce emissions, “the information was not sufficient to finalize a national standard representing BSER for liquids unloading.”<sup>152</sup> The BLM, however, has the flexibility to require a suite of best management practices to achieve waste reduction, as we have done here, rather than being required to identify the best system of emission reduction under the specific criteria in section 111 of the Clean Air Act.

### **Section 3179.301 Operator responsibility**

This section establishes that the LDAR requirements in §§ 3179.301 through 3179.305 of this subpart apply to oil or natural gas wells and all equipment associated with the well sites that produce, process, compress, treat, store, or measure natural gas from a Federal or Indian lease, or from a unit or communitized area, where the site is upstream of or contains the approved point of royalty measurement. These sections also apply to a site and all equipment operated by the operator and associated with a site that is used to store, measure, or dispose of produced water that is located on a Federal or Indian lease. The sections obligate operators to inspect all equipment that is used to produce, compress, treat, store, or measure natural gas or to store, measure or dispose of produced water for gas leaks from leak components, with the exception of wells and well equipment that have been depressurized, and sites that contain only a well head and no other equipment. The first inspection must occur within one year of the effective date of

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<sup>151</sup> 42 USC 7411(a)(1).

<sup>152</sup> 81 FR 35846.

the rule for sites that have begun production prior to the effective date. For production sites that begin production after the effective date, the first inspection must occur within 60 days of beginning production. For sites that were out of service and brought back into service, the first inspection must occur within 60 days of the date the site is brought back into service and re-pressurized. These sections do not apply to a site that contains a wellhead or wellheads and no other equipment, nor to a well or well equipment that has been depressurized.

Operators are required to conduct the inspections during production operations, and to fix any leaks found. Subsequent inspections must be conducted according to the schedule in § 3179.303. Operators may satisfy the requirements of §§ 3179.301 through 3179.305 for all of their equipment on a given lease by complying with the fugitive emissions requirements established under 40 CFR part 60, subpart OOOOa with respect to all equipment covered by the BLM leak detection requirements. This includes equipment such as covers and closed vent systems, and thief hatches and other openings on controlled storage vessels, which if new, modified or reconstructed, are subject to 40 CFR §§ 60.5411a or 60.5395a under OOOOa and not the fugitive emissions requirements under OOOOa. Specifically, the operator must treat each of its sites and equipment as if it were a collection of fugitive emissions components as defined in 40 CFR part 60 subpart OOOOa; comply with the requirements of 40 CFR part 60 subpart, OOOOa that apply to affected facility fugitive emissions components at a well site or compressor station, as applicable, under 40 CFR part 60, subpart OOOOa; and notify the BLM through a Sundry Notice of such compliance.

Several changes were made to this section in response to comments and to provide additional clarity. As discussed in Section V.B.2., § 3179.301(a) clarifies the specific sites and equipment subject to the leak inspection requirements, which apply to all equipment handling Federal or Indian gas, upstream of and including the site where the royalty measurement point is located—whether the equipment is on or off the lease and regardless of the ownership of the equipment. This section also specifies that the leak detection requirements apply to equipment handling produced water only if the equipment is operated by the operator and located on the Federal or Indian lease. The BLM added a provision to §3179.301(b) stating that the LDAR requirements do not apply to a well or well equipment that has been depressurized, nor to a site that contains a wellhead or wellheads and no other equipment. In § 3179.301(c), the BLM clarified that the operator must inspect for gas leaks from leak components. In conjunction with this change, we added definitions for “leak” and “leak component” in § 3179.3. We also moved the definition of “site” from §3179.303(a) to § 3179.301(e) and revised the definition for clarity.

Additionally, the BLM moved the requirement in proposed § 3179.303(c) that exempts leak components that are not accessible from the inspection and monitoring requirements to paragraph (d) of this section; added paragraph (f) to specify when the first inspection must take place; and replaced proposed paragraph (e) with new paragraph (j) to provide an exemption for sites and equipment that are in compliance with the fugitive emission requirements under 40 CFR part 60, subpart OOOOa.

This section of the preamble discusses additional comments on the LDAR provisions in § 3179.301, beyond the comments discussed in Section IV.A.d. The BLM

made changes to clarify the scope of LDAR coverage in the final rule in response to commenters who asserted that the proposed rule was not entirely clear on the scope of coverage. The final rule now explicitly describes the “sites” to which the LDAR provisions apply and no longer makes use of the term “facilities.” The proposed rule covered “facilities,” as well as compressors that were on lease and operated by the operator, regardless of whether they handled Federal or Indian product. “Facility” is defined in section 3170.3 to include a site and associated equipment used to process, treat, store, or measure production from a Federal or Indian lease, unit or communitized area, as well a site and associated equipment used to store, measure, or dispose of produced water. With respect to produced water, the definition of “facility” only includes sites on a Federal or Indian lease, unit or communitized area, but the definition is not similarly limited with respect to sites associated with Federal or Indian production. Using the term “facilities” to define the coverage of the LDAR program would create a distinction between equipment upstream and downstream of the approved point of royalties measurement on an otherwise covered site. In addition, the BLM has not retained in the final rule the proposed coverage for compressors that do not handle Federal or Indian product. Given the potential for confusion here, we believe that it is clearer to simply specify the sites and equipment subject to the LDAR requirements in the final rule, rather than use the term “facilities.”

With respect to the LDAR requirements in this rule, the BLM believes it is reasonable and appropriate to apply the requirements to all equipment at a site that is subject to these requirements. Once an operator is already on-site, inspecting additional equipment adds little cost and burden, particularly if the operator is using optical gas

imaging technology, and inspecting such equipment offers the same potential additional benefits as any other inspection. Thus, the BLM believes that requiring inspection of all of the equipment at a given site will make the rule more cost-effective in avoiding waste, as compared to exempting inspection of some equipment at a site that is already being inspected. Moreover, the BLM believes that applying the LDAR requirements to most but not all of the equipment at a single site would heighten the potential for inspection errors and confusion, and make administration and tracking of the results more difficult.

Commenters also urged the BLM to exclude from the LDAR requirements the following additional types of sites or equipment, beyond those discussed in Section IV.A.d.: wells that are shut-in at the time of an LDAR inspection; sites where there is only a small amount of mineral interest from or allocated to a Federal or Indian lease, unit, or communitization agreement; equipment operated by an entity other than the operator; sites with a legally and practically enforceable leak detection and repair requirement in an operating permit, or other enforceable requirement established under a Federal, State, local or tribal authority; and sites located on the North Slope of Alaska.

With respect to wells that are shut-in at the time an inspection occurs, coverage under LDAR depends on whether the shut-in is temporary, or the well or well equipment has been depressurized. Leaks will only be detectable when a well is operating, so the rule provides that leak inspections must occur during production operations. The BLM agrees that a well that has been depressurized is no longer in operation and should not leak, and the BLM has excluded such wells from the LDAR requirements. Depressurized wells that are brought back into service do not need to be inspected until 60 days after the date that the well is re-pressurized. A well that is temporarily shut-in but not

depressurized, however, may have significant leaks when it is brought back into production. Exempting such a well from any inspection obligations might provide an incentive for operators to schedule inspections during shut-ins to reduce the number of sites that would need to be inspected.

With respect to leases where the Federal or Indian mineral interest is a minority interest, the BLM has the authority and an obligation to minimize the waste of Federal and Indian mineral resources. The waste of Federal and Indian resources is of no less concern to the BLM when the Federal or Indian interest is a minority interest. Even a small percentage interest could still represent a significant volume of Federal or Indian resources, depending on the reservoir. Also, as a policy matter, the BLM believes that the LDAR requirements of this rule are cost-effective and provide net public benefits. Thus, the BLM does not believe that it is appropriate to arbitrarily limit the benefits of this rule based on the proportion of the Federal or Indian mineral interest at issue in the lease, unit, or communitized area. In the final rule, the BLM has clarified that where a site is upstream of or contains the royalty measurement point, the LDAR provisions cover the site and all equipment associated with it that handles Federal or Indian gas.

Similarly, neither legal nor policy considerations support exempting equipment operated by an entity other than the site operator. The operator is responsible for ensuring that operations conducted pursuant to a Federal or Indian lease are in compliance with the lease terms and applicable regulations.<sup>153</sup> Exempting equipment that is operated by an entity other than the operator could create an incentive for operators to establish contractual arrangements that avoid the LDAR requirements. The BLM

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<sup>153</sup> See *Luff Exploration Co.*, 115 IBLA 134 (1990) (upholding enforcement action against operator based on noncompliant equipment owned and operated by purchaser).

believes that through cooperation with contractors that own or operate equipment on the lease, the operator has the practical means of ensuring compliance with the LDAR requirements on lease, regardless of who owns the equipment.

The BLM recognizes that some equipment at the site containing the facility measurement point, such as storage vessels or compressors, may be downstream of the measurement point and may be in control of the purchaser rather than the operator.<sup>154</sup> Nevertheless, as discussed previously, the BLM believes that it is appropriate to require the operator to conduct LDAR on all equipment located at the site. Once the operator is inspecting a given site, particularly when using optical gas imaging, it will add minimal time and cost to inspect additional co-located equipment. It should be noted that, although a facility measurement point may be located on lands not covered by a Federal or Indian lease, unit, or communitization agreement (as might be the case when off-lease measurement occurs pursuant to applicable regulations in 43 C.F.R. subpart 3173), the LDAR requirements of this rule do not apply to sites that are not located on a Federal or Indian lease, unit or communitized area.

In addition, the BLM disagrees with the suggestion to create a blanket exemption from the LDAR requirements for sites with another legally and practically enforceable leak detection and repair requirement in an operating permit or other enforceable Federal, State, local or tribal requirement. The final rule already contains provisions to address overlapping EPA or State requirements, as discussed in sections III.B.3 VI.A. of this preamble. An operator with a specific program contained in its operating permit could, under section 3179.303(b) request approval of that program as an alternative to the BLM

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<sup>154</sup> The BLM's jurisdiction over Federal and Indian oil and gas production does not cease at the point of royalty measurement. *See* Wexpro Company, 174 IBLA 57 (2008) (requiring BLM to consider whether use of gas in operations downstream of the royalty measurement point constituted royalty-free "beneficial use").

requirements, provided the permit program is at least equally effective at detecting and reducing losses from leaks as the BLM requirements. By contrast, exempting any site with existing enforceable LDAR requirements provides no assurance that those requirements will produce results equivalent to the BLM requirement.

The BLM also declines to exclude automatically from the LDAR requirements sites that are located on the North Slope of Alaska. The BLM notes that one operator has argued that conditions on the North Slope make it impossible to meet all of the LDAR requirements, and that the operator has in place alternative practices, equipment, and techniques that reduce the likelihood of leaks and facilitate prompt detection of any that might occur. The final provision allowing the BLM to approve an operator's alternative instrument-based leak detection program is designed to address just this sort of situation.

Certain operators requested that facilities subject to the EPA subpart OOOOa fugitive emissions requirement be exempt from the BLM LDAR requirements. After review of these comments, the BLM agrees that those facilities should not have to comply with both the EPA subpart OOOOa program and a separate BLM LDAR program, and the final rule provides that an operator in compliance with the requirements of subpart OOOOa will be deemed in compliance with the BLM LDAR requirements as well. In addition, even though the BLM and the EPA have largely aligned their leak detection requirements, an operator might prefer to comply with the OOOOa requirements for all of its facilities on a lease, including existing facilities that are not covered by subpart OOOOa, rather than complying with subpart OOOOa for new, modified and reconstructed facilities and the BLM LDAR requirements for existing facilities. Thus, the final rule provides that an operator may satisfy the BLM LDAR



requirements by complying with the subpart OOOOa fugitive emission requirements for all sites and equipment on a given lease.

However, by providing that compliance with subpart OOOOa is deemed compliance with the BLM requirements, rather than simply exempting all facilities subject to subpart OOOOa, the BLM maintains enforcement authority if an operator is subject to both subpart OOOOa and the BLM requirements, but complies with neither. Under this approach, a BLM inspector in the field could review information to confirm that the operator is in fact in compliance with one set of leak detection requirements.

### **Section 3179.302 Approved instruments and methods**

This section prescribes the types of instruments that an operator must use to inspect for leaks. Specifically, operators must use: (1) an optical gas imaging device such as an infrared camera; (2) a portable analyzer capable of detecting leaks in compliance with Method 21 of 40 CR part 60, appendix A-7; or (3) a leak detection device not listed in this section that has been approved by BLM. The persons using the above devices must be adequately trained in their use.

Anyone may request approval of an alternative monitoring device and protocol by submitting a Sundry Notice with the information specified in paragraph (c) of this section, subject to the approval of the BLM as specified in paragraph (d).

In the final rule, the BLM amended paragraph (a) of this section by removing reference to monitoring methods since this paragraph specifies monitoring equipment, not methods. In paragraph (a)(2), we added a provision that portable analyzers must be operated in compliance with Method 21 rather than manufacturers specifications. We

removed from paragraph (a) the proposed option of using a comprehensive program approved by the BLM under § 3179.303(b).

The BLM also added a provision at paragraph (b) that the person operating the leak detection device must be adequately trained in the proper use of the device. We added an option at paragraph (c) where any person may request approval of an alternative monitoring device and protocol by submitting a Sundry Notice with the information specified in paragraph (c). The request will be subject to the approval of the BLM as specified in newly added paragraph (d), which includes the requirement that it must be demonstrated that the alternative leak detection device and associated protocol will achieve equal or greater reduction of gas lost through leaks compared to the approach specified in § 3179.302(a)(1). Paragraph (d) also establishes that the BLM will provide public notice of the submission of an alternative device or monitoring protocol for approval, and will post on the BLM website a list of each approved alternative monitoring device and protocol and limitations on its use. The final rule also notes that the BLM may approve an alternative device and monitoring protocol for use in all or most applications, or instead just for use on a pilot or demonstration basis.

Please see Section III.A.d for a discussion of major comments received on this section of the proposed rule.

### **Section 3179.303 Leak detection inspection requirements for natural gas wellhead equipment and other equipment**

This section requires operators to conduct initial site inspections within specified timeframes after the effective date of the rule. The section requires the operator initially to conduct site inspections twice a year, with consecutive semiannual inspections

conducted at least four months apart; and to conduct compressor station inspections quarterly, with consecutive quarterly inspections conducted at least 60 days apart. The inspection frequencies are fixed.

Paragraph (b) of this section authorizes the BLM to approve an alternative instrument-based leak detection program if the BLM finds that the alternative would achieve equal or greater reduction of gas lost through leaks compared with the approach specified in §§ 3179.302(a)(1) and 3179.303(a). The operator must submit the request through a Sundry Notice. The operator also has the option to request approval of a leak detection program that does not meet the criterion specified in § 3179.303(b) when it can be demonstrated that compliance with the requirements of §§ 3179.301 through 3179.305 would cause the operator to cease production and abandon significant recoverable oil or gas reserves under the lease.

In the final rule, the BLM clarified in paragraph (a) of this section that the operator must inspect leak components at the site, and that the inspection must be conducted using a leak detection device listed under § 3179.302. The BLM is maintaining a semiannual inspection frequency for each site, and added provisions for quarterly inspections of compressor stations. In the final rule, these inspection frequencies are fixed, and the BLM did not finalize the proposed table of variable, performance-based inspection frequencies.

Paragraph (b) of this section allows for BLM approval of an alternative program, if an operator submits an approval request via a Sundry Notice. It is the BLM's intent that those approvals be made at the State office level for intrastate programs, and at the national or Washington office level for interstate programs. Final § 3179.303(b) differs

slightly from the proposed version of this provision. First, the final rule specifies that the approval applies to an “alternative instrument-based leak detection program” instead of the proposed “alternative leak detection device, program, or method.” Next, the rule specifies that the approval is in lieu of complying with paragraph (a) of this section, and that the alternative must achieve equal or greater reduction of gas lost through leaks compared with the approach specified in §§ 3179.302(a)(1) and 3179.303(a). The BLM also added details of what the Sundry Notice must include at § 3179.303(b)(1)-(5), and added paragraph (e) stating that approved alternative LDAR programs will be posted online.

Additionally, the BLM added a provision at paragraph (c) of this section to provide the operator with the option to request approval of a leak detection program that does not meet the criterion specified in § 3179.303(b) when it can be demonstrated that compliance with the requirements of §§ 3179.301 through 3179.305 would cause the operator to cease production and abandon significant recoverable oil or gas reserves under the lease. The BLM also added paragraph (d) setting forth the requirements for the Sundry Notice to support a demonstration under paragraph (c).

Please see Section III.A.d for a discussion of major comments received on this section of the proposed rule.

#### **Section 3179.304 Repairing leaks**

This section requires operators to repair any leak as soon as practicable and no later than 30 calendar days after discovery of the leak, unless there is good cause for repair to take longer. The rule requires the operator to notify the BLM by Sundry Notice if there is good cause to delay the repairs beyond 30 days, and to complete the repair at

the earliest opportunity, but in no case longer than 2 years after discovery. The rule also requires the operator to conduct a follow-up inspection, using an authorized method, to verify the effectiveness of the repair within 30 calendar days after the repair, and to make additional repairs within 15 calendar days if the previous repair was not effective. This repair and follow-up process must be followed until the repair is effective. The BLM does not consider an inspection to verify the effectiveness of a repair to be a periodic inspection under § 3179.303.

In the final rule, the BLM increased the time period for completing repairs from the proposed 15 days to 30 days. Operators also have 30 days, as opposed to the proposed 15 days, to verify the effectiveness of the repair through a follow-up inspection. While the proposed rule would have required that the follow-up inspection be carried out using the method originally used to detect the leak, the final rule specifies that any of the instruments specified or approved under § 3179.302(a) or the soap bubble test under EPA's Method 21, section 8.3.3, may be used.

In paragraph (a) of this section in the proposed rule, the BLM specified that the operator must repair any leak "not associated with normal equipment operations." In the final rule, we specify that "any leak" must be repaired as soon as practicable, but within 30 days after discovery. In conjunction with this change, we have added to § 3179.3 a definition of "leak" that excludes releases due to normal operation of equipment that is intended to vent.

The proposed rule, as well as the final rule, allows the owner to delay repair if a good cause exists. Although "good cause" was not defined in the proposed rule, we have added a definition in paragraph (a) of the final rule. Also, the final rule allows the

operator up to two years to repair a leak if good cause for delay exists, although the operator must submit a Sundry Notice and repair the leak sooner than 2 years if the opportunity arises. Previously, we had proposed that the operator repair the leak within 15 days after the cause for the delay ceases to exist.

Please see Section III.A.d for a discussion of major comments received on this section of the proposed rule.

### **Section 3179.305 Leak detection inspection, recordkeeping and reporting**

This section requires operators to maintain records of LDAR inspections and repairs, including dates, locations, methods, where leaks were found, dates of repairs, and dates of follow-up inspections. These records must be made available to the BLM upon request. AVO inspections only have to be documented if they find a leak requiring repair. Paragraph (b) of the section also requires operators to submit to the BLM, by March 31 of each calendar year, an annual summary report on the previous year's LDAR inspection activities. The BLM plans to make these reports available to the public, subject to any protections for confidential business information.

The final rule amends the records that must be maintained. The BLM did not finalize the proposed recordkeeping requirements regarding the equipment or facility inspected, descriptions of each leak, and the date of each leak repair attempt. We clarified, however, that AVO checks need only be documented if they find a leak requiring repair.

Please see Section III.A.d for a discussion of major comments received on this section of the proposed rule.

**Section 3179.401 State or tribal requests for variances from the requirements of this subpart**

This section creates a variance procedure under which the BLM State Director may grant a State or tribe's request to have a State, local or tribal regulation apply in place of a provision or provisions of this subpart. The variance request must: (1) identify the specific provisions of the BLM requirements for which the variance is requested; (2) identify the specific State, local or tribal regulation that would substitute for the BLM requirements; (3) explain why the variance is needed; and (4) demonstrate how the State, local or tribal regulation will satisfy the purposes of the relevant BLM provisions. The BLM State Director will review a State or tribal variance request. To approve a request, the BLM State Director will determine that the State, local or tribal regulation: (1) would perform at least equally well in terms of avoiding waste of oil and gas, reducing environmental impacts from venting and/or flaring of gas, and ensuring the safe and responsible production of oil and gas, compared to the particular provision(s) from which the State or tribe is requesting the variance, and (2) would be consistent with the terms of the affected Federal or Indian leases and applicable statutes.

This section also clarifies that a variance granted under this proposed section does not constitute a variance from provisions of regulations, laws, or orders other than subpart 3179, and it reserves the BLM's authority to rescind a variance or modify any condition of approval in a variance. Additionally, this section requires States or tribes with approved variances to notify the BLM in writing of any substantive amendments, revisions, or other changes to the applicable State, local or tribal regulation(s) or rule(s). This section further specifies that if the BLM approves a variance for State, local or tribal

regulation(s) or rule(s), the variance can be enforced by the BLM as if the regulation(s) or rule(s) were provided for in this Subpart.

In response to comments received, the BLM made the following changes to the proposed rule requirements: (1) revised paragraph (a)(1) to change a reference to granting a variance from “any individual provision of this subpart” to “any provisions of this subpart”; (2) revised paragraphs (a)(2)(iv) and (b) to state that the State, local or tribal regulations or rules would “perform at least equally well in terms of reducing waste of oil and gas, reducing environmental impacts from venting and/or flaring of gas, and ensuring the safe and responsible production of oil and gas, compared to the particular provision(s) from which the State or tribe is requesting the variance”; (3) added text to allow variances for requirements and regulations of local governments, in addition to State and tribal requirements (though the variance request must still come from the State or tribe, not from a locality); (4) added new paragraph (e) that requires the State or tribe that requested the variance to notify the BLM of substantive amendments, revisions, or other changes to the applicable State, local or tribal regulation(s) or rule(s); and (5) added new paragraph (f) that clarifies that if the BLM approves a variance for State, local or tribal regulation(s) or rule(s), the variance can be enforced by the BLM as if the regulation(s) or rule(s) were provided for in this Subpart. Paragraph (f) also clarifies that a State’s or tribe’s enforcement of its own regulations would not be affected by the BLM’s approval of a variance.

Major comments received on variances are discussed in Section III.E.3 of this preamble; additional comments on variances are discussed below.



Some commenters requested that additional entities be allowed to apply for variances, such as local air authorities, multiple State agencies, or operators. Commenters asserted that allowing only States or tribes to request variances causes uncertainty for operators, and that if a State declined to put forth a variance request, companies would bear the cost and burden of complying with multiple regulatory regimes. As stated above, the BLM has modified the rule to allow local requirements, in addition to State and tribal requirements, to substitute for BLM requirements. Regarding the comment that multiple State agencies may need to request a variance, the final rule does not preclude different State or tribal agencies from requesting variances from different provisions of the rule. The BLM has not modified the final rule to allow localities or operators, in addition to States and tribes, to request a variance to be able to comply with State, local or tribal requirements in lieu of the BLM requirements. Specifically with respect to local requirements, the BLM believes that it is important to ensure that the State supports a variance request, and thus that the State prefers the BLM to enforce the State's or locality's requirements rather than federal requirements. Additionally, we believe that a State has the best understanding of its own regulatory requirements and how those compare to the requirements of this rule.

Several commenters asserted that the variance application and approval processes were unclear and/or overly burdensome. These commenters expressed various concerns, including: (1) lack of a clear and comprehensive description of the information needed to request a variance; (2) lack of timelines for review and approval; (3) lack of criteria by which the BLM would evaluate variance requests; and (4) lack of provisions stating how the BLM will address future modifications to either this rule or State regulations once

variances are approved. Commenters were also concerned about the BLM's ability to review variance requests in a timely manner. To address these concerns, comments suggested clarifying the regulatory text as well as developing formal implementation guidance in consultation with the States prior to the effective date of the rule.

In response to these comments, as discussed in Section III.E.2 of this preamble, the final rule provides three specific criteria for evaluating whether it is appropriate to apply the State, local or tribal requirements in lieu of this rule. In addition, the final rule added new paragraph (e) that requires the State or tribe that requested the variance to notify the BLM of substantive amendments, revisions, or other changes to the applicable State, local or tribal regulation(s) or rule(s). This requirement will ensure that the BLM is aware of changes to State, local or tribal regulations that may impact whether the State, local or tribal regulation or requirement continues to meet the variance criteria established in the final rule. Regarding the comments arguing for a timeline for submittal and processing of the variances, the BLM is confident that it will be able to process these requests in a timely manner that will allow sufficient time for operators to have a clear understanding of their compliance requirements.

Some commenters also expressed concern with the proposed BLM State Director review of the variance requests. These commenters asserted that delegating the approval process to the BLM State Director could result in uneven treatment among States. The BLM agrees that achieving consistent implementation of the regulations is an important goal, and this is one reason why the BLM does not believe that decisions on variance requests should be made below the BLM State Director level. Further, the BLM believes that BLM State Directors are in a good position to evaluate how State, local or tribal rules

or requirements compare to the requirements of this rule, given their familiarity with the regulatory regimes that apply in the relevant State or States. In addition, once the rule is in effect, the BLM would have the opportunity to issue guidance to enhance coordination among State Directors in evaluating variances, as well as with the BLM Washington office, to help ensure consistency across the BLM State Offices. Finally, the more specific criteria in the final rule for evaluating a variance request will enhance consistency across States.

Some commenters also opposed the proposed provision in § 3179.401(d) stating that the “BLM reserves the right to rescind a variance or modify any condition of approval.” These commenters asserted that such a proposal undermines certainty for operators and discourages States and tribes from seeking a variance. Other commenters requested that the BLM include an appeals process for revoked or denied variances, stating that if a variance were requested and denied, States would have no administrative means by which to address the BLM decision without going to court.

The BLM believes that maintaining BLM authority to rescind a variance or modify any condition of approval is necessary to guard against situations in which a variance leads to unintended or unforeseen consequences that run counter to the BLM’s determination that the State, local, or tribal regulation performs at least as well as the BLM rule. The BLM expects that such situations will arise infrequently, but the BLM nevertheless believes it is important to include a mechanism for addressing such situations as they occur. After considering the comments, the BLM determined that consideration of waste reduction, environmental, and safety interests outweighs commenters’ concerns. As a result, the final rule maintains the BLM’s discretion to

rescind a variance or modify any condition of approval. Regarding the comments requesting that the BLM include an appeals process for revoked or denied variances, the BLM did not provide for administrative appeals on similar variance decisions under the hydraulic fracturing rule, and the BLM is maintaining this practice in this final rule. Applying this approach also helps to avoid a protracted appeals process with respect to State and tribal variances.

## **VIII. Analysis of Impacts**

### **A. Description of the Regulated Entities**

#### **1. Potentially Affected Entities**

Entities that will be directly affected by the rule include most, if not all, entities involved in the exploration and development of oil and natural gas on Federal and Indian lands. According to AFMSS data (as of March 27, 2015), there are up to 1,828 entities that currently operate Federal and Indian leases.<sup>155</sup> We believe that these 1,828 entities will be most affected by the rule, in addition to entities currently involved with drilling and support activities, and any entities that become involved in the future.

The potentially affected entities are likely to fall within one of the following industries, identified by the North American Industry Classification System (NAICS) codes:

- NAICS Code 21111 “Oil and Gas Extraction”
- NAICS Code 213111 “Drilling Oil and Gas Wells”
- NAICS Code 213112 “Support Activities”

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<sup>155</sup> The actual number is expected to be slightly lower due to duplicate entries.

According to 2014 data from the U.S. Census Bureau, there were 6,532 entities directly involved in extraction of oil and gas in the United States, 2,121 entities involved in the drilling of wells, and 8,577 entities providing other support functions.<sup>156</sup> Therefore, the approximately 17,000 entities associated with developing, and producing of domestic oil and gas<sup>157</sup> represent an upper bound estimate of the operators that could potentially be affected by this rulemaking.

## **2. Affected Small Entities**

The Small Business Administration (SBA) has developed size standards to carry out the purposes of the Small Business Act.<sup>158</sup> For mining, including the extraction of crude oil and natural gas, the SBA defines a small entity as an individual, limited partnership, or small company, at “arm’s length” from the control of any parent companies, with fewer than 1,250 employees. For entities drilling oil and gas wells, the threshold is 1,000 employees. For entities involved in support activities, the standard is annual receipts of less than \$38.5 million Table 9-3a in the RIA displays the number of establishments in the oil and gas sector using a 1,000 employee cutoff. This table shows that over 99% of the establishments involved in oil and gas extraction and the drilling of oil and gas wells are classified as small.

To estimate a percentage of small firms involved in oil and gas support activities, we reference Table 9-3d of the RIA, which provides the NAICS information for firms involved in oil and gas support activities based on the size of receipts. The most recent data available from the U.S. Census Bureau for establishment/firm size based on receipts

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<sup>156</sup> RIA at 122.

<sup>157</sup> U.S. Census Bureau data does not readily differentiate between the number of firms involved in oil development and production activities versus gas development and production.

<sup>158</sup> 13 CFR 121.201.

is for 2007. Of the firms providing oil and gas support activities in 2007, about 97 percent had annual receipts of less than \$35 million and are classified as small.<sup>159</sup>

## **B. Impacts of the Requirements**

### **1. Overall Costs of the Rule**

Overall, the BLM estimates that this rule will pose costs of about \$114 – 279 million per year (with capital costs annualized using a 7% discount rate) or \$110 – 275 million per year (with capital costs annualized using a 3% discount rate).<sup>160</sup> These costs include engineering compliance costs and the social cost of minor additions of carbon dioxide to the atmosphere.<sup>161</sup> The engineering compliance costs presented do not include potential cost savings from the recovery and sale of natural gas (those savings are shown in the summary of benefits). In some areas, operators have already undertaken, or plan to undertake, voluntary actions to address gas losses. To the extent that operators are already in compliance with the requirements of this rule, the above estimates overstate the likely impacts of the rule.

### **2. Overall Benefits of the Rule**

The benefits of the rule include the additional production of resources from Federal and Indian leases; reductions in venting, flaring, and leaks of gas, including GHG emissions; and increased opportunities for royalties. We measure the benefits of the rule as the cost savings that the industry will receive from the recovery and sale of natural gas and the projected environmental benefits of reducing the amount of GHG pollution

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<sup>159</sup> 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 underestimate.

<sup>160</sup> RIA at 4.

<sup>161</sup> Some gas that would have otherwise been vented would now be combusted on-site or downstream to generate electricity. The estimated value of the carbon additions do not exceed \$30,000 in any given year.

released into the atmosphere. As with the estimated costs, we expect benefits on an annual basis.

The BLM estimates that this rule would result in monetized benefits of \$209 – 403 million per year (calculating the monetized emissions reductions using model averages of the social cost of methane with a 3 percent discount rate).<sup>162</sup> We estimate that the rule would reduce methane emissions by 175,000 – 180,000 tpy, which we estimate to be worth \$189 – 247 million per year (this social benefit is included in the monetized benefit above). We estimate that the rule would reduce VOC emissions by 250,000-267,000 (this benefit is not monetized in our calculations).<sup>163</sup> Overall, we predict the rule will reduce methane emissions by 35% from the 2014 estimates and reduce the flaring of associated gas by 49%, when the capture requirements are fully phased in.<sup>164</sup>

The rule will also have numerous ancillary benefits. These include improved quality of life for nearby residents, who note that flares are noisy and unsightly at night; reduced release of VOCs, including benzene and other hazardous air pollutants; and reduced production of NOx and particulate matter, which can cause respiratory and heart problems.

### **3. Net Benefits of the Rule**

Overall, the BLM estimates that the benefits of this rule outweigh its costs by a significant margin. The BLM expects net benefits ranging from \$46 – 199 million per

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<sup>162</sup> RIA at 5.

<sup>163</sup> RIA at 106.

<sup>164</sup> *Id.*

year (capital costs annualized using a 7% discount rate) or \$50 – 204 million per year (capital costs annualized using a 3% discount rate).<sup>165</sup>

#### **4. Distributional Impacts**

##### **a. Energy Systems**

The rule has a number of requirements that are expected to influence the production of natural gas and crude oil from onshore Federal and Indian oil and gas leases. We estimate the following incremental changes in production, noting the representative share of the total U.S. production in 2015 for context. We estimate additional natural gas production ranging from 9 – 41 Bcf per year (representing 0.03 – 0.15 percent of the total U.S. production) and a reduction in crude oil production ranging from 0.0 – 3.2 million bbl per year (representing 0 – 0.07 percent of the total U.S. production).<sup>166</sup> Separate from the volumes listed above, we also expect 0.8 Bcf of gas to be combusted on-site that would have otherwise been vented. Since the relative changes in production are expected to be small, we do not expect that the rule would significantly impact the price, supply, or distribution of energy.

##### **b. Royalties**

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. For requirements that would result in incremental gas production, we calculate the additional royalties based on that

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<sup>165</sup> RIA at 6. The highs and lows of the benefits and costs do not occur during the same years; therefore, the net benefit ranges presented here do not calculate simply as the range of benefits minus the range of costs presented above.

<sup>166</sup> RIA at 7.



production. We estimate that the rule will result in additional royalties of \$3 – 13 million per year.<sup>167</sup>

Royalty payments are recurring income to Federal or tribal governments and costs to the operator or lessee. As such, they are private 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 of the benefits and costs of a regulation, they may be important for describing distributional effects.

c. Small Businesses

The BLM identified up to 1,828 entities that currently operate Federal and Indian leases. The vast majority of these entities are small businesses, as defined by the SBA. We estimated a range of potential per-entity costs, based on different discount rates and scenarios. Those per-entity compliance costs are presented in the RIA.<sup>168</sup>

Recognizing that the SBA defines a small business for oil and gas producers as one with fewer than 1,250 employees, a definition that encompasses many 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<sup>169</sup> 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

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<sup>167</sup> RIA at 8.

<sup>168</sup> The BLM conducted a Final Regulatory Flexibility Analysis, RIA at 123-136.

<sup>169</sup> The profit margin was calculated by dividing the net income by the total revenue as reported in the companies' 10-K filings.

used the midpoint of the low and high average per-entity cost increase figures, or \$55,200, recognizing that this figure includes compliance costs (annualized using a 7% discount rate) and cost savings. For these 26 small companies, a per-entity compliance cost increase of \$55,200 would result in an average reduction in profit margin of 0.15 percentage points (based on the 2014 company data). The full detail of this calculation is available in the RIA.<sup>170</sup>

d. Employment

Executive Order 13563 states, “Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation.”<sup>171</sup> An analysis of employment impacts is a standalone analysis and the impacts should not be included in the estimation of benefits and costs.

The rule is not expected to materially impact employment within the oil and gas extraction, drilling, and support industries.<sup>172</sup> 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. Therefore, we believe that the rule would not alter the investment or employment decisions of firms or significantly adversely impact employment.

The requirements would require the one-time installation or replacement of equipment and the ongoing implementation of an LDAR program, and labor would be necessary to

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<sup>170</sup> RIA at 129.

<sup>171</sup> Executive Order 13563, *Improving Regulation and Regulatory Review* (Jan. 18, 2011).

<sup>172</sup> RIA at 118.

comply with each of these. The Supporting Statement for the Paperwork Reduction Act describes the labor requirements posed by the rule.

e. Impacts on Tribal Lands

This section presents the costs, benefits, net benefits, and incremental production associated with operations on Indian leases, as well as royalty implications for tribal governments.<sup>173</sup> We estimate that the rule's operation on Indian lands would pose costs ranging from \$15 – \$39 million per year (using a 7% discount rate to annualize capital costs) or \$14 – \$39 million per year (using a 3% discount rate to annualize capital costs).<sup>174</sup> Projected benefits from the rule's operation on Indian lands range from \$3 – \$23 million per year (using model averages of the social cost of methane with a 3 percent discount rate).<sup>175</sup> Net benefits from operation of the rule on leases on Indian lands range from \$3 – \$25 million per year (with capital costs annualized using 7% and 3% discount rates).<sup>176</sup>

For impacts on production from leases on Indian lands, the rule is projected to result in additional natural gas production ranging from 1.1 – 5.8 Bcf per year and a reduction in crude oil production ranging from 0 – 320,000 bbl per year.<sup>177</sup> We further estimate that the rule would reduce methane emissions from leases on Indian lands by 22,000 tpy, and would reduce VOC emissions by 30,000 – 32,000 tpy.<sup>178</sup> We estimate additional royalties from leases on Indian lands of \$0.3 – 1.9 million per year.<sup>179</sup>

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<sup>173</sup> RIA at 118-120.

<sup>174</sup> RIA at 118.

<sup>175</sup> RIA at 119.

<sup>176</sup> RIA at 119. The highs and lows of the benefits and costs do not occur during the same years; therefore, the net benefit ranges presented here do not calculate simply as the range of benefits minus the range of costs presented above.

<sup>177</sup> *Id.*

<sup>178</sup> *Id.*

<sup>179</sup> RIA at 120.

## **IX. Procedural Matters**

### **A. Executive Order 12866, Regulatory Planning and Review<sup>180</sup>**

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 is deemed significant under Executive Order 12866 if it may:

- (a) 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;
- (b) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- (c) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- (d) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

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

### **B. Regulatory Flexibility Act and Small Business Regulatory Enforcement Fairness Act of 1996<sup>181</sup>**

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<sup>180</sup> RIA at 138.

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.<sup>182</sup> 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 will likely affect a substantial number of small entities. The BLM believes, however, that the final rule will not have a significant economic impact on a substantial number of small entities. Although the rule will affect a substantial number of small entities, the BLM does not believe that these effects 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 chose to prepare an Initial Regulatory Flexibility Analysis and Final Regulatory Flexibility Analysis for this rule. Due to the

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<sup>181</sup> RIA at 167-168.

<sup>182</sup> 5 U.S.C. 601 – 612. The exception is found in 5 U.S.C. 605(b).

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

### **C. Unfunded Mandates Reform Act of 1995**

Under the Unfunded Mandates Reform Act (UMRA), agencies must prepare a written statement about benefits and costs prior to issuing a proposed rule that includes any Federal mandate 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 1 year, and prior to issuing any final rule for which a proposed rule was published.

This final rule does not contain a Federal mandate that may result in expenditures of \$100 million or more by State, local, and tribal governments, in the aggregate, or by the private sector in any 1 year. Thus, the final rule is also not subject to the requirements of Section 205 of UMRA.

This final 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. It contains no requirements that apply to such governments, nor does it impose obligations upon them.

### **D. Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights (Takings)**

Under Executive Order 12630, the final rule would not have significant takings implications. A takings implication assessment is not required. The final rule would establish a limited set of standards under which gas can be flared or vented, and under

which an operator can use oil and gas on a lease, unit, or communitized area for operations and production purposes, without paying royalty.

Oil and gas operators on BLM-administered leases are subject to lease terms that expressly require that subsequent lease activities be conducted in compliance with applicable Federal laws and regulations. The final rule is consistent with the terms of those Federal leases and is authorized by applicable statutes. Thus, the final rule is not a governmental action capable of interfering with constitutionally protected property rights, it would not cause a taking of private property, and it does not require further discussion of takings implications under this Executive Order.

**E. Executive Order 13132, Federalism**

The final rule would not have a substantial direct effect on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the levels of government. It would not apply to States or local governments or State or local government entities. Therefore, in accordance with Executive Order 13132, the BLM has determined that this final rule does not have sufficient Federalism implications to warrant preparation of a Federalism Assessment.

**F. Executive Order 12988, Civil Justice Reform**

This final rule would comply with the requirements of Executive Order 12988. Specifically, this rulemaking: (a) Meets the criteria of section 3(a) requiring that all regulations be reviewed to eliminate errors and ambiguity and be written to minimize litigation; and (b) Meets the criteria of section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

**G. Executive Order 13175, Consultation and Coordination with Indian Tribal Governments**

In accordance with Executive Order 13175, the BLM has evaluated this rulemaking and determined that it will not have substantial direct effects on federally recognized Indian tribes. Nevertheless, on a government-to-government basis we initiated consultation with tribal governments that the final rule may affect.

In 2014, the BLM conducted a series of forums to consult with tribal governments to inform the development of this proposal. We held tribal outreach sessions in Denver, Colorado (March 19, 2014), Albuquerque, New Mexico (May 7, 2014), Dickinson, North Dakota (May 9, 2014), and Washington, D.C. (May 14, 2014).<sup>183</sup> At the Denver and Washington, D.C. sessions, the tribal meetings were live-streamed to allow for the greatest possible participation by tribes and others. The tribal outreach sessions served as initial consultation with Indian tribes to comply with Executive Order 13175. As part of our outreach efforts, the BLM accepted informal comments generated as a result of the public/tribal outreach sessions through May 30, 2014.

After the proposed rule published on February 8, 2016, the BLM conducted another round of outreach meetings, with the tribal sessions taking place in the morning, and the general-public sessions taking place in the afternoon, with a conference call-in number for the public to listen in remotely. These meetings were held at four locations: Farmington, New Mexico (February 16, 2016), Oklahoma City, Oklahoma (February 18, 2016), Denver, Colorado (March 1, 2016), and Dickinson, North Dakota (March 3, 2016).

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<sup>183</sup> More info can be found at:  
[http://www.blm.gov/wo/st/en/prog/energy/public\\_events\\_on\\_oil.html](http://www.blm.gov/wo/st/en/prog/energy/public_events_on_oil.html)



## **H. Paperwork Reduction Act**

### **1. Overview**

The Paperwork Reduction Act (PRA)<sup>184</sup> provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information, unless it displays a currently valid OMB control number. Collections of information include requests and requirements that an individual, partnership, or corporation obtain information, and report it to a Federal agency. See 44 U.S.C. 3502(3); 5 CFR 1320.3(c) and (k).

This rule contains information collection activities that require approval by the OMB under the PRA. The BLM included an information collection request in the proposed rule. OMB has approved the information collection for the final rule under control number 1004-0211.

### **2. Summary of Information Collection Requirements**

- Title: Waste Prevention, Production Subject to Royalties, and Resource Conservation (43 CFR parts 3160 and 3170).
- Forms: Form 3160-3, Application for Permit to Drill or Reenter; and Form 3160-5, Sundry Notices and Reports on Wells.
- OMB Control Number: 1004-0211.
- Description of Respondents: Holders of Federal and Indian (except Osage Tribe) oil and gas leases, those who belong to federally approved units and CAs, and those who are parties to IMDA oil and gas agreements.
- Respondents' Obligation: Required to obtain or retain a benefit.

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<sup>184</sup> 44 U.S.C. 3501 – 3521.

- Frequency of Collection: On occasion and monthly.
- Abstract: This rule updates standards to reduce wasteful venting, flaring, and leaks of natural gas from onshore wells located on Federal and Indian oil and gas leases, units and CAs.
- Estimated Number of Responses: 63,200.
- Estimated Total Annual Burden Hours: 82,170 hours.
- Estimated Total Non-Hour Cost: None.

### **3. Discussion of Regulations**

Except for the recordkeeping required by 43 CFR 3179.305, the information-collection activities in the final rule involve new uses and burdens for BLM Forms 3160-3 and 3160-5, the use of which has been cleared by OMB under control number 1004-0137, Onshore Oil and Gas Operations (43 CFR part 3160) (expiration date January 31, 2018). After this rule goes into effect, the BLM plans to request that OMB merge the new uses and burdens of Forms 3160-3 and 3160-5 with control number 1004-0137.

The information collection activities in this rule are described below along with estimates of the annual burdens. Included in the burden estimates are the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing each component of the information collection.

#### ***Plan to Minimize Waste of Natural Gas (43 CFR 3162.3-1)***

This rule adds a new provision to 43 CFR 3162.3-1 that requires a plan to minimize waste of natural gas when submitting an APD for a development oil well. This information is in addition to the APD information that the BLM already collects under

OMB Control Number 1004-0137. The required elements of the waste minimization plan are listed at paragraphs (j)(1) through (j)(7).

***Request for Approval for Royalty-Free Uses On-Lease or Off-Lease (43 CFR 3178.5, 3178.7, 3178.8, and 3178.9)***

Section 3178.5 requires submission of a Sundry Notice (Form 3160-5) to request prior written BLM approval for use of gas royalty-free for the following operations and production purposes on the lease, unit or communitized area:

- Using oil or gas that an operator removes from the pipeline at a location downstream of the facility measurement point (FMP);
- Removal of gas initially from a lease, unit PA, or communitized area for treatment or processing because of particular physical characteristics of the gas, prior to use on the lease, unit PA or communitized area; and
- Any other type of use of produced oil or gas for operations and production purposes pursuant to § 3178.3 that is not identified in § 3178.4.

Section 3178.7 requires submission of a Sundry Notice (Form 3160-5) to request prior written BLM approval for off-lease royalty-free uses in the following circumstances:

- The equipment or facility in which the operation is conducted is located off the lease, unit, or communitized area for engineering, economic, resource-protection, or physical-accessibility reasons; and
- The operations are conducted upstream of the FMP.

Section 3178.9 requires the following additional information in a request for prior approval of royalty-free use under section 3178.5, or for prior approval of off-lease royalty-free use under section 3178.7:

- A complete description of the operation to be conducted, including the location of all facilities and equipment involved in the operation and the location of the FMP;
- The volume of oil or gas that the operator expects will be used in the operation and the method of measuring or estimating that volume;
- If the volume expected to be used will be estimated, the basis for the estimate (e.g., equipment manufacturer’s published consumption or usage rates); and
- The proposed disposition of the oil or gas used (e.g., whether gas used would be consumed as fuel, vented through use of a gas-activated pneumatic controller, returned to the reservoir, or some other disposition).

***Notification of Choice to Comply on County- or State-wide Basis (43 CFR***

***3179.7(c)(3)(ii)***

Section 3179.7 requires operators flaring gas from development oil wells to capture a specified percentage of the operator’s adjusted volume of gas produced over the relevant area. The “relevant area” is each of the operator’s leases, units, or communitized areas, unless the operator chooses to comply on a county- or State-wide basis and the operator notifies the BLM of its choice by Sundry Notice by January 1 of the relevant year.

***Request for Approval of Alternative Capture Requirement (43 CFR 3179.8(b))***

Section 3179.8 applies only to leases issued before the effective date of the final rule and to operators choosing to comply with the capture requirement in section 3179.7 on a lease-by-lease, unit-by-unit, or communitized area-by-communitized area basis. The regulation provides that operators who meet those parameters may seek BLM approval of a capture percentage other than that which is applicable under 43 CFR 3179.7. The operator must submit a Sundry Notice that includes the following information:

- The name, number, and location of each of the operator's wells, and the number of the lease, unit, or communitized area with which it is associated;
- The oil and gas production levels of each of the operator's wells on the lease, unit, or communitized area for the most recent production month for which information is available and the volumes being vented and flared from each well;

In addition, the request must include map(s) showing:

- The entire lease, unit, or communitized area, and the surrounding lands to a distance and on a scale that shows the field in which the well is or will be located (if applicable), and all pipelines that could transport the gas from the well;
- All of the operator's producing oil and gas wells, which are producing from Federal or Indian leases, (both on Federal or Indian leases and on other properties) within the map area;
- Identification of all of the operator's wells within the lease from which gas is flared or vented, and the location and distance of the nearest gas pipeline(s) to each such well, with an identification of those pipelines that are or could be available for connection and use; and
- Identification of all of the operator's wells within the lease from which gas is captured;

The following information is also required:

- Data that show pipeline capacity and the operator's projections of the cost associated with installation and operation of gas capture infrastructure, to the extent that the operator is able to obtain this information, as well as cost

projections for alternative methods of transportation that do not require pipelines;  
and

- Projected costs of and the combined stream of revenues from both gas and oil production, including:
  - The operator's projections of gas prices, gas production volumes, gas quality (i.e., heating value and H<sub>2</sub>S content), revenues derived from gas production, and royalty payments on gas production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less; and
  - The operator's projections of oil prices, oil production volumes, costs, revenues, and royalty payments from the operator's oil and gas operations within the lease over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

***Request for Exemption from Well Completion Requirements (43 CFR 3179.102(c) and (d))***

Section 3179.102 lists several requirements pertaining to gas that reaches the surface during well completion and related operations. An operator may seek an exemption from these requirements by submitting a Sundry Notice that includes the following information:

- (1) The name, number, and location of each of the operator's wells, and the number of the lease, unit, or communitized area with which it is associated;
- (2) The oil and gas production levels of each of the operator's wells on the lease, unit or communitized area for the most recent production month for which information is available;

- (3) Data that show the costs of compliance; and
- (4) Projected costs of and the combined stream of revenues from both gas and oil production, including: the operator's projections of oil and gas prices, production volumes, quality (i.e., heating value and H<sub>2</sub>S content), revenues derived from production, and royalty payments on production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

The rule also provides that an operator that is in compliance with the EPA regulations for well completions under 40 CFR part 60, subpart OOOO or subpart OOOOa is deemed in compliance with the requirements of this section. As a practical matter, all hydraulically fractured or refractured wells are now subject to the EPA requirements, so the BLM does not believe that the requirements of this section would have any independent effect, or that any operator would request an exemption from the requirements of this section, as long as the EPA requirements remain in effect.

***Request for Extension of Royalty-Free Flaring During Initial Production Testing (43 CFR 3179.103)***

Section 3179.103 allows gas to be flared royalty-free during initial production testing. The regulation lists specific volume and time limits for such testing. An operator may seek an extension of those limits by submitting a Sundry Notice to the BLM.

***Request for Extension of Royalty-Free Flaring During Subsequent Well Testing (43 CFR 3179.104)***

Section 3179.104 allows gas to be flared royalty-free for no more than 24 hours during well tests subsequent to the initial production test. The operator may seek authorization to flare for a longer period by submitting a Sundry Notice to the BLM.

### ***Reporting of Venting or Flaring (43 CFR 3179.105)***

Section 3179.105 allows an operator to flare gas royalty-free during a temporary, short-term, infrequent, and unavoidable emergency. Venting gas is permissible if flaring is not feasible during an emergency. The regulation defines limited circumstances that constitute an emergency, and other circumstances that do not constitute an emergency.

The operator must estimate and report to the BLM on a Sundry Notice the volumes flared or vented in the following circumstances that, as provided by 43 CFR 3179.105, do not constitute emergencies for the purposes of royalty assessment:

- (1) More than 3 failures of the same component within a single piece of equipment within any 365-day period;
- (2) The operator's failure to install appropriate equipment of a sufficient capacity to accommodate the production conditions;
- (3) Failure to limit production when the production rate exceeds the capacity of the related equipment, pipeline, or gas plant, or exceeds sales contract volumes of oil or gas;
- (4) Scheduled maintenance;
- (5) A situation caused by operator negligence; or
- (6) A situation on a lease, unit, or communitized area that has already experienced 3 or more emergencies within the past 30 days, unless the BLM determines that the occurrence of more than 3 emergencies within the 30 day period could not have been anticipated and was beyond the operator's control.

### ***Pneumatic Controllers —Introduction***

Section 3179.201 pertains to any pneumatic controller that: (1) is not subject to EPA regulations at 40 CFR 60.5360 through 60.5390, but would be subject to those



regulations if it were a new or modified source; and (2) has a continuous bleed rate greater than 6 standard cubic feet (scf) per hour. Section 3179.201(b) requires operators to replace each high-bleed pneumatic controller with a controller with a bleed rate lower than 6 scf per hour within 1 year of the effective date of the rule, unless (1) the pneumatic controller exhaust is routed to processing equipment; (2) the pneumatic controller exhaust was, as of the effective date of the rule, and continues to be routed to a flare device or low pressure combustor; or (3) one of the following applies:

***Notification of Functional Needs for a Pneumatic Controller (43 CFR 3179.201(b)(1))***

The operator notifies the BLM through a Sundry Notice that use of a pneumatic controller with a bleed rate greater than 6 scf per hour is required based on functional needs that may include, but are not limited to, response time, safety, and positive actuation, and the Sundry Notice describes those functional needs.

***Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves (Pneumatic Controllers) (43 CFR 3179.201(b)(4) and 3175.201(c))***

The operator demonstrates to the BLM through a Sundry Notice, and the BLM agrees, that replacement of a pneumatic controller would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. The Sundry Notice must include the following information:

(1) The name, number, and location of each of the operator's wells, and the number of the lease, unit, or communitized area with which it is associated;

(2) The oil and gas production levels of each of the operator's wells on the lease, unit or communitized area for the most recent production month for which information is available;

(3) Data that show the costs of compliance;

(4) Projected costs of and the combined stream of revenues from both gas and oil production, including: the operator's projections of gas prices, gas production volumes, gas quality (i.e., heating value and H<sub>2</sub>S content), revenues derived from gas production, and royalty payments on gas production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less; and the operator's projections of oil prices, oil production volumes, costs, revenues, and royalty payments from the operator's oil and gas operations within the lease over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

***Showing in Support of Replacement of Pneumatic Controller within 3 Years (43 CFR 3179.201(d))***

The operator may replace a high-bleed pneumatic controller within 3 years of the effective date of the rule (instead of within 1 year of the effective date) if the operator notifies the BLM through a Sundry Notice that the well or facility that the pneumatic controller serves has an estimated remaining productive life of 3 years or less from the effective date of the rule.

***Pneumatic Diaphragm Pumps — Introduction***

With some exceptions, section 3179.202 pertains to any pneumatic diaphragm pump that:

(1) Uses natural gas produced from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or Indian lease; and (2) Is not subject to EPA

regulations at 40 CFR 60.5360 through 60.5390, but would be subject to those regulations if it were a new or modified source. This regulation generally requires replacement of such a pump with a zero-emissions pump or routing of the pump's exhaust gas to processing equipment for capture and sale within 1 year of the effective date of the final rule.

This requirement does not apply to pneumatic diaphragm pumps that do not vent exhaust gas to the atmosphere. In addition, this requirement does not apply if one of the following applies:

***Showing that a Pneumatic Diaphragm Pump was Operated on Fewer than 90 Individual Days in the Prior Calendar Year (43 CFR 3179.202(b)(2))***

A pneumatic diaphragm pump is not subject to section 3179.202 if the operator documents in a Sundry Notice that the pump was operated fewer than 90 days in the prior calendar year.

***Notification of Functional Needs for a Pneumatic Diaphragm Pump (43 CFR 3179.202(d))***

In lieu of replacing a pneumatic diaphragm pump or routing the pump exhaust gas to processing equipment, an operator may submit a Sundry Notice to the BLM showing that replacing the pump with a zero emissions pump is not viable because a pneumatic pump is necessary to perform the function required, and that routing the pump exhaust gas to processing equipment for capture and sale is technically infeasible or unduly costly.

***Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves (Pneumatic Diaphragm Pumps) (43 CFR 3179.202(f) and (g))***

An operator may be exempted from the replacement requirement if the operator submits a Sundry Notice to the BLM that provides an economic analysis that demonstrates, and the BLM agrees, that compliance with these requirements would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. The Sundry Notice must include the following information:

- (1) Well information that must include: (i) The name, number, and location of each well, and the number of the lease, unit, or communitized area with which it is associated; and (ii) The oil and gas production levels of each of the operator's wells on the lease, unit or communitized area for the most recent production month for which information is available;
- (2) Data that show the costs of compliance with paragraphs (c) through (e) of § 3179.202; and
- (3) The operator's estimate of the costs and revenues of the combined stream of revenues from both the gas and oil components, including: (i) The operator's projections of gas prices, gas production volumes, gas quality (i.e., heating value and H<sub>2</sub>S content), revenues derived from gas production, and royalty payments on gas production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less; and (ii) the operator's projections of oil prices, oil production volumes, costs, revenues, and royalty payments from the operator's oil and gas operations within the lease over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

***Showing in Support of Replacement of Pneumatic Diaphragm Pump within 3 Years***  
***(43 CFR 3179.202(h))***

The operator may replace a pneumatic diaphragm pump within 3 years of the effective date of the rule (instead of within 1 year of the effective date) if the operator notifies the BLM through a Sundry Notice that the well or facility that the pneumatic controller serves has an estimated remaining productive life of 3 years or less from the effective date of the rule.

***Storage Vessels (43 CFR 3179.203(c))***

A storage vessel is subject to 43 CFR 3179.203(c) if the vessel: (1) contains production from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or Indian lease; and (2) Is not subject to any of the requirements of EPA regulations at 40 CFR part 60, subpart OOOO, but would be subject to that subpart if it were a new or modified source.

Within 60 days after the effective date of this section, and within 30 days after any new source of production is added to the tank, the operator must determine, record, and make available to the BLM upon request, whether the storage vessel has the potential for VOC emissions equal to or greater than 6 tpy based on the maximum average daily throughput for a 30-day period of production. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority that limit the VOC emissions to less than 6 tpy.

If a storage vessel has the potential for VOC emissions equal to or greater than 6 tpy, no later than 1 year after the effective date of this section, or 3 years if the operator must and will replace the storage vessel at issue in order to comply with the requirements of this section, the operator must:

- (1) Route all tank vapor gas from the storage vessel to a sales line;
- (2) If the operator determines that compliance with paragraph (c)(1) of this section is technically infeasible or unduly costly, route all tank vapor gas from the storage vessel to a device or method that ensures continuous combustion of the tank vapor gas; or
- (3) Submit an economic analysis to the BLM through a Sundry Notice that demonstrates, and the BLM agrees, based on the information identified in paragraph (d) of this section, that compliance with paragraph (c)(2) of this section would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

To support the demonstration described above, the operator must submit a Sundry Notice that includes the following information:

- (1) The name, number, and location of each well, and the number of the lease, unit, or communitized area with which it is associated;
- (2) The oil and gas production levels of each of the operator's wells on the lease, unit or communitized area for the most recent production month for which information is available;
- (3) Data that show the costs of compliance with paragraph (c)(1) or (c)(2) of this section on the lease; and
- (4) The operator must consider the costs and revenues of the combined stream of revenues from both the gas and oil components, including: the operator's projections of oil and gas prices, production volumes, quality (i.e., heating value and H<sub>2</sub>S content), revenues derived from production, and royalty payments on production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

***Downhole Well Maintenance and Liquids Unloading — Documentation and Reporting***  
***(43 CFR 3179.204(c) and (e))***

The operator must minimize vented gas and the need for well venting associated with downhole well maintenance and liquids unloading, consistent with safe operations.

Before the operator manually purges a well for liquids unloading for the first time after the effective date of this section, the operator must consider other methods for liquids unloading and determine that they are technically infeasible or unduly costly. The operator must provide information supporting that determination as part of a Sundry Notice within 30 calendar days after the first liquids unloading event by manual or automated well purging conducted after the effective date of this section. This requirement applies to each well the operator operates.

For any liquids unloading by manual well purging, the operator must:

- (1) Ensure that the person conducting the well purging remains present on-site throughout the event to minimize to the maximum extent practicable any venting to the atmosphere;
  - (2) Record the cause, date, time, duration, and estimated volume of each venting event;
- and
- (3) Maintain the records for the period required under § 3162.4-1 and make them available to the BLM, upon request.

***Downhole Well Maintenance and Liquids Unloading — Notification of Excessive Duration or Volume (43 CFR 3179.204(f))***

The operator must notify the BLM by Sundry Notice, within 30 calendar days, if:

- (1) The cumulative duration of manual well purging events for a well exceeds 24 hours during any production month; or

(2) The estimated volume of gas vented in liquids unloading by manual well purging operations for a well exceeds 75 Mcf during any production month.

***Leak Detection — Compliance with EPA Regulations (43 CFR 3179.301(j))***

Sections 3179.301 through 3179.305 include information collection activities pertaining to the detection and repair of gas leaks during production operations. These regulations require operators to inspect all equipment covered under § 3179.301(a) for gas leaks. Section 3179.301(k) allows an operator to satisfy the requirements of §§ 3179.301 through 3179.305 for all of the equipment on a given lease by notifying the BLM in a Sundry Notice that the operator is applying the EPA subpart OOOOa fugitive emissions requirements to such equipment.

***Leak Detection — Request to Use an Alternative Monitoring Device and Protocol (43 CFR 3179.302(c))***

Section 3175.302 specifies the instruments and methods that an operator may use to detect leaks. Section 3175.302(d) allows the BLM to approve an alternative monitoring device and associated inspection protocol if the BLM finds that the alternative would achieve equal or greater reduction of gas lost through leaks compared with the approach specified in §3179.302(a)(1) when used according to § 3179.303(a).

Any person may request approval of an alternative monitoring device and protocol by submitting a Sundry Notice to BLM that includes the following information: (1) Specifications of the proposed monitoring device, including a detection limit capable of supporting the desired function; (2) The proposed monitoring protocol using the proposed monitoring device, including how results will be recorded; (3) Records and data from laboratory and field testing, including but not limited to performance testing;



(4) A demonstration that the proposed monitoring device and protocol will achieve equal or greater reduction of gas lost through leaks compared with the approach specified in the regulations; (5) Tracking and documentation procedures; and (6) Proposed limitations on the types of sites or other conditions on deploying the device and the protocol to achieve the demonstrated results.

***Leak Detection — Operator Request to Use an Alternative Leak Detection Program***  
***(43 CFR 3179.303(b))***

Section 3179.303(b) allows an operator to submit a Sundry Notice requesting authorization to detect gas leaks using an alternative instrument-based leak detection program, different from the specified requirement to inspect each site semi-annually using an approved monitoring device.

To obtain approval for an alternative leak detection program, the operator must submit a Sundry Notice that includes the following information:

- (1) A detailed description of the alternative leak detection program, including how it will use one or more of the instruments specified in or approved under § 3179.302(a) and an identification of the specific instruments, methods and/or practices that would substitute for specific elements of the approach specified in §§ 3179.302(a) and 3179.303(a);
- (2) The proposed monitoring protocol;
- (3) Records and data from laboratory and field testing, including, but not limited to, performance testing, to the extent relevant;
- (4) A demonstration that the proposed alternative leak detection program will achieve equal or greater reduction of gas lost through leaks compared to compliance with the requirements specified in §§ 3179.302(a) and 3179.303(a);

(5) A detailed description of how the operator will track and document its procedures, leaks found, and leaks repaired; and

(6) Proposed limitations on types of sites or other conditions on deployment of the alternative leak detection program.

***Leak Detection — Operator Request for Exemption Allowing Use of an Alternative Leak-Detection Program that Does Not Meet Specified Criteria (43 CFR 3179.303(d))***

An operator may seek authorization for an alternative leak detection program that does not achieve equal or greater reduction of gas lost through leaks compared to the required approach, if the operator demonstrates that compliance with the leak-detection regulations (including the option for an alternative program under 43 CFR 3179.303(b)) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil or gas reserves under the lease. The BLM may approve an alternative leak detection program that does not achieve equal or greater reduction of gas lost through leaks, but is as effective as possible consistent with not causing the operator to cease production and abandon significant recoverable oil or gas reserves under the lease.

To obtain approval for an alternative program under this provision, the operator must submit a Sundry Notice that includes the following information:

(1) The name, number, and location of each well, and the number of the lease, unit, or communitized area with which it is associated;

(2) The oil and gas production levels of each of the operator's wells on the lease, unit or communitized area for the most recent production month for which information is available;

(3) Data that show the costs of compliance on the lease with the requirements of §§ 3179.301-305 and with an alternative leak detection program that meets the requirements of §3179.303(b);

(4) The operator must consider the costs and revenues of the combined stream of revenues from both the gas and oil components and provide the operator's projections of oil and gas prices, production volumes, quality (i.e., heating value and H<sub>2</sub>S content), revenues derived from production, and royalty payments on production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less;

(5) The information required to obtain approval of an alternative program under §3179.303(b), except that the estimated volume of gas that will be lost through leaks under the alternative program must be compared to the volume of gas lost under the required program, but does not have to be shown to be at least equivalent.

***Leak Detection —Notification of Delay in Repairing Leaks (43 CFR 3179.304(a))***

Section 3179.304(a) requires an operator to repair any leak no later than 30 calendar days after discovery of the leak, unless there is good cause for delay in repair. If there is good cause for a delay beyond 30 calendar days, section 3179.304(b) requires the operator to submit a Sundry Notice notifying the BLM of the cause.

***Leak Detection —Inspection Recordkeeping and Reporting (43 CFR 3179.305)***

Section 3179.305 requires operators to maintain the following records and make them available to the BLM upon request: (1) For each inspection required under § 3179.303, documentation of the date of the inspection and the site where the inspection was conducted; (2) The monitoring method(s) used to determine the presence of leaks; (3) A list of leak components on which leaks were found; (4) The date each leak was repaired;

and (5) The date and result of the follow-up inspection(s) required under § 3179.304. By March 31 each calendar year, the operator must provide to the BLM an annual summary report on the previous year's inspection activities that includes: (1) The number of sites inspected; (2) The total number of leaks identified, categorized by the type of component; (3) The total number of leaks repaired; (4) The total number of leaks that were not repaired as of December 31 of the previous calendar year due to good cause and an estimated date of repair for each leak; and (5) A certification by a responsible officer that the information in the report is true and accurate.

***Leak Detection —Annual Reporting of Inspections (43 CFR 3179.305(b))***

By March 31 each calendar year, the operator must provide to the BLM an annual summary report on the previous year's inspection activities that includes:

- (1) The number of sites inspected;
- (2) The total number of leaks identified, categorized by the type of component;
- (3) The total number of leaks repaired;
- (4) The total number leaks that were not repaired as of December 31 of the previous calendar year due to good cause and an estimated date of repair for each leak.
- (5) A certification by a responsible officer that the information in the report is true and accurate to the best of the officer's knowledge.

**4. Burden Estimates**

The following table details the estimated annual burdens of activities that would involve APDs and Sundry Notices, the use of which has been authorized under Control Number 1004-0137.

**Estimated Hour Burdens**

<b>A. Type of Response</b>	<b>B. Number of Responses</b>	<b>C. Hours per Response</b>	<b>D. Total Hours (Column B x Column C)</b>
Plan to Minimize Waste of Natural Gas 43 CFR 3162.3-1 Form 3160-3	2,000	8	16,000
Request for Approval for Royalty-Free Uses On-Lease or Off-Lease 43 CFR 3178.5, 3178.7, 3178.8, and 3178.9 Form 3160-5	50	4	200
Notification of Choice to Comply on County- or State-wide Basis 43 CFR 3179.7(c)(3)(iii)	200	1	200
Request for Approval of Alternative Capture Requirement 43 CFR 3179.8(b) Form 3160-5	50	16	800
Request for Exemption from Well Completion Requirements 43 CFR 3179.102(c) and (d) Form 3160-5	0	0	0
Request for Extension of Royalty-Free Flaring During Initial Production Testing 43 CFR 3179.103 Form 3160-5	500	2	1000

<b>A. Type of Response</b>	<b>B. Number of Responses</b>	<b>C. Hours per Response</b>	<b>D. Total Hours (Column B x Column C)</b>
Request for Extension of Royalty-Free Flaring During Subsequent Well Testing 43 CFR 3179.104 Form 3160-5	5	2	10
Reporting of Venting or Flaring 43 CFR 3179.105 Form 3160-5	250	2	500
Notification of Functional Needs for a Pneumatic Controller 43 CFR 3179.201(b)(1) Form 3160-5	10	2	20
Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves 43 CFR 3179.201(b)(4) and 3179.201(c) Form 3160-5	50	4	200
Showing in Support of Replacement of Pneumatic Controller within 3 Years 43 CFR 3179.201(d) Form 3160-5	100	1	100

<b>A. Type of Response</b>	<b>B. Number of Responses</b>	<b>C. Hours per Response</b>	<b>D. Total Hours (Column B x Column C)</b>
Showing that a Pneumatic Diaphragm Pump was Operated on Fewer than 90 Individual Days in the Prior Calendar Year 43 CFR 3179.202(b)(2) Form 3160-5	100	1	100
Notification of Functional Needs for a Pneumatic Diaphragm Pump 43 CFR 3179.202(d) Form 3160-5	150	1	150
Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves 43 CFR 3179.202(f) and (g) Form 3160-5	10	4	40
Showing in Support of Replacement of Pneumatic Diaphragm Pump within 3 Years 43 CFR 3179.202(h) Form 3160-5	100	1	100
Storage Vessels 43 CFR 3179.203(c) Form 3160-5	50	4	200

<b>A. Type of Response</b>	<b>B. Number of Responses</b>	<b>C. Hours per Response</b>	<b>D. Total Hours (Column B x Column C)</b>
Downhole Well Maintenance and Liquids Unloading — Documentation and Reporting 43 CFR 3179.204(c) and (e) Form 3160-5	5,000	1	5,000
Downhole Well Maintenance and Liquids Unloading — Notification of Excessive Duration or Volume 43 CFR 3179.204(f) Form 3160-5	250	1	250
Leak Detection — Compliance with EPA Regulations 43 CFR 3179.301(j) Form 3160-5	50	4	200
Leak Detection — Request to Use an Alternative Monitoring Device and Protocol 43 CFR 3179.302(c) Form 3160-5	5	40	200
Leak Detection — Operator Request to Use an Alternative Leak Detection Program 43 CFR 3179.303(b) Form 3160-5	20	40	800



<b>A. Type of Response</b>	<b>B. Number of Responses</b>	<b>C. Hours per Response</b>	<b>D. Total Hours (Column B x Column C)</b>
Leak Detection — Operator Request for Exemption Allowing Use of an Alternative Leak-Detection Program that Does Not Meet Specified Criteria 43 CFR 3179.303(d) Form 3160-5	150	20	3,000
Leak Detection — Notification of Delay in Repairing Leaks 43 CFR 3179.304(a) Form 3160-5	100	1	100
Leak Detection — Inspection Recordkeeping and Reporting 43 CFR 3179.305	52,000	.25	13,000
Leak Detection — Annual Reporting of Inspections 43 CFR 3179.305(b) Form 3160-5	2,000	20	40,000
Totals	63,200	—	82,170

### **I. National Environmental Policy Act**

The BLM prepared a draft environmental assessment (EA) to determine whether issuance of this proposed regulation pertaining to oil and gas waste prevention and royalty clarification would constitute a “major Federal action significantly affecting the quality of the human environment” under Section 102(2)(C) of the National Environmental Policy Act (NEPA). This EA was posted for public comment for a period of 75 days, from February 8 through April 22, 2016. During the public comment period for the

proposed rule and draft EA, BLM received comments that further informed the analysis of the potential environmental impacts of the rule. In response to these comments, BLM incorporated changes in the final EA, which will be released concomitantly with the rule. The BLM believes that the rule would benefit the environment by reducing emissions of methane (a potent GHG), VOCs (which contribute to smog), and hazardous air pollutants such as benzene (a known carcinogen). In addition, the rule would reduce light pollution and other impacts from flaring. These reductions would contribute to a more robust environmental quality overall. BLM has determined that the rule may also have a certain degree of adverse environmental impacts, primarily due to land disturbance from increased or accelerated construction of gas gathering lines or pipelines and compressors and/or increased truck traffic on existing disturbed surfaces from the increased use of mobile capture technology. After careful consideration of the impacts and alternatives discussed in the final EA, BLM has determined that this action does not meet the criteria of significance under 40 CFR 1508.27 either in terms of context or intensity; therefore, BLM finds that the promulgation of the rule has no significant impact.

**J. 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.”

Since the compliance costs for this rule would represent such a small fraction of company net incomes, we believe that the rule is unlikely to impact the investment decisions of firms. Also, the incremental production of gas estimated to result from the rule’s enactment constitutes a small fraction of total U.S. production, and any potential and temporary deferred production of oil would likewise constitute a small fraction of total U.S. production. For these reasons, we do not expect that the final rule will significantly impact the supply, distribution, or use of energy. As such, the rulemaking is not a “significant energy action” as defined in Executive Order 13211.

#### **K. Executive Order 13563, Improving Regulation and Regulatory Review**

Executive Order 13563 reaffirms the principles of E.O. 12866 while calling for improvements in the nation’s regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The executive order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the

public where these approaches are relevant, feasible, and consistent with regulatory objectives. E.O. 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. We have developed this final rule in a manner consistent with these requirements.

## **X. Authors**

The principal authors of this rule are: Timothy Spisak and James Tichenor of the BLM Washington Office; Eric Jones of the BLM Moab, Utah Field Office; and David Mankiewicz of the BLM Farmington, New Mexico Field Office; assisted by Faith Bremner of the staff of the BLM's Regulatory Affairs Division.

## **List of Subjects**

### **43 CFR part 3100**

Government contracts; Mineral royalties; Oil and gas reserves; Public lands-mineral resources; Reporting and recordkeeping requirements; Surety bonds.

### **43 CFR part 3160**

Administrative practice and procedure; Government contracts; Indians-lands; Mineral royalties; Oil and gas exploration; Penalties; Public lands--mineral resources; Reporting and recordkeeping requirements.

### **43 CFR part 3170**

Administrative practice and procedure; Flaring; Government contracts; Incorporation by reference; Indians-lands; Mineral royalties; Immediate assessments; Oil and gas exploration; Oil and gas measurement; Public lands--mineral resources; Reporting and record keeping requirements; Royalty-free use; Venting.

Dated: November 14, 2016.

Amanda Leiter  
Acting Assistant Secretary  
Land and Minerals Management

## **43 CFR Chapter II**

For the reasons set out in the preamble, the Bureau of Land Management amends 43 CFR parts 3100 , 3160 and 3170 as follows:

### **PART 3100 – ONSHORE OIL AND GAS LEASING**

1. Amend the authority citation for part 3100 to read as follows:

**AUTHORITY:** 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359 and 1751; 43 U.S.C. 1732(b), 1733, and 1740; and the Energy Policy Act of 2005 (Pub. L. 109-58).

2. Revise § 3103.3-1 to read as follows:

#### **§ 3103.3-1 Royalty on production.**

(a) Royalty on production will be payable only on the mineral interest owned by the United States. Royalty must be paid in amount or value of the production removed or sold as follows:

(1) For leases issued on or before January 17, 2017, the rate prescribed in the lease or in applicable regulations at the time of lease issuance;

(2) For leases issued January 17, 2017:

(i) 12½ percent on all noncompetitive leases;

(ii) A rate of not less than 12½ percent on all competitive leases, exchange and renewal leases, and leases issued in lieu of unpatented oil placer mining claims under §3108.2–4 of this title;

(3) 16 2/3 percent on noncompetitive leases reinstated under § 3108.2-3 of this title plus an additional 2 percentage-point increase added for each succeeding reinstatement;

(4) The rate used for royalty determination that appears in a lease that is reinstated or that is in force for competitive leases at the time of issuance of the lease that is reinstated, plus

4 percentage points, plus an additional 2 percentage points for each succeeding reinstatement.

(b) Leases that qualify under specific provisions of the Act of August 8, 1946 (30 U.S.C. 226c) may apply for a limitation of a 12½ percent royalty rate.

(c) The average production per well per day for oil and gas will be determined pursuant to 43 CFR 3162.7-4.

(d) Payment of a royalty on the helium component of gas will not convey the right to extract the helium from the gas stream. Applications for the right to extract helium from the gas stream will be made under part 16 of this title.

#### PART 3160 – ONSHORE OIL AND GAS OPERATIONS

3. The authority citation for part 3160 continues to read as follows:

AUTHORITY: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733, and 1740.

§ 3160.0-5 [Amended]

4. Amend § 3160.0-5 by removing the definition of “Avoidably lost.”

5. Amend § 3162.3-1 by adding paragraph (j) to read as follows:

#### **§ 3162.3-1 Drilling applications and plans.**

\* \* \* \* \*

(j) When submitting an Application for Permit to Drill an oil well, the operator must also submit a plan to minimize waste of natural gas from that well. The waste minimization plan must accompany, but would not be part of, the Application for Permit to Drill. The waste minimization plan must set forth a strategy for how the operator will comply with the requirements of 43 CFR subpart 3179 regarding control of waste from venting and

flaring, and must explain how the operator plans to capture associated gas upon the start of oil production, or as soon thereafter as reasonably possible, including an explanation of why any delay in capture of the associated gas would be required. Failure to submit a complete and adequate waste minimization plan is grounds for denying or disapproving an Application for Permit to Drill. The waste minimization plan must include the following information:

- (1) The anticipated completion date of the proposed well(s);
- (2) A description of anticipated production, including:
  - (i) The anticipated date of first production;
  - (ii) The expected oil and gas production rates and duration from the proposed well. If the proposed well is on a multi-well pad, the plan should include the total expected production for all wells being completed;
  - (iii) The expected production decline curve of both oil and gas from the proposed well;and
  - (iv) The expected Btu value for gas production from the proposed well.
- (3) Certification that the operator has provided one or more midstream processing companies with information about the operator's production plans, including the anticipated completion dates and gas production rates of the proposed well or wells;
- (4) Identification of a gas pipeline to which the operator plans to connect, with sufficient capacity to accommodate the anticipated production of the proposed well(s), and information on the pipeline, including, to the extent that the operator can obtain it, the following information:
  - (i) Maximum current daily capacity of the pipeline;



- (ii) Current throughput of the pipeline;
  - (iii) Anticipated daily capacity of the pipeline at the anticipated date of first gas sales from the proposed well;
  - (iv) Anticipated throughput of the pipeline at the anticipated date of first gas sales from the proposed well; and
  - (v) Any plans known to the operator for expansion of pipeline capacity for the area that includes the proposed well; and
- (5) If an operator cannot identify a gas pipeline with sufficient capacity to accommodate the anticipated production of the proposed well(s), the waste minimization plan must also include:
- (i) A gas pipeline system location map of sufficient detail, size, and scale as to show the field in which the proposed well will be located, and all existing gas trunklines within 20 miles of the well. The map should also contain:
    - (A) The name and location of the gas processing plant(s) closest to the proposed well(s), and of the intended destination processing plant, if different;
    - (B) The location and name of the operator of each gas trunkline within 20 miles of the proposed well;
    - (C) The proposed route and tie-in point that connects or could connect the subject well to an existing gas trunkline;
  - (ii) The total volume of produced gas, and percentage of total produced gas, that the operator is currently flaring or venting from wells in the same field and any wells within a 20-mile radius of that field; and

(iii) A detailed evaluation, including estimates of costs and returns, of opportunities for on-site capture approaches, such as compression or liquefaction of natural gas, removal of natural gas liquids, or generation of electricity from gas.

## **PART 3170 – ONSHORE OIL AND GAS PRODUCTION**

6. The authority citation for part 3170 continues to read as follows:

AUTHORITY: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733, and 1740.

7. Add subparts 3178 and 3179 to part 3170, to read as follows:

### **Subpart 3178 – Royalty-Free Use of Lease Production**

Sec.

3178.1 Purpose.

3178.2 Scope.

3178.3 Production on which a royalty is not due.

3178.4 Uses of oil or gas on lease, unit, or communitized area that do not require prior written BLM approval for royalty-free treatment of volumes used.

3178.5 Uses of oil or gas on a lease, unit, or communitized area that require prior written BLM approval for royalty-free treatment of volumes used.

3178.6 Uses of oil or gas moved off the lease, unit, or communitized area that do not require prior written approval for royalty-free treatment of volumes used.

3178.7 Uses of oil or gas moved off the lease, unit, or communitized area that require prior written approval for royalty-free treatment of volumes used.

3178.8 Measurement or estimation of volumes of oil or gas that are used royalty-free.

3178.9 Requesting approval of royalty-free treatment when approval is required.

3178.10 Facility and equipment ownership.

### **Subpart 3179 – Waste Prevention and Resource Conservation**

Sec.

3179.1 Purpose.

3179.2 Scope.

3179.3 Definitions and acronyms.

3179.4 Determining when the loss of oil or gas is avoidable or unavoidable.

3179.5 When lost production is subject to royalty.

3179.6 Venting prohibition.

3179.7 Gas capture requirement.

- 3179.8 Alternative limits on venting and flaring.
- 3179.9 Measuring and reporting volumes of gas vented and flared from wells.
- 3179.10 Determinations regarding royalty-free venting or flaring.
- 3179.11 Other waste-prevention measures.
- 3179.12 Coordination with State regulatory authority.

### **Flaring and Venting Gas During Drilling and Production Operations**

- 3179.101 Well drilling.
- 3179.102 Well completion and related operations.
- 3179.103 Initial production testing.
- 3179.104 Subsequent well tests.
- 3179.105 Emergencies.

### **Gas Flared or Vented from Equipment During Well Maintenance Operations**

- 3179.201 Equipment requirements for pneumatic controllers.
- 3179.202 Requirements for pneumatic chemical injection pumps or pneumatic diaphragm pumps.
- 3179.203 Storage vessels.
- 3179.204 Downhole well maintenance and liquids unloading.

### **Leak Detection and Repair (LDAR)**

- 3179.301 Operator responsibility.
- 3179.302 Approved instruments and methods.
- 3179.303 Leak detection and inspection requirements for natural gas wellhead equipment, facilities, and compressors.
- 3179.304 Repairing leaks.
- 3179.305 Leak detection inspection recordkeeping.

### **State or Tribal Variances**

- 3179.401 State or tribal requests for variances from the requirements of this subpart.

#### **§ 3178.1 Purpose.**

The purpose of this subpart is to address the circumstances under which oil or gas produced from Federal and Indian leases may be used royalty-free in operations on the lease, unit, or communitized area. This subpart supersedes those portions of Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases, Royalty or

Compensation for Oil or Gas Lost (NTL-4A), , pertaining to oil or gas used for beneficial purposes.

**§ 3178.2 Scope.**

(a) This subpart applies to:

(1) All onshore Federal and Indian (other than Osage Tribe) oil and gas leases, units, and communitized areas, except as otherwise provided in this subpart;

(2) Indian Mineral Development Act (IMDA) oil and gas agreements, unless specifically excluded in the agreement or unless the relevant provisions of this subpart are inconsistent with the agreement;

(3) Leases and other business agreements and contracts for the development of tribal energy resources under a Tribal Energy Resource Agreement entered into with the Secretary, unless specifically excluded in the lease, other business agreement, or Tribal Energy Resource Agreement;

(4) Committed State or private tracts in a federally approved unit or communitization agreement defined by or established under 43 CFR subpart 3105 or 43 CFR part 3180; and

(5) All onshore wells, and production equipment located on a Federal or Indian lease or a federally approved unit or communitized area, and compressors located on a Federal or Indian lease or a federally approved unit or communitized area and which compress production from the same Federal or Indian lease or federally approved unit or communitized area.

(b) For purposes of this subpart, the term “lease” also includes IMDA agreements.

**§ 3178.3 Production on which royalty is not due.**

(a) To the extent specified in §§ 3178.4 and 3178.5, royalty is not due on:

(1) Oil or gas that is produced from a lease or communitized area and used for operations and production purposes (including placing oil or gas in marketable condition) on the same lease or communitized area without being removed from the lease or communitized area; or

(2) Oil or gas that is produced from a unit PA and used for operations and production purposes (including placing oil or gas in marketable condition) on the unit, for the same unit PA, without being removed from the unit.

(b) For the uses described in § 3178.5, the operator must obtain prior written BLM approval for the volumes used for operational and production purposes to be royalty free.

**§ 3178.4 Uses of oil or gas on a lease, unit, or communitized area that do not require prior written BLM approval for royalty-free treatment of volumes used.**

(a) Oil or gas produced from a lease, unit, or communitized area may be used royalty-free for operations and production purposes on the lease, unit, or communitized area without prior written BLM approval in the following circumstances:

(1) Use of fuel to generate power or operate combined heat and power;

(2) Use of fuel to power equipment, including artificial lift equipment, equipment used for enhanced recovery, drilling rigs, and completion and workover equipment;

(3) Use of gas to actuate pneumatic controllers or operate pneumatic pumps at production facilities;

(4) Use of fuel to heat, separate, or dehydrate production;

(5) Use of gas as a pilot fuel or as assist gas for a flare, combustor, thermal oxidizer, or other control device;

- (6) Use of fuel to compress or treat gas to place it in marketable condition;
  - (7) Use of oil to clean the well and improve production, e.g., hot oil treatments. The operator must document the removal of the oil from the tank or pipeline under Onshore Oil and Gas Order No. 3 (Site Security), or any successor regulation;
  - (8) Use of oil as a circulating medium in drilling operations, if the use is part of an approved Drilling Plan under Onshore Oil and Gas Order No. 1;
  - (9) Injection of gas for the purpose of conserving gas or increasing the recovery of oil or gas, if the BLM has approved the injection under applicable regulations in parts 3100, 3160, or 3180 of this title; and
  - (10) Injection of gas that is cycled in a contained gas-lift system.
- (b) The volume to be treated as royalty free must not exceed the amount of fuel reasonably necessary to perform the operational function, using equipment of appropriate capacity.

**§ 3178.5 Uses of oil or gas on a lease, unit, or communitized area that require prior written BLM approval for royalty-free treatment of volumes used.**

- (a) Oil or gas produced from a lease, unit, or communitized area may also be used royalty-free for the following operations and production purposes on the lease, unit, or communitized area, but prior written BLM approval is required to ensure that production accountability is maintained:
- (1) Use of oil or gas that the operator removes from the pipeline at a location downstream of the Facility Measurement Point (FMP);
  - (2) Use of gas that has been removed from the lease, unit PA, or communitized area for treatment or processing because of particular physical characteristics of the gas that

require the gas to be treated or processed prior to use, where the gas is returned to, and used on, the lease, unit PA, or communitized area from which it was produced; and

(3) Any other types of use of produced oil or gas for operations and production purposes, which are not identified in § 3178.4.

(b)(1) The operator must obtain BLM approval to conduct activities under paragraph (a) of this section by submitting a Form 3160-5, Sundry Notices and Reports on Wells (Sundry Notice) containing the information required under § 3178.9. If the BLM disapproves a request for royalty-free treatment for volumes used under this section, the operator must pay royalties on such volumes. If the BLM approves a request for royalty-free treatment for volumes used under this section, such approval will be deemed effective from the date the request was filed.

(2) With respect to uses under paragraph (a)(1) of this section, the operator must measure the volume of oil or gas used in accordance with Onshore Oil and Gas Orders No. 4 (oil) and 5 (gas) as applicable, or other successor regulations.

(3) With respect to removals under paragraph (a)(2) of this section, the operator must measure any gas returned to the lease, unit, or communitized area under such an approval in accordance with Onshore Oil and Gas Order No. 5 or other successor regulations.

**§ 3178.6 Uses of oil or gas moved off the lease, unit, or communitized area that do not require prior written approval for royalty-free treatment of volumes used.**

Oil or gas used after being moved off the lease, unit, or communitized area may be treated as royalty free without prior written BLM approval only if the use meets the criteria under § 3178.4 and when:

(a) The oil or gas is transported from one area of the lease, unit, or communitized area to another area of the same lease, unit, or communitized area where it is used, and no oil or gas is added to or removed from the pipeline while crossing lands that are not part of the lease, unit, or communitized area; or

(b) A well is directionally drilled, the wellhead is not located on the producing lease, unit, or communitized area, and oil or gas is used on the same well pad for operations and production purposes for that well.

**§ 3178.7 Uses of oil or gas moved off the lease, unit, or communitized area that require prior written approval for royalty-free treatment of volumes used.**

(a) Except as provided in § 3178.6(b) and paragraph (b) of this section, royalty is owed on all oil or gas used in operations conducted off the lease, unit, or communitized area.

(b) The BLM may grant prior written approval to treat oil or gas used in operations conducted off the lease, unit, or communitized area as royalty free (referred to as off-lease royalty-free use) if the use is among those listed in § 3178.4(a) and § 3178.5(a) and if:

(1) The equipment or facility in which the operation is conducted is located off the lease, unit, or communitized area for engineering, economic, resource protection, or physical accessibility reasons; and

(2) The operations are conducted upstream of the FMP.

(c) The operator must obtain BLM approval under paragraph (b) of this section by submitting a Sundry Notice containing the information required under § 3178.9. If the BLM disapproves a request for royalty-free treatment for volumes used under this section, the operator must pay royalties on such volumes. If the BLM approves a request



for royalty-free treatment for volumes used under this section, such approval will be deemed effective from the date the request was filed.

(d) Approval of measurement or commingling off the lease, unit, or communitized area under other regulations does not constitute approval of off-lease royalty-free use. The operator or lessee must expressly request, and submit its justification for, approval of off-lease royalty-free use.

(e) If equipment or a facility located on a particular lease, unit, or communitized area treats oil or gas produced from properties that are not unitized or communitized with the property on which the equipment or facility is located, in addition to treating oil or gas produced from the lease, unit, or communitized area on which the equipment or facility is located, the operator may report as royalty free only that portion of the oil or gas used as fuel that is properly allocable to the share of production contributed by the lease, unit, or communitized area on which the equipment is located, unless otherwise authorized by the BLM under this section.

**§ 3178.8 Measurement or estimation of volumes of oil or gas that are used royalty-free.**

(a) The operator must measure or estimate the volumes of royalty-free gas used in operations upstream of the FMP.

(b) The operator must measure the volume of gas that is removed from the product stream downstream of the FMP and used royalty-free pursuant to sections 3178.4 through 3178.7.

(c) The operator must measure the volume of oil that is used royalty-free pursuant to sections 3178.4 through 3178.7. The operator must also document removal of such oil from the tank or pipeline.

(d) If the operator removes oil or gas downstream of the FMP and that oil or gas is used royalty-free pursuant to sections 3178.4 through 3178.7, the operator must apply for an FMP under section 3173.12 to measure the oil or gas that is removed for use.

(e) When estimating gas volumes, the operator must use the best available information to make a reasonable estimate.

(f) Each of the volumes required to be measured or estimated, as applicable, under this subpart, must be reported by the operator following applicable ONRR reporting requirements.

**§ 3178.9 Requesting approval of royalty-free treatment when approval is required.**

To request written approval of royalty-free use when required under § 3178.5 or § 3178.7, the operator must submit a Sundry Notice that includes the following information:

(a) A complete description of the operation to be conducted, including the location of all facilities and equipment involved in the operation and the location of the FMP;

(b) The volume of oil or gas that the operator expects will be used in the operation, and the method of measuring or estimating that volume;

(c) If the volume of gas expected to be used will be estimated, the basis for the estimate (e.g., equipment manufacturer's published consumption or usage rates); and

(d) The proposed disposition of the oil or gas used (e.g., whether gas used would be consumed as fuel, vented through use of a gas-activated pneumatic controller, returned to the reservoir, or used in some other way).

**§ 3178.10 Facility and equipment ownership.**

The operator is not required to own or lease the equipment or facility that uses oil or gas royalty free. The operator is responsible for obtaining all authorizations, measuring production, reporting production, and all other applicable requirements.

**Subpart 3179 – Waste Prevention and Resource Conservation**

**§ 3179.1 Purpose.**

The purpose of this subpart is to implement and carry out the purposes of statutes relating to prevention of waste from Federal and Indian (other than Osage Tribe) leases, conservation of surface resources, and management of the public lands for multiple use and sustained yield. This subpart supersedes those portions of Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases, Royalty or Compensation for Oil and Gas Lost (NTL-4A), , pertaining to, among other things, flaring and venting of produced gas, unavoidably and avoidably lost gas, and waste prevention.

**§ 3179.2 Scope.**

(a) This subpart applies to:

- (1) All onshore Federal and Indian (other than Osage Tribe) oil and gas leases, units, and communitized areas, except as otherwise provided in this subpart;
- (2) IMDA oil and gas agreements, unless specifically excluded in the agreement or unless the relevant provisions of this subpart are inconsistent with the agreement;

(3) Leases and other business agreements and contracts for the development of tribal energy resources under a Tribal Energy Resource Agreement entered into with the Secretary, unless specifically excluded in the lease, other business agreement, or Tribal Energy Resource Agreement;

(4) Committed State or private tracts in a federally approved unit or communitization agreement defined by or established under 43 CFR subpart 3105 or 43 CFR part 3180;

(5) All onshore wells, tanks, compressors, and other equipment located on a Federal or Indian lease or a federally approved unit or communitized area; and

(b) For purposes of this subpart, the term “lease” also includes IMDA agreements.

### **§ 3179.3 Definitions and acronyms.**

As used in this subpart, the term:

Accessible component means a component that can be reached, if necessary, by safe and proper use of portable ladders or by built-in ladders and walkways. Accessible components also include components that can be reached by the safe use of an extension on a monitoring probe.

Automatic ignition system means an automatic ignitor and, where needed to ensure continuous combustion, a continuous pilot flame.

Capture means the physical containment of natural gas for transportation to market or productive use of natural gas, and includes reinjection and royalty-free on-site uses pursuant to subpart 3178.

Capture infrastructure means any pipelines, facilities, or other equipment (including temporary or mobile equipment) used to capture, transport, or process gas. Capture

infrastructure includes, but is not limited to, equipment that compresses or liquefies natural gas, removes natural gas liquids, or generates electricity from gas.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Development oil well or development gas well means a well drilled to produce oil or gas, respectively, from an established field in which commercial quantities of hydrocarbons have been discovered and are being produced. For purposes of this subpart, the BLM will determine when a well is a development oil well or development gas well in the event of a disagreement between the BLM and the operator.

Gas-to-oil ratio (GOR) means the ratio of gas to oil in the production stream expressed in standard cubic feet of gas per barrel of oil.

Gas well means a well for which the energy equivalent of the gas produced, including its entrained liquefiable hydrocarbons, exceeds the energy equivalent of the oil produced. Unless more specific British thermal unit (Btu) values are available, a well with a gas-to-oil ratio greater than 6,000 standard cubic feet (scf) of gas per barrel of oil is a gas well. Except where gas has been re-injected into the reservoir, a mature oil well would not be

reclassified as a gas well even after normal production decline has caused the GOR to increase beyond 6,000 scf of gas per barrel of oil.

High pressure flare means an open-air flare stack or flare pit designed for the combustion of natural gas leaving a pressurized production vessel (such as a separator or heater-treater) that is not a storage vessel.

Leak means a release of natural gas from a component that is not associated with normal operation of the component, when such release is:

- (1) A visible hydrocarbon emission detected by use of an optical gas imaging instrument;
- (2) At least 500 ppm of hydrocarbon detected using a portable analyzer or other instrument that can measure the quantity of the release; or
- (3) Visible bubbles detected using soap solution.

Releases due to normal operation of equipment intended to vent as part of normal operations, such as gas-driven pneumatic controllers and safety release devices, are not considered leaks unless the releases exceed the quantities and frequencies expected during normal operations. Releases due to operator errors or equipment malfunctions or from control equipment at levels that exceed applicable regulatory requirements, such as releases from a thief hatch left open, a leaking vapor recovery unit, or an improperly sized combustor, are considered leaks.

Leak component means any component that has the potential to leak gas and can be monitored in the manner described in sections 3179.301 through 3179.305 of this subpart, including, but not limited to, valves, connectors, pressure relief devices, open-

ended lines, flanges, covers and closed vent systems, thief hatches or other openings on a storage vessel, compressors, instruments, and meters.

Liquid hydrocarbon means chemical compounds of hydrogen and carbon atoms that exist as a liquid under the temperature and pressure at which they are measured. The term is used to refer to oil, condensate, liquefied petroleum gas (LPG), liquefied natural gas (LNG), and natural gas liquids (NGL).

Liquids unloading means the removal of an accumulation of liquid hydrocarbons or water from the wellbore of a completed gas well.

Lost oil or lost gas means produced oil or gas that escapes containment, either intentionally or unintentionally, or is flared before being removed from the lease, unit, or communitized area, and cannot be recovered.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure, or temperature.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic), which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback, for a period that exceeds 60 days, is considered a storage vessel under this subpart unless the storage of the recovered liquids in the vessel is governed by § 3162.3-3 of this title. For purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less

than 180 consecutive days. This exclusion does not apply to well completion vessels or to storage vessels that are located at a site for at least 180 consecutive days.

(2) Process vessels such as surge control vessels, bottoms receivers, or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

(4) Tanks holding hydraulic fracturing fluid prior to implementation of an approved permanent disposal plan under Onshore Oil and Gas Order No.7.

Volatile organic compounds (VOC) has the same meaning as defined in 40 CFR 51.100(s).

**§ 3179.4 Determining when the loss of oil or gas is avoidable or unavoidable.**

For purposes of this subpart:

Unavoidably lost oil or gas means lost oil or gas provided that the operator has not been negligent; the operator has complied fully with applicable laws, lease terms, regulations, provisions of a previously approved operating plan, or other written orders of the BLM; and the oil or gas is:

(1) Produced oil or gas that is lost from the following operations or sources, and that cannot be recovered in the normal course of operations, where the operator has taken prudent and reasonable steps to avoid waste:

(i) Well drilling;

(ii) Well completion and related operations;

(iii) Initial production tests, subject to the limitations in § 3179.103;

(iv) Subsequent well tests, subject to the limitations in § 3179.104;

(v) Exploratory coalbed methane well dewatering;



- (vi) Emergencies, subject to the limitations in § 3179.105;
  - (vii) Normal operating losses from a natural gas-activated pneumatic controller or pump that is in compliance with § 3179.201 and § 3179.202;
  - (viii) Normal operating losses from a storage vessel or other low pressure production vessel that is in compliance with § 3179.203 and § 3174.5(b);
  - (ix) Well venting in the course of downhole well maintenance and/or liquids unloading performed in compliance with § 3179.204;
  - (x) Leaks, when the operator has complied with the leak detection and repair requirements in §§ 3179.301-305;
  - (xi) Facility and pipeline maintenance, such as when an operator must blow-down and depressurize equipment to perform maintenance or repairs; or
  - (xii) Flaring of gas from which at least 50 percent of natural gas liquids have been removed and captured for market, if the operator has notified the BLM through a Sundry Notice that the operator is conducting such capture; or
- (2) Produced gas that is flared or vented from a well that is not connected to a gas pipeline, provided the BLM has not determined loss of gas through such venting or flaring is otherwise avoidable.

Avoidably lost oil or gas means: lost oil or gas that is not “unavoidably lost,” as defined in paragraph (a) of this section; waste oil that became waste oil through operator negligence; and, any “excess flared gas,” as defined in § 3179.7.

**§ 3179.5 When lost production is subject to royalty.**

- (a) Royalty is due on all avoidably lost oil or gas.
- (b) Royalty is not due on any unavoidably lost oil or gas.

**§ 3179.6 Venting prohibition.**

(a) Gas well gas may not be flared or vented, except where it is unavoidably lost pursuant to §3179.4(a).

(b) The operator must flare rather than vent any gas that is not captured, except:

(1) When flaring the gas is technically infeasible, such as when the gas is not readily combustible or the volumes are too small to flare;

(2) Under emergency conditions, as defined in § 3179.105, when the loss of gas is uncontrollable or venting is necessary for safety;

(3) When the gas is vented through normal operation of a natural gas-activated pneumatic controller or pump;

(4) When the gas is vented from a storage vessel, provided that § 3179.203 does not require the combustion or flaring of the gas;

(5) When the gas is vented during downhole well maintenance or liquids unloading activities performed in compliance with § 3179.204;

(6) When the gas is vented through a leak, provided that the operator is in full compliance with §§ 3179.301 through 3179.305;

(7) When the gas venting is necessary to allow non-routine facility and pipeline maintenance to be performed, such as when an operator must, upon occasion, blow-down and depressurize equipment to perform maintenance or repairs; or

(8) When a release of gas is unavoidable under § 3179.4 and flaring is prohibited by Federal, State, local or Tribal law, regulation, or enforceable permit term.

(c) For purposes of this subpart, all flares or combustion devices must be equipped with an automatic ignition system.

**§ 3179.7 Gas capture requirement.**

(a) Except as provided in § 3179.8, on a monthly basis, each operator must capture for sale or use on site a volume of gas sufficient to meet the “capture percentage” requirement specified in paragraph (b) of this section.

(b) Beginning January 17, 2018, the operator’s capture percentage must equal:

(1) For each month during the period from January 17, 2018 until December 31, 2019: 85 percent;

(2) For each month during the period from January 1, 2020 until December 31, 2022: 90 percent;

(3) For each month during the period from January 1, 2023 until December 31, 2025: 95 percent; and

(4) For each month beginning January 1, 2026: 98 percent.

(c) The term “capture percentage” in this section means the “total volume of gas captured” over the “relevant area” divided by the “adjusted total volume of gas produced” over the “relevant area.”

(1) The term “total volume of gas captured” in this section means: for each month, the volume of gas sold from all of the operator’s development oil wells in the relevant area plus the volume of gas from such wells used on lease, unit, or communitized area in the relevant area.

(2) The term “adjusted total volume of gas produced” in this section means: the total volume of gas captured over the month plus the total volume of gas flared over the month from high pressure flares from all of the operator’s development oil wells that are in production in the relevant area, minus:

- (i) For each month from January 17, 2018 until December 31, 2018: 5,400 Mcf times the total number of development oil wells “in production” in the relevant area;
  - (ii) For each month in calendar year 2019: 3,600 Mcf times the total number of development oil wells in production in the relevant area;
  - (iii) For each month in calendar year 2020: 1,800 Mcf times the total number of development oil wells in production in the relevant area; and
  - (iv) For each month in calendar year 2021: 1,500 Mcf times the total number of development oil wells in production in the relevant area;
  - (v) For each month in calendar years 2022-2023: 1,200 Mcf times the total number of development oil wells in production in the relevant area;
  - (vi) For each month in calendar year 2024: 900 Mcf times the total number of development oil wells in production in the relevant area; and
  - (vii) For each month in calendar year 2025 and thereafter: 750 Mcf times the total number of development oil wells in production in the relevant area.
- (3) The term “relevant area” in this section means:
- (i) Each of the operator’s leases, units, or communitized areas; or
  - (ii) All of the operator’s development oil wells on leases, units, and communitized areas within a county or within a State, if the operator notifies the BLM by Sundry Notice by January 1, of the relevant year that the operator has chosen to comply on a county- or State-wide basis.
- (4) An oil well is considered “in production” only after the well has begun producing oil, and only during a month in which it produces gas (that is sold or flared) for 10 or more days.

(d) In any month in which the operator fails to meet the required capture percentage, the “excess flared gas” is royalty-bearing under § 3179.4. The term “excess flared gas” means:

Excess flared gas = (required capture percentage \* adjusted total volume of gas produced over the relevant area) - total volume of gas captured.

(e) For purposes of calculating royalties on an operator’s excess flared gas in a given month, the operator must prorate the excess flared gas across the relevant area to each lease, unit or communitized area that reported high-pressure flaring during the month.

**§ 3179.8 Alternative capture requirement.**

(a) With respect to leases issued before the effective date of this regulation, for operators choosing to comply with the capture requirement in § 3179.7 on a lease-by-lease, unit-by-unit, or communitized area-by-communitized area basis, the BLM may approve a capture percentage lower than the applicable capture percentage specified under § 3179.7, if the operator demonstrates, and the BLM agrees, that the applicable capture percentage under § 3179.7 would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

(b) To support a demonstration under paragraph (a) of this section, the operator must submit a Sundry Notice that includes the following information:

(1) The name, number, and location of each of the operator’s wells, and the number of the lease, unit, or communitized area with which it is associated;

(2) The oil and gas production levels of each of the operator’s wells on the lease, unit or communitized area for the most recent production month for which information is available and the volumes being vented and flared from each well;

(3) Map(s) showing:

(i) The entire lease, unit, or communitized area and the surrounding lands to a distance and on a scale that shows the field in which the well or wells are or will be located (if applicable), and all pipelines that could transport the gas from the well or wells;

(ii) All of the operator's producing oil and gas wells, which are producing from Federal or Indian leases (both on Federal or Indian leases and on other properties) within the map area;

(iii) Identification of all of the operator's wells within the lease, unit, or communitized area from which gas is flared or vented, and the location and distance of the nearest gas pipeline(s) to each such well, with an identification of those pipelines that are or could be available for connection and use; and

(iv) Identification of all of the operator's wells within the lease, unit, or communitized area from which gas is captured;

(4) Data that show pipeline capacity and the operator's projections of the cost associated with installation and operation of gas capture infrastructure, to the extent that the operator is able to obtain this information, as well as cost projections for alternative methods of transportation that do not require pipelines;

(5) Projected costs of and the combined stream of revenues from both gas and oil production, including:

(i) The operator's projections of gas prices, gas production volumes, gas quality (i.e., heating value and H<sub>2</sub>S content), revenues derived from gas production, and royalty payments on gas production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less; and

(ii) The operator's projections of oil prices, oil production volumes, costs, revenues, and royalty payments from the operator's oil and gas operations within the lease over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

(c) In establishing an alternative capture requirement under this section, the BLM will set the capture percentage at the highest level that the BLM determines, considering the information identified in paragraph (b) of this section, will not cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

**§ 3179.9 Measuring and reporting volumes of gas vented and flared.**

(a) The operator must estimate or measure all volumes of gas vented or flared from wells, facilities and equipment on a lease, unit PA, or communitized area and report those volumes under applicable ONRR reporting requirements.

(b) The operator may estimate such volumes, except:

(1) If the operator estimates that the volume of gas flared from a high pressure flare stack or manifold equals or exceeds an average of 50 Mcf per day for the life of the flare, or the previous 12 months, whichever is shorter, then, beginning January 17, 2018 the operator must either:

(i) Measure the volume of the flared gas; or

(ii) Calculate the volume of the flared gas based on the results of a regularly performed GOR test and measured values for the volumes of oil production and gas sales, so as to allow BLM to independently verify the volume, rate, and heating value of the flared gas;

or

(2) If the BLM determines and informs the operator that the additional accuracy offered by measurement is necessary for effective implementation of this Subpart, then the operator must measure the volume of the flared gas.

(c) If measurement or calculation is required under paragraph (b) of this section for a flare that is combusting gas that is combined across multiple leases, unit PAs, or communitized areas, the operator may measure or calculate the gas at a single point at the flare, but must use an allocation method approved by the BLM to allocate the quantities of flared gas to each lease, unit PA, or communitized area.

**§ 3179.10 Determinations regarding royalty-free flaring.**

(a) Approvals to flare royalty free, which are in effect as of the effective date of this rule, will continue in effect until January 17, 2018.

(b) The provisions of this subpart do not affect any determination made by the BLM before or after January 17, 2017, with respect to the royalty-bearing status of flaring that occurred prior to January 17, 2017.

**§ 3179.11 Other waste prevention measures.**

(a) If production from an oil well newly connected to a gas pipeline results or is expected to result in one or more producing wells already connected to the pipeline being forced off the pipeline, the BLM may exercise its authority under applicable laws and regulations, as well as its authority under the terms of applicable permits, orders, leases, and unitization or communitization agreements, to limit the production level from the new well until the pressure of gas production from the new well stabilizes at levels that allow transportation of gas from all wells connected to the pipeline.

(b) If gas capture capacity is not yet available on a given lease, the BLM may exercise its authority under applicable laws and regulations, as well as its authority under the terms of applicable permits, orders, leases, and unitization or communitization agreements, to delay action on an APD for that lease, or approve the APD with conditions for gas



capture or limitations on production. If the lease for which an APD is submitted is not yet producing, the BLM may direct or grant a lease suspension under 43 CFR 3103.4-4.

**§ 3179.12 Coordination with State regulatory authority.**

To the extent that any BLM action to enforce a prohibition, limitation, or order under this subpart may adversely affect production of oil or gas that comes from non-Federal and non-Indian mineral interests, the BLM will coordinate, on a case-by-case basis, with the State regulatory authority having jurisdiction over the oil and gas production from the non-Federal and non-Indian interests.

**FLARING AND VENTING GAS DURING DRILLING AND PRODUCTION OPERATIONS.**

**§ 3179.101 Well drilling.**

(a) Except as provided in § 3179.6 of this subpart, and unless technically infeasible, gas that reaches the surface as a normal part of drilling operations must be:

- (1) Captured and sold;
- (2) Directed to a flare pit or flare stack to combust any flammable gasses;
- (3) Used in operations on the lease, unit, or communitized area; or
- (4) Injected.

(b) If gas is lost as a result of loss of well control, the BLM will make a determination of whether the loss of well control is due to operator negligence. Such gas is avoidably lost if the BLM determines that the loss of well control is due to operator negligence. The BLM will notify the operator in writing when it makes a determination that gas was lost due to operator negligence.

**§ 3179.102 Well completion and related operations.**

(a) Except as provided in § 3179.6, and unless technically infeasible, after a well has been hydraulically fractured or refractured, gas that reaches the surface during well completion, post-completion, and fluid recovery operations must be:

(1) Captured and sold;

(2) Directed to a flare pit or flare stack to combust any flammable gasses, subject to the volumetric limitations in § 3179.103(a)(3);

(3) Used in operations on the lease, unit, or communitized area; or

(4) Injected.

(b) An operator will be deemed to be in compliance with the requirements of paragraph (a) of this section, if the operator is in compliance with the requirements for control of gas from well completions established under 40 CFR part 60, subpart OOOO or subpart OOOOa or if the well is not a “well affected facility” under either of those subparts.

(c) The requirements of paragraph (a) of this section will not apply where the operator demonstrates through a Sundry Notice, and the BLM agrees, that compliance with paragraph (a) of this section would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

(d) To support a demonstration under paragraph (d) of this section, the operator must submit a Sundry Notice that includes the following information:

(1) The name, number, and location of each of the operator’s wells, and the number of the lease, unit, or communitized area with which it is associated;

(2) The oil and gas production levels of each of the operator’s wells on the lease, unit or communitized area for the most recent production month for which information is available;

- (3) Data that show the costs of compliance with paragraph (a) of this section on the lease;
- (4) Projected costs of and the combined stream of revenues from both gas and oil production, including: the operator's projections of oil and gas prices, production volumes, quality (i.e., heating value and H<sub>2</sub>S content), revenues derived from production, and royalty payments on production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

**§ 3179.103 Initial production testing.**

- (a) Gas flared during a well's initial production test is royalty-free under §§ 3179.4(a)(1)(iii) and 3179.5(b) of this subpart until one of the following occurs:
  - (1) The operator determines that it has obtained adequate reservoir information for the well;
  - (2) 30 days have passed since the beginning of the production test, except as provided in paragraph (b) and paragraph (d) of this section;
  - (3) The operator has flared 20 million cubic feet (MMcf) of gas, when volumes flared under this section are combined with volumes flared under § 3179.102(a)(2), except as provided in paragraph (c) of this section; or
  - (4) Production begins.
- (b) The BLM may extend the period specified in paragraph (a)(2) not to exceed an additional 60 days, based on testing delays caused by well or equipment problems or if there is a need for further testing to develop adequate reservoir information.
- (c) The BLM may increase the limit specified in paragraph (a)(3) by up to an additional 30 million cubic feet of gas for exploratory wells in remote locations where additional testing is needed in advance of development of pipeline infrastructure.

(d) During the dewatering and initial evaluation of an exploratory coalbed methane well, the 30-day period specified in paragraph (a)(2) of this section is extended to 90 days.

The BLM may approve up to two extensions of this evaluation period, of up to 90 days each.

(e) The operator must submit its request for a longer test period or increased limit under paragraphs (b), (c), or (d) of this section using a Sundry Notice.

**§ 3179.104 Subsequent well tests.**

During well tests subsequent to the initial production test, the operator may flare gas for no more than 24 hours royalty free, unless the BLM approves or requires a longer period. The operator must request a longer period under this section using a Sundry Notice.

**§ 3179.105 Emergencies.**

(a) An operator may flare or, if flaring is not feasible given the emergency, vent gas royalty-free under § 3179.4(a)(vi) of this subpart during an emergency. For purposes of this subpart, an “emergency” is a temporary, infrequent and unavoidable situation in which the loss of gas or oil is uncontrollable or necessary to avoid risk of an immediate and substantial adverse impact on safety, public health, or the environment. For purposes of royalty assessment, an “emergency” is limited to a short-term situation of 24 hours or less (unless the BLM agrees that the emergency conditions necessitating venting or flaring extend for a longer period) caused by an unanticipated event or failure that is out of the operator’s control and was not due to operator negligence.

(b) The following do not constitute emergencies for the purposes of royalty assessment:

- (1) More than 3 failures of the same component within a single piece of equipment within any 365-day period;
  - (2) The operator's failure to install appropriate equipment of a sufficient capacity to accommodate the production conditions;
  - (3) Failure to limit production when the production rate exceeds the capacity of the related equipment, pipeline, or gas plant, or exceeds sales contract volumes of oil or gas;
  - (4) Scheduled maintenance;
  - (5) A situation caused by operator negligence; or
  - (6) A situation on a lease, unit, or communitized area that has already experienced 3 or more emergencies within the past 30 days, unless the BLM determines that the occurrence of more than 3 emergencies within the 30 day period could not have been anticipated and was beyond the operator's control.
- (c) Within 45 days of the start of the emergency, the operator must estimate and report to the BLM on a Sundry Notice the volumes flared or vented beyond the timeframes specified in paragraph (b) of this section.

**GAS FLARED OR VENTED FROM EQUIPMENT AND DURING WELL MAINTENANCE OPERATIONS**

**§ 3179.201 Equipment requirements for pneumatic controllers.**

- (a) A pneumatic controller that uses natural gas produced from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or Indian lease, is subject to this section if the pneumatic controller:
- (1) Has a continuous bleed rate greater than 6 standard cubic feet (scf) per hour; and

(2) Is not subject to any of the requirements of 40 CFR part 60, subpart OOOO or subpart OOOOa, but would be subject to one of those subparts if it were a new, modified, or reconstructed source.

(b) The operator must replace a pneumatic controller subject to this section with a controller (including but not limited to a continuous or intermittent pneumatic controller) having a bleed rate of 6 scf per hour or less within the timeframes set forth in paragraph (d) of this section, unless:

(1) Use of a pneumatic controller with a bleed rate greater than 6 scf per hour is required based on functional needs that may include, but are not limited to, response time, safety, and positive actuation, provided that the operator notifies the BLM through a Sundry Notice that describes the functional needs necessitating the use of a pneumatic controller with a bleed rate greater than 6 scf per hour;

(2) The pneumatic controller exhaust was, as of January 17, 2017 and continues to be, routed to a flare device or low-pressure combustor;

(3) The pneumatic controller exhaust is routed to processing equipment; or

(4) The operator notifies the BLM through a Sundry Notice and demonstrates, and the BLM agrees, based on the information identified in paragraph (c) of this section, that replacement of a pneumatic controller subject to paragraph (a)(1)(i) of this section would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

(c) To support a demonstration under paragraph (b)(4) of this section, the operator must submit a Sundry Notice that includes the following information:

- (1) The name, number, and location of each of the operator's wells, and the number of the lease, unit, or communitized area with which it is associated;
- (2) The oil and gas production levels of each of the operator's wells on the lease, unit or communitized area for the most recent production month for which information is available;
- (3) Data that show the costs of compliance with paragraph (b) of this section on the lease;
- (4) Projected costs of and the combined stream of revenues from both gas and oil production, including:
  - (i) The operator's projections of gas prices, gas production volumes, gas quality (i.e., heating value and H<sub>2</sub>S content), revenues derived from gas production, and royalty payments on gas production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less; and
  - (ii) The operator's projections of oil prices, oil production volumes, costs, revenues, and royalty payments from the operator's oil and gas operations within the lease over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.
- (d) The operator must replace the pneumatic controller(s) no later than 1 year after the effective date of this section as required under paragraph (b) of this section. If, however, the well or facility that the pneumatic controller serves has an estimated remaining productive life of 3 years or less from the effective date of this section, then the operator may notify the BLM through a Sundry Notice and replace the pneumatic controller no later than 3 years from the effective date of this section.
- (e) The operator must ensure pneumatic controllers are functioning within manufacturers' specifications.

**§ 3179.202 Requirements for pneumatic diaphragm pumps.**

(a) A pneumatic diaphragm pump is subject to this section if it:

(1) Uses natural gas produced from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or Indian lease; and

(2) Is not subject to any of the requirements of 40 CFR part 60, subpart OOOOa, but would be subject to that subpart if it were a new, modified or reconstructed source.

(b) An operator is not required to comply with paragraphs (c) through (h), with respect to a pneumatic diaphragm pump or pumps if:

(1) The pump does not vent exhaust gas to the atmosphere; or

(2) The operator submits a Sundry Notice to the BLM documenting that the pump(s) operated on less than 90 individual days in the prior calendar year.

(c) For each pneumatic diaphragm pump subject to this section and within the timeframes set forth in paragraph (h) of this section, the operator must:

(1) Replace the pump with a zero-emissions pump, which may be an electric-powered pump; or

(2) Route the pump exhaust gas to processing equipment for capture and sale.

(d) As an alternative to compliance with paragraph (c), the operator may route the pump exhaust gas to a flare or low pressure combustor device within the timeframes set forth in paragraph (h) of this section, if the operator determines and notifies the BLM through a Sundry Notice that:

(1) Replacing the pump with a zero-emissions pump is not viable because a pneumatic pump is necessary to perform the function required; and



(2) Routing the pump exhaust gas to processing equipment for capture and sale is technically infeasible or unduly costly.

(e) If the operator has met the criteria in paragraph (d) allowing the operator to use the compliance alternative provided in paragraph (d), but the operator has no flare or low pressure combustor device on site, or routing the exhaust gas to such a flare or low pressure combustor device would be technically infeasible, the operator need take no further action to comply with paragraphs (c) through (h).

(f) An operator that is required to replace a pump or route the exhaust gas from a pump to capture or a flare or combustion device under this section, may nonetheless be exempt from such requirement if the operator submits a Sundry Notice to the BLM that provides an economic analysis that demonstrates, and the BLM agrees, based on the information identified in paragraph (g) of this section, that compliance with the provisions of this section would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

(g) The Sundry Notice described in paragraph (f) must include the following information:

(1) Well information must include:

(i) The name, number, and location of each well, and the number of the lease, unit, or communitized area with which it is associated; and

(ii) The oil and gas production levels of each of the operator's wells on the lease, unit or communitized area for the most recent production month for which information is available;

(2) Data that show the costs of compliance with paragraphs (c) through (e) of this section on the lease;

(3) The operator must consider the costs and revenues of the combined stream of revenues from both the gas and oil components and provide:

(i) The operator's projections of gas prices, gas production volumes, gas quality (i.e., heating value and H<sub>2</sub>S content), revenues derived from gas production, and royalty payments on gas production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less; and

(ii) The operator's projections of oil prices, oil production volumes, costs, revenues, and royalty payments from the operator's oil and gas operations within the lease over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

(h) The operator must replace the pneumatic diaphragm pump(s) or route the exhaust gas to capture or to a flare or combustion device no later than 1 year after the effective date of this section, except that if the operator will comply with paragraph (c) of this section by replacing the pneumatic diaphragm pump with a zero-emission pump and the well or facility that the pneumatic diaphragm pump serves has an estimated remaining productive life of 3 years or less from the effective date of this section, the operator must notify the BLM through a Sundry Notice and replace the pneumatic diaphragm pump no later than 3 years from the effective date of this section.

(i) The operator must ensure its pneumatic diaphragm pumps are functioning within manufacturers' specifications.

**§ 3179.203 Storage vessels.**

(a) A storage vessel is subject to this section if the vessel:

(1) Contains production from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or Indian lease; and

(2) Is not subject to any of the requirements of 40 CFR part 60, subparts OOOO or OOOOa, but would be subject to one of those subparts if it were a new, modified or reconstructed source.

(b) Within 60 days after the effective date of this section, and within 30 days after any new source of production is added to the storage vessel, the operator must determine, record, and make available to the BLM upon request, whether the storage vessel has the potential for VOC emissions equal to or greater than 6 tpy based on the maximum average daily throughput for a 30-day period of production. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority that limit the VOC emissions to less than 6 tpy.

(c) If a storage vessel has the potential for VOC emissions equal to or greater than 6 tpy under paragraph (b) of this section, no later than one year after the effective date of this section, or three years if the operator must and will replace the storage vessel at issue in order to comply with the requirements of this section, the operator must:

(1) Route all tank vapor gas from the storage vessel to a sales line;

(2) If the operator determines that compliance with paragraph (c)(1) of this section is technically infeasible or unduly costly, route all tank vapor gas from the storage vessel to a device or method that ensures continuous combustion of the tank vapor gas; or

(3) Submit an economic analysis to the BLM through a Sundry Notice that demonstrates, and the BLM agrees, based on the information identified in paragraph (d) of this section, that compliance with paragraph (c)(2) of this section would impose such costs as to cause

the operator to cease production and abandon significant recoverable oil reserves under the lease.

(d) To support a demonstration under paragraph (c) of this section, the operator must submit a Sundry Notice that includes the following information:

(1) The name, number, and location of each well, and the number of the lease, unit, or communitized area with which it is associated;

(2) The oil and gas production levels of each of the operator's wells on the lease, unit or communitized area for the most recent production month for which information is available;

(3) Data that show the costs of compliance with paragraph (c)(1) or (c)(2) of this section on the lease;

(4) The operator must consider the costs and revenues of the combined stream of revenues from both the gas and oil components and provide:

(i) The operator's projections of oil and gas prices, production volumes, quality (i.e., heating value and H<sub>2</sub>S content), revenues derived from production, and royalty payments on production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

(e) If the rate of total uncontrolled VOCs released from a storage vessel declines to 4 tpy or less for any continuous 12 month period, the requirements of paragraph (c) no longer apply.

(f) Storage vessels subject to this section must be adequately sized to accommodate the operator's production levels and equipped to meet any applicable regulatory requirements regarding tank vapors.

(g) Storage vessels subject to this section may only vent through properly functioning pressure relief devices.

**§ 3179.204 Downhole well maintenance and liquids unloading.**

(a) The operator must minimize vented gas and the need for well venting associated with downhole well maintenance and liquids unloading, consistent with safe operations.

(b) For wells equipped with a plunger lift system and/or an automated well control system, minimizing gas venting under paragraph (a) includes optimizing the operation of the system to minimize gas losses to the extent possible consistent with removing liquids that would inhibit proper function of the well.

(c) Before the operator manually purges a well for liquids unloading for the first time after the effective date of this section, the operator must consider other methods for liquids unloading and determine that they are technically infeasible or unduly costly. The operator must provide information supporting that determination as part of the Sundry Notice required under paragraph (e) of this section.

(d) For any liquids unloading by manual well purging, the operator must:

(1) Ensure that the person conducting the well purging remains present on-site throughout the event to minimize to the maximum extent practicable any venting to the atmosphere;

(2) Record the cause, date, time, duration, and estimated volume of each venting event;  
and

(3) Maintain the records for the period required under § 3162.4-1 of this title and make them available to the BLM, upon request.

(e) The operator must notify the BLM by Sundry Notice within 30 calendar days after the first liquids unloading event by manual or automated well purging conducted after the effective date of this section. This requirement applies to each well the operator operates.

(f) The operator must notify the BLM by Sundry Notice, within 30 calendar days, if:

(1) The cumulative duration of manual well purging events for a well exceeds 24 hours during any production month; or

(2) The estimated volume of gas vented in liquids unloading by manual well purging operations for a well exceeds 75 Mcf during any production month.

(g) For purposes of this section, “well purging” means blowing accumulated liquids out of a wellbore by reservoir gas pressure, whether manually or by an automatic control system that relies on real-time pressure or flow, timers, or other well data, where the gas is vented to the atmosphere, and it does not apply to wells equipped with a plunger lift system.

(h) Total estimated volumes vented as a result of downhole well maintenance and liquids unloading, including through the operation of plunger lifts and automated well controls, during the production month must be included in volumes reported to ONRR as vented.

#### **LEAK DETECTION AND REPAIR (LDAR)**

##### **§ 3179.301 Operator responsibility.**

(a) The requirements of §§ 3179.301 through 3179.305 of this subpart apply to:

(1) A site and all equipment associated with it used to produce, process, compress, treat, store, or measure natural gas (including oil wells that also produce natural gas) from or allocated to a Federal or Indian lease, unit, or communitized area, where the site is upstream of or contains the approved point of royalty measurement; and

(2) A site and all equipment operated by the operator and associated with a site used to store, measure, or dispose of produced water, where the site is located on a Federal or Indian lease.

(b) The requirements of §§ 3179.301 through 3179.305 of this subpart do not apply to:

(1) A site that contains a wellhead or wellheads and no other equipment; or

(2) A well or well equipment that has been depressurized.

(c) As prescribed in §§ 3179.302 and 3179.303 of this subpart, the operator must inspect all equipment covered under this section, as provided in paragraph (a) of this section, for gas leaks from leak components.

(d) The operator is not required to inspect or monitor a leak component that is not an accessible component.

(e) For purposes of §§ 3179.301 through 3179.305, the term “site” means a discrete area located on a lease, unit, or communitized area, and containing a wellhead, wellhead equipment, or other equipment used to produce, process, compress, treat, store, or measure natural gas or store, measure, or dispose of produced water, which is suitable for inspection in a single visit.

(f) The operator must make the first inspection of each site:

(1) Within one year of January 17, 2017 for sites that have begun production prior to January 17, 2017;

(2) Within 60 days of beginning production for sites that begin production after January 17, 2017; and

(3) Within 60 days of the date when a site that was out of service is brought back into service and re-pressurized.

- (g) The operator must make subsequent inspections as prescribed in § 3179.303.
- (h) All leak inspections must occur during production operations.
- (i) The operator must fix identified leaks as prescribed in §§ 3179.304 and 3179.305 of this subpart. See 43 CFR 3162.5-1 for responsibility to repair oil leaks.
- (j) With respect to new, modified or reconstructed equipment, an operator will be deemed to be in compliance with the requirements of this section for such equipment, if the operator is in compliance with the requirements of subpart OOOOa applicable to such equipment.
- (k) For each lease, unit, or communitized area, for all covered sites and equipment not already deemed in compliance with the requirements of this section pursuant to paragraph (j), an operator may choose to satisfy the requirements of §§ 3179.301 through 3179.305 by:
  - (1) Treating each of those sources as if it were a collection of fugitive emissions components as defined in 40 CFR part 60 subpart OOOOa;
  - (2) Complying with the requirements of 40 CFR part 60 subpart OOOOa that apply to affected facility fugitive emissions components at a well site (or for compressor stations, that apply to affected facility fugitive emissions components at a compressor station) under 40 CFR part 60, subpart OOOOa; and
  - (3) Notifying the BLM through a Sundry Notice regarding such compliance.

**§ 3179.302 Approved instruments and methods.**

- (a) The operator must use one or more of the following instruments, operated according to the manufacturer's specifications or as specified below, to detect leaks:



- (1) An optical gas imaging device capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of less than or equal to 60 grams per hour from a quarter inch diameter orifice;
  - (2) A portable analyzer device capable of detecting leaks, such as catalytic oxidation, flame ionization, infrared absorption or photoionization devices, used for a leak detection survey conducted in compliance with the relevant sections of Method 21 at 40 CFR part 60, appendix A-7, including section 8.3.1. and assisted by audio, visual, and olfactory inspection; or
  - (3) A leak detection device not listed in this section that is approved by the BLM for use by any operator under § 3179.302(d) of this subpart.
- (b) The person operating any of the leak detection devices listed in or approved under this section must be adequately trained in the proper use of the device.
  - (c) Any person may request approval of an alternative monitoring device and protocol by submitting a Sundry Notice to BLM that includes the following information:
    - (1) Specifications of the proposed monitoring device, including a detection limit capable of supporting the desired function;
    - (2) The proposed monitoring protocol using the proposed monitoring device, including how results will be recorded;
    - (3) Records and data from laboratory and field testing, including but not limited to performance testing;
    - (4) A demonstration that the proposed monitoring device and protocol will achieve equal or greater reduction of gas lost through leaks compared with the approach specified in § 3179.302(a)(1) when used according to § 3179.303(a) of this subpart;

- (5) Tracking and documentation procedures; and
  - (6) Proposed limitations on the types of sites or other conditions on deploying the device and the protocol to achieve the demonstrated results.
- (d) The BLM may approve an alternative monitoring device and associated inspection protocol, if the BLM finds that the alternative would achieve equal or greater reduction of gas lost through leaks compared with the approach specified in § 3179.302(a)(1) when used according to § 3179.303(a) of this subpart.
- (1) The BLM will provide public notice of a submission for approval under section 3179.302(c).
  - (2) The BLM may approve an alternative device and monitoring protocol for use in all or most applications, or for use on a pilot or demonstration basis under specified circumstances that limit where and for how long the device may be used.
  - (3) The BLM will post on the BLM website a list of each approved alternative monitoring device and protocol, along with any limitations on its use.

**§ 3179.303 Leak detection inspection requirements for natural gas wellhead equipment and other equipment.**

(a) Except as provided below or otherwise authorized in paragraph (b) of this section, the operator must inspect leak components located on and around the equipment identified in § 3179.301(a) of this subpart for leaks using a leak detection device listed under § 3179.302 according to the following parameters:

- (1) The operator must inspect each site at least semi-annually, and consecutive semiannual inspections must be conducted at least 4 months apart; and

(2) The operator must inspect each compressor station at least quarterly, and consecutive quarterly inspections must be conducted at least 60 days apart.

(b) The BLM may approve an operator's request to use an alternative instrument-based leak detection program, in lieu of compliance with the requirements of § 3179.303(a), if the BLM finds that the alternative program would achieve equal or greater reduction of gas lost through leaks compared with the approach specified in §§ 3179.302(a)(1) and 3179.303(a) of this subpart. The operator must submit its request for an alternative leak detection program through a Sundry Notice that includes the following information:

(1) A detailed description of the alternative leak detection program, including how it will use one or more of the instruments specified in or approved under § 3179.302(a) and an identification of the specific instruments, methods and/or practices that would substitute for specific elements of the approach specified in §§ 3179.302(a) and 3179.303(a);

(2) The proposed monitoring protocol;

(3) Records and data from laboratory and field testing, including, but not limited to, performance testing, to the extent relevant;

(4) A demonstration that the proposed alternative leak detection program will achieve equal or greater reduction of gas lost through leaks compared to compliance with the requirements specified in §§ 3179.302(a) and 3179.303(a);

(5) A detailed description of how the operator will track and document its procedures, leaks found, and leaks repaired; and

(6) Proposed limitations on types of sites or other conditions on deployment of the alternative leak detection program.

(c) If the operator demonstrates, and the BLM agrees, that compliance with the requirements of §§ 3179.301-305, including the option for compliance with an alternative leak detection program under §3179.303(b) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil or gas reserves under the lease, the BLM may approve an alternative leak detection program for that operator that does not meet the criterion specified in §3179.303(b)(4), but is as effective as possible consistent with not causing the operator to cease production and abandon significant recoverable oil or gas reserves under the lease.

(d) To support a demonstration under paragraph (c) of this section, the operator must submit a Sundry Notice that includes the following information:

(1) The name, number, and location of each well, and the number of the lease, unit, or communitized area with which it is associated;

(2) The oil and gas production levels of each of the operator's wells on the lease, unit or communitized area for the most recent production month for which information is available;

(3) Data that show the costs of compliance on the lease with the requirements of §§ 3179.301-305 and with an alternative leak detection program that meets the requirements of §3179.303(b);

(4) The operator must consider the costs and revenues of the combined stream of revenues from both the gas and oil components and provide the operator's projections of oil and gas prices, production volumes, quality (i.e., heating value and H<sub>2</sub>S content), revenues derived from production, and royalty payments on production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less;

(5) The information required under § 3179.303(b), except that in lieu of the demonstration required under § 3179.303(b)(4), the operator must demonstrate that the alternative program is as effective as possible, consistent with not imposing such costs as to cause the operator to cease production and abandon significant recoverable oil or gas reserves under the lease.

(e) For any BLM approval of an operator's use of an alternative leak detection program under subparagraph (b) or (c) of this section, the BLM will post online the alternative program approved for that operator, including, at minimum, the information required in subparagraph (b)(1), (b)(2), (b)(5), and (b)(6) of this section.

**§ 3179.304 Repairing leaks.**

(a) The operator must repair any leak as soon as practicable, and in no event later than 30 calendar days after discovery, unless good cause exists for repair requiring a longer period. Good cause for delay of repair exists if the repair (including replacement) is technically infeasible (including unavailability of parts that have been ordered), would require a pipeline blowdown, a compressor station shutdown, a well shut-in, or would be unsafe to conduct during operation of the unit.

(b) If there is good cause for delaying the repair beyond 30 calendar days, the operator must notify the BLM of the cause by Sundry Notice and must complete the repair at the earliest opportunity, for example during the next compressor station shutdown, well shut-in, or pipeline blowdown. In no case may the repair be delayed beyond 2 years.

(c) Not later than 30 calendar days after completion of a repair, the operator must verify the effectiveness of the repair through a follow-up inspection using one of the

instruments specified or approved under § 3179.302(a) or a soap bubble test under Section 8.3.3 of EPA Method 21 – Determination of Volatile Organic Compound Leaks (40 CFR Appendix A-7 to part 60).

(d) If the repair is not effective, the operator must complete additional repairs within 15 calendar days, and conduct follow-up inspections and repairs until the leak is repaired.

(e) A follow-up inspection to verify the effectiveness of repairs does not constitute an inspection for purposes of § 3179.303.

**§ 3179.305 Leak detection inspection recordkeeping and reporting.**

(a) The operator must maintain the following records for the period required under § 3162.4-1 of this title and make them available to the BLM upon request:

(1) For each inspection required under § 3179.303 of this subpart, documentation of:

(i) The date of the inspection; and

(ii) The site where the inspection was conducted;

(2) The monitoring method(s) used to determine the presence of leaks;

(3) A list of leak components on which leaks were found;

(4) The date each leak was repaired; and

(5) The date and result of the follow-up inspection(s) required under § 3179.304

paragraph (c) or (d) of this subpart.

(b) By March 31 each calendar year, the operator must provide to the BLM an annual summary report on the previous year's inspection activities that includes:

(1) The number of sites inspected;

(2) The total number of leaks identified, categorized by the type of component;

(3) The total number of leaks repaired;

(4) The total number leaks that were not repaired as of December 31 of the previous calendar year due to good cause and an estimated date of repair for each leak.

(5) A certification by a responsible officer that the information in the report is true and accurate to the best of the officer's knowledge.

(c) AVO checks are not required to be documented unless they find a leak requiring repair.

#### **STATE OR TRIBAL VARIANCES**

##### **§ 3179.401 State or tribal requests for variances from the requirements of this subpart.**

(a)(1) At the request of a State (for Federal land) or a tribe (for Indian lands), the BLM State Director may grant a variance from any provision(s) of this Subpart that would apply to all Federal leases, units, or communitized areas within a State or to all tribal leases, units, or communitized areas within that tribe's lands, or to specific fields or basins within the State or that tribe's lands, if the BLM finds that the variance would meet the criteria in paragraph (b) of this section.

(2) A State or tribal variance request must:

(i) Identify the provision(s) of this subpart from which the State or tribe is requesting the variance;

(ii) Identify the State, local, or tribal regulation(s) or rule(s) that would be applied in place of the provision(s) of this subpart;

(iii) Explain why the variance is needed; and

(iv) Demonstrate how the State, local, or tribal regulation(s) or rule(s) would perform at least equally well in terms of reducing waste of oil and gas, reducing environmental

impacts from venting and or flaring of gas, and ensuring the safe and responsible production of oil and gas, compared to the particular provision(s) from which the State or tribe is requesting the variance.

(b) The BLM State Director, after considering all relevant factors, may approve the request for a variance, or approve it with one or more conditions, only if the BLM determines that the State, local or tribal regulation(s) or rule(s) would perform at least equally well in terms of reducing waste of oil and gas, reducing environmental impacts from venting and/or flaring of gas, and ensuring the safe and responsible production of oil and gas, compared to the particular provision(s) from which the State or tribe is requesting the variance, and would be consistent with the terms of the affected Federal or Indian leases and applicable statutes. The decision to grant or deny the variance will be in writing and is within the BLM's discretion. The decision on a variance request is not subject to administrative appeals under 43 CFR part 4.

(c) A variance from any particular requirement of this rule does not constitute a variance from provisions of other regulations, laws, or orders.

(d) The BLM reserves the right to rescind a variance or modify any condition of approval.

(e) If the BLM approves a variance under this section, the State or tribe that requested the variance must notify the BLM in writing in a timely manner of any substantive amendments, revisions, or other changes to the State, local or tribal regulation(s) or rule(s) to be applied under the variance.

(f) If the BLM approves a variance under this section, the State, local or tribal regulation(s) or rule(s) to be applied under the variance can be enforced by the BLM as if



the regulation(s) or rule(s) were provided for in this Subpart. The State, locality, or tribes' own authority to enforce its regulation(s) or rule(s) to be applied under the variance would not be affected by the BLM's approval of a variance.