The Cost of Doing Business:
How Federal Regulatory Initiatives Threaten to Undermine Efforts toEnhance Revenue Collection From Oil and Gas Development on Public Lands
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The federal government owns approximately 640 million acres of land in the United States – roughly 28% of the nation’s surface area – the overwhelming majority of which is located in twelve western states, including Alaska. Beyond those surface lands, the federal government exercises management responsibility for approximately 700 million acres of subsurface federal mineral estate underlying both federal and non-federal lands and another 56 million acres of mineral estate beneath Indian lands. Given the significant amounts of oil and natural gas estimated to be found on federal lands, the proximity to the large domestic oil and gas market, and the traditionally favorable business climate within the United States, federal lands have traditionally been considered an acceptable place for oil and gas companies to invest. Production of oil and gas from these lands represents an important part of the national energy portfolio – domestic production from onshore oil and gas wells accounts for eleven percent of the United States’ natural gas supply and five percent of its oil.

Developing federal oil and gas resources has historically been a profitable enterprise, not only for the private companies that produce the resources, but also for the federal treasury. The Bureau of Land Management (“BLM”), the agency with primary responsibility for administering the federal minerals system, describes itself as “one of a handful of Federal agencies that generates more revenue for the United States than it spends.” In fiscal year 2014, onshore federal oil and gas leases alone “produced about 148 million barrels of oil, 2.48 trillion cubic feet of natural gas, and 2.9 billion gallons of natural gas liquids, with a market value of almost $27 billion and generating royalties of almost $3.1 billion.” BLM recognizes that

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1 The federal government controls more than 54% of the land in the eleven contiguous states west of the 100th Meridian: Arizona, 48.06%; California, 45.3%; Colorado, 36.63%; Idaho, 50.19%; Montana, 29.92%; Nevada, 84.48%; New Mexico, 41.77%; Oregon, 53.11%; Utah, 57.45%; Washington, 30.33%; and Wyoming, 42.33%. See U.S. Gen. Servs. Admin., Fed. Real Property Profile at 18 & Table 16 (Sept. 30, 2004). The federal government also controls more than 69% of the surface acreage in Alaska. See id. Management responsibility for more than 620 million federal acres is concentrated in five federal agencies: the Bureau of Land Management, 247.3 million acres; the Forest Service, 192.9 million acres; the Fish and Wildlife Service, 89.1 million acres; the National Park Service, 79.6 million acres; and the Department of Defense, 14.4 million acres. See Congressional Research Serv., Fed. Land Ownership: Overview and Data at 1 & Table 2 (Dec. 29, 2014).


5 BLM, Mineral & Surface Acreage, supra n.2.

6 80 Fed. Reg. 22,148, 22,150 (Apr. 21, 2015). The federal government is not the only entity concerned with the profitability of the federal mineral program. Particularly for the western public land states, the successful development of federal minerals is of critical importance. A state receives fifty percent of all monies received in the form of sales,
“[r]evenue generated from developing public energy resources that belong to all Americans helps fund critical investments in communities across the United States and creates American jobs, fosters land and water conservation efforts, improves critical infrastructure, and supports education.”

Yet despite the historic profitability of the federal oil and gas program, numerous observers have called for major reforms to the federal leasing program. Alleging that the “American people are getting shortchanged for the extraction of their resources,” both lawmakers and private advocacy groups have proposed legislation increasing the amount of money oil and gas companies pay the federal government to drill on public lands. Observing that the royalty rate on oil and gas production on federal lands, 12.5%, is lower than the average royalty rates for production on state lands, these would-be reformers contend that “prices for developing public resources are at rock bottom” and assert that taxpayers are being deprived of royalty revenue to the tune of hundreds of millions of dollars per year. Specific proposals include raising the federal royalty rate from 12.5% to 18.75% and doubling minimum bonus bids and annual rentals on federal acreage.

Setting aside any subjective debate on whether the current system is “fair” to either producers or taxpayers, there is no guarantee that raising royalty rates and associated fees would result in the federal government receiving increased revenues from mineral production. Many of the proposals to reform the existing system treat specific components of an oil and natural gas lease – the royalty rate, the bonus bid, and the rental rate – as proxy for the lease’s value. But the economic (and environmental) value of an oil and natural gas lease, both to the lessor and the lessee, derives from the interplay of many more aspects than these three. Other features of a lease that affect the lease’s value include, but are not limited to, operational costs, borrowing costs, regulatory costs, taxes, transportation costs, and distribution costs. Adjusting any one of these features in isolation, without consideration of the effect on other features, may have significant impact on an operator’s decision to develop federal resources and is not tailored to optimize the value of the lease to the government.

While the government cannot control all these costs, any economic reform of the minerals program must focus on the elements the government can control. That taxpayers are entitled to a fair return on federal mineral development is not a controversial proposition. But what is missing from the most recent proposals to modify the terms of federal oil and gas leases is the impact federal oil and gas regulation has on the value of those leases. At the same time that policy makers are considering raising the price for obtaining leases and producing federal minerals, federal regulators have advanced a broad programmatic agenda that has the potential to make federal development economically impractical. For royalty and leasing reforms to be

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8 Amanda Reilly, Democrats’ bill would raise royalty rates, E&E Greenwire (Jan. 14, 2016).
9 The Wilderness Soc’y, Outdated & Undervalued at 2 (Nov. 2015).
11 In a report encouraging the Department of the Interior to consider royalty reform, the Government Accountability Office (“GAO”) opined that “[i]ncreasing royalty rates on future federal oil and gas leases would likely increase the federal government take,” but cautioned that the increase in the money the government received would be “less than the percentage increase in the royalty rate because higher royalty rates would likely reduce some taxes and other fees and may also discourage some development and production.” GAO-07-676R at 3.
effective, those reforms must account for and balance against the impact those regulatory efforts are likely to have on the production of federal minerals.

I. BROAD REGULATORY INITIATIVES.

The Obama Administration has not been shy in expressing its belief that reform of federal minerals management programs is necessary to account for advancements in extraction technology and ensure that development reflects contemporary principles of economic fairness and environmental stewardship. In the past two years alone, executive agencies have advanced a broad suite of regulatory initiatives proposing new or amended rules to govern the sources of energy Americans can develop; how and where oil and gas are extracted; how extracted minerals are transported; and how energy produced from oil and gas competes in the markets against other energy sources. In President Obama’s most recent (and final) State of the Union Address, the President emphasized that he would “push to change the way we manage our oil and coal resources, so that they better reflect the costs they impose on taxpayers and our planet.”

The economic impact of the President’s regulatory agenda can be felt in both obvious and subtle ways. While high-profile regulatory efforts focused on regulating hydraulic fracturing, defining waters of the United States, protecting endangered species, and limiting greenhouse gas emissions from power plants have grabbed media headlines over the last several months, a potent stew of seemingly mundane technical initiatives has been simmering under the noses of domestic energy companies. Taken individually, narrow regulatory proposals related to oil and gas accounting, permitting and planning requirements, procedure rules for administrative appeals, royalty reporting, weights and measures, bonding requirements, and infrastructure development have been of interest to only a small group of regulatory and legal technocrats. But understood collectively, these less glamorous initiatives have the potential to fundamentally change the scale and nature of oil and gas development in the United States.

In just the past three years, the Obama Administration has engaged in rulemaking and enforcement initiatives related to, among other topics:

- The “unbundling” of processing costs necessary to put natural gas into “marketable condition” for the purposes of royalty reporting.

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• Permitting and planning for private oil and gas development on National Wildlife Refuge System lands and within national parks.\textsuperscript{19}

• Culpability standards for civil penalties associated with royalty reporting and procedural rules for administrative challenges to civil penalty assessments.\textsuperscript{20}

• Valuation standards for calculating the value of oil and gas produced from federal lands for royalty assessment purposes.\textsuperscript{21}

• Royalty rates, annual rental payments, minimum acceptable bids, bonding requirements, and civil penalty assessments for federal onshore oil and gas leases.\textsuperscript{22}

• The application of “major portion” pricing for the calculation of royalties derived from production on Indian oil and gas leases.\textsuperscript{23}

• Facility measurement points, site facility diagrams, the use of seals, bypasses around meters, documentation, record keeping, commingling, off-lease measurement, and the reporting of incidents of unauthorized removal or mishandling of oil and condensate.\textsuperscript{24}

• Oil meter technology, proper measurement documentation, record-keeping requirements, and penalties associated with measurement errors.\textsuperscript{25}

• Gas measurement at production facilities.\textsuperscript{26}

• Processing of rights-of-way on Indian lands.\textsuperscript{27}

• Venting and flaring of natural gas from oil and gas wells on federal and Indian lands.\textsuperscript{28}

Each of these initiatives represents an illustrative example of how regulatory policy affects the cost of developing oil and gas properties on federal and Indian lands. Some represent overt efforts to change the terms of federal lease agreements; others increase federal oil and gas producers’ costs in the field itself; others increase back-office, accounting, and legal costs. All impact the bottom line of oil and gas operators producing federal minerals. A more detailed look at several of these initiatives provides insight into the relationship between regulation and the economic value of federal minerals.

A. NATURAL GAS: UNBUNDLING COST ALLOCATIONS.

Lessees producing natural gas from federal lands must pay royalties to the federal government calculated on the “value of production” from these lands.\textsuperscript{29} Although simple in


\textsuperscript{21} 80 Fed. Reg. 608 (Jan. 6, 2015).


\textsuperscript{23} 80 Fed. Reg. 33,553 (June 12, 2015).

\textsuperscript{24} 80 Fed. Reg. 40,767 (July 13, 2015).

\textsuperscript{25} 80 Fed. Reg. 58,952 (Sept. 30, 2015).

\textsuperscript{26} 80 Fed. Reg. 61,646 (Oct. 13, 2015).

\textsuperscript{27} 80 Fed. Reg. 72,492 (Nov. 19, 2015).

\textsuperscript{28} 81 Fed. Reg. 6,616 (Feb. 8, 2016).

\textsuperscript{29} See generally 30 C.F.R. Part 1206, Subpart D; see also 30 C.F.R. § 1206.152(a)(2) (unprocessed gas); 30 C.F.R. § 1206.153(a)(2) (processed gas).
theory, determining that value often proves difficult in practice. Natural gas is rarely ready to be sold at the moment it is withdrawn from the ground. Often the gas must be treated or processed to place the gas into “marketable condition” before the gas has meaningful value as a saleable commodity. “Marketable condition” means “lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area.”30 Existing regulations assign the burden for that processing to the federal lessee; lessees are required to “place gas in marketable condition . . . at no cost to the Federal Government.”31

For the purpose of calculating royalties, it makes no difference whether the federal lessee is the party that performs the gas processing necessary to make the gas marketable. When calculating royalties on natural gas, residue gas, or gas plant products, the Office of Natural Resources Revenue (“ONRR”) will assign a value to production that reflects a price for gas in “marketable condition.”32 In other words, if the price a lessee receives for the sale of natural gas is reduced because the purchaser of the gas takes the gas in a less than marketable condition, the “value of production” is not calculated on the sales price of the gas, but on the price the lessee would have received if the gas were sold after any necessary treatment to make the gas marketable.

The obligation to place natural gas in “marketable condition” does not mean, however, that federal lessees may not deduct any costs in calculating a royalty value for the gas. When reporting royalties, federal lessees are permitted to deduct a transportation allowance reflecting the cost of moving the natural gas from the lease site to a point away from the lease site or from a processing plant to a point away from the plant.33 Lessees may also deduct the cost of the processing required to separate natural gas liquids from the natural gas stream. These transportation and processing costs are deductible because the costs are distinct from costs attributable to making natural gas marketable; when claiming either transportation or processing allowances, lessees are still required to adhere to the marketable condition rule.

Until recently, only the Interior Board of Land Appeals (through audits and other case-by-case decisions) and the federal courts (through disputes between lessees and ONRR) have made the determination of costs that may properly be deducted as processing and transportation allowances and costs that must be included in the value of production, i.e., “marketable condition costs.” But since 2010, ONRR has undertaken a new enforcement initiative premised not on these adjudicated assessments of deductible costs, but on the agency’s subjective interpretation of which costs may be deducted as transportation allowances,

30 30 C.F.R. § 1206.151.
31 30 C.F.R. § 1206.152(i) (“The lessee must place gas in marketable condition and market the gas for the mutual benefit of the lessee and the lessor at no cost to the Federal Government.”); 30 C.F.R. § 1206.153(i) (“The lessee must place residue gas and gas plant products in marketable condition and market the residue gas and gas plant products for the mutual benefit of the lessee and the lessor at no cost to the Federal Government.”).
32 See 30 C.F.R. § 1206.152(i) (providing that the value of gross proceeds for unprocessed gas “will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition or to market the gas.”); 30 C.F.R. § 1206.153(i) (providing that the value of residue gas or gas plant products will be increased when a purchaser or other third party is “providing certain services the cost of which ordinarily is the responsibility of the lessee to place the residue gas or gas plant products in marketable condition or to market the residue gas and gas plant products.”).
33 30 C.F.R. § 1206.157.
34 30 C.F.R. § 1206.158. If a lessee sells the gas before processing, royalties are assessed on the unprocessed gas. See 30 C.F.R. § 1206.152.
which may be deducted as processing allowances, and which must be included in the value of production as marketable condition costs.

During this period, ONRR has been aggressively auditing producers and third-party midstream entities responsible for gathering, transporting, and processing natural gas produced from federal lands to gather data helpful to determining the cost of placing gas into marketable condition. And in November 2010, ONRR began publishing on the agency’s website initial “Unbundling Cost Allocations” ("UCAs") for arm’s-length transactions occurring at five natural gas plants in New Mexico: Carlsbad, Ignacio, Kutz, Lybrook, and Manzanares. ONRR’s UCAs represent generalized determinations of the percentage of transportation and processing costs that could be deducted as allowances, and the percentage of costs disallowed as marketable condition costs for gas being delivered into these plants. The following graphic represents ONRR’s original calculation for the Carlsbad gas plant:35

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\begin{array}{|c|c|c|c|c|}
\hline
\text{YEAR} & 2004 & 2005 & 2006 & 2007 \\
\hline
\text{Allowed Costs} & 93.40\% & 85.10\% & 90.50\% & 90.00\% \\
\text{Disallowed Costs} & 6.60\% & 14.90\% & 9.50\% & 10.00\% \\
\hline
\end{array}
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Since the original publication of UCAs for the five plants in New Mexico, ONRR has since revised and republished its initial 2010 UCAs and has additionally published, revised, and republished UCAs for twelve other natural gas systems in New Mexico, Wyoming, Louisiana, and Mississippi.36

As presently enforced, ONRR requires natural gas producers to either use ONRR’s UCAs when calculating royalties on natural gas produced on federal lands or to refrain from deducting any allowances at all.37 Although ONRR acknowledges the possibility that producers might calculate their own unbundling cost allocations, ONRR does not provide lessees with any of the background data, accounting information, or methodology used when calculating the agency’s UCAs, such that producers could review this data for errors or use ONRR’s methodology in the producer’s individual calculation. Even more complicated, ONRR frequently

35 Original ONRR file, dated Nov. 3, 2010, retrieved via FOIA Request (on file with the authors).
revises its UCAs, compelling natural gas producers to review and revise previously filed royalty reports to account for the changes in the agency’s figures.\(^{38}\)

What is more, ONRR threatens lessees with stringent civil penalties of up to $5,000 per day for each violation of the agency’s royalty reporting and collection regulations and up to $25,000 per day if the agency determines the violation to be “knowing and willful.”\(^{39}\) And if a lessee chooses to deduct transportation and/or processing allowances different from the published UCAs, ONRR uniformly presumes the deductions to be unauthorized, pushing lessees to expend legal costs defending their deductions through federal audit, administrative hearing, or court process.

The result is that ONRR has created a process that elevates the convenience that using standard "cookie cutter" UCAs affords the agency over the application of a regulatory framework designed to ensure royalty payments are fair to both the federal treasury and the private companies that do the work of extracting the resources. By controlling not only the data necessary to determine proper allowances and marketable condition costs, but also the penalties levied on lessees that do not comply, ONRR has created a scenario in which lessees may choose to take fewer allowances per the published UCA – and therefore pay higher royalties than the operator actually owes the federal government – or continue taking previously determined allowances and face civil penalties. Both scenarios raise the cost and risks of developing federal minerals and discourage development of federal lands.

\section*{B. \textbf{ROYALTY REPORTING: PENALTIES AND PROCESS.}}

Since the passage of the Federal Oil and Gas Royalty Management Act in 1983, ONRR and its predecessor agency conducted regulatory activity through two principal means: (i) notice-and-comment rulemaking for general rules having the force of law; and (ii) appealable orders in individual cases applying the rules to the findings of company-specific audits. While the agency did from time to time issue guidance documents (e.g., “Dear Payor” and “Dear Operator” letters), this guidance was universally acknowledged to be non-appelable and non-binding. If a company wished to challenge the guidance, it had to await an order applying the guidance after an audit. Under this system, oil and gas producers traded an immediate right to bring a legal action for the certainty that a producer would not be subject to immediate penalty for failing to comply with the terms of guidance documents. On May 20, 2014, however, ONRR published a proposal to amend the way civil penalties for allegedly inadequate reporting and payment of royalties would be identified, calculated, and imposed.\(^{40}\) Several aspects of ONRR’s proposed rule would fundamentally change operators’ risk assessments and investment strategies when deciding whether to conduct business on federal lands.

Under existing regulations, if ONRR believes a reporting or payment error has been made – typically uncovered through the agency’s automated Data Mining services – ONRR is likely to first issue a Data Request under 30 C.F.R. § 1217.50.\(^{41}\) In the Data Request, ONRR will seek information confirming compliance or noncompliance with royalty reporting and payment

\footnotesize{\(^{38}\) Industry commentators have noted the “sizable financial burden royalty reporters incur to keep in compliance with the federal government’s extremely complex keep-whole unbundling and marketable condition rules,” advising that “the complexity of federal reporting requirements requires operators to incur substantial legal and consulting fees to maintain compliance with reporting regulations.” Letter from Barry Russell & Tim Wigley to Neil Kornze at 3 n.6 (June 19, 2015), http://www.regulations.gov/#/documentDetail;D=BLM-2015-0002-0048.\(^{39}\) See 30 C.F.R. §§ 1241.53, 1241.60, 1241.61.\(^{40}\) See 79 Fed. Reg. 28,862 (May 20, 2014).\(^{41}\) See 30 C.F.R. § 1217.50 (authorizing audits of oil and gas royalty payments and records).}
obligations, and will request that the reporter/payor provide compliance data to the agency, typically within thirty days. After ONRR reviews the data submitted in response to such a request, ONRR may close the matter, may issue additional or follow-up Data Requests, or may issue a compliance order or a notice of alleged noncompliance.42

If after investigation ONRR concludes that an oil and gas producer has inadvertently reported or paid royalties incorrectly, the agency may issue either a Notice of Noncompliance (“NONC”) or a Notice of Noncompliance and Civil Penalty (“NONC-CP”).43 When ONRR issues a NONC, a royalty reporter/payor is given twenty days (or longer if specified in the notice) to correct the errors that ONRR alleges.44 If the reporter/payor corrects all identified violations within the time allowed, the matter will be closed and no civil penalties will issue.45 If a reporter/payor does not correct all violations identified in a NONC within the time specified in the NONC, ONRR may then issue a Notice of Civil Penalty.46 Civil penalties for failure to cure a NONC may be as much as $500 per violation per day for the first forty days,47 escalating to as much as $5,000 per violation per day after forty days.48

If ONRR believes that an oil and gas producer has “knowingly or willfully” prepared, maintained, or submitted false, inaccurate, or misleading reports, the agency may issue the producer a NONC-CP, resulting in civil penalties of as much as $25,000 per day without prior notice or an opportunity to correct the alleged violation.49 ONRR considers an inaccurate royalty report a “knowing or willful” violation when the reporter submits the report with actual knowledge, reckless disregard, or deliberate ignorance of the truth or falsity of the information reported.50 ONRR may reach a finding that an inaccurate submission was made “knowingly and willfully” when, among other circumstances, a reporter/payor: (i) admits the intentionality of the inaccurate submission; (ii) submits contradictory documents; (iii) fails to take action responsive to agency orders, fails to correct errors, or repeats mistakes; (iv) fails to resolve adverse findings uncovered during an agency inspection or audit; or (v) is the subject of a complaint from another agency or the public.51

Although ONRR’s enforcement of this regulatory scheme requires that ONRR establish that the alleged offender conducted the offense “knowingly or willfully,” the phrase “knowingly or willfully” is not expressly defined in the current rules. ONRR now proposes to amend its

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42 Companies that timely and fully respond to these Data Requests typically also receive a Preliminary Audit Finding, allowing the company to review ONRR’s determinations before ONRR issues any order related to the agency’s inquiry.
43 30 C.F.R. § 1241.51(a)
44 30 C.F.R. § 1241.52.
45 Id.
46 30 C.F.R. § 1241.53(a).
47 Id.
48 30 C.F.R. § 1241.53(b).
49 30 C.F.R. §§ 1241.60 to 1241.61. Certain violations presently accrue penalties up to $10,000 per day. These violations include: (i) knowing or willful failure to make a required royalty payment; (ii) failure to permit lawful entry, inspection, or audit of operations; and (iii) knowing or willful failure to timely notify the Secretary of the Interior that any well associated with a lease has begun production. See 30 U.S.C. § 1719(c)(1)-(3). Other violations are subject to penalties of up to $25,000 per day. These violations include: (i) knowing or willful preparation, maintenance, or submission of false, inaccurate, or misleading reports, notices, affidavits, records, data, or other written information; (ii) knowing or willful removal, transportation, or diversion of oil or gas from a lease site without valid legal authority; or (iii) purchasing, accepting, selling, transporting, or conveying any oil or gas when knowing or having reason to know that such oil or gas was stolen or unlawfully removed or diverted. See 30 U.S.C. § 1719(d)(1)-(3).
51 Id.
regulations to include a definition of “knowing or willful” that would govern the agency’s enforcement of the violations identified in 30 U.S.C. § 1719. Under the proposed amendment, “[k]nowing or willful means that a person, including its employee or agent, with respect to the prohibited act, acts with gross negligence.” ONRR believes “gross negligence” requires only that the agency show a company or person has “fail[ed] to exercise even that care which a careless person would use” and “does not require specific intent.”

ONRR represents that the agency’s intention is to define “knowing and willful” as the lowest possible standard so that it encompasses all higher standards. But “knowing and willful” is not a generic standard that Congress intended to apply broadly to all categories of violations. To the contrary, the statutory structure of 30 U.S.C. § 1719 demonstrates that “knowing and willful” is a high standard that reflects the gravity of the most severe offenses to which Congress made it applicable. This change has meaningful consequences for oil and gas producers comparing regulatory risk on federal lands to those risks attendant to developing on state and private lands.

Congress recognized that not all violations of reporting and payment requirements are equal and structured a civil penalty statute, 30 U.S.C. § 1719, that accounts for varying degrees of significance and culpability. Certain violations are deemed more minor and require companies have an opportunity to correct a noticed violation of a lease term, regulation, or agency order before ONRR may impose a penalty. Subsection (a) provides for penalties of up to $500 per day for those persons who receive a NONC and fail to correct the noticed violation within 20 days. Subsection (b) provides for penalties of up to $5,000 for those persons who receive a NONC and fail to correct the noticed violation within 40 days.

Subsection (c) provides for larger penalties – up to $10,000 per day – without opportunity to correct for more significant offenses: the knowing or willful failure to make timely royalty payments, the knowing or willful failure to alert the government that production has commenced from a well on a federal lease, or the refusal to allow an inspection or audit of operations. It is only here, in subsection (c), that the “knowing and willful” condition is first found in the statutory language, applicable only to those violations that Congress determined were sufficiently serious that the violations did not even warrant an opportunity to correct. And even in this subsection, the “knowing and willful” standard does not apply to every enumerated offense; Congress has chosen not to apply the standard to refusals to allow audits or inspections.

Subsection (d) is structured similarly to subsection (c). Under subsection (d), ONRR may impose penalties of up to $25,000 per day for the most serious offenses: the knowing or willful stealing of government oil or gas, either through direct removal of the oil or gas or through the provision of false reports, or the purchase or acceptance of gas that the purchaser knows to be stolen. Like subsection (c), subsection (d) does not provide alleged offenders any opportunity to correct. Unlike subsection (c), however, all of these offenses enumerated in subsection (d) require ONRR to establish a knowledge element. This elevated standard of proof is not

52 ONRR contends that “knowing and willful” is “largely self-explanatory and readily implementable without regulation.” 79 Fed. Reg. at 28,863. Given this admission, it is difficult to understand why ONRR believes amending existing regulations to provide a definition is necessary at this time.


54 Id. (internal quotation omitted).

55 Id.

56 The statute expressly prohibits the imposition of any penalty under subsection (a) if the violation is corrected within twenty days. See 30 U.S.C. § 1719(a)(2).
surprising, given that the violations listed in subsection (d) also subject alleged offenders to possible criminal liability.57

ONRR’s attempt to dilute the “knowing and willful” standard disregards this statutory structure entirely. Unlike ONRR, Congress did not choose to establish one standard of proof applicable to all offenses irrespective of the gravity of the conduct being penalized. Congress did the opposite. Congress’ decision to apply the “knowing and willful” standard only to those offenses deemed most serious belies ONRR’s suggestion that “knowing and willful” is somehow a minimum, easily proven standard. By exposing producers to the very severe penalties that 30 U.S.C. § 1719(c)-(d) imposes even for the relatively minor and inadvertent violations that Congress intended to be enforced under 30 U.S.C. § 1719(a)-(b), ONRR would establish a major disincentive to produce oil or gas from leases on federal and Indian lands.

ONRR’s proposal is particularly troubling because the agency is simultaneously attempting to limit procedural protections to which alleged violators are entitled when ONRR accuses an oil and gas producer of violating a rule. ONRR’s regulatory proposal would, among other provisions: (i) deny an Administrative Law Judge (“ALJ”) the discretion to stay accrual of penalties while a hearing is pending;58 (ii) increase daily penalty amounts;59 (iii) limit ALJs’ discretion to reduce penalties;60 and (iv) consider a person’s failure to follow Dear Reporter and Dear Operator letters as establishing the “knowing or willful” element of a violation enumerated under 30 U.S.C. § 1719(c)-(d).61

ONRR suggests that it intends to tighten the rules governing civil penalties as means to promote strict compliance with the regulations. Yet the proposal would not promote compliance so much as strong-arm oil and gas operators into following any directive ONRR might issue, regardless of the directive’s legality or reasonableness. By elevating penalty amounts and divesting ALJs of the power to stay the accrual of a penalty during an administrative appeal of an agency decision, among other provisions, ONRR would effectively remove the right of companies to challenge government decision-making premised on errors of fact or law. Without the possibility of a stay some companies will choose to forego challenging agency action even if the company knows the company is correct factually and legally, because the accrual rate can be prohibitive and challenges within ONRR’s administrative system can take so long.62 Even when a company has a good faith basis to believe that it will be successful in an administrative appeal, the risk of exponentially multiplying the penalty should the company not prevail will frequently deter the company from filing an otherwise meritorious appeal. The dollar value of the penalty amounts, complete with the lack of procedural flexibility to account for the circumstances of a specific appeal, will force companies to choose between gambling on a successful administrative appeal or simply paying meritless penalties because even the small

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60 79 Fed. Reg. at 28,868.
chance of an adverse agency decision could have a severe, and possibly lethal, economic impact. Neither result encourages oil and gas companies to do business on federal lands.

C. LEASE TERMS.

The most direct manner in which the federal government can increase the cost of developing federal minerals is through modification of the financial terms of federal leases. On April 21, 2015, BLM published an Advanced Notice of Proposed Rulemaking advising that the agency is considering raising royalty rates, annual rental payments, minimum acceptable bids, bonding requirements, and civil penalty assessments for federal onshore oil and gas leases. BLM’s concern appears to be the possibility that, under the agency’s current lease terms, the “Government take [is] generally lower on Federal lands than the lessor’s ‘take’ on State lands or private lands.”

BLM’s exclusive focus on the direct revenue an oil and gas lease generates for the government overlooks important economic consequences that should inform the agency’s analysis. BLM is aware that “a lower royalty rate can encourage oil companies to pursue oil exploration and production and thereby provide an economic stimulus to oil producing regions.” One GAO report that BLM cites as influential in its decision to reconsider lease terms recognizes that a healthy domestic oil and natural gas industry is essential “to meet the nation’s energy needs and balance the impacts of energy use on the environment and climate, . . . and that means that the United States must continue to create a market that is competitive in attracting investment in oil and natural gas development.” Because BLM is likewise cognizant that increasing rates and fees may discourage some development and production, one would expect BLM to strive for “balance between the attractiveness of federal lands and waters for oil and gas investment and a reasonable assurance that the public is getting an appropriate share of revenues from this investment.”

While federal royalty rates are presently lower than royalty rates in some states, there are good reasons why royalties on federal leaseholds are lower. For federal leases to be attractive to oil and gas producers as compared to leases on state and private lands, the federal lease rate must account for the time and expense involved in obtaining the lease, complying with overlapping state and federal regulations, performing the environmental review required under federal law, and the difficulty involved with accessing federal lands. While it is reasonable for BLM to attempt to set royalty rates at values that maximize the federal government’s return on federal leases, the marketplace sets a limit on how high rates can be before federal leases become an unattractive asset. Once that point is reached, rational producers will avoid federal lands and federal royalty rates become immaterial. It is a tautology that the royalty rate received on zero production is zero.

Nor does the royalty rate serve as a reliable predictor of the revenue the government will necessarily receive from production. Compare, for example, a 12.5% federal royalty rate with a
(hypothetical) 15% rate for non-federal leases in North Dakota. In those cases where lease language requires royalties to be paid on the value of production “at the well,” North Dakota law permits the lessee to deduct all post-production costs. Assume the price for residue gas is $4 per MMBtu and the price for natural gas liquids is $1 per gallon. If a North Dakota lessee has revenues of $4,864 from the sale of residue gas and natural gas liquids and post-production costs of $1,074, the lessor collects 15% of the net value of $3,690. The royalty owed equals $553.50. Federal royalty regulations are more onerous. Using ONRR’s UCA for valuing gas through the Torre Alta transportation system in New Mexico, one sees that a federal lessee with $4,864 in revenue and $1,074 in post-production costs may not deduct the full $1,074. It may deduct only $326 of post-production costs. So the lessee owes 12.5% royalty on a net value of $4,538. The royalty owed equals $567.25. The North Dakota lessee has a higher royalty rate than the federal lessee, but pays less royalty on the same volume of production. The lower federal royalty rate does not make the federal lease financially more attractive than the North Dakota lease.

Higher royalty rates and associated lease fees impact federal oil and natural gas production in at least two ways: (i) higher costs make marginal projects uneconomical; and (ii) higher costs increase the risk premium that oil and natural gas producers will require before bidding on leases. The extent of the impact on production is likely to vary based on a host of geologic and economic factors. Under current production costs and economic conditions, for example, royalty rate changes may have little impact on oil and gas projects because commodity prices make new development uneconomic under any royalty scenario. In legacy oil fields, however, where many drilling permits are issued and the drilling of inexpensive vertical wells is common, the impact of increasing royalties and associated leasing fees is much more significant.

The unique regulatory and operational circumstances of federal leases mean modifying the lease’s royalty rate and associated fees will not impact a lease’s value in the same way such a modification might affect lease value were the lease on state or private lands. The impact of rental rates, for example, is often more significant on federal lands than on state and fee surface. The federal government’s own statistics reveal that, under the current rules governing oil and natural gas development on federal lands, lengthy delays should be expected between the time an operator submits an Application for Permit to Drill (an “APD”) to BLM and BLM’s approval of the APD. In recent testimony before the Senate Energy and Natural Resources Committee, BLM’s Director indicated that the average time to process an APD currently exceeds 200 days. And review of individual permits is often only a comparatively minor source

\footnote{Bice v. Petro-Hunt LLC, 768 N.W. 2d 496 (N.D. 2009).}
\footnote{See discussion supra, Part I.A.}
\footnote{Higher costs also mean that projects that are not presently economic are even less likely to occur in the future because more significant economic change is necessary before those projects can become economic. At least one federal agency has concluded that the development of marginally economic projects is already deterred because of the federal government’s “regressive fiscal regime.” Irena Agalliu, Comparative Assessment of the Fed. Oil & Gas Fiscal Sys. at 5 n.5 (Oct. 2011), http://www.boem.gov/Oil-and-Gas-Energy-Program/Energy-Economics/Fair-Market-Value/CERA-Final-Report.aspx. Higher royalty rates and lease costs would further exacerbate this existing problem.}
\footnote{One strategy that operators are likely to employ to mitigate this risk is offering lower bonus bids when bidding on federal leases.}

Bureau of Land Mgmt.’s Final Hydraulic Fracturing Rule Before the S. Energy & Natural Res. Subcommittee on Pub. Lands, Forests, & Mining (Apr. 30, 2015) (statement of Hon. Neil Kornze) (“Do I think that 200 days is a great number? I don’t.”). With the possible addition of new review and permitting requirements that operators will have to overcome before conducting hydraulic fracturing to complete individual wells, development delays will almost certainly increase. See 80 Fed. Reg. 16,126 (Mar. 26, 2015). By comparison, the average time for processing a permit within the State of North Dakota is forty-four days. See Wyoming v. Jewell, No. 2:15-CV-043-SWS (D. Wyo.),
of delay when operating on federal lands. Many significant energy projects across the country continue to be delayed as a result of extended environmental review under the National Environmental Policy Act. Numerous oil and natural gas projects, particularly in western public land states, are subject to ongoing environmental review approaching or exceeding ten years.  

Rental rates can be an important tool to incentivize drilling on leased properties and to discourage operators from leasing federal land and then leaving that property idle. But rental rates can also be punitive when operators are eager to drill and prevented from doing so because federal agencies are delinquent in exercising their management responsibilities. Delays in administrative approvals, environmental review, and permit processing mean that operators on federal lands are not in control of when drilling can occur, and are subjected to rental obligations that are largely avoided on private and state lands where approvals are more timely and where operators have control over drilling time frames. Whereas oil and gas producers might choose to weather modest rental rates on federal lands when a project’s potential justifies absorbing the cost of rentals during periods of delay, escalating rental rates has potential to change that analysis and push operators off federal lands onto more predictable state and private assets.

D. LIMITATIONS ON OPERATIONAL FLEXIBILITY.

Even in fields focused on producing from oil reservoirs, gas is produced in association with the oil at the wellhead as a by-product of oil production. During oil production, it may be necessary to burn or release this gas for a number of operational reasons, including lowering the pressure to ensure safety. But the current gas-gathering infrastructure in many parts of the country is insufficient to accommodate the volume of gas produced because of, among other reasons, the high liquid content of the gas, the prolific volumes of oil and gas released during initial production, increasing pipeline pressure that requires installation of additional compressors, and in some cases, undersized pipe.

With limited exception, oil-well gas produced in the development of federal and Indian minerals “may not be vented or flared unless approved in writing by [BLM’s Area Oil & Gas Supervisor].” The Supervisor may approve venting or flaring based on the submission of:

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Tr. of Prelim. Inj. Proceedings at 44:24-25 (June 23, 2015) (testimony of Lynn D. Helms, Director of the North Dakota Department of Mineral Resources).


76 Beyond royalty rates and rental fees, BLM has also considered raising minimum bonus bids for federal leases. See 80 Fed. Reg. at 22,153. The only possible impact that raising minimum bids could have is to discourage more exploratory prospects from being leased in the first instance. Because bonus bids are only applicable to federal properties that are leased at competitive auctions, the winning bid, and not the artificial minimum, reflects the true value of the leases.

77 See In re Hrg Called on a Mot. of the Comm’n to Consider Amending the Current Bakken, Bakken/Three Forks, and/or Three Forks Pool Field Rules to Restrict Oil Prod. and/or Impose Such Provisions as Deemed Appropriate to Reduce the Amount of Flared Gas, Case No. 22058, Order No. 24665 ¶ 10, at 3 (N. Dakota Indus. Comm’n, July 1, 2014), https://www.dmr.nd.gov/oilgas/or24665.pdf.


79 Notice to Lessees & Operators of Onshore Fed. & Indian Oil & Gas Leases § IV(B) (Jan. 1, 1980) (“NTL-4A”). Under NTL-4A § III, flaring is authorized and can be conducted without incurring a royalty obligation under the following circumstances: (i) emergencies; (ii) well-purging and evaluation tests not to exceed twenty-four hours; (iii) initial production tests not exceeding a period of thirty days or the production of 50 MMcf of gas, whichever occurs first; and (iv) routine and special well tests for which the operator has received the Supervisor’s approval. See id. § III(A)-(D).
(1) an evaluation report supported by engineering, geologic, and economic data which demonstrates to the satisfaction of the Supervisor that the expenditures necessary to market or beneficially use such gas are not economically justified and that conservation of the gas, if required, would lead to the premature abandonment of recoverable oil reserves and ultimately to a greater loss of equivalent energy than would be recovered if the venting or flaring were permitted to continue or (2) an action plan that will eliminate venting or flaring of the gas within 1 year from the date of application.80

Particularly where gas cannot be gathered, transported, and sold economically, the Supervisor’s approval is essential to oil and gas producers because no royalty obligation is incurred on gas that is “vented or flared with the Supervisor’s prior authorization or approval during drilling, completing, or producing operations.”81

BLM’s regulations require operators to “conduct operations in such a manner as to prevent avoidable loss of oil and gas.”82 A royalty payment will accrue for oil or gas lost or wasted from a lease site, or allocated to a lease site, “when such loss or waste is due to negligence on the part of the operator of such lease, or due to the failure of the operator to comply with any regulation, order or citation issued pursuant to this part.”83 The essence of the existing regulatory framework is that royalties are not due on oil or gas that is “unavoidably lost.”84 That premise accounts for the unique circumstances of individual projects and allows BLM the flexibility to shape development in a manner that reflects the environmental and economic character of oil and gas development at the local level. By evaluating the engineering and economic factors on a well-by-well basis, BLM ensures that oil and gas producers are not obligated to incur costs in a manner that will undermine the financial returns on a well’s production or that would keep a prudent operator from developing what otherwise would be an economic oil project.

BLM’s newly proposed venting and flaring regulation would eliminate these localized analytics and replace NTL-4A with a one-size-fits-all standard.85 The proposed regulations would prohibit virtually all venting of natural gas from well sites86 and would place universally applicable limits on flaring—the average rate at which gas may be flared under the proposed rule is 1,800 Mcf per month per producing well on a lease.87 BLM’s new proposed rule does contemplate “alternative flaring limits” when the economics of a field do not justify gas capture, but raises the standard for the economic impact that must be demonstrated before a project will qualify for those alternative limits. BLM acknowledges that the agency has historically approved flaring requests when an operator could demonstrate some net cost that might cause the operator to abandon a well earlier than the operator otherwise would have. Going forward, BLM intends to allow flaring “only on a showing that the net costs of compliance with the flaring limit would be sufficient to cause the operator to cease production and abandon ‘significant’ recoverable oil reserves.”88 Absent this showing, operators on federal lands will be liable for royalties on all gas flared above the new generally applicable limits.

80 Id. § IV(B).
81 Id. § I.
82 43 C.F.R. § 3162.7-1(d).
83 Id.
84 NTL-4A § I.
85 81 Fed. Reg. at 6,627.
86 See id. at 6,638-39.
87 See id. at 6,639.
88 Id. at 6,640.
These royalties are not the end of the costs operators on federal lands are likely to incur as a result of the new regulation. This royalty obligation would be in addition to the operational compliance costs that BLM acknowledges operators will incur to implement the venting and flaring rule. BLM notes that, among other requirements, operators on federal lands will have to “add or improve gas-capture capability, and some would have to replace existing equipment.” BLM estimates that the venting and flaring rule will impose costs on operators “ranging from $125-$161 million per year (using a 7 percent discount rate) or $117-$134 million per year (using a 3 percent discount rate) over the next 10 years.” It is notable that BLM’s estimates are predicated on another agency, the Environmental Protection Agency, finalizing its own set of regulations for methane emissions from oil and gas sources. In other words, BLM characterization of the compliance costs oil and gas producers will incur as minimal – despite being in the hundreds of millions of dollars – is premised on BLM’s understanding that operators will already have taken steps to comply with another federal agency’s entirely separate set of regulations. Requiring compliance with multiple layers of regulation that multiple agencies promulgate exponentially elevates the cost of doing business on federal lands and encourages oil and gas producers to seek alternative development opportunities on non-federal lands.

II. OIL AND GAS REGULATION AND LEASE VALUE.

Since 1920, the Mineral Leasing Act has authorized the Secretary of the Interior “to prescribe necessary and proper rules and regulations and to do any and all things necessary to carry out and accomplish the purposes of this [Act].” Congress’ purpose in enacting the Mineral Leasing Act was “[t]o promote the mining of coal, phosphate, oil, oil shale, and sodium on the public domain.” Congress has determined that it is “in the national interest to foster and encourage private enterprise in,” among other endeavors, “the orderly and economic development of domestic mineral resources, reserves, and reclamation of metals and minerals to help assure satisfaction of industrial, security and environmental needs.” And Congress has instructed that “[i]t shall be the responsibility of the Secretary of the Interior to carry out this policy when exercising [her] authority under such programs as may be authorized by law.

These obligations are intertwined with the role that executive agencies, and particularly the Department of the Interior, play as stewards of the nation’s public lands. The Federal Land Policy and Management Act (“FLPMA”) obligates BLM to “manage the public lands under principles of multiple use and sustained yield.” To meet this obligation, BLM must consider “a combination of balanced and diverse resource uses that takes into account the long-term needs of future generations for renewable and nonrenewable resources.” The result of this statutory scheme is that, while BLM has a responsibility to “prevent unnecessary or undue degradation of the [public] lands,” accounting for the productivity of the federal mineral estate is a statutory imperative.

95 Id.
97 43 U.S.C. § 1702(c).
99 Because “FLPMA prohibits only unnecessary or undue degradation, not all degradation,” BLM must ensure that regulatory measures do not prevent the extraction of federal minerals. Theodore Roosevelt Conservation P’ship v.
Congress has also directed that access to federal lands for energy development must be efficient. BLM is required “[t]o ensure timely action on oil and gas leases and applications for permits to drill” and to effect policy that: (i) “ensures] expeditious compliance” with the National Environmental Policy Act and any other applicable environmental and cultural resources laws; (ii) “improve[s] consultation and coordination with the States and the public”; and (iii) “improve[s] the collection, storage, and retrieval of information relating to the oil and gas leasing activities.”\textsuperscript{100} Whether the comprehensive suite of regulatory initiatives described above is consistent with statutory requirements is beyond the scope of this paper. What is certain is that, individually and collectively, the proposed and final regulations are in tension with and cast doubt upon the efficacy and legitimacy of proposals to impose financial terms in federal oil and gas leases in a manner that raises the cost of developing those leases.

Each of the regulatory measures represents a reaction to a pair of related themes that run throughout the Obama Administration’s energy policy. The first theme is the idea that federal agencies have not kept pace with technological and economic developments that precipitated the contemporary boom in domestic oil and gas production. The result has been, according to the agencies, a proliferation of activities alleged to be either unregulated (or under-regulated) and long backlogs for federal permits and authorizations. Because of the explosive growth of production from shale, combined with federal budget restraints, BLM field offices around the country have amassed long backlogs for administrative review and approvals of drilling permits, rights-of-way, and other authorizations necessary for production.

The second theme is a concern that the current rules for calculating and collecting royalties on production are insufficient to ensure that the American people receive a fair return on development of the federal mineral estate. This concern is both distinct from and related to the first theme. The scope, volume, pace, and (until recently) profitability of oil and gas development, combined with the mistrust some maintain for the oil and gas industry, left many industry observers lacking confidence that the public was receiving its share of oil and gas revenue. Regulatory efforts to address that concern reflect a desire to control where and how oil and gas is produced, measured, transported, and sold.

Meeting the companion goals of incentivizing development and ensuring a fair return to the public requires evaluating federal leases against two metrics: (i) the rate of return that oil and gas companies achieve developing federal leases; and (ii) the total revenue that the government achieves from federal production. Comparing royalty rates (or bonus bids or rental rates) with royalty rates on state lands or in other countries does not provide a meaningful comparison. As referenced earlier, the value of an oil and natural gas asset derives from the interplay of many aspects. Royalty rates, bonus bids, operational costs, borrowing costs, regulatory costs, taxes, transportation costs, and distribution costs all impact an asset’s value. Oil and gas companies make investment decisions based on the totality of all these factors (and often others).

\textsuperscript{100} Salazar, 661 F.3d 66, 78 (D.C. Cir. 2011) (holding setbacks that protected sage-grouse but which prevented natural gas extraction did not satisfy BLM’s obligation to balance development with conservation). The Interior Board of Land Appeals has interpreted “unnecessary or undue degradation” to mean the occurrence of “something more than the usual effects anticipated from appropriately mitigated development.” Id. at 76 (quoting \textit{Biodiversity Conservation Alliance}, 174 IBLA 1, 5-6 (2008)). More than speculation is required: “Without evidence that . . . future injury will occur, it cannot be argued that degradation of the lands will occur, . . . or that the future degradation is unnecessary or undue.” \textit{Wyo. Outdoor Council}, 171 IBLA 108, 121-22 (2007) (internal quotations omitted).

For any reform of federal leasing to be effective, it must incorporate this conceptual foundation. Companies’ investment decisions are based on reasonable expectations about what a company will earn from a proposed project. When development costs, operational costs, taxes, regulatory compliance costs, and other obstacles are manageable, higher rates of development can be expected. When operational requirements and regulatory policy undermine profitability, development is unrealistic. The most essential point is that companies choose to develop on the lands that promise to deliver the highest returns.

The good news is that, while both contractual terms and regulatory policy can be used to frustrate development, both also represent effective tools the government can use to promote responsible development. A lean regulatory program that imposes only those costs necessary to protect environmental and public health values, taking advantage of opportunities to coordinate and cooperate with private companies and state regulators, may present BLM with an opportunity to modify the financial terms of oil and gas leases in a manner that maximizes the public’s share of revenue generated from federal lands. On the other hand, should regulators adopt more onerous regulations, BLM can adjust lease terms to account for the costs operators incur complying with those regulatory initiatives.

But what the government cannot do is lose sight of the relationship between these tools. The Obama Administration’s current regulatory agenda could have sweeping implications for domestic producers and consumers. And even before all the regulations are finalized, anecdotal evidence from operators across the country suggests that the legal, operational, and accounting costs associated with the new regulations have impacted the bottom line, threatening the economics of developing federal lands.

Proposed leasing reforms, combined with recent regulatory initiatives, may produce higher revenue on production that occurs on federal leaseholds, but royalties are paid only when production occurs. If regulatory requirements diminish the overall return producers earn on a project, the most likely result is less production on federal lands. Federal policy makers must understand that federal lands are in competition with state and private lands to attract investment and commercial activity; and when competing for investment dollars, federal lands begin from a position of disadvantage. Any effort to adjust the financial terms of federal oil and gas leases must account for these regulatory initiatives. Lease reform that fails to do so threatens to undermine the nation’s energy security and denies the public the benefits to be derived from development of the federal mineral estate.
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