June 19, 2015

Via e-filing on www.regulations.gov

Mr. Neil Kornze
Director
Attn: 1004-AE41
Bureau of Land Management
United States Department of the Interior
1849 C Street NW Room 2134LM
Washington, DC 200240

Re: RIN 1004-AE41. *Oil and Gas Leasing; Royalty on Production, Rental Payments, Minimum Acceptable Bids, Bonding Requirements, and Civil Penalty Assessments* (80 Fed. Reg. 22,148)

Dear Mr. Kornze:

On April 21, 2015, the Bureau of Land Management ("BLM") published an Advanced Notice of Proposed Rulemaking ("ANPR") soliciting public comments and suggestions that may be used to amend BLM's regulations "related to royalty rates, annual rental payments, minimum acceptable bids, bonding requirements, and civil penalty assessments for Federal onshore oil and gas leases."[1] This submission constitutes the comments of the Independent Petroleum Association of America ("IPAA") and Western Energy Alliance (the "Alliance") (collectively, the "Associations") and addresses in detail each subject referenced in the ANPR.

IPAA is the leading, national upstream trade association representing oil and natural gas producers and service companies. IPAA represents thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts.[2]

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[1] 80 Fed. Reg. 22,148 (Apr. 21, 2015).
[2] The typical independent oil and natural gas producer is a small business which employs twelve full-time and three part time employees. *See* Independent Petroleum Ass'n of Am., Profile of Independent Producers at 2 (2012-2013)

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The Alliance represents over 450 members involved in all aspects of environmentally responsible exploration and production of oil and natural gas in the West. The Alliance represents independents, the majority of which are small businesses with an average of fifteen employees. The proposed rule will significantly affect the Associations' members. Independent producers drill about ninety-five percent of American oil and natural gas wells, produce more than fifty percent of American oil, and produce more than eighty-five percent of American natural gas.

BLM recognizes that "[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."[3] Yet BLM's ANPR suggests that the agency is considering sweeping changes that will significantly modify the agency's onshore oil and natural gas leasing program. BLM has identified specific objectives that any proposed change should be defined to meet: (i) incentivize development of leased federal resources; (ii) ensure a fair return to American taxpayers; (iii) provide deterrence sufficient to prevent non-compliance with applicable laws, regulations, and permit conditions; and (iv) facilitate adequate reclamation of federal lands when development is complete. The Associations share each of these goals.

The Associations do not believe, however, that a dramatic overhaul of existing regulations is necessary to meet BLM's objectives. The proposed ANPR appears to portray 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, regulatory costs, taxes, transportation, 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.

A simple example illustrates the danger of drawing comparisons based on viewing each feature in isolation. Suppose one were to compare 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.[4] 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

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(describing the median size of independent oil and natural gas producing firms based on a survey of IPAA members), available at:
http://www.ipaa.org/wp-content/uploads/downloads/2014/07/2012-2013ProfileOfIndependentProducers.pdf.

[3] 80 Fed. Reg. at 22,150.

[4] *Bice v. Petro-Hunt LLC*, 768 N.W. 2d 496 (N.D. 2009).

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 guidance the Office of Natural Resources Revenue ("ONRR") issued on valuing gas through the Torre Alta transportation system in New Mexico,[5] 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.[6]

BLM's focus on bonding and civil penalty provisions as mechanisms for enforcement and deterrence is likewise overly narrow and does not account for existing measures that already ensure legal compliance and environmental preservation. Oil and natural gas companies conduct their operations subject to a suite of federal, state, and local laws that provide comprehensive parameters for development activities. Economic forces and commitments to shareholders and customers also serve as independent restraints on commercial activity and represent incentives to conduct operations in a manner consistent with BLM's objectives.[7]

When crafting regulations, BLM must also consider the statutory mandates that define the agency's mission and guide its policy. The Mineral Leasing Act authorizes 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 chapter."[8] Congress' purpose in enacting the Mineral Leasing Act was "[t]o promote the mining of coal, phosphate, oil, oil shale,

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[5] *See* Office of Natural Res. Revenue, *Dear Reporter Letter Re: Guidance on Valuing Gas for Royalty Purposes – Transp. Sys. & Processing Plants – Onshore Federal Leases* (Oct. 6, 2010), available at http://onrr.gov/unbundling/pdf/DRL_Transportation_Systems_and_Processing_Plants_October_6_2010.pdf; Office of Natural Res. Revenue, *Lybrook Plant & Torre Alta Transp. Sys. Cost Allocation* (Apr. 15, 2015), available at http://onrr.gov/unbundling/pdf/Williams_Torre_Alta_Transportation_System_Lybrook_Plant..pdf; Office of Natural Res. Revenue, Kutz Plant & Torre Alta Transp. Sys. Cost Allocation (July 8, 2014), available at http://onrr.gov/unbundling/pdf/Williams_Torre_Alta_Transportation_System_Kutz_Plant.pdf.

[6] This raw calculation also fails to account for the sizable financial burden royalty reporters incur to keep in compliance with the federal governments extremely complex keep-whole unbundling and marketable condition rules. One member company, a medium-sized oil and natural gas producer, reports that it has invested over $2 million in additional staff time and accounting software to ensure that royalty reporting is accurate and compliant with ONRR's complex rules. Numerous member companies report that the complexity of federal reporting requirements requires operators to incur substantial legal and consulting fees to maintain compliance with reporting regulations.

[7] In many instances, protecting a company's reputation is an even stronger deterrent than penalties.The existence of these external constraints on behavior counsel against removing limits on penalties. Removing caps adds an element of uncertainty to an operator's fiscal calculus, discouraging companies from operating on federal lands in the first place.

[8] 30 U.S.C. § 189.

and sodium on the public domain."[9] 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."[10] 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."[11]

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[s] 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."[12] The result of this statutory scheme is that accounting for the productivity of the federal mineral estate is a statutory imperative and any rulemaking in which BLM engages must incorporate that objective.

I. POLICY CONCERNS.

A. MEASURING A LEASE'S VALUE.

Meeting BLM's goals of incentivizing development and ensuring a fair return to the taxpayers requires evaluating federal leases against two metrics: (i) the rate of return that companies achieve developing federal leases; and (ii) the total revenue that the government achieves from federal revenue. Comparing royalty rates (or bonus bids or rental rates) to royalty rates on state lands or in other countries does not provide a meaningful comparison. Companies do not make investment decisions based on royalty rates. Those decisions are based on reasonable investment-backed expectations about what a company will earn from a proposed project. In places where development costs, operational costs, taxes, regulatory compliance costs, and other obstacles are more manageable, higher royalty rates can be borne. The most essential point is that, irrespective of what the royalty rate is, companies will choose to develop on the lands that promise to deliver the highest returns.

The government should also focus on its own returns. Raising royalty rates *may* produce higher revenue on production that occurs on federal leases, but royalties are only paid when production occurs. If raising royalty rates results in diminishing the overall return producers earn on a project, the most likely result is less production on federal lands. BLM must ensure that any decrease in production attributable to increasing royalty rates and other fees does not offset

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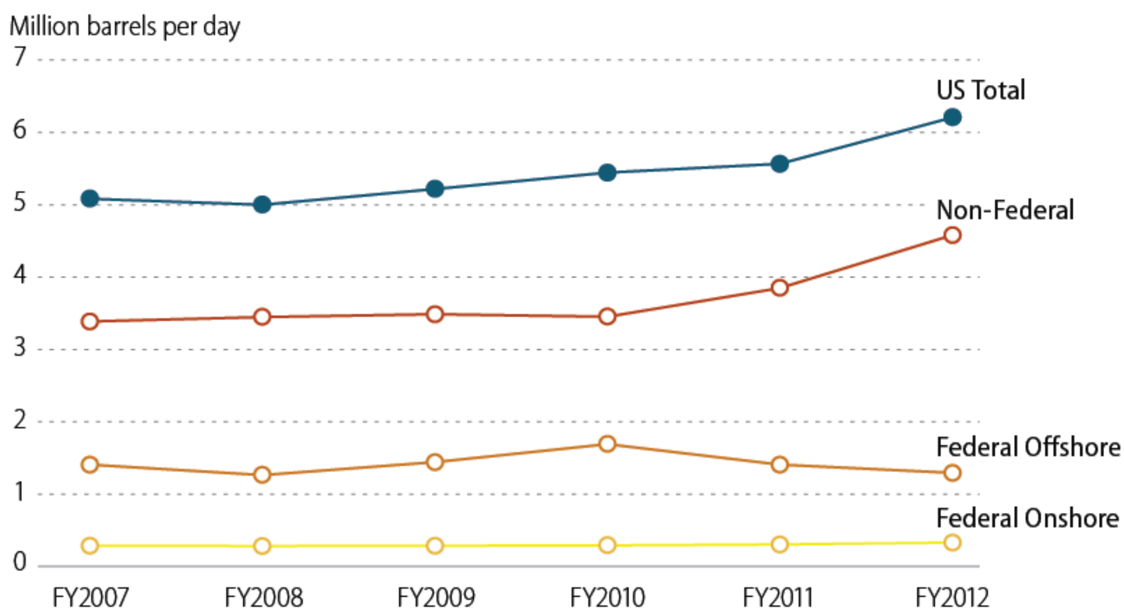
[9] Law of Feb. 25, 1920, c. 85, § 32, 41 Stat. 437.
[10] Mining & Minerals Policy Act of 1970, 30 U.S.C. § 21a.
[11] *Id.*
[12] Energy Policy Act of 2005, 42 U.S.C. § 15921(a)(1)(A)-(C).

increased revenue received from those projects that continue despite the increase.[13] Federal lands are in competition with state and private lands to attract investment and commercial activity; BLM must ensure that the terms of accessing federal lands allow federal lands to compete favorably.

It is no secret that under present circumstances, and other conditions being equal, oil and natural gas producers already work to avoid projects on federal lands. While domestic oil and natural gas production has grown in recent years, the percentage of that production that is extracted from federal lands has declined in the same period.

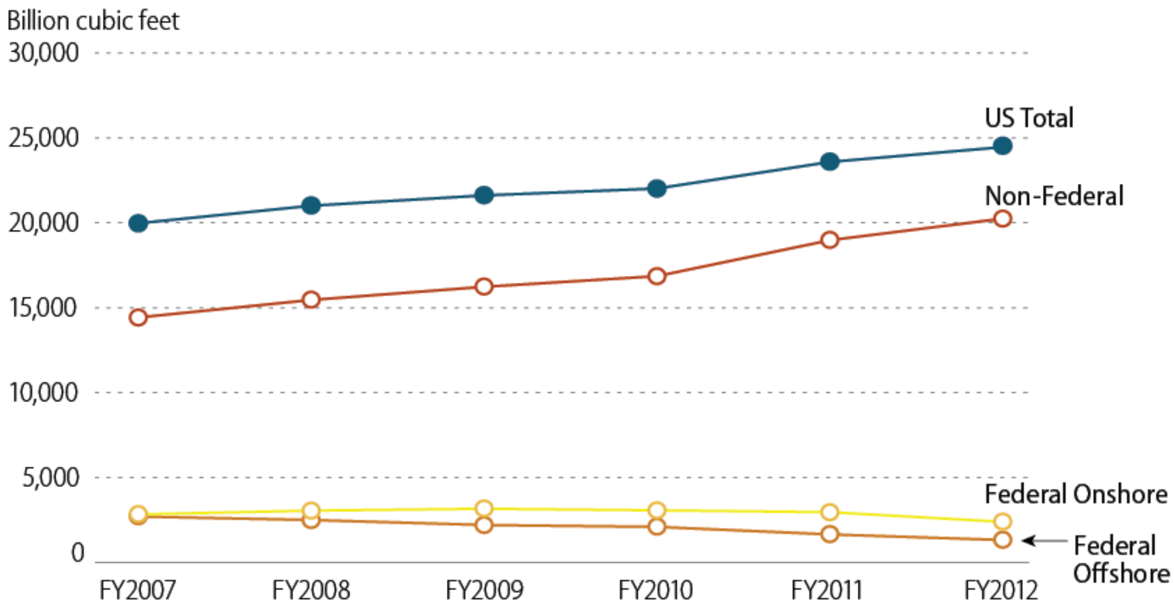
Figure 1. U.S. Oil & Lease Condensate Production: Federal and Non-Federal Areas, FY 2007-2012[14]



[13] Higher production also generates more federal revenue in the form of taxes received from companies and individuals involved in oil and natural gas development activities. *See* Ex. A, Mem. from John Dunham to Kathleen Sgamma at 12 (June 18, 2015).

[14] Congressional Research Serv., U.S. Crude Oil & Natural Gas Prod. in Fed. & Non-Fed. Areas, Fig. 1, at 3 (Mar. 7, 2013).

Figure 2. U.S. Natural Gas Production: Federal and Non-Federal Areas, FY 2007-2012[15]



The reasons for this divergence are not difficult to understand. A complex network of regulatory requirements -- both existing and proposed -- as well as logistical inefficiencies inherent in the management of federal lands represents an enormous incentive for operators to focus their efforts on state and private lands.

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 testimony before the Senate Energy and Natural Resources Committee, BLM's Director indicated recently that the average time to process a permit currently exceeds 200 days.[16] With the addition of new review and permitting requirements that operators will have to overcome before conducting hydraulic fracturing to complete individual wells,[17] those delays will almost certainly increase. And review of individual permits is often only a comparatively minor source 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

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[15] *Id.*, Fig. 2, at 4.

[16] *Bureau of Land Mgmt.'s Final Hydraulic Fracturing Rule Before the S. Energy & Natural Resources 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.").

[17] 80 Fed. Reg. 16,126 (Mar. 26, 2015).

in western public lands states, are subject to on-going environmental review approaching or exceeding ten years.[18]

This context must inform BLM's rulemaking analysis. When competing for investment dollars, federal lands begin from a position of disadvantage. Given the greater regulatory context, comparing royalty rates or other fees attendant to federal leasing to the fees state and private lessors charge is not a like-for-like comparison. To promote BLM's economic objectives, BLM must therefore focus its rulemaking on the returns that both oil and natural gas producers and the government achieve over the life of a lease, rather than on any individual component of lease value.

B. PENALTY PROVISIONS UNFAIRLY TARGET INDEPENDENT PRODUCERS.

As referenced above, independent producers are responsible for the overwhelming amount of domestic oil and natural gas production. Just last year, oil and natural gas reserves increased nine percent, virtually all of which is attributable to independent producers as opposed to major, integrated oil companies.[19]

It is therefore not surprising that independent producers are also the target most vulnerable to regulatory enforcement activity. The graph below demonstrates the relationship between the size of the civil penalties that ONRR imposed between 2010 and 2014 and the annual revenues of the companies upon whom the penalties were imposed.[20] Particularly for companies with annual revenues below five million dollars, the size of the penalties that ONRR imposed represent a meaningful percentage of revenues, implicating the company's fiscal solvency and its ability to survive economically. Recognizing the importance of independent producers to America's energy industry and overall economy, policies that exacerbate this disproportionate effect on small businesses are unjustifiable.[21]

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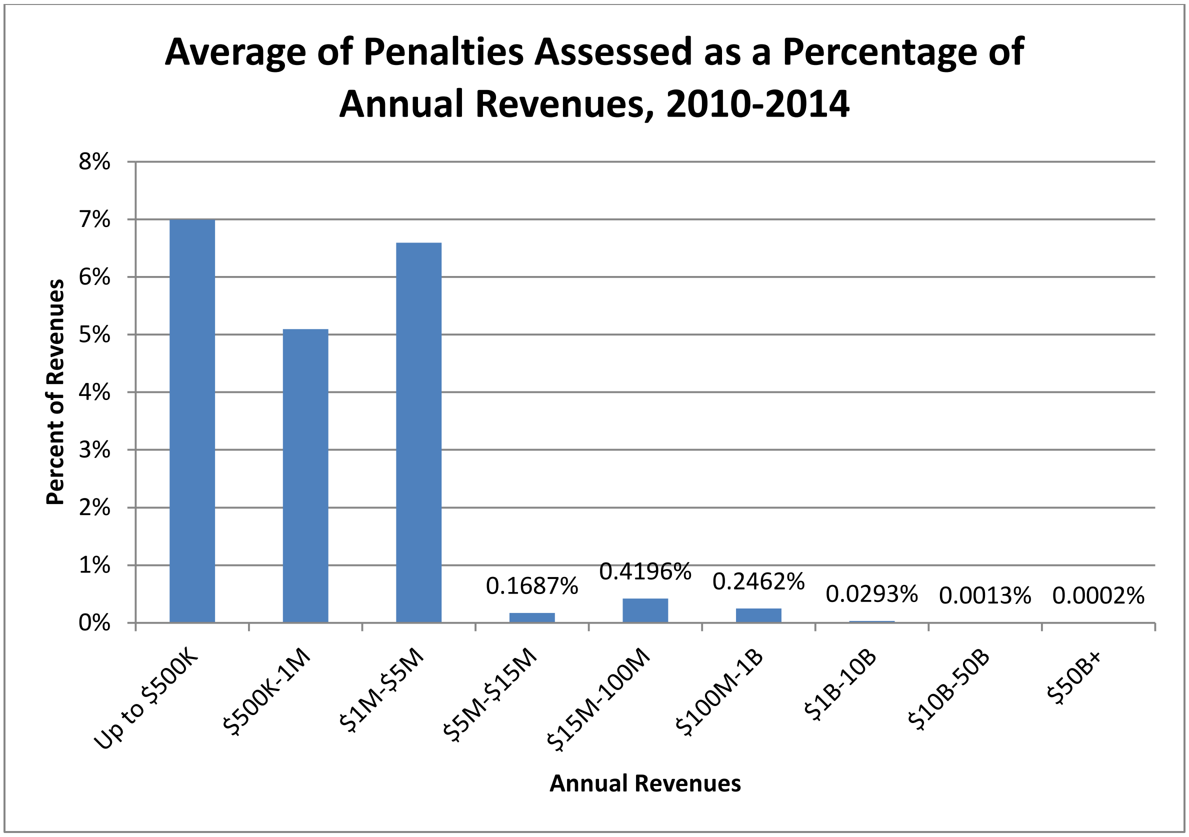
[18] *See, e.g.*, Bureau of Land Mgmt. Wyo. State Office, NEPA Hotsheet (May 2015), http://www.blm.gov/style/medialib/blm/wy/information/NEPA.Par.24843.File.dat/hot_sheet.pdf.

[19] EY, US Oil and Gas Reserves Study at 6-7 (2013), available at: http://www.ey.com/Publication/vwLUAssets/US_oil_and_gas_reserves_study_2013/$FILE/US_oil_and_gas_reserves_study_2013_DW0267.pdf.

[20] ONRR publishes the amounts of the civil penalties it collects on its website. *See* Office of Natural Res. Revenue, *Civil Penalties*, available at: http://onrr.gov/compliance/civil-penalties.htm. Information related to individual companies' annual revenues was collected from internet searches of publicly available websites.

[21] Given the dominance of small business entities in the oil and natural gas production business, any eventual rulemaking must involve the preparation of an enhanced regulatory flexibility analysis under, among other authorities, the Regulatory Flexibility Act, 5 U.S.C. §§ 601-12, and Small Business Regulatory Enforcement Fairness Act, 5 U.S.C. §§ 801-08.



C. ACTION COULD BE DUPLICATIVE OF INDEPENDENT ENFORCEMENT MECHANISMS.

BLM requires the lessee, operating rights owner or operator[22] to supply a personal or surety bond on federal oil and natural gas leases to ensure proper plugging and abandonment of wells, reclamation of the lease area, and remediation of any environmental impacts resulting after abandonment. For prudent operators, securitizing risk through bonding is superfluous--wells are timely and properly plugged and abandoned, the surface is reclaimed, and environmental issues are promptly addressed throughout the lifespan of the well. For the overwhelming majority of operators, it will never be an issue if a bond amount is "too low" because the bond will never be called upon to fund any of these activities.

[22] For ease of reference, these comments will use "operator" to refer to any party responsible for providing security, and "bond" to refer to both surety and personal bonds even though the processes differ for supplying or collecting on the different forms of financial security permitted under the regulations.

Nor is the loss of a bond likely to represent a substantial motivating factor in ensuring compliance with standards of industry best practices. The risk of civil and criminal penalties associated with violations of federal, state, and local law prohibiting pollution and threats to public safety will virtually always overshadow bonding costs, not to mention the damage that such conduct poses to company reputation. Responsibilities to investors, shareholders, and customers are likewise likely to hold oil and natural gas producers accountable for meeting best practices standards. Operators are committed to environmental and resource stewardship, and additionally recognize that properly plugged wells can result in substantial cost savings through avoidance of lost production from fields that are candidates for re-entry.

At the same time, the Associations' members recognize the reality that bonding is necessary to ensure protection against those occasions when an operator is absent or has insufficient financial resources to plug its wells and clean up the site. But it is a delicate endeavor to strike the proper balance between holding sufficient security to protect against operator insolvency while not over-securitizing and therefore hindering responsible operators' development. BLM has previously recognized the important of remaining "mindful of the need to maintain an acceptable risk level, yet not to place an undue burden on industry."[23]

In many ways, the historical issue of orphan wells drives the present discussion of proper bonding rates.[24] Before the adoption of regulatory standards requiring plugging and documenting oil and natural gas wells before they are abandoned, generally around the 1950s, thousands of wells were not plugged or plugged with very little cement in them. But this legacy problem (which includes wells the federal government drilled)[25] is not solved through bonding,[26] so to the extent BLM's analysis is premised on work performed on legacy wells, cost estimates for plugging and reclaiming abandoned wells may not accurately reflect current economics. For example, soil remediation expenses for an abandoned well that may have been leaking for decades or plugging an orphan well that requires removal of a structure built over the top of it likely will result in exponentially higher reclamation costs than costs associated with plugging and abandoning a modern, properly constructed well. This concern is addressed in greater detail below.

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[23] *See* BLM Instruction Mem. No. 2006-206, *Oil and Gas Bond Adequacy Reviews* (Aug. 3, 2006); BLM Instruction Mem. No. 2008-122, *Oil and Gas Bond Adequacy Reviews* (May 5, 2008). This mindfulness was unfortunately dropped from subsequently-issued BLM Instruction Memoranda. *See* BLM Instruction Mem. No. 2010-161, *Federal Oil and Gas Bonds* (July 13, 2010); BLM Instruction Mem. No. 2013-151, *Oil and Gas Bond Adequacy Reviews* (July 3, 2013).

[24] Orphan wells in this context means wells that are not producing or injecting that have neither express state approval to remain idle nor a known and solvent operator. These are to be distinguished from idle wells – wells that have approval to remain idle, or where no approval is necessary or attaches but the wells has a known and solvent operator.

[25] The BLM has estimated that reclaiming 37 of its own 67 legacy wells in Alaska could exceed $40 million. GAO 10-245 – page 20.

[26] Funds to plug orphan wells usually come from taxes on production, assessments on well operators, and penalties imposed on well operators for statutory or regulatory violations.

II. TECHNICAL PROPOSALS.

BLM recognized that the government should "strike a balance between encouraging private companies to invest in the development of oil and gas resources on federal lands . . . while maintaining the public's interest in collecting the appropriate level of revenues from the sale of the public's resources."[27]

A. ROYALTIES.

As discussed above, changes in royalty rates cannot be analyzed in isolation from other features of a lease's value. John Dunham & Associates, an economic consultancy, has therefore modeled the impact of federal production under twenty-four scenarios involving varying degrees of change to royalty rates and rental rates on federal leases.[28] Net expected production was calculated at a base royalty rate of 12.5%, and potential increases to 14.75%, 16.75%, 17.75%, and 18.75% with corresponding rental rates of the current $1.50/$2.00 per acre, $2.00 per acre, $3.00 per acre, $4.00 per acre, and $5.00 per acre. Under every scenario, raising royalty rates and rental rates had a negative impact on federal oil and natural gas production. The net result of that lost production is a reduction in federal energy revenues of up to about $51 million.[29]

While federal royalty rates are presently lower than royalty rates in some states,[30] there are good reasons why royalties on federal leaseholds are lower. For federal leases to be attractive to operators 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 requisite environmental review required under federal law, and the difficulty involved with accessing federal lands. Our members' experience reveals that the overall cost of developing leases on federal and Indian lands is consistently higher than for similar projects on state and fee 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.

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[27] 80 Fed. Reg. at 22,152.
[28] Dunham & Associates' full report describing the modeling efforts and conclusions is attached as Exhibit A to these comments.
[29] *See* Ex. A at 1. It must be noted that the model used for this analysis only assesses development in thirteen western states: Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. Some states with meaningful activity on federal lands, and particularly California and Alaska, are not included in the model. As a result, the model likely underestimates the value of lost revenue attributable to higher royalty rates and lease fees.
[30] *See id.* at 3, Table 2.

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;[31] and (ii) higher costs increase the risk premium that oil and natural gas producers will require before bidding on leases.[32] 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 projects focused on natural gas 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.

Nor are losses limited to lost royalty revenue. The oil and natural gas industry currently generates more than 173,000 direct jobs (not including additional secondary jobs) in the thirteen states the model analyzes. Depending on which of the twenty-four scenarios examined is ultimately adopted, as many as 1,330 direct jobs could be lost in these states alone. And because workers in the oil and natural gas sector tend to be highly compensated relative to workers in other economic sectors, job losses in oil and natural gas development disproportionately impact overall economic activity.[33]

Under the modeled scenarios, the loss of direct revenue to the federal government from oil and natural gas leasing resulting from a reduction in wells developed due to increased royalty rates and lease fees could be as much as $37 million annually. This represents meaningful losses to the federal government, but also to the states that receive fifty percent of all monies from oil and natural gas production on federal lands within a state's borders.[34] But losses are not limited to the revenues from wells that are not drilled. Both federal and state governments also stand to lose business and personal tax revenue from companies and individuals in the oil and natural gas activity, as well as the benefits of economic activity associated with full employment in the oil and natural gas industry. Modeling results suggest that these losses could well exceed $13.8 million for the federal government alone.

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[31] 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). available at: 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.

[32] One strategy that operators are likely to employ to achieve this risk premium is offering lower bonus bids when bidding on federal leases. *See* discussion *infra* Part II.C.

[33] Ex. A at 10-11.

[34] *See* 30 U.S.C. § 191(a).

B. RENTALS.

The Associations understand the purpose of rental rates as a tool to incentivize drilling on leased properties and to discourage operators from leasing federal land and then leaving that property idle. Nothing suggests that the program BLM presently has in place is insufficient to meet those objectives. A survey of rental rates for non-producing acreage in various states demonstrates that federal rental rates are presently competitive to rental rates on state land and private land. As a matter of industry practice, traditional rental rates on private land are $1 per acre, and range between $1 per acre and $5 per acre on state land.[35]

But while rental rates on federal lands are comparable to rates on state and private lands, the impact of federal rates is often more significant than on state and fee surface. Delays in administrative approvals, environmental review, and permit processing mean that operators on federal land 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 much more timely and where operators have control over drilling timeframes. The Associations therefore suggest that any modification to rental rates be tied to the expediency of permit processing. Should BLM decide to increase rental rates, those increases should not be applicable to any lands on which operators have not yet received authorization to drill and complete wells because of delays in conducting review under the National Environmental Policy Act, processing permits, granting federal rights-of-way, or administering other required approvals. The Associations could support raising rental rates only if those increases are combined with improved administrative performance targets.

C. MINIMUM BIDS.

A review of minimum bids in states that offer competitive bids on oil and natural gas properties indicates that federal minimum bids are presently comparable and that there is no reason to adjust the bidding structure.[36] But more important, because bonus bids are only applicable to federal properties that are leased at competitive auctions, the winning bid, and not an artificial minimum, reflects the true value of the leases. As BLM acknowledges, most federal parcels already "sell for well in excess of the current minimum acceptable bid."[37]

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[35] Average state rental rates are as follows: Colorado, $1 per acre; New Mexico, $1 per acre; Oklahoma, $1 per acre; Utah, $1.50 per acre; Wyoming, $2 per acre; Montana, $2 per acre; North Dakota, $2 per acre; Texas, $5 per acre.

[36] A survey of minimum bids in states suggests that the minimum bid for federal properties is the same or comparable to other jurisdictions' minimum bid: Wyoming, $2 per acre; North Dakota, $1 per acre; Montana, $1.50 per acre; Oklahoma, none; Utah, $2 per acre; Colorado, $2.5 per acre; New Mexico, no minimum.

[37] 80 Fed. Reg. at 22,153.

D. BONDING.

BLM's stated goal is "to ensure that bonds required for oil and gas activities on public lands adequately capture costs associated with potential non-compliance with any terms and conditions applicable to a Federal onshore oil and gas lease."[38] BLM's authority for imposing bonds derives from the Mineral Leasing Act, which empowers BLM to require "an adequate bond, surety, or other financial arrangement . . . to ensure the complete and timely reclamation of the lease tract, and the restoration of any land or surface waters adversely affected by lease operations after the abandonment or cessation of oil and gas operations on the lease."[39] Increases in bond levels can be either mandatory or permissive. BLM *must* require a higher bond when the operator applying for an APD has, within the previous five years, been subject to a demand for payment under the bond for failure to comply with plugging or reclamation requirements.[40] BLM *may* require a higher bond when, among other factors: (i) the operator has a history of previous violations; (ii) there are uncollected royalties due; or (iii) the estimated total cost of plugging existing wells and reclaiming lands exceeds the present bond amount.[41]

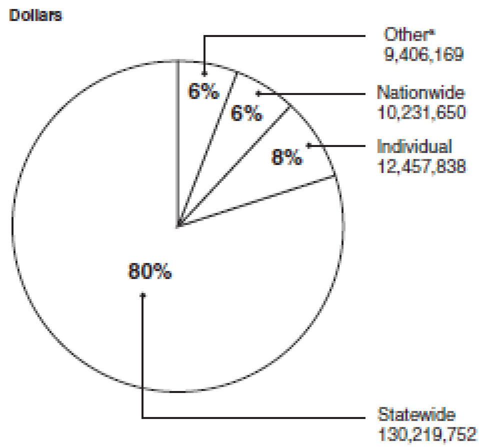
1. <u>Bonding Must Account for Unique Project Features</u>.

Based on a review of BLM's own data, the Government Accountability Office ("GAO") determined that, as of December 2008, oil and natural gas operators had provided 3,879 bonds, valued at $162 million, to ensure compliance with lease terms and conditions for 16,809 leases covering 88,357 wells.[42] Of those wells, seventy percent were located in New Mexico and Wyoming.[43]

GAO also reported that 52% of these bonds were surety bonds valued at approximately $84 million, and 48% were personal bonds valued at $78 million.[44] Most bonds fell into the "statewide bond" category:[45]

[38] 80 Fed. Reg. at 22,148.
[39] 30 U.S.C. § 226(g). *See also* 43 CFR 3104.1(a).
[40] 43 C.F.R. § 3104.5(a).
[41] 43 C.F.R. § 3104.5(b). When the authorized BLM officer determines an adjustment is necessary, the officer is directed to follow the procedure identified in Instruction Memorandum No. 2013-151. A request for increase or decrease must be forwarded to the BLM state office, which decides whether and in what amount to increase the bonding requirement. *See* Instruction Mem. No. 2013-151, at Attachment 2 "Procedures to Increase (or Decrease) Bond Amount."
[42] GAO-10-245, "Oil and Gas Bonds: Bonding Requirements and BLM Expenditures to Reclaim Orphaned Wells" page 10 (January 2010).
[43] Id.
[44] Id. at 11.
[45] GAO-10-245, at page 15, Figure 4.

Figure 4: Total Value of All Bond Categories, and Percentage of Total Bond Value, as of December 1, 2008



Source: GAO analysis of BLM data.

*Includes unit and NPR-A bonds.

GAO calculated an average costs of plugging and abandoning a well at $12,788 per well,[46] but acknowledged the range of costs per project vary widely: as little as $300 for three wells in Wyoming closed in 1994 versus $582,829 for another Wyoming well abandoned a decade later.[47]

This information alone, however, provides little insight into actual present risk to the federal government. The disparity between average costs and costs associated with individual wells results from each project's unique attributes including, but not limited to:

- Well type;
- Well depth;
- Wellbore condition;
- Proximity to freshwater;
- Whether any of these involved replugging of a previously inadequately plugged well (a more expensive endeavor);
- Unique wildlife or land uses affected the project;
- Project delays;

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[46] GAO 10-245 – page 16.
[47] GAO 10-245 – page 16.

- Whether and to what degree environmental impacts required mitigation;
- The degree to which recovery of equipment through the P&A has been used to offset the costs of the P&A;
- The number of times the federal government has had to collect on a bond in order to perform plugging or reclamation activities; and
- Where the federal government has performed such activities, the deficiency between the amount of bonding available and the total remediation cost.

So while data on the number of orphan wells and the historical costs associated with well abandonment exists, that data tells us little about the actual risk to the government, if any, attributable to current bond rates as opposed to costs that will have to be incurred to address legacy abandoned wells. More important than adjusting minimums, which are of course only floors, any rulemaking should begin with an effort to understand the particularized risk that an individual project poses rather than universally elevating bond rates to prejudice operators whose projects are sufficiently securitized. And as with all other aspects of oil and natural gas development, technological advancements that reduce surface disturbance and environmental impact, as well as efficiencies in the plugging and abandonment process, promise to reduce the costs associated with abandoning wells in the future. Should BLM adopt new bonding regulations, those regulations should include the opportunity for downward adjustment if implementation of new technologies results in cost savings.

Just as all projects are unique, so too are all operators. BLM is aware of the concerns and challenges small operators face. Because surety bonds are typically more costly to acquire, personal bonds may represent the only viable option for small operators; but more capital tied up in personal bonds means fewer funds available for plugging and reclamation. BLM should continue to assure that field offices have flexibility to craft alternative financial arrangements that account for small operators' restricted access to capital.

2. A Role for States.

There is opportunity for greater cooperation between states and the federal government to avoid duplicative bonding requirements. The Office of Surface Mining Reclamation and Enforcement ("OSM"), for example, allows states to implement state-administered programs to regulate the surface mining of coal in accordance with federal laws and with OSM's approval. States with approved programs can enter into a cooperative agreement with the Secretary of the Interior to enforce the state's program on federal lands within the state. OSM then delegates responsibility for the establishment and release of bonds required for surface coal mining and reclamation operations on federal lands to the state regulatory authority, with OSM concurring in the release of any bond.

While implementation of a cooperative program is outside the scope of BLM's authority under the Mineral Leasing Act's present bonding mandate, the fact that such programs have been used in other areas of natural resource management demonstrates that there is precedent for statutory reforms that grant states complete or shared authority with the federal government in managing and regulating activities on public lands within their borders.[48] Such laws take advantage of the fact that states are in a better position to set bonding rates that are appropriate for the geography of the region given that estimated reclamation costs in each state differ substantially.[49] Statewide treatment of bonding provides operators with a clear understanding of the expectations for securitization within a specific region and is consistent with the fact that the majority of bonds the federal government holds presently are statewide bonds.

Cooperation with states may also assist BLM address staffing and resource issues that prevent proper administration of the agency's bonding program. BLM should not increase bond amounts simply because it does not have sufficient staff to adequately conduct bond reviews.[50] If the problem is insufficient staff, the solution should be to address the staffing issue, not to shift the burden to all operators in the form of higher bond amounts.

3. Responses to ANPR Questions.

With this background in mind, the Associations' members offer the following comments in response to the ANPR's bonding questions.

Should the BLM increase the minimum bond amounts? and

If the BLM were to increase minimum bond amounts, what factors should it consider?

BLM has already begun a program of stepping up the bonding requirements over the past several years. The payments associated with the escalated bonds are having a negative effect on many operators' return on investment. Current commodities prices simply do not support large increases in bonding amounts, and may lead to prematurely plugged wells.

A comparison to state bonding requirements for states with significant oil and natural gas production suggest bonds are adequate. Wyoming and New Mexico, the states in which BLM holds the most federal bonds, have requirements similar to the federal standard. Wyoming requires a blanket bond in the amount of $75,000; and well bonds are $10,000 for each well less than or equal to 2,000 feet and $20,000 for each well deeper than 2,000 feet.[51] New Mexico requires a blanket financial assurance in the amount of $50,000 covering all wells in the state; or

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[48] *See* Western Energy Alliance Press Release, "Voters Support Energy Development on Public Lands, State Authority" (May 11, 2015).

[49] GAO-10-245, at page 18 (citing an average cost of $93,641 per well in Wyoming but an average cost of $9,100 per well in Arizona and stating "The estimated reclamation costs in each state differ substantially…These differences are due to factors such as well age, well depth, the amount of surface disturbance, and costs for materials and labor.").

[50] *See, e.g.*, GAO-11-292 at 32 ("Officials at 12 of the 16 field offices reported that they had too few resources to effectively manage potential liability.").

[51] *See* Oil and Gas Conservation Commission Rules and Regulations, Chapter 3, Section 4; Wyo. Stat. § 30-5-401, *et seq*.

a one-well financial assurance in the amount of $5,000 + $1.00 per foot of projected depth in major producing counties, and $10,000 + $1.00 per foot of projected depth for wells located elsewhere.[52]

BLM must also understand that it cannot adjust bonding costs in a manner isolated from the other aspects of this ANPR. If royalty rates and other lease-related fees are increased, then along with reaping the rewards of this increased benefit, the government should shoulder some increased risk as well. Increased revenue represents compensation for the possibility an operator fails to comply with its plugging and reclamation obligations, and because this risk is accounted for through higher royalties and fees, the risk should not be double-secured through increased bond amounts. If royalties and lease fees are increased, then bond rates should remain unchanged.[53]

Are there any other activities for which the BLM should consider requiring a bond?

Just as BLM presently treats bonds as "conditioned on compliance with all of the terms and conditions of the lease, including but not limited to, paying royalties, plugging wells, reclaiming disturbed land, and cleaning up abandoned operations,"[54] any increased bond amount would likewise cover all of these activities. Utilizing a single bond to securitize the risks associated with all of these activities is preferable to requiring multiple bonds. A single bond reduces the chances for errors and requires less management of the bonding process, promoting administrative efficiencies for both BLM and operators.

E. CIVIL PENALTIES.

At present, operators on federal lands are subject to the following penalty conditions:

- BLM may assess civil penalties of up to $500 per violation per day for failure to comply with FOGRMA, any mineral leasing law, any rule or regulation thereunder, or the terms of any lease.[55] These penalties accrue only after failure to correct a violation within 20 days after issuance of a notice. If corrective action is not taken within 40 days, the maximum daily penalty increases to up to $5,000 per violation per day. Current regulations impose a cap of a maximum of 60 days, resulting in a maximum possible civil penalty assessment of $300,000.[56]

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[52] *See* 19.15.8.9.D. NMAC.
[53] The Associations note that BLM may still choose to update bond rates to account for inflation. Adjusted for inflation, bond rates would be adjusted to approximately $75,000 for a lease bond; $200,000 for a statewide bond; and $1 million for a national bond. But because minimum bond rates are only minimums, there is no need to make this adjustment.
[54] GAO-10-245, page 12.
[55] *See* 30 U.S.C. §§ 1719(a)-(b).
[56] *See* 43 C.F.R. § 3163.2(b).

- BLM may assess civil penalties of up to $10,000 per violation per day for failure or refusal to permit lawful entry or inspection.[57] No prior notice or opportunity to correct is provided. Current regulations impose a cap of a maximum of 20 days, resulting in a maximum possible civil penalty assessment of $200,000.[58]

- BLM may assess civil penalties of up to $25,000 per violation per day for knowingly or willfully preparing or submitting false, inaccurate, or misleading reports or information, or for knowingly or willfully taking, removing, or diverting oil or gas from any lease site without valid legal authority.[59] No prior notice or opportunity to correct is provided. Current regulations impose a cap of a maximum of 20 days, resulting in a maximum possible civil penalty assessment of $500,000.[60]

BLM now proposes to remove or modify these caps due to concerns that the current penalty levels may not "provide an adequate deterrence given the current costs of completing a well in places like North Dakota."[61] BLM states that "the intent of the potential removal of the regulatory caps would be to ensure that the penalties provide adequate deterrence of unlawful conduct, particularly drilling on Federal onshore leases without authorization and drilling into leased parcels in knowing and willful trespass."[62] Given that an Interior Department Inspector General report has provided data demonstrating that the scale of trespass and drilling without approval ("DWOA") is very small, this is not adequate justification for removing or modifying the caps. The Inspector General's Report explains that the issue is not willful intent to drill without proper federal authorization, but rather mistakes due to the complexity of fragmented mineral ownership.[63]

The current regulations and their caps address and affect many more violations than merely unlawful drilling without authorization or unlawful drilling in knowing and willful trespass. Civil penalties arise from failure to comply with "*any* requirement of a statute, regulation, order, or terms of a lease for any Federal or Indian oil or gas lease;"[64] when a

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[57] *See* 30 U.S.C. § 1719(c)(2).
[58] *See* 43 C.F.R. § 3163.2(e).
[59] *See* 30 U.S.C. §§ 1719(d)(1)-(2).
[60] *See* 43 C.F.R. § 3163.2(f)
[61] 80 Fed. Reg. at 22,154.
[62] *Id.* at 22,148.
[63] *Bureau of Land Management: Federal Onshore Oil & Gas Trespass and Drilling Without Approval*, Report No. CR-IS-BLM-0004-2014, Office of Inspector General, U.S. Department of the Interior, September 2014. The report states that "in the past several years" BLM has identified ten cases of potential trespass and seventy cases of DWOA in North Dakota. Taking "several" as three years, as the report does not specify, we find from ONRR data for 2011-2013 that $579 million were collected in federal royalties from North Dakota. Comparing that to the $530,000 in lost royalties cited in the report indicates an error rate of .0009%. And if "several" means more than three years, that number becomes even more infinitesimal.

[64] 30 C.F.R. § 1241.51 (emphasis added) (describing penalties under 30 U.S.C. §§ 1719(a)-(b)).

company "knowingly or willfully fails to make *any* royalty payment by the date as specified," when a company "fails or refuses to permit lawful entry, inspection, or audit," or when a company knowingly or willfully fails or refuses to timely notify the Secretary of the date on which well production has begun or resumed;[65] or when a company "knowingly or willfully prepares, maintains, or submits false, inaccurate, or misleading reports, notices, affidavits, records, data, or other written information," when a company "knowingly or willfully takes or removes, transports, uses or diverts any oil or gas from any lease site without having valid legal authority to do so," or when a company "purchases, accepts, sells, transports, or conveys to another, any oil or gas knowing or having reason to know that such oil or gas was stolen or unlawfully removed or diverted."[66] Removing the penalty caps on all the foregoing scenarios would therefore affect much more than the concerns BLM raises in the ANPR. If BLM is specifically concerned with unlawful drilling, such concern affects only civil penalties issued pursuant to 30 U.S.C. § 1719(d), and specifically only the latter two scenarios of that sub-section. The consequences of removing the foregoing regulatory caps go far beyond BLM's current intent.

Another significant concern is that the current regulations do not automatically provide for a stay of penalty accrual upon a company's request for a hearing on the record. Penalties continue to accrue, even if a lessee requests a hearing, and will continue to accrue until resolution.[67] ONRR, the agency that administrates most penalty provisions of FOGRMA, has conceded that petitions to stay the accrual of penalties are "routinely denied."[68] When facing civil penalties without a cap, and with little possibility of a stay of accrual, 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 and absence of a cap can be prohibitive and because challenges within the federal administrative system can take so long.[69]

III. <u>CONCLUSION</u>.

The Associations request that BLM carefully consider the concerns discussed in these comments. We request that, should BLM proceed to propose regulatory updates, those updates

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[65] 30 U.S.C. § 1719(c)(2). *See also* 30 U.S.C. § 1712.
[66] 30 U.S.C. §§ 1719(d)(1)-(2).
[67] *See* 30 C.F.R. § 1241.55 ("If you do not correct the violations identified in the Notice of Noncompliance, the penalties will continue to accrue even if you request a hearing on the record").
[68] *See* 79 Fed. Reg. at 28,862 (May 20, 2014).
[69] It is not uncommon for hearing processes to take multiple years. *See, e.g.*, *Enter. Prods. Partners, L.P. v. Office of Natural Res. Revenue*, MMS 2009-8, Case No. CP08-052 (Dep't of Interior June 3, 2011) (delaying indefinitely appeal of a NONC dated June 29, 2009); *Cimarex Energy Co. v. Office of Natural Res. Revenue*, MMS 2009-9, Case No. CP08-123 (Feb. 25, 2011) (extending discovery deadlines through at least May 9, 2011 in an appeal of a NONC dated July 2, 2009); *K2 Am. Corp. v. Bureau of Ocean Energy Mgmt.*, MMS 2008-1, 2008-2, 2009-1 (Aug 31, 2010 Order) (denying motion to enforce settlement agreement and ordering appeals of five NONCs issued in 2007 and 2008 to proceed); *Statoil USA E&P Inc. v. Office of Natural Res. Revenue*, ONRR 2012-03, Case No. CP11-098 (Mar. 7, 2013) (denying summary judgment in appeal of NONC issued February 17, 2012).

take into account the broader legal and commercial context in which onshore oil and natural gas leasing is conducted and that reflect the agency statutory mandate to account for the productivity of the federal mineral estate.

Thank you for your consideration of these comments,

Barry Russell
President & CEO
Independent Petroleum Association of America

Tim Wigley
President
Western Energy Alliance

MEMORANDUM

TO:	Kathleen Sgamma, VP of Government & Public Affairs, Western Energy Alliance
FROM:	John Dunham, Managing Partner
DATE:	June 18, 2015
RE:	Estimated Economic Effect of Increased Federal Royalty and Bonus Bids

Executive Summary:

On April 21, 2015, the Department of Interior, Bureau of Land Management published an Advance Notice of Proposed Rulemaking (ANPR) that would effectively raise the cost of producing oil and natural gas on federal leases.[70] The ANPR asked for public comments and suggestions that the BLM could use in changing regulations related to a number of aspects of its oil and natural gas leases. Specifically the ANPR asks for comments on:

1. Regulations related to royalty rates, which are currently set at 12.5 percent for Federal leases;
2. Regulations pertaining to annual rental payments;
3. Regulations related to minimum acceptable bids;
4. Regulations related to leaseholder bonding requirements; and
5. Regulations related to civil penalty assessments for violations of Federal leases.

Regulations that would increase royalty rates of minimum annual rental payments are expected to have a direct and negative effect on oil and natural gas production activity on Federal leaseholds. Table 1 outlines the expected impact based on 24 different scenarios.

70 *Oil and Gas Leasing: Royalty on Production, Rental Payments, Minimum Acceptable Bids, Bonding Requirements, and Civil Penalty Assessments*, Department of the Interior, Bureau of Land Management, RIN 1004-AE41, Federal Register, April 21, 2015.

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Table 1

Estimated Reduction in Federal Oil and Natural Gas Wells by Scenario

Royalty Rate ↓	Rental Rate Per Acre → $1.50/$2.00	$2.00	$3.00	$4.00	$5.00
12.50	-	(106.3)	(107.2)	(108.0)	(108.8)
14.75	(322.1)	(312.7)	(313.5)	(314.3)	(315.1)
16.75	(311.8)	(387.1)	(388.0)	(388.8)	(389.6)
17.75	(280.8)	(418.1)	(419.0)	(419.8)	(420.6)
18.75	(206.3)	(428.4)	(429.2)	(430.0)	(430.8)

All told existing Federal revenues could fall by as much as $51 million annually as a result of this reduced development. These revenues take two forms: Expected royalty payments under the current 12 percent structure, and lost personal and business taxes that would result from lower oil and natural gas development activities.

The following analysis outlines the methodology used to arrive at these estimates.

Background:

On April 21, 2015, the Department of Interior, Bureau of Land Management published an Advance Notice of Proposed Rulemaking (ANPR) that would effectively raise the cost of producing oil and natural gas on federal leases.[71] The ANPR asked for public comments and suggestions that the BLM could use in changing regulations related to a number of aspects of its oil and natural gas leases. Specifically the ANPR asks for comments on:

1. Regulations related to royalty rates, which are currently set at 12.5 percent for Federal leases;
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[71] *Oil and Gas Leasing: Royalty on Production, Rental Payments, Minimum Acceptable Bids, Bonding Requirements, and Civil Penalty Assessments*, Department of the Interior, Bureau of Land Management, RIN 1004-AE41, Federal Register, April 21, 2015.

3. Regulations related to minimum acceptable bids;
4. Regulations related to leaseholder bonding requirements; and
5. Regulations related to civil penalty assessments for violations of Federal leases.

The BLM makes a number of suggestions in the ANPR; however, the agency does not provide any actual guidance on how any proposed rules will actually change the existing leasing and royalty system. For the purpose of this analysis John Dunham & Associates (JDA) has run a range of scenarios in order to determine how differences in the magnitude of the change would impact potential oil and natural gas developments.

Potential Rule Changes:

Regulations related to royalty rates: Current law sets the royalty rate on Federal leases at 12.5 percent. This is slightly lower than rates on state leases which the ANPR states can range from 12.5 to 18.75 percent in the states covered in this analysis. (See Table 2 on the following page) There may be very good reasons why royalties on Federal leaseholds might be lower including the time and expense involved in obtaining the lease and complying with overlapping state and Federal regulations, difficulty of accessing Federal lands or the quality of the leases themselves. This means that the overall cost of developing leases on Federal lands, or leases on Native American lands that are regulated by the Federal government is generally higher than for similar projects on state and fee lands.[72] That said, the Federal government through either Congress or the regulatory process can attempt to set higher royalty rates as long as the market can bear them. In this case, as the ANPR makes no direct recommendation as to what a reasonable rate should be, we model the impact of a range of rates, starting at 12.5 percent and rising to a high of 18.75 percent.[73]

<u>Regulations pertaining to annual rental payments</u>: Leaseholders are obligated to pay a fixed rental rate on undeveloped leases of $1.50 per acre per year for the first two years and $2.00 per acre for any subsequent year. Once production begins, this converts to the royalty payment. The BLM has not raised these rental rates since 1987 and is looking to increase them to at least the minimum rental rates charged by States and private landholders.

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72 While actual production costs are assumed to be similar in the model, the process of receiving approval of an Application for Permit to Drill (APD) can be quite extensive. If the APD delays the development of an average project in Utah (for example) by just a month, the delay costs to an operator could be about $2,750.

73 Rates as high as 20 percent are charged by some states but these are outside of the 13 state Western Region

Table 2

Examples of Royalty Rates on State Lands

State	Low Rate	High Rate
Colorado	16.67	16.67
Montana	16.67	16.67
New Mexico	16.67	18.75
North Dakota	16.67	18.75
Utah	12.5	16.67
Wyoming	12.5	16.67

Regulations related to minimum acceptable bids: The minimum acceptable bid for lease sale auctions is important because it establishes the floor payment which a potential bidder will offer to acquire a lease. This is currently $2.00 per acre and grants a bidder an option to develop a site. So for a one-time payment of $2.00 per acre, a bidder gains the right to propose development of a site (subject to BLM licensing and review) and to pay annual rentals and current royalty rates. Therefore, were the royalty rates or rental payments to rise, the actual value of the option would fall. This is, therefore, basically a risk premium which development companies are willing to pay for the option to develop federal land.

Regulations related to leaseholder bonding requirements: Currently the Secretary of the Interior has the authority to establish standards to ensure that an adequate bond or other financial arrangement is in place prior to the commencement of any surface-disturbing activities on any lease. Currently bonds for BLM leases are set at about $10,000 for an individual lease and upwards of $150,000 for a nationwide bond. These requirements may or may not be adequate to fund timely reclamation of land that is abandoned or otherwise harmed by operator activities; however, it is important to ensure that the public is adequately compensated if proper exploration and development activities do not occur. Since the Secretary of Interior already has the authority to set higher bonding requirement in cases where problems might occur, there is no need to model any impacts from changes in bonding requirements.

Regulations related to civil penalty assessments for violations of Federal leases: According to the ANPR, the BLM's Office of the Inspector General (OIG) is concerned that penalties in place to deter direct trespass on public lands or for drilling without permits may not be adequate. In both cases these activities are currently illegal and any economic impact of illegal activities should generally be discounted. For this reason, no model of changes in penalty fees is included in this analysis.

Data and Model:

This analysis is based on a model of the oil and natural gas production industry in 13 western states, which was developed for the Western Energy Alliance by JDA, a New York City-based economic consulting firm. It is based on a wide range of data sources and assumptions, each of which impacts the final results. JDA has strived to ensure that the assumptions are as cautious as possible leading to what is likely a low estimate of the overall cost of the proposed rule. Each of these assumptions, along with the data used in the development of the models, is detailed below:

Model:

Average Development Costs: Are estimated based on data derived from the U.S. Department of Commerce, Bureau of Economic Analysis as compiled by IMPLAN Inc. in 2012.[74] These data come from the Input/Output accounts of the United States and provide detailed information on the input costs for oil and gas well drilling, including wages, capital costs and leasing costs, as well as costs for various materials and services used in the drilling and completion of oil and gas

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74 The IMPLAN model uses data from many different sources – as published government data series, unpublished data, sets of relationships, ratios, or as estimates. IMPLAN LLC gathers this data, converts it into a consistent format, and estimates the missing components. There are three different levels of data generally available in the United States: Federal, state and county. Most of the detailed data is available at the county level, and as such there are many issues with disclosure, especially in the case of smaller industries, such as brewing. IMPLAN overcomes these disclosure problems by combining a large number of datasets and by estimating those variables that are not found from any of them. The data is then converted into national input-output matrices (Use, Make, By-products, Absorption and Market Shares) as well as national tables for deflators, regional purchase coefficients and margins. The IMPLAN Make matrix represents the production of commodities by industry. The Bureau of Economic Analysis (BEA) Benchmark I/O Study of the US Make Table forms the bases of the IMPLAN model. The Benchmark Make Table is updated to current year prices, and rearranged into the IMPLAN sector format. The IMPLAN Use matrix is based on estimates of final demand, value-added by sector and total industry and commodity output data as provided by government statistics or estimated by IMPLAN. The BEA Benchmark Use Table is then bridged to the IMPLAN sectors. Once the re-sectoring is complete, the Use Tables can be updated based on the other data and model calculations of interstate and international trade. In the IMPLAN model, as with any input-output framework, all expenditures are in terms of producer prices. This allocates all expenditures to the industries that produce goods and services. As a result, all data not received in producer prices is converted using margins which are derived from the BEA Input-Output model. Margins represent the difference between producer and consumer prices. Deflators, which account for relative price changes during different time periods, are derived from the Bureau of Labor Statistics (BLS) Growth Model. The BLS model is mapped to the IMPLAN model. Where data are missing, deflators from BEA's Survey of Current Businesses are used. Finally, one of the most important parts of the IMPLAN model, the Regional Purchase Coefficients (RPCs) must be derived. IMPLAN is derived from a national model, which represents the "average" condition for a particular industry. Since national production functions do not necessarily represent particular regional differences, adjustments need to be made. Regional trade flows are estimated based on the Multi-Regional Input-Output Accounts.

wells.[75] The figures used in this model are based on the average cost per dollar of output (basically sales) multiplied by the estimated sale of oil and natural gas at the wellhead in each state. Annual average prices and production volumes by state are gathered from the US Department of Energy.[76] Costs are divided into well development stages, broadly 'exploration, leasing and permitting' and 'drilling and completion.' Costs for lease bids, rental payments and all permitting costs are part of the exploration, leasing and permitting equations, and are based on input commodity and service costs.[77]

<u>Production Costs</u>: Are derived from the IMPLAN model. These data present detailed figures on the input costs for oil and gas production, including wages, capital costs and leasing costs, as well as costs for various materials and services used in the exploration/leasing/permitting, production, infrastructure development and reclamation of oil and gas plays.[78] The figures used in this model are based on the average cost per dollar of output (basically sales) multiplied by the estimated sale of oil and natural gas at the wellhead in each state as of 2012, which are the latest data available. Annual average prices and production volumes by state are gathered from the US Department of Energy.[79] Royalty payments are included as part of production costs.

Production cost assumptions were taken from IMPLAN and then divided into eight components, representing 4 different types of production outcomes for both oil and natural gas wells. These types were: Dry holes (wells with zero production), small production (or stripper wells), medium production wells and large production wells. Breaks between small, medium and high production wells in each state came from the US Department of Energy, Energy Information Administration (EIA) and represent data from 2009, which is the last year for which data are available.[80] The total number of existing oil and gas wells in each state (as provided by each state licensing department) was then used to create a proxy of an "average well." This serves as the unit of analysis in the model, but does not represent a physical well or field as might be

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75 Based on the IMPLAN tables, inputs from 119 different industries go into the exploration, development and infrastructure surrounding the extraction of oil and natural gas, and while inputs from many industries (for example insurance) are used in all of the states of development, some are predominant in certain parts of the process. In this case, inputs from 74 specific industry categories are assigned to the drilling/completion process. Inputs from 17 industries are assigned to the development of collection infrastructure.

76 See for example: *Domestic Crude Oil First Purchase Prices by Area*, US Department of Energy, Energy Information Administration, at: www.eia.gov/dnav/pet/pet_pri_dfp1_k_a.htm

77 The model is based on average costs and revenues. These can vary greatly by play, product and individual well.

78 Based on the IMPLAN tables, inputs from 116 different industries go into the drilling and completion of oil and natural gas wells. The input/output tables assign drilling and completion of wells to a different industry than oil and natural gas development.

79 See for example: *Domestic Crude Oil First Purchase Prices by Area*, US Department of Energy, Energy Information Administration, at: www.eia.gov/dnav/pet/pet_pri_dfp1_k_a.htm

80 *Distribution and Production of Oil and Gas Wells by State*, US Department of Energy, Energy Information Administration, January 7, 2011. Available on-line at: www.eia.gov/pub/oil_gas/petrosystem/petrosysog.html. Data retrieved May 6, 2014.

developed by a specific company. It is rather an analytical tool that allows for shocks to the system, such as increased costs, to be used to measure percentage changes in economic activity.

Anticipated Revenues: Are based on data from the US Department of Energy. Revenues are simply equal to the annualized price of either oil or natural gas at the wellhead (by state) multiplied by annual production.[81] Revenues over the life of a well cannot be derived simply by dividing total revenues by the number of producing wells and multiplying by the expected life. This is because oil and gas wells tend to have either a hyperbolic or an exponentially declining production trend. Based on discussions with industry personnel, a well will generally not be drilled and put into production unless it can recoup at least the direct drilling and completion costs in the first year after completion. In the case of this model, the lifetime expected return from an "average well" is modeled such that 80 percent of the discounted value will be recovered during the first 4 years of production.

It should be noted that the model used in this analysis was developed in 2014. This means that revenues are based on average wellhead prices for the prior year (2013). Since that time, energy prices have fallen dramatically. Based on Federal government data, oil prices are down by about 47 percent, and natural gas prices are off 24 percent from an already low base.[82]

Table 3

Change in Energy Prices

	West Texas Spot ($ Per Barrel)	Henty Hub Spot ($ per '000 CF)
2013	$97.91	$3.84
2015	$51.86	$2.92
Change	-$46.04	-$0.92
Pct Chg	-47.03%	-24.00%

[81] Ibid.
[82] *Table 2. U.S. Energy Prices*, Short-Term Energy Outlook, June 2015, US Department of Energy, Energy Information Administration, June 2015, on-line at: www.eia.gov/forecasts/steo/data.cfm?type=tables

The Number of Wells to be Drilled: Estimated based on data from individual state permitting authorities. Each authority uses different methods to identify whether wells are gas or oil (or both) and the wells' stage in the production process. While complete standardization between the states is not possible, in general it is possible to label a well as "oil" or "gas," and determine its stage of pre-production. Again, these are analytical "average wells" which are calculated for each individual state based on current conditions, but do not necessarily represent fields that a specific company may actually drill and develop.

The number of potentially impacted wells on Federal and federally-controlled lands is based on the assumption that about 4,000 APDs are granted each year. In the states being examined, the number averaged about 3,600 per year.[83]

The Number of Producing Wells: Estimated based on data from individual state permitting authorities. Again, each authority uses different methods to identify whether wells are gas or oil (or both) and the wells' stage of production. While complete standardization between the states is not possible, in general it is possible to label a well as "oil" or "gas," and determine its stage of production. Water wells, disposal wells, capped wells, injection wells, and other operations not directly used to extract petroleum are not included.

Data:

Data on current royalty payments were gathered from the BLM by state and by product.[84] Oil and oil based liquids were aggregated into oil royalties, flash gas, unprocessed gas and gas lost, were combined into dry gas royalties, and fuel gas, gas plant products and gas hydrate were combined into natural gas liquids royalties. In addition, data on the number of leaseholds, the number of well bores on federal lands and the number of permits issues by state were gathered from the BLM.[85]

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83 Based on data for the past 5 years. In FY 2014, the last year for which data are available, only 3,485 were issued. See: *Number of Drilling Permits Approved by Fiscal Year on Federal Lands*, US Department of the Interior, Bureau of Land Management, October 29, 2014 at: www.blm.gov/wo/st/en/prog/energy/oil_and_gas/statistics.html

84 US Department of Interior, Office of Natural Resource Revenue, Statistical Information Website at: http://statistics.onrr.gov/ReportTool.aspx

85 See US Department of Interior, Bureau of Land Management, Oil & Gas Statistics webpage at: http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/statistics.html

Modeling The Proposed Changes:

Higher royalty fees and rental payments will have a negative impact on the development of oil and natural gas on federal leaseholds, simply because higher costs will make more marginal projects uneconomical. In addition, since the actual economic return on projects is not certain prior to actually drilling and completing wells, there is an increase in the risk premium that companies will require prior to even bidding on a Federal lease.

In order to determine the impact on development, the representative well model described above was "shocked" with a range of price changes, leading to twenty-four different scenarios across all of the 13 states. The following scenario assumptions were used:

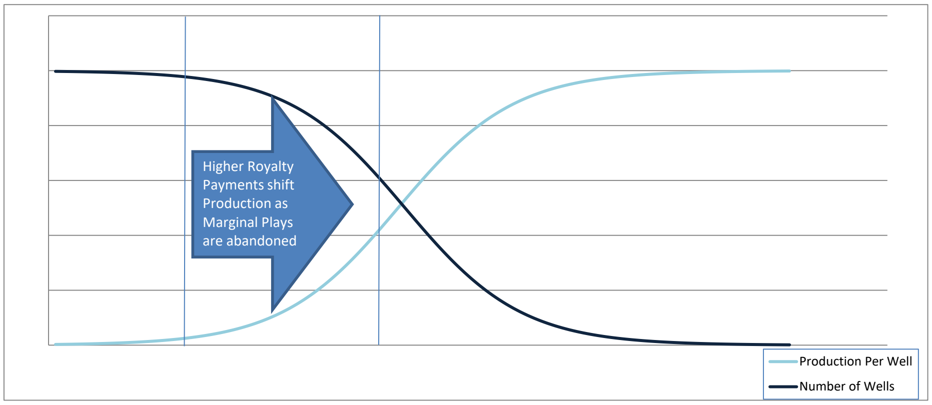
1. Royalty rate set to 18.75 percent
2. Royalty rate set to 17.75 percent
3. Royalty rate set to 16.75 percent
4. Royalty rate set to 14.75 percent
5. Average rent increased to $2 per acre
6. Average rent increased to $3 per acre
7. Average rent increased to $4 per acre
8. Average rent increased to $5 per acre.

Depending on the mix of oil and natural gas in each state, and the relative cost structure of a representative well, and the actual likelihood of the BLM approving a project in a given state are used to determine the estimated number of wells that would not be developed under each of the eight scenarios. In some cases, particularly royalty rate changes for projects that are predominately geared toward natural gas, the impact is rather small since prices are so low that significant new developments are uneconomical, while in other cases, where there are a lot of drilling permits issued and projects are dominated by inexpensive vertical oil wells, the impacts are significantly higher.

The model works by eliminating the least productive wells from consideration first, then eliminating more and more wells based on their potential profitability. (See Figure 1) This likely underestimates the effects of the proposed changes in royalty rates and rental payments, as developers may not consider entire leaseholds for development consideration even though they may have individually profitable drilling opportunities on them.

Figure 1

Graphic Description of Regulatory Impact Model



First changes in royalty rates were modeled, and then the less onerous changes in the minimum pre-development rental payments were examined. The results were then combined to form the values reported for each of the 24 separate potential scenarios included in this report.

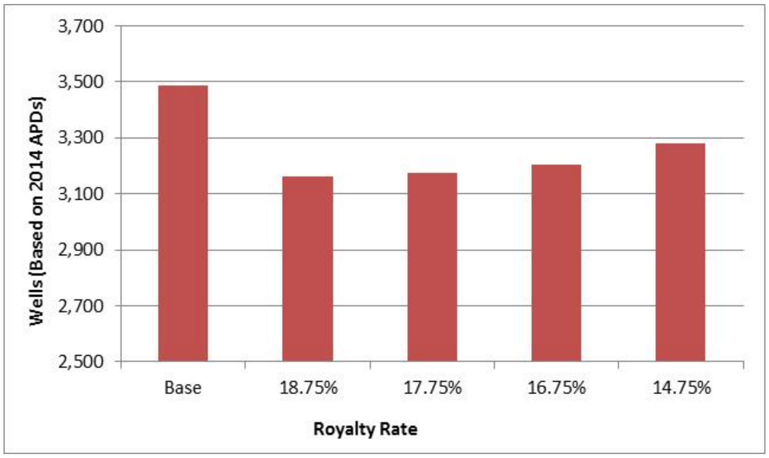
Royalty Rate Increases:

Current law sets the royalty rate on federal leases at 12.5 percent. This analysis examines the impact of increasing this rate to 18.75 percent stepping it up from 14.75 percent to 16.75 percent and from 17.75 percent. Overall, in the states examined, it is estimated that the number of new wells drilled would fall by 9.24 percent on Federal leaseholds in the states examined were the royalty rate to be raised to 18.75 percent. A royalty rate of 14.75 percent would lead to a reduction of 5.92 percent (or just over 200 new wells). Nearly all of these would be primarily oil wells, as the number of primary gas wells would only be marginally impacted by higher royalty rate payments. Note that these reductions assume that the minimum rental payments will be held at the current figure of $1.50 per acre for the first two years, and $2.00 per acre thereafter. Figure 2 outlines the expected number of projects based on the fact that only 3,485 APDs were issued in the 13 states represented by the Western Energy Alliance.[86]

86 Ibid.

Figure 2

Effect of Royalty Rate Increases on the Number of New Wells on Federal Lands



The states which would be most impacted by royalty rate increases would be Utah, followed by New Mexico, Wyoming and Colorado, in part because these are the states where most APDs are being issued. In some states, including Arizona, Oregon, South Dakota and Washington it would likely not be productive to engage in any development on Federal leaseholds under these higher royalty assumption scenarios. However, since there currently is no development activity being approved in these states, the actual effect would be nil.

Table 4

Effect of Royalty Rate Increases on the Number of New Wells on Federal Lands by State

	18.75% Royalty		17.75% Royalty		16.75% Royalty		14.75% Royalty	
	Primary Well Type		Primary Well Type		Primary Well Type		Primary Well Type	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Arizona	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%
Colorado	-7.5%	-0.7%	-6.3%	-0.7%	-5.2%	-0.7%	-2.8%	-0.6%
Idaho	-100.0%	-0.3%	-100.0%	-0.3%	-100.0%	-0.3%	-100.0%	-0.3%
Montana	-4.2%	-0.1%	-3.5%	-0.1%	-2.9%	-0.1%	-1.6%	-0.1%
Nebraska	-16.4%	-0.2%	-15.7%	-0.2%	-14.8%	-0.2%	-11.9%	-0.2%
Nevada	-100.0%	0.0%	-100.0%	0.0%	-100.0%	0.0%	-100.0%	0.0%
New Mexico	-24.6%	0.0%	-21.5%	0.0%	-18.2%	0.0%	-10.5%	0.0%
North Dakota	-4.0%	0.0%	-3.4%	0.0%	-2.8%	0.0%	-1.5%	0.0%
Oregon	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%
South Dakota	-100.0%	0.0%	-100.0%	0.0%	-100.0%	0.0%	-0.4%	0.0%
Utah	-31.7%	-0.1%	-34.6%	-0.1%	-33.1%	-0.1%	-28.7%	0.0%
Washington	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%
Wyoming	-14.9%	-0.2%	-13.0%	-0.2%	-11.0%	-0.2%	-6.6%	-0.2%

<u>Rent Rate Increases</u>:

Leaseholders are obligated to pay a fixed rental rate on undeveloped leases of $1.50 per acre per year for the first two years and $2.00 per acre for any subsequent year. Once production begins, this converts to the royalty payment. The baseline rent used in this analysis is considered to be $1.75 per acre which is the simple average of these two rates. Scenarios were tested raising the average rent to $2 per acre, $3 per acre, $4 per acre and $5 per acre. The impact on Federal oil and natural gas developments by state are shown in Table 5.

Table 5

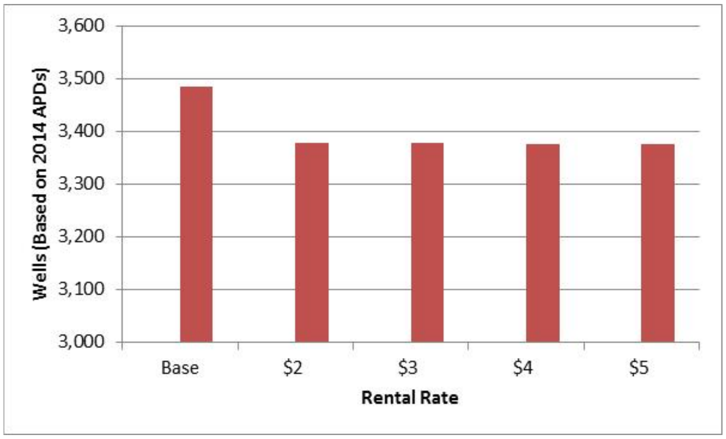
Effect of Rent Rate Increases on the Number of New Wells on Federal Lands by State

	$2 Average Rent		$3 Average Rent		$4 Average Rent		$5 Average Rent	
	Primary Well Type		Primary Well Type		Primary Well Type		Primary Well Type	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Arizona	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%
Colorado	-0.3%	-0.7%	-0.5%	-0.7%	-0.6%	-0.7%	-0.8%	-0.7%
Idaho	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.4%	-0.3%
Montana	-0.1%	-1.6%	-0.1%	-2.3%	-0.2%	-2.9%	-0.2%	-3.6%
Nebraska	-9.2%	-13.0%	-9.2%	-13.0%	-9.1%	-13.0%	-9.1%	-13.0%
Nevada	-35.2%	0.0%	-35.2%	0.0%	-35.2%	0.0%	-35.2%	0.0%
New Mexico	0.0%	0.0%	-0.1%	0.0%	-0.1%	0.0%	-0.1%	0.0%
North Dakota	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Oregon	-100.0%	-1.1%	-100.0%	-1.3%	-100.0%	-1.5%	-100.0%	-1.7%
South Dakota	-0.1%	-0.2%	-0.1%	-0.2%	-0.2%	-0.1%	-0.2%	-0.2%
Utah	-22.8%	0.0%	-22.9%	0.0%	-22.9%	0.0%	-22.9%	0.0%
Washington	-31.2%	-0.4%	-35.1%	-0.6%	-35.1%	-0.9%	-35.1%	-1.2%
Wyoming	-1.0%	-0.2%	-1.0%	-0.2%	-1.1%	-0.2%	-1.1%	-0.2%

Many of these states do not currently have any development in them so the actual changes are tempered by the low level of actual development occurring in some states, like Oregon or Arizona. Even so, rental rate increases on leaseholds prior to any development occurring will increase the overall cost of projects, and would be anticipated to reduce the actual number of wells drilled in the future.

Figure 3

Effect of Rental Rate Increases on the Number of New Wells on Federal Lands



Based on existing APD data, it is estimated that nearly all of the impact of higher rental payments would occur in the state of Utah.[87] Figure 3 on the prior page outlines the overall impact of higher rental rates on future well development on Federal land. These figures assume that the royalty rates are held at the current level of 12.5 percent.

Economic Implications of the Proposed Changes:

Based on a recent analysis conducted for the Western Energy Alliance, the oil and natural gas exploration and production industry currently generates more than 173,860 jobs in the 13 western states.[88] Approximately 62 percent (107,700) of these jobs are in 4 states – Colorado, Montana, Utah, and Wyoming.

Table 6

Jobs Related to Oil and Natural Gas Development in Western States

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[87] The model used in this analysis is based on state level costs as reported by IMPLAN. Leasing costs in Utah are generally lower than in other states included in this model, therefore, the marginal change in rental payments has a larger effect in that state. Nearly all of the wells lost would be small marginal primarily natural gas wells.

[88] Based on John Dunham and Associates, *Western Oil & Natural Gas Employs America*, prepared for Western Energy Alliance, 2014, at: www.westernenergyalliance.org/employsamerica

State	Direct Jobs	Total Jobs	Direct Wages	Total Wages	Direct Output	Total Output
Colorado	21,058	60,136	$ 2,739,768,489	$ 5,176,786,489	$ 15,935,425,960	$ 22,222,430,317
Montana	2,899	7,664	$ 274,251,980	$ 475,526,040	$ 1,675,865,657	$ 2,320,606,580
Utah	5,278	15,077	$ 584,658,649	$ 1,056,837,694	$ 2,054,221,093	$ 3,526,374,159
Wyoming	11,925	24,814	$ 1,273,854,998	$ 1,912,099,182	$ 9,362,228,936	$ 11,365,909,199
New Mexico	11,832	24,568	$ 991,177,500	$ 1,585,603,041	$ 5,311,422,775	$ 7,124,296,604
Arizona	3,270	8,730	$ 367,698,853	$ 651,420,962	$ 2,057,919,973	$ 2,924,480,381
Washington	821	4,077	$ 41,958,983	$ 253,230,632	$ 899,268,861	$ 1,594,558,718
Oregon	303	2,440	$ 20,739,112	$ 134,794,039	$ 1,179,364,993	$ 1,631,605,850
Nebraska	411	2,731	$ 482,178,055	$ 592,446,965	$ 210,633,631	$ 563,760,813
North Dakota	9,722	19,935	$ 1,144,415,812	$ 1,660,982,018	$ 2,841,522,559	$ 4,350,427,906
Nevada	479	1,797	$ 45,783,195	$ 116,510,231	$ 107,407,015	$ 324,650,229
idaho	269	1,335	$ 52,229,691	$ 99,182,804	$ 237,546,585	$ 395,440,069
South Dakota	87	551	$ 18,413,773	$ 38,582,351	$ 55,804,628	$ 137,018,577
Western States	68,354	173,856	8,037,129,088	13,754,002,449	41,928,632,666	58,481,559,400

These jobs could be impacted by higher royalty rates or minimum rental payments. In fact, depending on which of the 24 scenarios examined is ultimately adopted, as many as 1,330 jobs could be lost in the 13 western states that were modeled.

Table 7

Potential Job Losses due to Higher Royalty and Lease Costs

Royalty Rate ↓	Rental Rate Per Acre → $1.50/$2.00	$2.00	$3.00	$4.00	$5.00
12.50	-	(353.7)	(355.3)	(356.9)	(358.4)
14.75	(751.9)	(1,105.6)	(1,107.2)	(1,108.7)	(1,110.3)
16.75	(897.2)	(1,251.0)	(1,252.5)	(1,254.1)	(1,255.6)
17.75	(958.3)	(1,312.1)	(1,313.6)	(1,315.2)	(1,316.7)
18.75	(972.1)	(1,325.8)	(1,327.4)	(1,328.9)	(1,330.5)

These are real jobs and impact real people, not only in the oil fields themselves, but also throughout communities up and down the 13 Western states included in the analysis. Everyone from cooks and waitresses in restaurants near drilling activity, to engineers working in downtown Denver developing drilling plans will be impacted.

But the impact goes far beyond jobs. The people working in the oil and natural gas sector tend to be highly compensated relative to other workers in the mountain west, and therefore losses in petroleum development disproportionately impact wages and overall economic activity. Based on an examination of the 24 scenarios, the job reductions due simply to reduced activity on Federal leases would cost workers in the impacted states nearly $90 million in overall wages and benefits.

Table 8

Potential Wage Losses due to Higher Royalty and Lease Costs

Royalty Rate ↓	Rental Rate Per Acre → $1.50/$2.00	$2.00	$3.00	$4.00	$5.00
12.50	-	$ (22,347,764)	$ (22,472,322)	$ (22,596,053)	$ (22,719,194)
14.75	$ (48,582,410)	$ (70,930,174)	$ (71,054,732)	$ (71,178,463)	$ (71,301,604)
16.75	$ (59,080,537)	$ (81,428,301)	$ (81,552,859)	$ (81,676,590)	$ (81,799,731)
17.75	$ (63,567,622)	$ (85,915,386)	$ (86,039,944)	$ (86,163,675)	$ (86,286,816)
18.75	$ (65,019,971)	$ (87,367,735)	$ (87,492,293)	$ (87,616,023)	$ (87,739,165)

Reduced wages are one part of an overall loss in economic activity in the impacted states. Table 9 shows that estimated overall economic losses could reach as high as $288 billion dollars. Certain states will fare worse than others, with the largest impacts across all scenarios occurring in Utah, New Mexico and Nevada. This is because development activity in these states is more concentrated in Federal leaseholds, and the size of projects in these states tends to be smaller than in for example Montana or North Dakota.

Table 9

Potential Overall Economic Losses due to Higher Royalty and Lease Costs

Royalty Rate ↓	Rental Rate Per Acre → $1.50/$2.00	$2.00	$3.00	$4.00	$5.00
12.50	-	$ (72,281,995)	$ (72,723,292)	$ (73,161,670)	$ (73,597,907)
14.75	$ (157,876,309)	$ (230,158,305)	$ (230,599,601)	$ (231,037,980)	$ (231,474,216)
16.75	$ (194,434,874)	$ (266,716,869)	$ (267,158,166)	$ (267,596,544)	$ (268,032,781)
17.75	$ (210,012,022)	$ (282,294,017)	$ (282,735,314)	$ (283,173,692)	$ (283,609,928)
18.75	$ (215,509,596)	$ (287,791,592)	$ (288,232,888)	$ (288,671,267)	$ (289,107,503)

Fiscal Implications of the Proposed Changes:

Even though the Federal Government is considering increasing royalties and other fees on oil and natural gas developments on public lands as a way to raise revenue, there are offsetting costs that should be considered. Most importantly, due to low wellhead prices, development on many, if not most Federal leases is not currently profitable. This is particularly true in the case of plays that will generate mostly dry natural gas. At the same time existing regulatory burdens have significantly limited the number of APD's being granted.

Table 10

Potential Reduction in Expected Royalty Payments Due to Lost Drilling Opportunities

	Rental Rate Per Acre →				
Royalty Rate ↓	**$1.50/$2.00**	**$2.00**	**$3.00**	**$4.00**	**$5.00**
12.50	-	$ (9,090,782)	$ (9,160,858)	$ (9,230,415)	$ (9,299,582)
14.75	$ (27,531,910)	$ (26,729,714)	$ (26,799,791)	$ (26,869,348)	$ (26,938,515)
16.75	$ (26,654,834)	$ (33,096,418)	$ (33,166,494)	$ (33,236,051)	$ (33,305,218)
17.75	$ (24,005,636)	$ (35,745,616)	$ (35,815,692)	$ (35,885,249)	$ (35,954,417)
18.75	$ (17,638,933)	$ (36,622,692)	$ (36,692,768)	$ (36,762,325)	$ (36,831,492)

Were the estimates for reduced development under the above scenarios to actually occur, there would be a loss in royalty payments under the current 12 percent standard. Based on average Federal royalty payments per well, under some of the more draconian scenarios, the loss in wells would reduce current payments by as much as $37 million dollars annually.[89] (See Table 10) It should be noted that these are just Federal payments, and the figures do not take into account losses to state governments that receive a portion of the revenues on Federal mineral activities within their borders.

Table 11

Potential Reduction in Federal Business and Personal Taxes Due to Lost Drilling Opportunities

89 Note that this assumes that average production per operating well will not change from year to year.

Royalty Rate ↓	Rental Rate Per Acre → $1.50/$2.00	$2.00	$3.00	$4.00	$5.00
12.50	-	$ (3,342,724)	$ (3,367,111)	$ (3,391,338)	$ (3,415,451)
14.75	$ (7,243,599)	$ (10,586,323)	$ (10,610,710)	$ (10,634,937)	$ (10,659,050)
16.75	$ (9,232,848)	$ (12,575,571)	$ (12,599,958)	$ (12,624,185)	$ (12,648,299)
17.75	$ (10,092,641)	$ (13,435,364)	$ (13,459,751)	$ (13,483,978)	$ (13,508,092)
18.75	$ (10,441,335)	$ (13,784,059)	$ (13,808,446)	$ (13,832,673)	$ (13,856,786)

In addition to losing royalty payments on wells that would not be drilled, the Federal government could lose significant revenues that it is currently receiving from businesses and workers involved in oil and natural gas development in the 13 Western states. Based on this analysis, it is likely that overall Federal business and personal tax revenues could fall by as much as $13.8 million annually under some of the scenarios analyzed.

Table 12

Overall Federal Revenue Offsets Due to Higher Royalty and Minimum Rent Requirements

Royalty Rate ↓	Rental Rate Per Acre → $1.50/$2.00	$2.00	$3.00	$4.00	$5.00
12.50	-	$ (12,433,505)	$ (12,527,969)	$ (12,621,753)	$ (12,715,033)
14.75	$ (34,775,509)	$ (37,316,037)	$ (37,410,501)	$ (37,504,285)	$ (37,597,565)
16.75	$ (35,887,682)	$ (45,671,989)	$ (45,766,453)	$ (45,860,237)	$ (45,953,517)
17.75	$ (34,098,277)	$ (49,180,980)	$ (49,275,444)	$ (49,369,228)	$ (49,462,508)
18.75	$ (28,080,268)	$ (50,406,750)	$ (50,501,214)	$ (50,594,998)	$ (50,688,278)

Impacted states and their localities could lose similar amounts of tax revenues were these higher costs to go into effect. All told the offset to Federal revenues that could occur as a result of higher royalty payments and minimum rents would be nearly $51 million annually. This is a significant amount of revenues and is something that the government should take into account when proposing sizable changes to the existing development lease provisions.