September 10, 2012

U.S. Department of the Interior
Director (630), Bureau of Land Management
Mail Stop 2134 LM
1849 C St. NW
Washington D.C., 20240

Attn: 1004-AE26 (77 Fed. Reg. 27,691, May 11, 2012)
Comments by ANGA, AXPC, and USOGA to BLM's Proposed Rule to Regulate Hydraulic Fracturing on Public and Indian Lands

Dear Mr. Pool:

Thank you for the opportunity to comment on the Bureau of Land Management's ("BLM's") Proposed Rule to Regulate Hydraulic Fracturing on Public and Indian Lands ("Proposed Rule"). These comments are filed on behalf of America's Natural Gas Alliance ("ANGA"), the American Exploration & Production Council ("AXPC"), and the U.S. Oil and Gas Association ("USOGA").

ANGA is an educational and advocacy organization formed by North America's leading independent natural gas exploration and production companies. ANGA represents 29 of North America's largest independent natural gas exploration and production companies and the leading developers of the shale plays now transforming the clean energy landscape. ANGA is dedicated to increasing appreciation for the environmental, economic and national security benefits of clean, abundant, affordable and dependable natural gas. Its members produce approximately 40% of our nation's domestic natural gas supply.

AXPC is a national trade association representing 32 of the largest United States independent upstream natural gas and crude oil exploration and production (E&P)

companies. AXPC members are leaders in developing and applying technology necessary to explore for and extract oil and gas onshore and offshore, including in deep water and from unconventional sources. AXPC's member companies, as a group, are leaders in adding domestic energy reserves by being among the most active in drilling natural gas and oil exploration and development wells in the United States, accounting for nearly one quarter of all wells drilled.

USOGA is a national trade association for the oil and gas industry established in 1917 in Tulsa, Oklahoma. USOGA currently has about 4,500 members covering the full spectrum of the domestic petroleum industry. USOGA advocates for mutually beneficial domestic exploration and production policies that support our country's economic and strategic stability.

All three of these organizations ("the Associations") have members with extensive lease holdings on federal and Tribal lands and thus have a strong interest in BLM's Proposed Rule. The Associations and their members urge BLM to respect the existing balance of federal and state regulation of oil and gas development activities. The Associations firmly believe that current regulation of oil and gas activities, including those involving hydraulic fracturing on federal lands, whether through state regulation of oil and gas operations, state environmental regulation, or existing federal regulatory requirements, protects the environment, the public, and our nation's resources. Hydraulic fracturing is not new; it is a safe and effective technology that has been in use for decades. Both BLM Director Bob Abbey and U.S. Environmental Protection Agency ("EPA") Administrator Lisa Jackson have acknowledged that there are no proven cases where fracturing processes have affected water on federal lands, and Director Abbey has acknowledged that "based upon the track record so far, [hydraulic fracturing] is safe."[1]

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[1] Challenges Facing Domestic Oil and Gas Development: Review of Bureau of Land Management/U.S. Forest Service Ban on Horizontal Drilling on Federal Lands: Hearing before

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The Associations share BLM's goals of assuring environmental protection and enhancing public understanding of hydraulic fracturing. Given the existing robust regulatory frameworks in place under state law and BLM's own regulatory program, however, an additional set of federal regulations is not a sound way to meaningfully advance those goals. As currently drafted, the Proposed Rule would lead to uncertainty, confusion, longer delays, potentially conflicting requirements, and, in some instances, a loss of development of resources on federal lands. The Rule would not provide meaningful benefits to the environment or the public. Simply put, we oppose the imposition of these impediments on this critical domestic energy development given the fact that the public already enjoys the benefits of safe and responsible development on federal lands due to existing federal and state rules and oversight, as well as the vigilance and commitment of industry.

Given the importance of the subject of this rulemaking, the Associations hereby request a follow-up meeting with BLM to address the various issues raised below. The Associations also propose that BLM convene a working group of knowledgeable stakeholders, including representatives from industry and from state oil and gas agencies, to try to resolve the issues raised by these and other comments.

I. General Comments

Hydraulic fracturing operations and related activities, like other oil and gas operations, vary greatly across different regions of the country. Oil and gas operations are, of course, driven by the specifics of local geology and other circumstances, and thus are most appropriately

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the Subcomm. on Energy and Mineral Resources of the H. Comm. on Natural Resources and the Subcomm. on Conservation, Energy and Forestry of the H. Comm. on Agriculture, 112th Cong. (July 8, 2011); *see also* Pain at the Pump: Policies that Suppress Domestic Production of Oil and Gas: Hearing Before the H. Comm. on Oversight & Gov't Reform, 112th Cong. (May 24, 2011).

addressed at the state, rather than the federal level. Accordingly, these operations have traditionally been regulated at the state level. As a result, states generally have the best understanding of the local geologic, hydrologic, and other factors central to regulating these operations. Also, they have greater on-the-ground experience and resources to support an effective regulatory program. States have also responded to calls for more focused regulation of hydraulic fracturing in recent years and, together with widespread stakeholder input, have developed highly-effective, and publicly-supported, expanded regulatory programs. The industry, including our member companies, has worked closely with state regulators to ensure these programs are technically sound and effective. The current and growing state opposition to BLM's Proposed Rule underscores that states have a strong interest in and are better positioned to continue regulating hydraulic fracturing.

A federal, one-size-fits-all approach cannot sufficiently account for the local and regional differences among operations in different parts of the country. Further, BLM, has neither the resources, nor the collective expertise to implement broad regulation of hydraulic fracturing operations on federal lands throughout the country. Nor is there a compelling interest in committing additional taxpayer funds to perform work that would largely duplicate existing state efforts, particularly given the recent Executive Order 13,604 on Improving Performance of Federal Permitting and Review of Infrastructure Projects, which calls for "execut[ing] Federal permitting and review processes with *maximum efficiency* and effectiveness" and for "early and active consultation with State, local, and tribal governments to *avoid conflicts or duplication of effort*," among other things.[2] Processing BLM's existing Applications for Permits to Drill

[2] Exec. Order No. 13,604, 77 Fed. Reg. 18,887 (Mar. 28, 2012) (emphasis added).

("APDs") already leads to substantial delays.[3] The additional approvals contemplated in BLM's Proposed Rule will significantly increase these delays and provide opponents of oil and gas development with an additional route to raise legal challenges to safe and responsible development on federal lands. BLM's estimates of the resources needed to fulfill its obligations under the Proposed Rule are vastly understated.[4] As discussed in greater detail below, creating new regulatory approvals and requirements is not justified scientifically or as a matter of policy, nor is it legally appropriate.

BLM's Proposed Rule does not take sufficient advantage of existing state regulatory programs, multi-stakeholder approaches, and other regulatory mechanisms that offer broader involvement and present opportunities to develop a more tailored and effective regulatory framework. This is one of several areas that would benefit from additional dialogue. Any rulemaking efforts should begin with an evaluation of existing federal, state, and local regulations to determine if or where a regulatory need exists. This should include, at a minimum, a focused discussion with all state oil and gas regulators on the scope and strength of existing regulation. Again, in light of Executive Order 13,604, any Federal efforts should build on local experience and the existing efforts of collaborative entities, including the Groundwater

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[3] *See, e.g.*, Cappiello, Dina, New process to expedite drilling on public lands, Associated Press, (April 3, 2012), *available at*: www.newsvine.mobi/_news/2012/04/03/11002223-new-process-to-expedite-drilling-on-public-lands (average APD approval process takes 298 days); Sgamma, Kathleen, Western Energy Alliance, Testimony Before the House Natural Resources Committee Subcommittee on Energy and Mineral Resources Legislative Hearing on H.R. 4381, H.R. 4382 and H.R. 4383 (Apr. 26, 2012) (noting that it is not uncommon for APD approval processes to take years).

[4] *Compare* BLM, Well Stimulation Proposed Rule: Economic Analysis and Initial Regulatory Flexibility Analysis, BLM-2012-0001-0003, *with* Memorandum from John Dunham to Kathleen Sgamma, Western Energy Alliance (June 11, 2012), *available at* http://westernenergyalliance.org/wp-content/uploads/2009/05/John-Dunham-Associates-Economic-Analysis-of-BLM-Fracing-Regulations-FINAL.pdf.

Protection Council, which has developed the FracFocus public disclosure system that has been adopted and/or modified for use in 10 states with 7 additional states in the process of adopting it and the State Review of Oil and Natural Gas Regulations ("STRONGER"), which is a multi-stakeholder review process that has to date examined the regulatory programs of 22 states representing approximately 94% of domestic onshore oil and gas development. STRONGER, in particular, has the potential to provide state-by-state guidance on areas for regulatory improvement and would give BLM the opportunity to require this multi-stakeholder review process and concomitant state-specific progress toward improvements without establishing across-the-board requirements of its own that fail to allow for regional differences. Further, it should be noted that BLM already has tools to address new circumstances through onshore orders and notices to lessees regarding evolving technologies and practices or issues that extend beyond regional considerations.

The Proposed Rule also poses issues regarding enforcement and appeal mechanisms. The new requirements of the Proposed Rule appear to be subject to existing requirements in 43 C.F.R. §§ 3163 and 3165. These include provisions that vest the "authorized officer" with expansive discretion to immediately shut down operations and approve or prescribe procedures and practices for tests and surveys of the isolation of usable water.

Thus, the new provisions in the Proposed Rule would create additional areas in which overly broad discretion could be exercised to the public's detriment. Shutdowns, particularly immediate shutdowns, raise serious safety and environmental concerns. The rule does not adequately address such risks or provide procedural assurances to address a discretionary shutdown decision premised on issues under the new regulations. The review process for a challenge to the discretion of the authorized officer could be time-consuming, as it involves review by both the BLM State Director and review by the Interior Board of Land Appeals. This delay could create significant hardship, and entail significant risk, particularly if a decision to require shutdown is extended throughout the review period.

With regard to information disclosure, the Associations strongly endorse the use of the FracFocus public disclosure registry that has been developed by state regulators to inform the American public and to make information available to regulators in the exercise of their duties. FracFocus and state law requirements on chemical disclosure have been effective in addressing public interest in fracturing operations, while encouraging the use of innovative technologies, including many cutting-edge “green” technologies, by protecting proprietary business information. The Associations urge BLM to draw upon these existing resources and contribute to a strong and cohesive disclosure framework, which benefits all stakeholders—from the public, to policymakers, to industry.

The existing state regulatory requirements and the advent and steady, rapid expansion of FracFocus have rendered unnecessary the creation, implementation, and maintenance of another disclosure scheme, particularly one that would apply only on federal and Indian lands. BLM should defer to these existing mechanisms and avoid creating duplicative requirements. This is particularly true given our concerns regarding the Proposed Rule’s treatment of proprietary information.

Proprietary information must be protected to assure that the best and most protective technologies and formulations are developed and utilized on federal lands. The Proposed Rule provides inadequate assurances of this protection. By way of contrast, FracFocus and state laws regulating chemical disclosure for hydraulic fracturing recognize the complex relationship among operators, service companies and other contractors. Additional federal rules are unnecessary. However, if BLM implements regulations governing chemical disclosure, it should do so with full recognition of these complex relationships and should direct any related inquiries to those parties holding the relevant information. As written, the Proposed Rule is inappropriate to the extent that it places obligations for disclosure and certification on parties that do not have access to the information necessary to make these disclosures and certifications. As a general proposition, operators are not in a position to provide confidential business information about chemical formulations that are owned by other companies. Service companies and/or their suppliers hold the necessary proprietary rights, and thus are the only parties in a position to provide the information and/or make the representations BLM appears to seek. We are deeply concerned that the practical outcome of the ongoing confusion over the parties subject to the Proposed Rule and the parties holding rights to proprietary information could be to limit the use of up-to-date and even more environmentally friendly products and technologies on federal lands.

For all of these reasons, and as set forth in greater detail below, the Associations and their members cannot support the Proposed Rule. Any BLM regulation should recognize the effectiveness of state regulatory frameworks, and rely on existing state expertise and experience, working within the bounds of BLM's appropriate and traditional role and authority. The Proposed Rule does not meet this standard. As a result, the public, local communities, Indian Tribes, and many others would be denied the benefits of robust, safe, and responsible development on federal lands. The Associations therefore respectfully urge BLM not to implement the Proposed Rule, but rather to engage in further dialogue with industry, with state regulators and other key stakeholders who all share a strong commitment to ensuring robust, safe, and responsible domestic energy development—across both public and private lands.

Discussions of the economic impacts, legal issues, and the individual provisions in the Proposed Rule are set forth below.

II. Economic Impacts

BLM has significantly underestimated the economic impact of compliance with the proposed rule on drilling operations on federal and tribal lands. The Proposed Rule creates significant economic impacts in two ways. First, the rule will adversely impact federal and state revenues by pushing production away from federal lands because of increased permitting delays and associated uncertainty. This results in lost royalty and tax revenue. Second, as set out in independent economic analyses, the cost to operators to comply with the rules is far greater than the BLM has estimated.

BLM oil and gas statistics compiled in 2010 and 2011 show that between 2007/2008 and 2009/2010:

- The number of new federal oil and gas leases issued by the BLM has decreased by 44% from an average of 1,874 to 1,053;[5]
- The number of new permits to drill issued by the BLM is down 39%, from an average of 6,444 to 3,962;[6] and
- The number of new wells drilled on federal lands declined 39%, from an average of 4,890 to 2,973.[7]

Some of these decreases were due to the economic downturn that began in 2007; however, if market factors were the sole cause of these declines, one would expect to see similar

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[5] "Employment, Government Revenue, and Energy Security Impacts of Current Federal Lands Policy in the Western U.S.," EIS Solutions (Jan. 2012), at 10.

[6] *Id.* at 12.

[7] *Id.* at 14.

declines in oil and gas operations on non-federal lands. But this is not the case. Rather, over the same time period, permits to drill on non-federal lands decreased by only 20%, about one half of the decrease on federal lands.[8] In 2010, non-federal permits increased in the West by 31%, while federal drilling permits decreased by 13%.[9]

These remarkable declines in drilling and production on federal lands appear to be due to adverse federal land policy.[10] The additional impacts and redundancies of the Proposed Rule will exacerbate the decline in production from federal and tribal lands, with a concomitant decline in federal revenues from lease sales, bonuses and royalties. According to an analysis conducted for ANGA by John Dunham & Associates,[11] foregone federal revenues attributed to the rule would total around $1.16 billion, including over $1 billion in royalties and other related payments and over $73 million in federal business and personal tax payments. State revenues are also reduced. In the same study, John Dunham & Associates estimates that in addition to the federal impact, states and their localities will see a reduction in anticipated business and personal tax payments of as much as $40.6 million and almost $1.2 billion in foregone additional royalties and other related payments. This puts the total cost in federal, state and local government revenues at nearly $2.4 billion. These estimates are conservative in that they only capture the current impact of the proposed rules – looking solely at the estimated 5,058 existing permits or permits in the review process. They do not predict state and federal revenue losses associated with the rule's impact on future permitting and production.

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[8] *Id.* at 13.

[9] *Id.*

[10] *Id.* at 16-17.

[11] *See* John Dunham & Associates, "Analysis of Bureau of Land Management Proposed Rule Impacts on State and Federal Revenues" (Sept. 4, 2012) (Appendix A).

These federal and state revenues at risk are substantial. This is further supported by BLM's own recent analysis. In the BLM's latest Oil and Natural Gas Environmental Impact Statement, Greater Natural Buttes, it is estimated that the 3,750-well development project will create over 1,700 jobs and generate in excess of $4.8 billion in royalties and taxes to the federal, state and local governments over the life of the project. Additional cost burdens as proposed in the Proposed Rule will impact the development of this project and reduce immediate job growth and much-needed revenue to the state, local and federal governments.

Moreover, the Proposed Rule will have far more significant economic impacts on the regulated industry than BLM has estimated in the Regulatory Impact Analysis summarized in the Federal Register notice.[12] BLM asserts that the Proposed Rule will not exceed the $100 million threshold for annual effects identified in certain federal laws (*e.g.*, the Unfunded Mandates Reform Act, the Congressional Review Act, Executive Order 12866, etc.) and that it will not have a significant economic impact on a substantial number of small entities.[13] According to an analysis conducted by John Dunham & Associates for the Western Energy Alliance, however, the Proposed Rule would impose total additional costs on the industry of "at least $1.499 billion and as high as $1.615 billion" per annum – some 40 times BLM's estimate.[14]

The costs associated with the Proposed Rule include the cost of delays caused by added approvals as well as the capital costs required to meet the BLM standards. The capital costs of

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[12] BLM states that "the estimated costs range from $37 million to $44 million per year." 77 Fed. Reg. at 27,692.

[13] *See* 77 Fed. Reg. at 27,703-04.

[14] "Business Impact of Proposed Changes to Well Completion Regulations," John Dunham & Associates (June 11, 2012), *available at* http://www.ourenergypolicy.org/wp-content/uploads/2012/06/John-Dunham-Associates-Economic-Analysis-of-BLM-Fracing-Regulations-FINAL.pdf (Appendix B).

the rule are exacerbated by the broad scope of the proposed rule. On an individual well basis, the cost of the regulation is substantial and, when attributed to 5,500 wells per year approved to drill on federal lands (based on the 5,500 APDs BLM is expected to process in 2012 under the existing regulatory scheme), the cost to industry is material.

Two major drivers of added capital cost include conducting an additional CBL on surface casing and the need to run additional surface casing to comply with the significantly over-reaching definition of "usable water" in BLM's proposal. As described in Sections IV and VI below, these new requirements are unnecessary and not supported by science, engineering, and drilling experience, which support the use of alternative tests to demonstrate the integrity of surface casing as well as reliance on state-provided information and analyses to identify usable water. With the expanded definition of usable water (10,000 ppm TDS), operators will need to run additional surface casing – on average 2,350' of surface casing per well. The total increase in administrative and capital costs for new well construction is estimated at $493 million annually. Industry estimates that the total annual cost of the regulation for 5,000 new wells constructed on federal lands to be approximately $1.27 billion.

In addition to the cost associated with new well construction, the definition of well stimulation in the proposed rule would include routine well work as well. It is estimated that approximately 1,171 wells of the 90,000 currently producing wells on federal land will require remedial stimulation, acidizing or refracturing annually. To meet the increased well stimulation requirements, there will be significant cost added to each remedial stimulation in delayed production and additional capital cost. It is estimated that the additional cost per well is $234,000. This represents an annual cost to industry of $273 million for remedial stimulation. Such significant costs increases will shorten the life of many low production wells resulting in pre-mature abandonment, impacting direct and indirect jobs and revenue to the federal and state governments.

Industry-wide these additional costs are significant, but the impact on individual wells is also substantial. The cost increases to new well construction on federal lands under the Proposed Rule is estimated at $254,000/well. This is a significant increase in cost when looking at an individual gas well in a $3.00/mcf NYMEX gas price. A typical gas well on federal lands cost approximately $1.5 million to drill, complete and equip with reserves of 1.0 bcf. The Net Present Value at 10% of this type well is $40,000. With these additional new well construction costs of $254,000, the industry would seek to invest in projects outside of federal lands that generate an acceptable Rate of Return on their investment. A graph showing the Net Present Value at 10% of a typical gas well on federal lands and the impacts of delays can be found in Appendix C.

In light of these significant economic impacts, BLM should, at a minimum, conduct a more robust economic impact analysis as required under the Regulatory Flexibility Act, the Small Business Regulatory Enforcement Fairness Act, the Unfunded Mandates Reform Act, Executive Order 12,866, among others, before it attempts to promulgate such a burdensome rule. In doing so, it should address the various concerns raised by stakeholders to the Office of Management and Budget ("OMB").

III. Legal Issues

A. Limits on BLM Authority to Regulate Private or State Lands

BLM's proposed regulatory approach would almost certainly result in regulation of private and state land. BLM will likely claim authority to require operators drilling in a unit that includes federal leases to abide by the new regulations even if the unit includes private or state leases and the well is actually drilled on private or state surface. Similarly, in the split estate setting, in which the surface is private, but the minerals are federally owned, BLM may assert that the regulations apply. The cited authority for the proposed rule is primarily the Mineral Leasing Act of 1920 ("MLA"), and the Federal Land Policy and Management Act of 1976 ("FLPMA").[15] The apparent constitutional authority for these statutes is the Property Clause. But the Property Clause, by its terms, does not authorize the federal government to regulate private or state lands. In order to regulate private or state lands, there must be some other constitutional grant of authority.

B. Potential Violation of Existing Lease Terms

In some contexts, government action that alters material terms of mineral leases can create a repudiation of the lease contract. Older lease forms contain language which provides that "only statutes and regulations existing at the time of the contract" will apply. *See Mobil Oil Exploration and Producing Southeast, Inc. v. United States*, 530 U.S. 604, 616 (2000). Arguably, an attempt to impose new regulatory requirements on lessees with the older lease form may be a breach of contract.

C. Potential Delay of BLM Action Beyond Statutory Deadline

The Energy Policy Act of 2005 ("EnPA") amended the Mineral Leasing Act ("MLA") to require that BLM act on an APD within 30 days of submission of a complete application. *See* P.L. 109-58, Sec. 366. This provision was designed to ensure that BLM addresses APDs in a timely fashion. The Proposed Rule will add to existing delays in APD processing and will further contravene the intent, and in some instances, may directly violate the letter of, the MLA and the EnPA.

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[15] The authority to promulgate the Proposed Rule as it relates to Indian lands is the Indian Mineral Leasing Act of 1938 ("IMLA").

Congress clearly declared it a priority and set forth requirements to assure that decisions on APDs be made in a timely manner in 30 U.S.C. § 226(p):

- Under 30 U.S.C. § 226(p)(1), the Secretary is required to notify an applicant for a permit to drill of any information that must be submitted to complete the application. This notification is required within ten days of receipt and must specify the claimed deficiencies.
- Once the application is complete, the Secretary must either (i) issue the permit within 30 days (assuming compliance with NEPA and other laws), or (ii) defer the decision while specifying what information or steps need to be taken. 30 U.S.C. § 226(p)(2).
- If the prescribed steps are completed, the statute instructs that "the Secretary shall issue a decision on the permit ***not later than 10 days*** after" the applicant completes the specified requirements.

This provision is intended to promote timely action in response to APDs. The proposed new regulatory requirements will significantly delay the APD process. If unauthorized steps are imposed upon the applicants, the Secretary will have failed to meet his obligation to issue his decision within 10 days of completing "requirements" that are specified pursuant to this statutory provision. *See* 30 U.S.C. § 226(p)(3)(B).

D. Conflict With State Authority Under Existing Laws

Under the Safe Drinking Water Act ("SDWA") and the Clean Water Act ("CWA"), most states have been delegated authority or primacy over permitting and the protection of water quality. States also have primacy over water quantity within their respective borders. BLM's Proposed Rule attempts to impose additional requirements with respect to disposal of water or brine from hydraulic fracturing operations, citing its authority under FLPMA and various mineral leasing statutes. None of those authorities allows BLM to insert itself into the SDWA's and CWA's state primacy or authority structure or to otherwise disrupt the balance between the states and the federal government with respect to water resources. Management in these areas is adequately and thoroughly regulated through existing federal and state water and waste management statutes and regulations. There is no need to add redundant or inconsistent regulatory requirements on BLM lands.

The Supreme Court has long recognized that regulation of land and water use "is a quintessential state and local power." *Rapanos v. United States*, 547 U.S. 715, 738 (2006) (citing *FERC v. Mississippi*, 456 U.S. 742, 767-68 n.30 (1982); *Hess v. Port Authority Trans-Hudson Corp.*, 513 U.S. 30, 44 (1994)). The Court has further stated that "[i]f Congress intends to alter the usual constitutional balance between the States and the Federal Government, it must make its intention to do so unmistakably clear in the language of the statute." *Gregory v. Ashcroft*, 501 U.S. 452, 460-61 (1991) (citations omitted). Importantly, the CWA did not "express[] a desire to adjust the federal-state balance." *Solid Waste Agency of N. Cook Cty. v. Army Corps of Eng'rs*, 531 U.S. 159, 174 (2001). Rather, when Congress passed the CWA, it declared its policy "to recognize, preserve, and protect the primary responsibilities and rights of States to prevent, reduce, and eliminate pollution, [and] to plan the development and use . . . of land and water resources[.]" 33 U.S.C. § 1251(b). Congress further noted that "[e]xcept as expressly provided in this chapter, nothing . . . shall . . . be construed as impairing or in any manner affecting any right or jurisdiction of the States with respect to the waters . . . of such States." *Id.* § 1370. The SDWA similarly emphasizes state primacy over regulation and enforcement. *See* 42 U.S.C. §§ 300h–1.

Under the SDWA and the CWA, the federal government (specifically, EPA) retains some authority with respect to the protection of water resources. Nothing in those statutes, or in FLPMA or the MLA, carves out similar authority for BLM. On the contrary, those latter statutes also emphasize the preservation of state authority. *See* 30 U.S.C. § 189 (preserving "rights of States or other local authority to exercise any rights which they may have"); 43 U.S.C. §

1701(g)(6) ("Nothing in this act shall be construed as . . . a limitation upon . . . the police power of the respective States . . . or as depriving any State or political subdivision thereof of any right it may have to exercise civil and criminal jurisdiction on the natural resource lands[.]"); *see also Carden v. Kelly*, 175 F. Supp. 2d 1318, 1323 (D. Wyo. 2001) (stating that the FLPMA savings language's "intended purpose was not to preempt or conflict with state civil laws"). Accordingly, none of the statutory authorities cited in the Proposed Rule provide a clear and manifest statement by Congress to allow BLM to disrupt the federal-state balance with respect to groundwater regulation.

E. Unauthorized Assertion Of Clean Water Act Authority

Federal authority to regulate water quality rests with EPA under the CWA. It does not rest with BLM under any of the authorities identified in the Proposed Rule. Thus, to the extent BLM intends to regulate water quality under the Proposed Rule, it lacks the statutory authority to do so. Congress did not grant BLM authority over water quality under the CWA, SDWA, FLPMA, the MLA, or the Indian Mineral Leasing Act. Under the CWA's and SDWA's primacy structures, the states and EPA share responsibility for protecting water quality, and BLM has no role within that regulatory structure. Although BLM is responsible for managing federal lands under FLPMA, that statute does not transfer any state or EPA authority to regulate water quality or to enforce water quality standards over to BLM.

F. Absence of Explicit Authority to Regulate Drilling Operations

Supreme Court precedent requires that a federal intrusion into traditional state authority be supported by a "clear and manifest" statement from Congress. *See e.g. Wis. Pub. Intervenor v. Mortier*, 501 U.S. 597 (1991) (Federal Insecticide, Fungicide and Rodenticide Act does not contain necessary clear and manifest expression of congressional intent to supplant local regulation.) Congress has the authority under the Property Clause to pre-empt state regulation of drilling on federal lands. But neither of the statutes cited by the BLM as authority for the Proposed Rule (MLA and FLPMA) contains a clear and manifest statement that BLM is authorized to displace historic and traditional regulation of oil and gas drilling. On the contrary, the MLA expressly refers to the application of state law to federal mineral leases, 30 U.S.C. § 187, and preserves the "rights of States or other local authority to exercise any rights which they may have…" 30 U.S.C. § 189; *see also Texas Oil & Gas Corp. v. Phillips Petroleum Co.*, 277 F.Supp. 366 (W.D. Okla. 1967), *aff'd* 406 F.2d 1303 (10th Cir. 1969); *Gulf Oil Corp. v. Wyo. Oil & Gas Conservation Comm'n*, 693 P.2d 227, 235 (Wyo. 1985). Similarly, the savings clause in FLPMA provides: "Nothing in this act shall be construed as…a limitation upon any State criminal statute or upon the police power of the respective States…or as depriving any State or political subdivision thereof of any right it may have to exercise civil and criminal jurisdiction on the natural resource lands…." P.L. 94-579, Sec. 701(g)(6). This language indicates that "the intended purpose was ***not*** to preempt or conflict with state civil laws." *Carden*, 175 F.Supp. 2d at 1323 (emphasis added).

G. Arbitrary and Capricious Requirements for Well Integrity, Reporting Requirements, Water Management, Etc.

To the extent that the Proposed Rule adopts regulatory requirements that are contradictory, duplicative, in conflict with existing BLM practices, are counterproductive, are unsupported by sound science or engineering, or otherwise may be considered "arbitrary and capricious," such requirements would run afoul of the Administrative Procedure Act. As explained throughout these comments, many provisions in the Proposed Rule meet one or more of the foregoing criteria and are thus, arbitrary and capricious.

IV. Proposed § 3160.0-5: Definition of Usable Water

In the Proposed Rule, BLM defines "usable water" as "generally those waters containing up to 10,000 ppm of total dissolved solids."[16] The Proposed Rule requires the operator to "isolate all usable water and other mineral-bearing formations and protect them from contamination," and requires the operator to conduct "tests and surveys of the effectiveness of such measures…using procedures and practices approved or prescribed by the authorized officer."[17] The existing rule, 43 C.F.R. § 3162.5-2(d), requires the operator to isolate and protect "freshwater-bearing and other usable water containing 5,000 ppm or less of total dissolved solids and other mineral-bearing formations."[18]

A. The Proposed Rule Conflicts with the Safe Drinking Water Act, BLM's Own Water Policy, and State Rules and Regulations.

As written, the Proposed Rule admits of no exceptions, and therefore would conflict with provisions of the SDWA, BLM's own water policy, and long-standing state rules and regulations. The Proposed Rule is also over-inclusive, and therefore, arbitrary and capricious, contrary to law, and in excess of BLM's authority.

BLM lacks the authority to define usable water in the context of these rules. As written, the provision would violate the SDWA, as amended by the EPA.

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[16] 77 Fed. Reg. at 27,709.

[17] *Id.* at 27,711.

[18] In the preamble to the Proposed Rule, the BLM explains: "The proposed rule would delete the definition of 'fresh water.' The BLM has maintained a definition of fresh water in its oil and gas operating regulations since 1988. However, in its onshore orders, the BLM has sought to protect all usable waters during drilling operations, not just fresh water. This distinction has led to confusion in the regulations. Usable water includes fresh water and water that is of lower quality than fresh water. The BLM intends to be more protective when it seeks to protect all usable water during drilling operations, not just fresh water. Therefore, the BLM proposes to delete the definition of fresh water." *Id.* at 27,695.

Further, this change in the definition of usable water usurps state primacy under the SDWA, and conflicts with BLM Water Policy. The SDWA expressly grants primary enforcement authority to those States that have approved underground injection control programs. *See* 42 U.S.C. § 300h-1(b)(3). Thus, for any state that has an approved underground injection control program, this change in definition usurps that state enforcement primacy.

BLM water policy, in contrast, is consistent with the SDWA's state primacy provision. That policy provides:

> A. Water Policy: The water policy of the BLM is that the States have the primary authority and responsibility for the allocation and management of water resources within their own boundaries, except as otherwise specified by Congress on a case-by-case basis.
>
> B. Implement Water Policy: In order to implement the BLM water policy of State water resources primacy, Bureau personnel shall:
>
> 1. Cooperate with State governments under the umbrella of State law to protect all water uses identified for public land management purposes.
>
> 2. Comply with applicable State law, except as otherwise specifically mandated by Congress, to appropriate water necessary to manage public lands for the purposes intended by Congress.[19]

Pursuant to this policy, BLM should defer to the states to regulate what is, and what is not, usable water. States are better able to make a reasoned determination based on local conditions and standards.

In addition to the fact that BLM does not have the authority to define usable water, the definition in this rulemaking is overly broad. BLM's definition does not take into account regional or geographic information. Further, BLM's definition encompasses instances in which water may theoretically meet the numeric criterion for "usability," but is unlikely, in fact, ever to

[19] BLM Manual, Rel. 7-86, Water Rights § 7250.06A-B (Mar. 19, 1984).

be usable due to parameters other than Total Dissolved Solids ("TDS"), which is BLM's lone criterion. State laws as well as the SDWA, as implemented by EPA, take into consideration other parameters and characteristics of groundwater in identifying where requirements apply. For example, coal bed methane "produced water" in the San Juan and Powder River Basins would qualify as usable water under the proposed definition, but removal of the water is required to produce the coal bed methane. This water is found in the hydrocarbon-producing zone, and therefore, isolation of the water-producing zone is incompatible with the production of the coal bed methane. Similarly, in other instances, groundwater meeting the proposed definition is found at such depths that it cannot economically be used for any purpose.

Both EPA, with respect to underground sources of drinking water regulated in the SDWA, and state regulatory agencies provide more rational water classifications to which the BLM should defer. For example, under the SDWA, EPA defines an "underground source of drinking water" ("USDW") as an aquifer or part of an aquifer which (a) supplies a public water system, or contains a sufficient quantity of ground water to supply a public water system and currently supplies water for human consumption or contains fewer than 10,000 mg/l of total dissolved solids; and (b) is not an exempted aquifer. 40 C.F.R. § 114.3. An "exempted aquifer" is part or all of an aquifer which meets the definition of a USDW, but which has been exempted under the criteria found in 40 C.F.R. § 146.4 (where an aquifer does not currently serve as a source of drinking water, and cannot now or in the future serve as a source of drinking water because it is: (1) mineral, hydrocarbon or geothermal energy producing or can be shown to contain minerals in quantities and location to be commercially producible; (2) situated at a depth or location which makes recovery of water for drinking purposes economically or technologically impractical; (3) so contaminated that it would be economically or technologically impractical to render the water fit for human consumption; (4) located over a Class III well mining area subject to subsidence or catastrophic collapse; or (5) the TDS content of the water is between 3,000 and 10,000 mg/l and it is not reasonably expected to supply a public water system).

Thus, EPA recognizes that water that is suitable for human consumption by virtue of its TDS content may nonetheless be unsuitable due to a variety of other factors affecting its potential for use. Similarly, states recognize that TDS is not the only measure appropriate for determining usability of water. For example, Colorado classifies water according to TDS content ***plus*** other relevant factors. *See e.g.* Colorado Department of Public Health and Environment, Water Quality Control Commission, 5 CCRS 1002-41, The Basic Standards for Ground Water, § 41.4.B. (in addition to TDS standard, "Domestic Use" classification appropriate when, if not currently used for domestic purposes, a reasonable probability is shown that the water will be so used in the future). New Mexico incorporates the 10,000 mg/l TDS standard, "except that this designation shall not include any, water for which there is no present or reasonably, foreseeable beneficial use that would be impaired by contamination." *See* http://www.emnrd.state.nm.us/ocd/EH-NMGroundwater.htm. Wyoming provides that certain groundwater may be unusable or unsuitable for use due to excessive concentrations of TDS or other constituents, ***or*** is so contaminated that it would be economically or technologically impractical to make the water usable, ***or*** is located in such a way, including depth below the surface, so as to make use economically and technologically impractical. Wyo. Department of Environmental Quality, Water Quality Division, Rules & Regulations, Ch. 8, Section 4(d)(ix); Wyo. Oil & Gas Conservation Comm'n, Rules & Regulations, Ch. 1, §§ 2(s), (w).

The proposed definition of "usable water" coupled with the requirement that usable water be isolated and tested will create excessive costs and increase the time required to drill a well—all without adding any tangible environmental benefit. Drill stem testing of water-bearing zones necessitated by this provision may cost as much as $200,000 per test, and the change in the rule could add 10 to 20 days to the time involved in drilling a well, depending on the depth to the water zone. The cost of additional casing to isolate zones that fall outside of existing state classifications may run as high as $250,000 per well. As noted above, the rule should exempt "usable water" in hydrocarbon-bearing zones, similar to EPA's exemption of aquifers subject to Class II or III operations. *See* 40 C.F.R. §§ 144.3, 146.4.

For exploratory wells, operators typically obtain information about the geology and hydrology of the proposed well site from the state oil and gas and water regulatory agencies. This information becomes the basis for the operator's determination of the depth of surface casing necessary to protect water-bearing strata. For in-fill or development drilling, information regarding the subsurface hydrology is available from previously completed wells, and that information forms the basis for the depth of surface casing proposed on the APD. Operators should be permitted to rely on information provided to them by the relevant state agencies with regard to the isolation and protection of usable water.

B. The Proposed Rule Is Overbroad in that It Imposes Significant and Costly Requirements on the Operator with No Added Public Benefit.

By defining usable water solely in terms of TDS, BLM will impose expensive and time-consuming requirements on the operator with little or no added public benefit. Water that is not usable, for example due to contamination by other substances, must nevertheless be protected by cementing the casing and isolating the water-bearing zone.

Requiring a water-bearing zone to be isolated by cementing, even where the water is unusable due to other factors, is unreasonable. Typically, operators rely on state information to define which of the water-bearing zones contain less than 10,000 ppm TDS. Indeed, minimum depths for surface casing are normally established by states based on their determination of the maximum depth of economically usable water. Moreover, in New Mexico, for example, the State Engineer has defined protectable groundwater as generally all state waters containing 10,000 mg/L or less of TDS, and has made available a map showing areas and formations where such water commonly occurs. *See* http://www.emnrd.state.nm.us/ocd/EH-NMGroundwater.htm.

The Proposed Rule would also require that operators collect information about brine aquifers that have little or no potential to be considered as sources of usable water. Where there is little or no potential for aquifers to be considered sources of usable water, data is not likely to be available, so in many cases, operators would have to conduct downhole tests of water-bearing zones to comply with this requirement. The Proposed Rule does not specify where the concentration of TDS is to be measured, nor does it explain how salient gradients are to be taken into account, nor whether operators are expected to sample each zone. Moreover, the Proposed Rule appears to provide the "authorized officer" with overly broad discretion to approve testing methods, creating needless uncertainty and leading to a lack of uniformity and predictability in implementation.

Last, the Proposed Rule requires the isolation of "*all* usable water" (emphasis added), rather than the isolation of freshwater-bearing and other usable water "containing 5,000 ppm or less of dissolved solids." *See* proposed § 3162.5-2(d). Although the Preamble suggests that this proposed revision merely ensures consistency with Onshore Order No. 2, the deletion of the phrase "containing 5,000 ppm or less of dissolved solids" would be impractical and unnecessarily burdensome.

V. <u>Proposed § 3160.0-5: Definition of Well Stimulation</u>

BLM has indicated repeatedly that it does not intend the Proposed Rule to regulate operations other than hydraulic fracturing. Nevertheless, as written, the Proposed Rule could be interpreted to do just that. BLM should defer to existing state regulations rather than create a redundant regulatory scheme, the scope of which is ill-defined.

BLM should clarify that the Proposed Rule's definition of "well stimulation" is limited to hydraulic fracturing activities. This clarification would avoid the potential for well stimulation to be interpreted to cover minor and routine activities that BLM does not intend to encompass. Such misinterpretations could result in the regulations exceeding their intended scope and increasing the regulatory burden on both BLM and industry, and could collaterally impact operator's accounting practices and other regulatory obligations. Accordingly, BLM should adopt a more specific definition of "well stimulation" that is expressly limited to hydraulic fracturing.

A. The Definition of "Well Stimulation" Is Too Broad Because It Includes Non-Hydraulic Fracturing Activities, Contrary to BLM Intent

BLM has said that it intends to address hydraulic fracturing in the Proposed Rule and that it does not intend activities such as routine maintenance to be within that scope. The Preamble explains that the Proposed Rule "is necessary to provide useful information to the public and to assure that hydraulic fracturing is conducted in a way that adequately protects the environment."[20] The Proposed Rule aims to address concerns about the potential impacts of

[20] 77 Fed. Reg. at 27,691.

hydraulic fracturing on water quality by, among other things, providing for the disclosure of chemicals used in hydraulic fracturing operations.

The Proposed Rule's definition of "well stimulation," however, reaches beyond hydraulic fracturing activities to include routine maintenance activities. The Proposed Rule defines "well stimulation" as:

> Those activities conducted in an individual well bore designed to increase the flow of hydrocarbons from the rock formation to the well bore through modifying the permeability of reservoir rock. Examples of well stimulation operations are acidizing and hydraulic fracturing.

Because the definition is overly broad, operators and field staff are left to infer the scope of the definition from the "examples," which plainly contemplate that activities other than hydraulic fracturing, even routine maintenance activities and activities already regulated under different provisions, are subject to the new regulations.

Such a broad definition of "well stimulation" will have unintended consequences. The explicit reference to "acidizing" is particularly problematic. While acid can be used in hydraulic fracturing to etch the fracture face and enhance fracture conductivity, it is also routinely used at lower pressures to remove carbonate scale from well-bore tubulars and to improve reservoir productivity. These latter maintenance operations are performed below the pressure needed to fracture the reservoir rock. They are therefore not appropriately treated as "hydraulic fracturing." For example, a formation matrix treatment (matrix acidizing), used to restore or enhance the natural near-wellbore permeability of the reservoir, is performed below the reservoir's fracture pressure. The proposed definition of "well stimulation," nevertheless suggests that matrix treatments are within its purview. Similarly, "swabbing," which the Preamble specifically mentions in connection with sections 3162.3-3(c)(6)(i) and 3162.3-3(g)(10)(i), can be used during the hydraulic fracturing process, but is also used during workovers for routine well maintenance and to remove fluids from the well. Indeed, swabbing is more frequently used as a technique for maintaining flow at pressures below those required for fracturing, than as part of the fracturing process. In short, even though certain types of these activities are used during the hydraulic fracturing process, others are also commonly used in the regular maintenance of existing wells in ways that are not appropriately regulated as hydraulic fracturing. We request that BLM distinguish between these various types of operations in order to clarify for both operators and field staff that these types of routine maintenance activities are ***not*** covered by the Proposed Rule.

The proposed definition of "well stimulation" is also broad enough to include minor fracturing activities at wells that have already been stimulated. These include "bucket" refracturing activities that involve introducing limited quantities of fluids and proppants into a zone that has already been stimulated, and also "water-only" breakdowns. Because BLM has indicated its intent not to regulate such activities, BLM should revise its definition to specifically exclude these and similar activities from the scope of the regulations.

We support BLM's recognition that the proposed definition of "well stimulation" does not apply to all other injection activities that must comply with section 3162.3-2.[21] These activities include deep well injection of produced water and various fluid injection technologies (i.e., steam, water, carbon dioxide) for tertiary recovery. This also includes workovers that entail completion of a well in one or more newly completed pay zones within a well or refracturing of previously completed intervals. Workovers are already identified in existing 43 C.F.R. § 3162.3-

[21] 77 Fed. Reg. at 27,695 ("Proposed section 3162.3-3(a) would make clear that this section applies only to well stimulation activities and that all other injection activities must comply with section 3162.3-2. This language is necessary to make the distinction between well stimulation activities and other well injection activities, such as secondary and tertiary recovery operations.").

2(a) as being subject to subsequent well operation requirements and should not be included in the definition of well stimulation. This is consistent with existing 43 C.F.R. § 3162.3-2(c), which excludes routine maintenance from prior approval and subsequent reporting requirements. We request that BLM clarify its intent by defining "well stimulation" to exclude such workovers, thus avoiding an internal inconsistency with existing regulations.

Thermal injection operations also provide an example of the confusion the proposed definition could cause regarding tertiary and secondary recovery operations. Thermal injection operations involve the application of regular steam injections (as frequently as every six weeks) to increase the flow of oil resources. Although injection of steam can modify the permeability of the reservoir rock, neither proppant nor chemicals are used as part of steam injection. Thus, this type of thermal injection should not be covered by the Proposed Rule. But, in its current form, the proposed definition of "well stimulation" could be interpreted to include thermal injections that increase the flow of hydrocarbons and modify reservoir rock. This interpretation would be contrary to BLM's intent.[22]

B. A Clear Definition of Regulated Activities Is Necessary for Operator Accounting Practices and Compliance with Other Regulations.

In addition to avoiding an over-expansive interpretation of the scope of the Proposed Rule, a more precise definition of "well stimulation" would clarify what expenditures operators may consider to be capital versus lease operating expenses for accounting purposes. For example, the costs incurred for drilling and completion of a well and recompletions and refracturing are classified as capital expenditures. But workovers that entail replacing, repairing,

[22] Interpreted expansively, this provision could also cause the shutdown of a significant amount of diatomite productions to shut down due to the infeasible operating and cost schedule resulting from the new regulatory requirements.

or maintaining a well are classified as lease operating expenses. The proposed definition, however, could be understood to reclassify such workovers as well completion activities with costs that should be considered capital expenditures. Such an interpretation will have significant implications for operators determining how they account for lease operating expenses on their fee lands as opposed to their federal leases.

Similarly, a limited definition of "well stimulation" is necessary to conform to guidelines established by the SEC for booking reserves. The SEC requires reporting of proved oil reserves, and according to SEC guidance, "[r]eservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test."[23] Thus, well stimulation methods, including improved recovery techniques (such as fluid injection), that result in the proving of reserves through subsequent actual production should be subject to the proposed requirements for submitting a well stimulation plan for approval. But other stimulation methods that are used to repair, replace, or maintain a well and do not contribute to the proving of reserves should not be subject to well stimulation plan requirements.

C. BLM Should Substitute the Term "Hydraulic Fracturing," and Its Definition, for the Term "Well Stimulation," and Its Definition.

The potentially broad interpretation of "well stimulation" and the consequently broad scope of the Proposed Rule would conflict with BLM's expressed intent that the Proposed Rule regulate only hydraulic fracturing activities. To correspond to the stated policy justification for the regulatory proposal, BLM should revise its definition of "well stimulation" to be limited to hydraulic fracturing. The following definition would achieve those goals:

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[23] *See* Section VIII.A.16. Current Disclosure, Legal and Processing Issues — Disclosure, Legal and Processing Issues — Clarification of Oil and Gas Reserve Definitions and Requirements, *available at* http://www.sec.gov/divisions/corpfin/guidance/cfoilgasinterps.htm.

> **"Hydraulic fracturing" is a well stimulation treatment that involves the injection of engineered fluids and proppant into an underground reservoir formation at a pressure and rate for the purpose of creating, propagating, and sustaining fractures, thereby causing or improving the production of oil or gas from the well.**

This definition expresses BLM's intent to regulate the specific hydraulic fracturing activities that have raised public and governmental concerns.

1. Subsequent Well Operations: Definition of Well Stimulation

As noted above in the discussion of the proposed changes to § 3160.0-5 Definitions, the proposed definition of "well stimulation" is overly broad, and does not provide operators with sufficient understanding of what constitutes "well stimulation." Given the shortcomings of the definition of "well stimulation", the applicability of the notification requirements contained in § 3162.3-3 are problematic for operations occurring after hydraulic fracturing. As discussed above in Section V.A, the Associations suggest that BLM adopt a narrower definition of the term "well stimulation" that is specifically meant to capture activities involving the injection of fluids at high pressure for the purpose of fracturing geological formations. Subsequent operations should be excluded.

2. Proposed § 3162.3-3(b): Subsequent Well Operations; Well Stimulation: When an Operator Must Submit Notification for Approval of Well Stimulation

a. Pre-Approval of Well Stimulation Activities Will Cause Unnecessary Delay.

Requiring advance approval of individual well stimulation activities – as provided for in proposed § 3162.3-3(b) – will add unreasonable additional delays for operators. The existing APD approval process is already severely constrained by a shortage of internal BLM resources. The shortage of resources frequently interferes with BLM's ability to approve APDs within the statutorily mandated time period. The added notification and approval requirements for well stimulation activities will only aggravate the substantial, existing delays in the approval process and the ensuing uncertainty for operators. BLM should defer to existing state processes, which typically are able to address these types of approvals in a more timely fashion, rather than to impose an additional layer of review and delay that offers no additional environmental protections or benefits.

Given the existing inefficient APD approval and review process, it is disconcerting that BLM's proposal contains no explanation of how the Agency will review and approve well stimulation proposals in a timely fashion. The Proposed Rule ignores BLM's current inability to issue decisions on APDs in a timely fashion. Nothing in the Proposed Rule indicates that BLM will increase sufficiently its APD review staff or implement other measures that will allow the Agency to handle effectively the massive increase in approvals that would result when BLM suddenly must handle not only the APD approvals under existing rules but also a parallel well stimulation operations pre-approval (as would be required under the Proposed Rule) for each APD submitted. Even taking into account the anticipated increased decline in drilling on federal lands that the Proposed Rule is likely to engender, BLM lacks the resources to adequately address this additional workload, particularly given the complexity of the information being submitted and BLM's shortage of personnel with sufficient familiarity and expertise on these operational issues. BLM's failure to address this issue is arbitrary and capricious. Both the design and implementation of well stimulation activities are highly technical undertakings that require specialized expertise to understand and analyze. Yet, BLM does not employ enough personnel with the requisite expertise to effectively review and analyze plans for well stimulation activities. Further, the Proposed Rule offers no discussion of how BLM plans to address this institutional shortcoming. The preamble to the Proposed Rule fails to discuss BLM plans to either hire additional personnel expert in these matters, or to train current personnel in the intricacies of well stimulation design and operation. Even if BLM were to hire expert personnel or train existing staff appropriately, it would take time for BLM to become competent and capable in its review of well stimulation activities, which necessarily translates into a period of additional delay for APD review and approval.

That BLM lacks sufficient manpower with the requisite expertise and lacks resources dedicated to APD and well stimulation proposal review will undoubtedly cause both delay and uncertainty for operators. Operators will experience uncertainty because they will not be able to effectively plan well stimulation activities because they will not know when or if their activities will be allowed to take place. Additionally, well stimulation activities are often performed in conjunction with related activities that precede or follow. The uncertainty associated with well stimulation approvals will delay all related activities by impeding operators' abilities to coordinate among activities and efficiently deploy resources. As discussed in Section II and the WEA study, this operational and scheduling uncertainty will lead to additional costs and wasted resources as drilling rigs remain idle and other activities cannot occur because it is unclear when, if, or how well stimulation activities will occur.[24]

b. BLM's Proposed Rule Will Impair Oil and Gas Development on Federal Lands.

The delays, uncertainty, increased costs, and wasted resources all provide operators with serious disincentives to pursue oil and gas development on federal lands. If oil and gas

[24] WEA's recent study estimates the potential costs from, among other things, the increased delays that will result from BLM's proposed rule and the additional approval processes. *See* Memorandum from John Dunham & Associates to Western Energy Alliance (June 11, 2012), *available at* http://westernenergyalliance.org/wp-content/uploads/2009/05/John-Dunham-Associates-Economic-Analysis-of-BLM-Fracing-Regulations-FINAL.pdf. (Appendix B).

companies can conduct their operations on state and private lands without the duplicative rules and resulting negative consequences arising from the proposed rule, they will in all likelihood choose to minimize their operations on federal lands. This trend would have negative implications for BLM's royalty revenue, and also run afoul of the Agency's mandate to encourage natural resource development on the lands it administers.

c. Advance Review of Every Well Stimulation Activity Is Unnecessary.

Even assuming that BLM regulation of well stimulation activity is deemed appropriate and lawful, there is no basis for concluding that individual BLM review and advance approval of every well stimulation activity is a necessary or appropriate mechanism to provide such regulation. If BLM determines it is necessary to issue regulations governing well stimulation activities, it should do so by issuing specific performance standards that are consistent with existing state requirements and technical/operational feasibility. BLM's proposed approach to regulate well stimulation activities is both overly burdensome and unprecedented.

State regulators have decades of experience regulating the technical aspects of well stimulation activities. The preferred approach for state regulators is to set performance standards, and not to engage in the burdensome process of pre-reviewing and pre-approving every single well stimulation activity. This approach to regulation ensures that operators adhere to requisite standards and that they will not be inhibited by unnecessary delay and uncertainty.

BLM should defer to the substantial experience that states have accumulated in the regulation of well stimulation activities. One reasonable alternative that is far preferable to the approach set out in the Proposed Rule would be for BLM to follow state regulations in the applicable state(s) where individual oil and gas operations will occur on federal lands. Doing so would implement a regulatory structure on federal lands that has proved to work for both industry and state governments. It would also eliminate the negative consequences that will be certain to accompany BLM's current proposal.

We urge BLM to abstain from requiring advance review and approval of all individual well stimulation activities. This element of the Proposed Rule is by far the most troubling for operators. There are several alternative methods of regulation that BLM can choose that would avoid the pitfalls associated with advanced review of every individual well stimulation activity, any of which is preferable.

d. Mandatory Advance Approval of Well Stimulation Activities Should be Accompanied by Procedural Safeguards for Industry.

If BLM proceeds with the current proposal and implements a regulatory regime requiring advance review and approval of individual well stimulation activities, the Agency must include procedural safeguards to mitigate the negative impacts on operators. For example, BLM should include strictly enforced deadlines for its approval of well stimulation activities. BLM should conduct a thorough review of the causes for delay in the current APD approval process, and demonstrate in the final rule that it has created procedural safeguards to ensure that well stimulation approvals will not delay operations.

e. BLM Provided No Details Regarding the Procedural or Substantive Review and Approval of Well Stimulation Proposals.

The Proposed Rule provides no details regarding BLM's procedural and substantive requirements with respect to review and approval of well stimulation proposals. This level of opacity greatly increases uncertainty for operators, as their procedural and substantive rights are not evident from the text of the rule.

BLM does not clearly articulate the basis or standards it will use to determine whether or how a proposal for well stimulation will be approved. This shortcoming causes uncertainty for operators because they will not be able to tailor well stimulation proposals accordingly. Certainly in any regulatory setting, an applicant must know the criteria by which its application will be judged, and such criteria should be promulgated through notice-and-comment rulemaking, not through informal guidance. Similarly, BLM must inform operators as to the level of information necessary to avoid delays of approvals for lack of information. Any sort of regulatory approval process that lacks these basic criteria is both inherently unfair and lacks required transparency. Knowing BLM's bases and the standards for approval will also improve the quality of operators' proposals, and the submission of supplemental information.

Compounding the problem that well stimulation approval lacks any defined criteria is the fact that opponents of oil and gas development could exploit this ambiguity through obstructionist judicial and administrative challenges. The lack of standards for BLM approval of well stimulation proposals will complicate judicial and administrative review. This lack of clarity will only provide more uncertainty for operators who choose to conduct activities on federal lands because judicial and administrative outcomes will be much less predictable.

In terms of procedural structure, the Proposed Rule does not provide operators with any mechanisms to address situations where BLM initially declines to approve a proposal for well stimulation. For example, if BLM reviewers determine more information is needed from an operator, or that the proposal should be denied for certain reasons, operators do not have any way to quickly address these issues and receive timely approval. In order to mitigate the delay and uncertainty that will accompany advance approvals of well stimulation activities, BLM must provide operators with a procedural structure that provides ample opportunity to expeditiously resolve impediments to advance approval.

f. Advance Approval of Well Stimulation Activities Requires Operators To Drill Wells Prior to Approval.

The Proposed Rule allows operators to submit an NOI detailing well stimulation activities along with an APD. However, the NOI will not be approved until the operator has proven, through submission of a cement bond log, that measures have been taken to comply with the requirements relating to the Proposed Rule's overly expansive definition of "usable water." In practical terms, this means that operators must drill wells prior to well stimulation approval. This adds further unnecessary uncertainty. Under this regime, operators must allocate significant resources to wells that may only be economically viable through well stimulation before knowing whether BLM will approve well stimulation activities. This advance approval process asks operators to take on an unnecessary level of risk.

g. If BLM Retains Separate Stimulation Approval, BLM Should Allow Targeted Well Stimulation Proposals that Are Applicable Across Fields With Common Features/Conditions.

While we do not believe a separate stimulation approval is appropriate or provides meaningful additional environmental protection, should BLM proceed with seeking separate approval one way to reduce the administrative burden on both BLM and operators, and to reduce uncertainty for operators, would be to allow operators to submit targeted well stimulation proposals applicable across fields within resource play areas that share common geological features and/or operating conditions. These proposals could be submitted and approved for certain areas in advance of APDs, and operators would need only to reference the generic plan when they submit APDs for specific wells. Because individual well stimulation proposals would not be submitted, this system would significantly reduce the time it takes operators to prepare well stimulation proposals, and would greatly reduce the time required by BLM to review proposals. A system with area-wide well stimulation proposals would also provide operators with much more certainty, as they would know whether well stimulation activities would be approved prior to drilling wells. Additionally, allowing for area-wide proposals makes practical sense because well stimulation activities from one operator to the next, or one well to the next, within a given area are unlikely to differ greatly from one another.

3. Proposed § 3162.3-3(b)(ii): Wells Permitted Prior to the Effective Date of the New Rule

Proposed § 3162.3-3(b)(ii) provides that operators of all wells permitted prior to the effective date of the proposed rule must submit an NOI with a well stimulation proposal prior to commencing any well stimulation activities. Operators with existing APD approvals should not be retroactively subjected to additional approval requirements based on the passage of a new rule. Indeed, imposing additional requirements on mineral lessees after the execution of the lease could lead to extensive contract litigation between operators and BLM.

This subsection also requires the submission of a surface use plan if well stimulation activities will entail "additional surface disturbance." Similar to the requirement to submit a well stimulation proposal, the requirement to submit a surface use plan after a lease has been executed should not be imposed. This requirement may well violate terms of BLM's mineral leases. Additionally, this provision does not adequately define what constitutes "additional surface disturbance." BLM needs to provide a clear definition of this term, so that operators have certainty on the timing and breadth of this requirement.

4. Proposed § 3162.3-3(b)(iii): Submission of a New NOI if Well Stimulation Does Not Commence Within Five Years or if Significant New Information Becomes Available

The Proposed Rule requires operators to submit a new NOI in two circumstances: 1) if well stimulation activities have not commenced within five years of the effective date of the well stimulation approval; or 2) if the operator has "significant new information" about the geology of the area, the stimulation operation or technology to be used, or the anticipated impacts of stimulation activity. This requirement will add further uncertainty and delay to oil and gas operations on federal lands.

As with the requirement to submit well stimulation proposals for other wells, BLM has provided no information on how it will ensure that requests to conduct well stimulation activities for wells in this category will be reviewed and approved in a prompt manner. The absence of procedural safeguards and the lack of approval criteria create uncertainty and delay for operators of wells that have been in service five years or more just as it does for operators of new wells.

The Proposed Rule does not adequately define what constitutes "significant new information" such that a new NOI is required. In order to provide guidance and certainty to the regulated community, the Proposed Rule must be refined so that it is clear to operators what types of information or events would qualify as "significant new information."

Because there will likely be delays in BLM's approval of these subsequent NOIs, and because the threshold for when a new NOI must be submitted is not clear, this subsection appears to create the potential for a perpetual process of re-applying for well stimulation approvals that will be issued after substantial delay, if at all. The Associations urge BLM to require only submission of a new NOI when there are fundamental changes in understanding of geology, anticipated impacts, or the technology to be used. We further recommend that BLM detail the circumstances that would prompt a new well stimulation review. In order to avoid delays in approving these subsequent NOIs, BLM should impose a maximum review period of 15 days.

VI. Proposed § 3162.3-3(c): What the Notice of Intent Sundry Must Include

The Proposed Rule requires operators to submit a proposal for well stimulation, before the commencement of operations, that includes extensive information listed in proposed

§ 3162.3-3(c). Prior to well stimulation, operators can only estimate much of the information requested in this provision. Since the operators can only provide estimates prior to well stimulation, BLM should set forth the level of precision necessary for this submission.

A. Proposed § 3162.3-3(c)(2): Usable Water

As discussed in greater detail above, BLM's definition of usable water is overly broad and unworkable. BLM should defer to state definitions of usable water for purposes of implementing these requirements as minimum depths for surface casing are normally set by the states based on their determinations of the maximum depth of usable water.

Moreover, the proposed section 3162.3-3(c)(2) imposes an excessive and unachievable requirement that operators submit "[t]he proposed measured depths (both top and bottom) of all occurrences of usable water" before the commencement of operations. Operators rely on information and analyses gathered by state regulators on usable water, including analyses and mapping of water supply wells in the region, interpreted electrical logs, or other state or federal sources of information such as U.S. Geological Survey data.

As discussed above, BLM's implementation of the definition of "usable water" through this requirement violates the SDWA and the Energy Policy Act and exceeds BLM's regulatory authority. (See Sections IV.A)

B. Proposed § 3162.3-3(c)(2): Cement Bond Log Requirements

The Associations object to the cement bond log ("CBL") requirements for surface casing. The Proposed Rule is overly prescriptive and overly reliant on the use of surface casing CBLs as required in proposed § 3162.3-3(c)(2).

1. BLM Should Not Require CBLs For Surface Casing

BLM should eliminate the requirement that operators submit CBLs for surface casing for BLM approval. This requirement adds an unnecessary approval process, and CBLs should not be viewed as the definitive singular mechanism to assure or describe well bore integrity for surface casing. A surface casing that has been installed at the proper depth and achieved the required casing pressure test and shoe test will establish a barrier system that effectively isolates usable water from the fluids contained in deeper formations. These two pressure tests (the casing pressure test and the shoe test) verify the integrity of the well and the isolation of usable water resources from potential contact with hydrocarbons. Attempts to provide further verification through means other than these methods of pressure testing do not reliably provide additional assurances of well integrity or isolation of water resources.

Surface casings must be cemented to surface by existing regulation. This work is done to provide both a structural foundation and a barrier against fluid movement behind pipe. Pressure tests help ensure no fluid transfers will occur from deeper formations. With regard to barriers installed behind casing, industry relies primarily on cement design and implementation practices to establish effective barriers. Much is known about the principles and practices that result in good cement performance behind casing. A key principle is the effective replacement of the drilling mud with cement in the casing annulus. This requires the development of a cement job design that facilitates mud removal. Best practices for cement placement include direct observation that cement circulates back to the surface, centralization of the casing across usable water zones, establishing a hierarchy of fluid rheology and density for the drilling mud, the mud-cement spacer, and the cement slurry. Best practices also include the design of pump rates to establish desired fluid flow regimes, proper cement density, and cement additive control while mixing. Engineering design and placement simulation programs assist engineers in the development of process that reliably installs the cement barrier. Adequate volumes of cement are used to ensure that the hole will be fully displaced and that mud-contaminated cement will be circulated from the hole. Real-time job data is available to the cementing operator for quality control, and it is possible to collect a digital record of the cement job that can be compared to the design for purposes of a final quality assessment.

Surface casings are among the easiest to cement. They are normally installed in vertical holes, can be centralized, and rotated and reciprocated as necessary to facilitate effective cement placement. When proper design and operational practices are used, industry has a good record of annular cement barrier performance. The use of accepted cement job design and implementation practices, and the correlation to historical performance, has been sufficient to establish a reliable qualitative measure of expected barrier performance.

In the current permitting process, operators submit casing and cementing programs for review by BLM petroleum engineers. These programs are designed to establish the required barrier systems. BLM petroleum engineers review these programs to "determine if the proposed cementing program provides for the proper types and quantities to support the casing, protects usable subsurface water and prevents hydrocarbon and fluid migration between zones." Using this current regulatory review process, the cement job design can be determined to be "fit for purpose."

Provisions are also in place to report key aspects of the barrier system installation and verification process. Under Onshore Order No. 2, operators are already required to submit completion reports to BLM that include formation integrity tests ("FITs"), pump pressures, and other operational data. Onshore Order No. 2 also adopts a number of industry best practices for well construction and cementing, such as pressure testing, temperature surveys, and circulation of cement to surface. These, along with state requirements, allow for adaptive approaches that optimize groundwater protection. In the event an operator does not comply with these requirements, or if an anomaly is observed during cement placement operations, then it might be appropriate to run a CBL. CBLs are thus the exception for surface casing, not the rule.

Rather than look to these industry practices or existing state regulations, however, BLM proposes a blanket CBL requirement for surface casing that appears to be based on the belief that CBLs for surface casing provide a definitive test demonstrating the integrity of the surface casing annular cement barrier. BLM's statement that "many operators routinely perform cement bond logs for zones of interest"[25] is incorrect with regard to surface casing. Operators use a CBL or other acceptable evaluation methods on surface casing only to the extent that they are needed. The CBL does not provide a direct measure of cement seal or barrier integrity. It provides only a measure of acoustic signal attenuation, which is then used to correlate to the presence of cement. The quality of the correlation is a function of the conditions in which the log is run. The physics used in CBL technology is not ideally suited to surface casing interval cement evaluation. A pre-authorization CBL requirement for surface casing would not "help BLM in its efforts to make sure that water resources are protected,"[26] but would only increase costs and delays for operators.

Sonic and ultrasonic "CBL" evaluation logs provide qualitative information about material in the annulus and the quality of the information they provide is affected by a number of variables. Two of these variables that significantly affect acoustic response are the differences in material properties such as density and strength. Formation stresses (horizontal and vertical stresses in the earth) also significantly affect sonic and ultrasonic log response. The horizontal stresses generated in the earth push against the cement and dampen acoustic response (like

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[25] 77 Fed. Reg. at 27,696.

[26] 77 Fed. Reg. at 27,696.

putting your hand on a bell to damp down the ring). This radial stress is a significant factor in creating the true bond or seal of cement against casing and the wellbore.

The effect of low density, low strength cement response to a sonic or ultrasonic bond log (CBL) can be explained with a very basic example. The acoustic impedance of a material is:

$Z = pv$

Where:

Z = acoustic impedance of a material

p = density of material

v = velocity of sound wave through material

Low strength materials have low sonic velocities. For example, the sonic travel time of a compressional wave from a 400KHz transducer commonly used to non-destructively measure cement compressive strength is:

Table 1

Travel Time of Compressional Sonic Wave in Different Materials

Material	Travel time of compressional wave (400 KHz transducer)
Water	18 to 20 microseconds/inch
Unset Cement Slurry	16 to 18 microseconds/inch
100 psi Compressive Strength Cement	14 microseconds/inch
1000 psi Compressive Strength Cement	11 microseconds/inch
4000 psi Compressive Strength Cement	8 to 8.5 microseconds/inch

As the travel time data shows, the travel time of low compressive strength cements is close to unset cement and water. Therefore, low density, low strength materials have low acoustic impedance and can be difficult to reliably characterize and evaluate with acoustic methods, even though a 100 psi compressive strength cement can be an effective annular sealant and provide an effective barrier. The data in Table 1 also support use of sonic/ultrasonic cement bond log tools in deeper formations due to the typically higher compressive strength and more rapid compressive strength development of cement under higher temperature and pressure conditions.

Light weight (low density) cements have lower compressive strengths and horizontal stresses in shallow formations common to surface casing intervals are lower than deeper in the well. Therefore, CBL technology is technically better suited to evaluation of deeper casing string cementing operations.

Surface casings are typically cemented with a lighter weight “lead” slurry and a higher density “tail” slurry because the fracture gradient of exposed shallow formations cannot support an entire column of the higher density cement slurry. The compressive strength and strength development of the higher density (tail) slurry is higher and faster than the lower density (lead) slurry. Material property contrast is one of the key factors used by CBL techniques to differentiate cement from other fluids behind casing. Having higher density and stronger cement improves the response from sonic or ultrasonic CBL tools. Therefore, allowing sufficient time for the lead cement to develop its ultimate (or near-ultimate) compressive strength improves the evaluation from CBL. It takes much longer for the lead cement to develop strength than the tail cement. The time required for many cement slurries to develop stabilized, near-ultimate compressive strength is often over 72 hours at the relatively low temperatures common in surface casing strings. This is illustrated in Figure 1 (below) by laboratory data from lead and tail cement comparing compressive strength and compressive strength development. Therefore, CBL evaluation of cement for surface casing may require waiting-on-cement times of several days, and material property differences may not be significantly different.

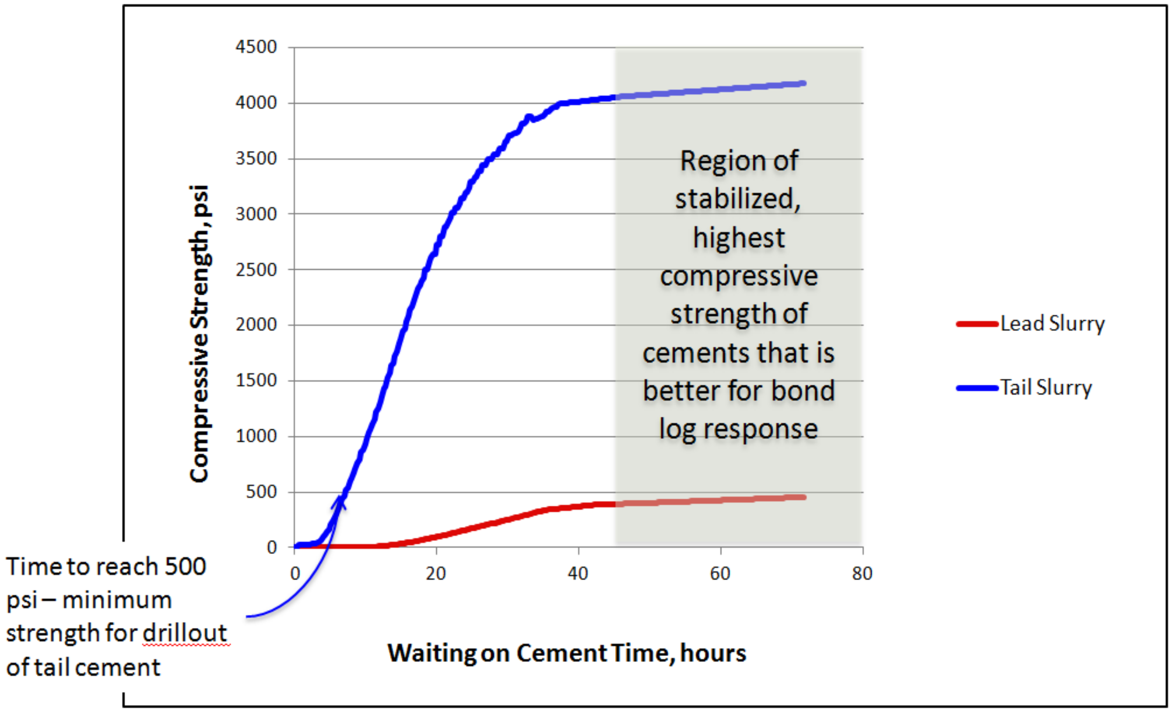

Figure 1: Comparison of compressive strength versus time for lead and tail cement slurries.

Also, a lack of expertise in CBL interpretations within BLM could lead to misinterpretation of CBL results and may result in unwarranted repair attempts or "remediation." Such "repairs" and "remediation" could be counterproductive and actually create a greater, rather than lower, risk of contamination of usable water strata because they could unnecessarily compromise the integrity of the well casing.

2. The CBL Requirement Requires Clarification

The CBL requirement, as currently drafted, does not clearly describe operators' obligations. For example, the Proposed Rule does not establish when the operator must run the CBL, the well conditions while logging, or whether there is a minimum compressive strength that must be achieved before the well is logged. These and other omissions will make it difficult for operators to comply with the regulation, complicate interpretation, and lead to inconsistent requirements from different BLM offices. Further, the Proposed Rule fails to establish how long BLM's approval process will take or how the approval process will proceed if a CBL is not acceptable, but clearly contemplates that BLM can request additional information.[27] Without knowing how long the process will take or be delayed, operators cannot make effective business decisions regarding their operations.

The Proposed Rule does not explain how CBL results would be interpreted. Interpretation of CBLs requires specialized expertise and knowledge. Of course, interpretation of CBLs by inexperienced personnel increases the risk of incorrect interpretation and false positives and other inaccuracies. Inconsistent implementation of the rule may also result in unnecessary delays and increased costs.

The Proposed Rule also does not establish a process or standards regarding when a CBL variance will be approved. Proposed § 3162.3(c)(2) allows the operator to submit "another log acceptable to the authorized officer." This provision is beneficial and consistent with the adaptive approach used by state agencies. Although BLM provides some examples of the types of variances that may be allowed,[28] it does not provide clear standards or criteria for approval or establish a process for requesting variances and evaluating such requests. BLM should clarify, as part of this rulemaking, the variance process, explaining the bases for a variance and why it might be modified or rescinded. BLM should provide a variety of approved technologies or methodologies that operators can choose to utilize that would minimize the need to apply for a variance, including less expensive, reliable logging alternatives.

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[27] *See* Proposed § 3162.3-3(c)(7); *see also* 77 Fed. Reg. at 27,696-97.

[28] *See* 77 Fed. Reg. 27,696.

3. BLM Should Defer to State Regulations and Require CBLs Only in Limited Circumstances.

The CBL requirement is also misplaced because the responsibility for protecting water resources lies with the states. States have a long history of regulating drilling permits and this approach has been successful. Operators have the responsibility to meet these regulations and requirements, and there may be limited circumstances in which CBLs on surface casing could be an appropriate diagnostic tool where other tests or analyses have produced inconclusive results or indicated potential insufficiencies in the cementing process. Requiring pre-authorization CBLs in all circumstances, however, is duplicative and unnecessary.

Using the existing BLM process to ensure the surface casing cementing operation is properly designed, recording job execution data, and analyzing and comparing critical parameters for design and execution provide a more effective evaluation of the cementing process affecting zonal isolation.

C. Proposed § 3162.3-3(c)(3): Measured Depth to Casing Perforations; Water Sources; Proppants; Pressures

Proposed § 3162.3-3(c)(3) requires, among other things, that operators submit information regarding the sources of water they propose to use for well stimulation. BLM does not, however, have the authority to require such information. Indeed, BLM only has the authority to require water source disclosure when it may come from sources over which it has direct regulatory authority, and these are rare. Further, the regulation would impose unnecessary burdens on operators. Thus, we recommend that BLM eliminate this requirement, or at the least, clarify the scope of the requirement so that operators can provide meaningful input.

BLM's requirement that operators submit water source information needlessly creates delay and adds costs. Water sourcing and cost is a major component of completions costs, and mandating submission of this information risks disclosure of commercially confidential information. In particular, well-by-well disclosure of sourcing is a sensitive matter. Supplier relationships in this rapidly expanding area of operations present strong competitive advantages, and information about how water is supplied, by whom, and how much, could hurt an operator's business position if it were made public. Operators may be willing to consolidate information for water boards, but there must be some protection for confidential business information. A further complicating factor arises because operators often get water from multiple sources, and the sources of water change. These burdens are particularly excessive given that BLM has no authority to deny approval on the basis of this information, and because the requirement provides no clear environmental benefit.

In addition, the proposed provision omits critical information. If BLM retains the water source information requirement, BLM should clarify what the requirement entails. For example, BLM does not detail procedures for how it might plausibly expect to address approval of water sources or transport routes. Nor does BLM establish the criteria that it will use to review water source information or the obligations of an operator if there is a change in water supplies, transport routes, or the other listed information items. Nor does BLM explain how it purports to control water supplies or usage.

Similarly, BLM suggests that this provision could trigger mitigation obligations without providing details about those obligations. BLM states that the information about water sources is necessary "to determine the impacts associated with operations and the need for any mitigation applicable to Federal and Indian lands."[29] But BLM does not explain what mitigation may be required, the associated costs, or what the mitigation process would encompass.

[29] 77 Fed. Reg. at 27, 696.

D. Proposed § 3162.3-3(c)(4): Certification of Stimulation Fluid Compliance

Proposed § 3162.3-3(c)(4) requires that the operator certify that the treatment fluid complies with all applicable permitting and notice requirements, and all laws and regulations. This requirement is unnecessary and unacceptable in light of existing BLM rules and state rules, including other certification requirements related to the sundry notice of APD. Instead of providing any additional assurance of compliance, this certification requirement creates an additional layer of liability over existing legal requirements. Those requirements, however, can speak for themselves. To the extent that this requirement duplicates existing certification requirements, it is unnecessary. But to the extent this requirement expands operators' liability under existing regulations, the requirement exceeds BLM's regulatory authority and intrudes on the jurisdiction of state regulatory authorities. The Associations thus recommend that BLM remove this provision.

If BLM decides to retain proposed § 3162.3-3(c)(4), BLM should clarify that the provision does not require operators to certify information that is outside their knowledge or controlled by other parties. Although the Preamble suggests that the operator need only certify compliance with *its own* statutory and regulatory requirements,[30] the provision requires certification that "*the proposed treatment fluid complies*" with applicable laws and regulations. This language suggests that the operator could be liable for the obligations of third parties in connection with the treatment fluid.

Heightened liability for information beyond the operators' control would be inconsistent with existing certification requirements. For instance, the APD form clearly states that the operator is liable only if it knowingly or willfully makes false, fictitious, or fraudulent

[30] *See* 77 Fed. Reg. at 27,696.

statements. If the proposed requirement establishes liability greater than the liability imposed by the APD, it would conflict with BLM's goal of "creat[ing] a consistent oversight and disclosure model that will work in concert with other regulators' requirements while protecting Federal and tribal interests and resources."[31] Also, this heightened liability will likely dissuade operators and more importantly the service companies they rely upon from seeking to develop on public and tribal lands.

The current BLM Onshore Order provides an alternative to the overly broad and unrealistic proposed certification requirement. The Onshore Order certification is as follows:

> 6. Operator Certification
>
> The operator must include its name, address, and telephone number, and the same information for its field representative, in the APD package. The following certification must carry the operator's original signature or meet the BLM standards for electronic commerce:
>
> I hereby certify that I, or someone under my direct supervision, have inspected the drill site and access route proposed herein; that I am familiar with the conditions which currently exist; that I have full knowledge of state and Federal laws applicable to this operation; that the statements made in this APD package are, to the best of my knowledge, true and correct; and that the work associated with the operations proposed herein will be performed in conformity with this APD package and the terms and conditions under which it is approved. I also certify that I, or the company I represent, am responsible for the operations conducted under this application. These statements are subject to the provisions of 18 U.S.C. 1001 for the filing of false statements.

E. Proposed § 3162.3-3(c)(5): Description of the Well Stimulation Design

Proposed § 3162.3-3(c)(5) requires a detailed description of the proposed well stimulation design, including estimated or calculated fracture length and height. BLM should eliminate this requirement and instead rely on information developed by expert state agencies because, unlike state personnel with a long history of regulating oil and gas operations, BLM

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[31] *See* 77 Fed. Reg. at 27,692.

lacks adequate personnel with the expertise and experience to evaluate the design information requested in the Proposed Rule. This requirement also risks improper disclosure of confidential business information.

First, design information submitted prior to drilling would be preliminary. But even well design information submitted after drilling, but before well stimulation, would be costly to develop and submit. Thus, BLM should rely on information submitted and developed through existing state regulatory regimes rather than set up a duplicative program. In light of the information and expertise available from states, § 3162.3-3(c)(5) imposes unnecessary costs to obtain duplicative information with no concomitant benefit.

Second, BLM should also refrain from collecting detailed well design information from operators because BLM does not need to gather this information itself in order to protect well integrity. Additionally, much of this information is confidential and proprietary business information, the disclosure of which would seriously damage an operator's competitive position. This information implicates an operator's competitive advantage both prior to *and* after well completion.

If BLM retains the requirement, BLM should clarify that operators need not disclose protected business information. At a minimum, BLM should provide that sensitive business information collected under § 3162.3-3(c)(5) will not be disclosed to third parties.

F. Proposed § 3162.3-3(c)(6): Information Concerning the Handling of Recovered Fluids

Proposed § 3162.3-3(c)(6) requires information regarding the handling of flowback fluids. BLM has not provided a reasoned justification for why it needs this information. First, Onshore Orders 1, 3, and 7, and the Gold Book address the information required under this provision. Indeed, the Preamble acknowledges that BLM already requires the requested information.[32] The proposed provision is clearly duplicative of these existing provisions.

BLM has not provided any explanation of the need or purpose of the proposed provision, including its intention for use of the information. Although BLM generically states that the information is necessary "in the event that the information is needed to help protect health and safety or to prevent unnecessary or undue degradation of the public lands," or "to ensure that the handling methods will adequately protect public health and safety,"[33] these statements do not take into account that this information is already being gathered and available. If BLM intends that this provision will require information above and beyond what operators already provide, it should clearly identify those new requirements and address how BLM will keep this information confidential. Moreover, this new information-reporting requirement could create a federal scheme that conflicts with state authority. Should BLM use this information to impose requirements for handling methods, such requirements could also interfere with state authority.

More generally, BLM should clarify operator's obligations under this provision. For instance, BLM should provide more information on the scope and applicability of this provision, including the time frame involved. Also, because much of the required information, including information on chemical composition, is necessarily estimated, BLM should clarify how exact the required information needs to be and acknowledge that the information will only be an estimate.

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[32] *See* 77 Fed. Reg. at 27,696 ("This [information regarding the proposed disposal method] is currently required by existing BLM regulations (i.e., Onshore Order Number 7, Disposal of Produced Water, (58 FR 47354).").

[33] 77 Fed. Reg. at 27,696.

G. Waste Streams

BLM also requested comments as to whether or not the operator should be required to submit additional information about how it will dispose of waste streams. This subject matter was not specifically addressed in the Proposed Rule and is inappropriate in the context of this particular rulemaking. The request at this stage creates an unrelated process in which BLM may introduce additional potential regulations without benefit of the full procedures of formal rulemaking. Any additional requirements relating to waste streams should be addressed in future rulemakings and subject to full notice and comment rulemaking procedures. Without more information regarding what BLM may propose, it is not possible to provide complete comments. Nonetheless, it appears that any regulation that BLM might purport to implement with respect to the disposal of waste streams generated by operations would be beyond BLM's authority under FLPMA and the MLA and beyond its authority under the Property Clause.

H. Proposed § 3162.3-3(c)(7): Authorized Officer May Request Additional Information

Proposed § 3162.3-3(c)(7) allows the authorized officer to request additional information prior to approval of the notice of intent sundry. This rule is unnecessary and gives the authorized officer undefined discretion, which risks BLM exceeding its regulatory authority and also imposing unnecessary additional costs and delays for operators.

The proposed provision gives the authorized officer unbridled discretion to request additional information. Although the Preamble states that the authorized officer can only request information "necessary for the BLM to ensure that operations are consistent with the applicable laws and regulations,"[34] the examples provided show that the requests could result in the costly

[34] 77 Fed. Reg. at 27,697.

development of information or even remedial action and long operating delays.[35] This result is contrary to BLM's stated intent to not create extensive delays and eliminates any predictability in the timing of the BLM approval process.

The Associations agree that operators should take steps to ensure the safety and integrity of their wells, and compliance with applicable laws, but we also believe that states are better equipped to achieve the purpose of this requirement. State rules already allow authorized officials to request additional information. Additionally, state officials have significant professional experience in the oil and gas industry and with dealing with their rules and the regulated community. BLM has underestimated the number of experienced employees required for effective, timely permitting approval. Inexperienced BLM personnel are less likely to have the depth of knowledge necessary to evaluate the submitted information and more likely to request unnecessary information that will impose costs and delays on operators.

Additionally, states already have the resources to review well approval information and determine the need for additional information. BLM does not appear to appreciate the number of personnel required to support timely permitting. BLM's estimates of its own administrative costs are greatly understated.[36]

BLM specifically requested comments on how to make the additional information requests under this provision the least burdensome as possible. Because these information requests are inherently duplicative and likely to lead to additional costs and delays, BLM should rescind this provision and rely on state regulatory authorities performing this function.

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[35] *See id.*

[36] *See generally* BLM, Well Stimulation Proposed Rule: Economic Analysis and Initial Regulatory Flexibility Analysis, BLM-2012-0001-0003.

VII. <u>Proposed § 3162.3-3(d): Mechanical Integrity Test</u>

Section 3162.3-3(d) of the Proposed Rule requires the operator to perform a successful mechanical integrity test ("MIT") of the casing before well stimulation and also provides specifications and engineering criteria for the test depending on whether the stimulation is through the casing or through a fracture string. Because "mechanical integrity testing" is a term that can have multiple meanings and is not tailored to address the most relevant concerns in the context of hydraulic fracturing,[37] BLM should focus its efforts on pressure testing, which would provide an appropriate assurance of well integrity.

A. BLM Should Eliminate the MIT Requirement Because It Is Duplicative.

BLM's proposed MIT requirement is duplicative of existing state regulations and well-established industry practice, and is therefore unnecessary. States require pre-hydraulic fracturing pressure testing, and unlike BLM, have the resources and experience to direct and interpret the results of such tests. Second, industry best practices such as API HF-1 and individual operators' internal procedures recommend this testing. Third, hydraulic fracturing pumping service companies have resources and experience to test the integrity of the well.[38]

As currently drafted, the proposed MIT requirement fails to recognize basic operational practices that are well-established in the industry and reinforced by state regulations. For example, in designing a well, operators determine the maximum anticipated treatment pressure and then apply an appropriate safety factor to provide a reasonable and prudent test pressure. Some states already require this type of planning and pressure limitation. North Dakota rules,

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[37] MIT in the context of the Underground Injection Control program involves far more than pressure testing, and thus would be largely unnecessary for hydraulic fracturing.

[38] *See* 77 Fed. Reg. at 27,697.

for example, set a maximum treating pressure to no more than 85% of the casing API rating. Another common operational practice that is not recognized by BLM's proposed MIT requirement is the pressure testing of the fracturing string while it is being run into the hole. An operator may prefer to do this because perforations already exist in the wellbore or because a plug cannot be set in the packer after landing the tubing. It goes without saying that operators already have a very strong incentive to ensure that fracturing fluids enter the reservoir without leaks in the casing, tubing, packer, wellhead, surface lines or equipment; hence the evolution of these basic operational practices.

B. If BLM Retains the MIT Requirement, BLM Should Clarify the Requirement and Make It Consistent with Existing Regulations.

If BLM retains the proposed MIT requirement, it should clarify the requirement and make it consistent with Onshore Order No. 2, which requires a pressure integrity test. As an initial matter, the term "mechanical integrity test" is ambiguous – "mechanical integrity testing" can mean different things under various federal and state agency programs, including pressure testing, CBL, a temperature log, or a tracer survey. Thus, the use of that term in the context of this regulation is inappropriate.

Pressure integrity testing, rather than mechanical integrity testing, is the more appropriate requirement to achieve BLM's goals and to ensure consistency with existing regulations and avoid unnecessary costs. Pressure integrity testing provides adequate assurances of well integrity in the context of approving well stimulation proposals. For the reasons mentioned above, operators should be allowed flexibility in performing a pressure test based on the design and construction of the wellbore and the most efficient process of completing a well.

In addition to generally making the proposed MIT requirement consistent with existing regulations, BLM should explicitly state that non-hydraulic fracturing activities are not subject to the proposed MIT requirement.

VIII. Proposed § 3162.3-3(e)(1): Monitoring and Recording the Annulus Pressure at the Bradenhead

Proposed § 3162.3-3(e)(1) requires continuous monitoring and recording of the annulus pressure at the bradenhead. We believe such monitoring and recording is an industry best practice. We support this practice and operators are currently doing this now as a course of business. This proposed monitoring and recording requirement is unnecessary in most states in light of existing state requirements. For example, Colorado, Montana, North Dakota, and Wyoming require notifications reporting much the same information required in this provision. In states where there is a monitoring and recording requirement, BLM should simply obtain this data from the states. In states where there is no such requirement, we do not object to BLM imposing this type of requirement.

IX. Proposed § 3162.3-3(e)(2): Reporting an Increase in Pressure

Proposed § 3162.3-3(e)(2) requires operators to notify the authorized officer if the annulus pressure increases more than 500 psi during the stimulation as compared to the pressure immediately before the stimulation. This proposed requirement is duplicative of state requirements and is thus unnecessary and should be eliminated. Alternatively, the commenters recommend that BLM replace the reporting trigger with a more reliable indicator of potential problems or breaches in the casing.

The proposed requirement duplicates state requirements that exist at least in Colorado, North Dakota, and Wyoming. These States each require notification if there are indicators of problems with the well casing. BLM can obtain these notifications, and should rely on them rather than burden operators with redundant reporting obligations.

If BLM retains this requirement, it should revise the event that triggers the reporting obligation. As proposed, the reporting requirements are triggered if the annulus pressure increases more than 500 psi during the stimulation. At the same time, however, monitoring of potential increases over 500 psi is not a reliable indicator of potential problems or breaches in casing. Notification should be based upon a variety of factors including the compressible volume in the annulus, whether there are exposed casing shoes in the annulus, the physical properties of the fluids in the annulus, the physical limitations of the tubular, the pore pressure/fracture gradient profile, and others.

X. Proposed § 3162.3-3(f): Storage of Recovered Fluids

Proposed § 3162.3-3(f) requires recovered fluids to be stored in tanks or lined pits. The authorized officer may also require additional measures. The proposed storage requirement overlaps with and is duplicative of state requirements and Onshore Order No. 7 and thus should not be adopted. Also, the proposed requirement confers overly broad discretion on the authorized officer, which risks drilling delays and increased compliance costs.

BLM specifically requests comments on whether additional conditions of approval for the handling of flowback water may be placed on a project by the BLM, and specifically whether the rule should impose additional requirements. Generally, operators today use either tanks or lined pits for their completion operations either due to existing state rules, Onshore Order No. 7, or industry practice. To obtain further feedback, however, BLM should provide more details on the type of requirements it is considering and allow operators an opportunity to provide meaningful input. Further, we recommend that BLM obtain this information through consultations with the industry. At this time, however, BLM should not impose any additional requirements.

XI. Proposed § 3162.3-3(g): Information that Must Be Provided to the Authorized Officer After Completion

Proposed § 3162.3-3(g) lists 11 categories of information that an operator must provided to the authorized officer as a Subsequent Report Sundry Notice within 30 days of the completion of operations. The Associations recommend revisions to this requirement that will ease the compliance burden on operators. First, BLM should clarify what constitutes the "completion" of operations. Second, BLM should extend the 30-day timeline for submitting the required notice to 90 days to allow companies time to receive and review the necessary information from service companies. Third, BLM should eliminate duplicative requirements. Fourth, the BLM should develop standard completion reports for operators. This will assist BLM regulators and operators to both understand what is required for the notice, and also reduce the burden on operators preparing the notice.

A. Proposed § 3162.3-3(g)(1): Information Regarding Actual Measured Depth of Perforations, Source and Location of Water, Type of Proppants, and Actual Pump Pressure

Proposed § 3162.3-3(g)(1) requires operators to provide information about actual measured depths of perforation, actual water sources, actual proppants used, and actual pump pressures. This provision mirrors Proposed § 3162.3-3(c)(3) in requiring operators to provide this information as a proposal prior to well stimulation. Like Proposed § 3162.3-3(c)(3), this proposed requirement usurps states' rights to manage and allocate water. This exercise of federal control over water resources exceeds BLM's authority. (*See* Section VI.C) Thus, as previously discussed, BLM should remove from the Proposed Rule any references concerning the definition, use, transport, disposal or other activities involving water, including requirements of cement bond logs, as this is clearly within State regulatory jurisdiction.

Also, the information requirement of Proposed § 3162.3-3(g)(1) could require the production of proprietary information. BLM should clarify that it will not disclose to third parties any proprietary information submitted under this provision.

B. Proposed § 3162.3-3(g)(2): Information Regarding the Actual Volume of Fluid Use

Proposed § 3162.3-3(g)(2) is duplicative and unnecessary and should be eliminated. Proposed § 3162.3-3(g)(2) requires operators to report the actual volume of fluid used so that BLM can "maintain a record of the stimulation operation as actually performed."[39] But operators already submit this information under current BLM and state rules. For instance, BLM currently requires this information on Form 3160-4 (Well Completion or Recompletion Report and Log), which requires operators to report amounts and types of materials used. States such as Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming also have rules for maintaining a record of the stimulation operation actually performed. Additionally, operators voluntarily provide this information through FracFocus. Requiring operators to separately submit information that they already post on FracFocus would conflict with BLM's goal of integrating its disclosure requirements into the FracFocus website.[40] BLM should eliminate proposed § 3162.3-3(g)(2) and rely on information voluntarily submitted and also collected under existing regulatory regimes.

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[39] 77 Fed. Reg. at 27,698.

[40] *See* 77 Fed. Reg. at 27,692, 27,694.

C. Proposed § 3162.3-3(g)(3): Information Regarding Surface Pressure, Flush Volume, and Pump Pressure

Proposed § 3162.3-3(g)(3) requires operators to submit information regarding the actual surface pressure and rate, the actual flush volume and rate, and the final pump pressure. This information is duplicative of state rules. States such as North Dakota and Wyoming have rules addressing this information. Thus, the information requested under this provision is available, and BLM should obtain the information from existing sources rather than impose a duplicative and unnecessary additional obligation on operators.

If BLM retains this requirement, the commenters recommend that BLM expressly ensure that information submitted under this provision would not be disclosed to third parties. Operators consider this information proprietary. The proposed requirement should provide this protection to any submitted proprietary information.

D. Proposed § 3162.3-3(g)(4): Information Regarding Additives

Proposed § 3162.3-3(g)(4) requires operators to disclose all additives of the actual stimulation fluid by additive trade name and purpose. This proposed requirement is unnecessary in light of state requirements and information that operators already submit voluntarily. The requirement should therefore be eliminated.

As an initial matter, states such as Wyoming, Colorado, New Mexico, and North Dakota already require reporting of additives in the actual stimulation fluid. Thus, the information that BLM seeks is already available through state regulations. Further, operators voluntarily disclose additive information through the Ground Water Protection Council's FracFocus website. Indeed, BLM intends to integrate its regulations into the FracFocus website and to post the information collected under this proposed requirement on a public website.[41] Considering this BLM goal, and the fact that operators already submit additive data (pursuant to state requirements and voluntarily), the proposed requirement is duplicative without any additional benefit.

If BLM nevertheless intends to require the submission of additive information, BLM should consult with states that have studied and developed regulations pertaining to this information. State oil and gas regulators have through the STRONGER program audited various state regulatory programs with the intent of educating and proactively improving the development of regulation. Several states have made FracFocus part of their disclosure rule. BLM should study these state regulations and consult with state regulators to ensure the rule developed for federal and tribal lands does not conflict with or duplicate existing rules. In cases where FracFocus is not required, a great many operators nevertheless voluntarily share this information on FracFocus.

E. Proposed § 3162.3-3(g)(5): Information Regarding Chemical Makeup of Fracture Fluid

Proposed § 3162.3-3(g)(5) requires operators to disclose the chemical makeup of the actual fracture fluid. This proposed requirement is duplicative of state regulations and seeks information that industry voluntarily discloses on FracFocus. As discussed in relation to proposed § 3162.3-3(g)(4) (see Section XI.D), BLM should eliminate this requirement and rely on existing information sources, or at least consult with states that have studied and developed regulations integrated with FracFocus.

Additionally, the proposed requirement is not well-crafted, seeks inappropriate and excessive information, and risks the disclosure of proprietary information. First, proposed §

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[41] *See* 77 Fed. Reg. at 27,692, 27,694, 27,698.

3162.3-3(g) requires the submission of CAS numbers, but not every component used in hydraulic fracturing fluid has a CAS number and much of this information is not available to the operator.

Second, BLM should distinguish operators and service companies, and should not require operators to submit information about which they have no direct responsibility, including about trace chemicals and contaminants. The Colorado regulations recognize this and establish reasonable limits on operators' responsibilities. Under the Colorado Oil and Gas Conservation Commission's Order 1R-114, operators are not responsible for inaccuracies in information provided to them by vendors or service providers, and vendors, service providers, and operators are not required to disclose chemicals that were unintentionally added to the fracturing fluid or that occur incidentally or are otherwise unintentionally present in trace amounts.

Requirements regarding the chemical makeup of fracture fluid should also ensure protection for proprietary information. In particular, operators should not be required to disclose percent mass of chemicals because that requirement needlessly risks the disclosure of proprietary information. Further, BLM should clarify the scope and basis of confidentiality protections available under "federal laws" for information submitted under the Proposed Rule. (*See* Section XII)

F. Proposed § 3162.3-3(g)(6): Information Regarding the Actual, Estimated, or Calculated Fracture Length and Height

Proposed§ 3162.3-3(g)(6) requires the reporting of the actual, estimated, or calculated fracture length and height. This proposed requirement is problematic for the same procedural reasons discussed in connection with the proposed fracture design information. (*See* Section VI.E)

Operators are strongly motivated to design to maximize confinement of fractures to zones of economic interest. Where the characteristics of the play dictate its necessity, operators estimate a range of values based on detailed calculations, modeling and validation. Operators also recognize that the first principles of geology and physics adequately limit the range of possibilities for fracture propagation and especially limit their vertical growth. It is not rational to suggest that hydraulic fracturing is capable of propagating fractures upward for as much as a mile into usable waters, and there is absolutely no credible evidence to suggest it is possible. A huge body of science, experiments, and detailed monitoring supports this practical position. Among the most well-known factors is that the laminated (i.e. layered) nature of formations tends to arrest the vertical growth of fractures, and it takes a massive amount of energy to overcome this tendency.

Equally certain, there is no rational reason to expect significant water flow to defy principles of fluid dynamics and flow toward the surface when it "wants" to flow toward pressure depleted formations or well bores. While some may argue capillary action and other minor forces may allow fluids to move against gravity and away from the lowest pressure, the preponderance of evidence shows that fluids will flow from the formation to the wellbore and then to surface, not the other way around.

Operators find modeling of the fracture length and height helpful to test and optimize engineering designs, but it is not helpful for determining if an individual fracture could propagate to usable waters, as BLM suggests in the Proposed Rule. Furthermore, operators tend to run these models over a regional or broad area because there is very little lateral variation in rock properties, and the sensitivity of measurements and models do not provide added value for well-by-well model creation. Operators are also quite cognizant that the cost of information used in these models is high. A single diagnostic fall-off injectivity test might cost $40,000 and supporting seismic data may cost over $1 million.

Industry is driven by performance, and there is no economic incentive to invest the pumped horsepower to overcome fracture gradients that would extend substantially into unproductive formations, either above or below the targeted pay zone. A typical horizontal well completion will cost over $1 million. If fractures propagate out of the targeted zone, an operator can get unwanted water or saline brine that limits production of hydrocarbons and adds additional costs for water separation and handling on the surface and eventual treatment or disposal.

In the few basins where hydraulic fracturing jobs are shallow enough and powerful enough to potentially reach into usable water, discussion and implementation of additional controls is warranted. In those very limited cases, it makes sense to assure operators "can verify that the intended effects of the well stimulation operation remain confined to the petroleum-bearing rock layers and will not have unintended consequences on other rock layers or aquifers."[42] However, here we again encourage BLM to look to the states, which have the needed local experience and understanding of the conditions of these shallow fields to determine the steps needed to protect underground sources of drinking water, where it exists.

We encourage BLM to have further dialogue with expert stakeholders from state and federal agencies and, in particular industry, to design appropriate controls for these exceptional cases of hydraulic fracturing, while not burdening the vast preponderance of drilling and completions activity where fracture propagation presents no meaningful risk to usable water.

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[42] 77 Fed. Reg. at 27,698.

G. Proposed § 3162.3-3(g)(7): Information Regarding the Attachment of Job Logs or Other Reports

Proposed § 3162.3-3(g)(7) allows operators to complete their Subsequent Report Sundry Notice by attaching service contractor job logs or other reports. As an initial matter, this rule is duplicative and unnecessary because operators commonly attach contractor job logs or other reports to comply with state reporting requirements and to complete current BLM Sundry Notification reports. This proposed requirement is also problematic because this rule does not address how the operator certifies the information. BLM states in the Preamble that "[t]he operator is responsible for ensuring the accuracy of any information provided to the BLM even if originally drafted by a third party."[43] As discussed in connection with proposed § 3162.3-3(c)(4), it is not practical for operators to certify information provided by third parties. (*See* Section VI.D) Further, holding operators responsible for information provided by third parties conflicts with existing BLM information certification rules. Currently, BLM holds signatories liable only for knowingly or willingly submitting false, fictitious, or fraudulent requirements to federal governments. BLM should not use this proposed requirement to extend operator liabilities beyond those imposed in current certification requirements.

H. Proposed § 3162.3-3(g)(8): Certification of Treatment Fluid

Proposed § 3162.3-3(g)(8) requires operator certifications that the treatment fluid used was in compliance with applicable law. This proposed requirement is inappropriate for all the reasons discussed in connection with proposed § 3162.3-3(c)(4), *see* Section VI.D, including because the requirement is duplicative and unnecessary. Current state and BLM rules meet the intent of this requirement. For instance, current drilling permit procedures require operator

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[43] 77 Fed. Reg. at 27,698.

certification of the truth of information submitted to agencies. The proposed requirement offers no additional assurance of compliance than that provided under current certification obligations.

To the extent BLM intends to extend operator liability for submitted information, BLM exceeds its authority. As discussed above, BLM cannot require operators to certify information about which they have no knowledge or control. (*See* Section VI.D) The liability imposed by such a requirement would dissuade operators and, perhaps more importantly, the service companies that they rely on, from seeking development opportunities on federal and Indian lands. If BLM decides that a certification, although duplicative, is necessary, BLM should model it after the certification language of the BLM Onshore Order. (*See* Section VI.D)

I. Proposed § 3162.3-3(g)(9): Certification of Wellbore Integrity

Proposed § 3162.3-3(g)(9) requires operator certifications that the wellbore integrity was maintained throughout the operation. For similar reasons as those discussed in connection with proposed § 3162.3-3(g)(8), this is duplicative and inappropriate. The Department of Interior's "Well Completion and Recompletion Report and Log" (Form 3160-4) and "Sundry Notices and Reports on Wells" (Form 3160-5) include self-certification statements that are currently sufficient for the operator to attest to the information described in proposed § 3162.3-3(g)(9) and to transmit that data to BLM. The additional proposed certification thus provides no additional assurance of compliance and is unnecessary.

Even if BLM retains this certification requirement, it should revise the proposed provision. First, the proposed requirement is ambiguous. BLM has failed to define "wellbore integrity" and the phrase "maintained throughout the operation." BLM's incorporation of § 3162.3-3(d) and -3(e) implies that compliance with the mechanical integrity testing and annular pressure monitoring requirements is sufficient to ensure wellbore integrity. BLM provides no engineering or legal basis for adopting this standard.

Additionally, BLM has failed to provide the specific certification language required under this provision. The public, including industry, cannot adequately comment on the certification that has not been provided. Before adopting any certification requirement, BLM should provide the public with an opportunity to review the specific self-certification language and to provide adequate comment.

To fill in these gaps and avoid the problems of requiring certification, BLM should consider modifying either Form 3160-4 or 3160-5 to include a series of well construction and stimulation "check boxes" to confirm accomplishment with industry "best practices." The forms should include the following elements:

- Cement circulated to surface (Yes or No)
- Centralizers run on surface casing (Yes or No) If yes, how many?
- Leak-off test/pressure test confirms hydraulic seal around surface casing shoe (Yes or No)
- Corrective action taken (Yes or No Action Required Upon Further Investigation and Consultation with BLM)
- Annular pressure monitored and recorded through stimulation (Yes or No)[44]

J. Proposed § 3162.3-3(g)(10): Information Concerning the Handling of Recovered Fluids

Proposed § 3162.3-3(g)(10) requires operators to submit information concerning the handling of recovered fluids. This requirement is duplicative and unnecessary. To the extent the proposed requirement requires compliance with Onshore Order Number 7, Disposal of Produced

[44] An increase in annular pressure change of 500 psi is not a definitive indicator of the integrity of the well casing and thus, the requirement to certify the requirement of proposed § 3162.3-3(e)(2) should be removed.

Water, the proposed requirement is duplicative of that order. To the extent the proposed requirement applies to recovered fluids, it is unnecessary because existing state requirements sufficiently regulate flowback.

Additionally, this proposed requirement is unclear regarding the time frame for volume reporting requirements. We suggest that volume reporting should be limited to the volume recovered as of the date the sundry notice is due.

K. Proposed § 3162.3-3(g)(11): Documentation of Deviations

Proposed § 3162.3-3(g)(11) requires documentation and explanation of deviations between the approved well stimulation plan and actual operations. This provision is overly burdensome, and BLM does not have the experience or expertise to implement it.

Before BLM attempts to implement this provision, BLM should first clarify what information operators must submit to comply with proposed § 3162.3-3(g). The Proposed Rule simply requires that "[i]f the actual operations deviate from the approved plan, the deviation(s) must be documented and explained." This blanket requirement does not take into account the numerous potential deviations between the proposed well stimulation plan and the actual operations. Given the complexities of well stimulation and the broad range of information operators must submit under the Proposed Rule, the executed well stimulation is likely to deviate from the proposed plan. For example, after the well is drilled and logged:

- The completion design may be modified;
- The planned number and depth of target zones to be completed in hydrocarbon bearing formations may change;
- The number of stages for hydraulic fracturing treatments may vary;

- The availability of the specific type of proppant from service providers can be uncertain, and may require a change in the proposed proppant;
- The actual source and location of water may vary; and,
- The actual pressures, and fluid volumes used, recovered, and disposed of, are likely to be different.

The Proposed Rule does not explain which of these types of changes must be reported, nor does it provide flexibility in the reporting of these differences in information. A requirement for operators to submit every single one of these deviations regardless of its substance or magnitude would be overly burdensome.

BLM acknowledges that in light of the complexities of well stimulation, it "expects there to be slight differences between the proposed plan and the actual operation."[45] But BLM does not indicate what constitutes a "slight" difference compared to a significant difference requiring BLM approval prior to implementation. Rather than attempt to define and clarify this regulation, ideally BLM should defer to experienced state regulators. State regulations define what constitutes a "deviation," and expert state regulators are able to ascertain the impacts of the deviation. BLM does not have the same resources or enough personnel with the necessary experience. BLM should not create a duplicative regulatory requirement; instead, it should coordinate with existing state regulators to obtain information.

If BLM is unwilling to defer to state regulators on this subject, it should, at a minimum, clarify whether deviations like these (and what other deviations) must be reported. Without clear and explicit language defining a deviation from the proposed stimulation operation, operators

[45] 77 Fed. Reg. at 27,698.

will have difficulty complying and BLM will have difficulty implementing this requirement, which, in turn, is likely to result in drilling delays.

XII. Proposed §§ 3162.3-3(h) and –3(i): Identifying Information Claimed To Be Exempt from Public Disclosures

Proposed §§ 3162.3-3(h) and (i) provide a new process for claiming trade secret or confidential business information ("CBI") protection, and provides that any information for which the operator does not substantiate a reason for withholding on trade secret or CBI grounds shall not be protected and shall instead be released to the public. As stated above in the General Comments, BLM should not create the new disclosure system in the Proposed Rule. It should instead rely on existing disclosure mechanisms set forth in state regulations and FracFocus. If, however, BLM chooses to retain the disclosure requirements in the Proposed Rule, it must significantly revise them to address the many concerns outlined below.

As written, the Proposed Rule would require operators to try to claim exemptions from public disclosure with respect to trade secrets that are the property of other entities. As existing state disclosure schemes appear to recognize, in order to provide adequate protection for proprietary information, the holder of the trade secrets must actually be involved in the process. BLM should, at a minimum, expand the scope of proposed §§ 3162.3-3(h) and (i) to cover more than just "operators".

Second, BLM should clarify the applicable federal statutes or regulations for determining what is exempt or prohibited from disclosure. The proposed rule vaguely incorporates "Federal statutes and regulations," but it does not specify which federal laws are actually included. This is an important omission. Presumably, BLM is referring to the Freedom of Information Act ("FOIA"), the Federal Trade Secrets Act, and its own regulations in 43 C.F.R. part 2, among other authorities. BLM should clarify this, and specifically identify the standards it will use. The regulated community should have clear information as to whether BLM is prohibited by a specific law (*e.g.*, FOIA) from disclosing information or whether BLM retains discretion under some other statute, regulation, or policy to determine whether information ought to be disclosed. Simply put, BLM should clarify the exact standards that it will use to determine whether information will be protected under the Proposed Rule.

Third, BLM should add procedures for regulated entities to contest or appeal BLM determinations – notwithstanding detailed written explanations as to why information is protected from disclosure – to release information to the public. Any such appeal procedures should clarify that information is to remain confidential throughout the dispute period.

Additionally, the 10 business day notice of BLM's determination to release claimed CBI is far too short. BLM should provide at least 60 days of notice and should include a mechanism to extend that time period based on a showing of good cause. By including defined procedures to contest a determination in favor of disclosure and by extending the notice period prior to disclosure, BLM may be able to more efficiently resolve disputes over whether information is protected without costly and time-consuming litigation.

Even if BLM revises the proposed provisions to address the above-referenced deficiencies, it lacks the expertise and personnel to evaluate trade secret claims on a well-by-well basis. By requiring regulated entities to make a detailed showing of why information is protected from disclosure at the time of submission for *each* covered activity, BLM will be inundated by document submissions, legal reviews, and, in all likelihood, litigation. BLM simply does not have the staff or expertise to evaluate those trade secret claims and associated challenges, especially those implicating federal statutes and regulations that it does not enforce.

The consequences of BLM failing to improve its information protection provisions are serious. BLM's proposal effectively asks each regulated entity to entrust its cumulative investment, and its future investment, to a process with an uncertain legal standard. BLM's already overtaxed resources will need to be directed to this process, and BLM personnel do not have experience in evaluating trade secret claims of this nature. BLM is likely to face frequent legal challenges by organizations opposing oil and gas development.

The Proposed Rule would also inhibit the introduction of innovations—*e.g.*, green fracturing fluids, waterless or foam fracturing fluids, synthetic proppants, dry batch blending, solid chemicals. These technologies are geared towards improving the environmental profile of the practice by reducing the chemical profile of fracturing systems, water demand, wastewater, the surface storage and handling of chemicals, air emissions, truck trips and downhole chemical applications. But they are also innovative, proprietary technologies in which companies have invested tremendous resources, and which those companies will be reluctant to risk losing absent robust trade secret protection. Ironically, the use of those environmentally beneficial technologies is likely to be driven from federal lands by a rule that is intended to provide environmental protection.

The balance of these considerations thus weighs heavily in favor of finding an alternative to the disclosure requirements in BLM's Proposed Rule. This is a challenge that states have addressed and overcome by adopting FracFocus, with provisions for disclosure of CBI to the government on an as-requested basis in certain defined circumstances. BLM should do the same.

XIII. Proposed § 3162.3-3(j): Requesting a Variance

Proposed § 3162.3-3(j) provides that operators may request a variance from the requirements of the proposed § 3162.3-3. BLM should clarify the governing standards and the scope of this provision. First, the proposed provision establishes no standards for when a variance may be granted or rejected, or when a variance may be rescinded. Without such standards, the authorized officers will have overly broad authority and there is no assurance that the officers uniformly will apply the variance provision, which undermines BLM's intent to provide a single, unified approach on such issues and creates even greater risk and uncertainty for operators. BLM should also constrain the circumstances in which an authorized officer can rescind or modify a variance. These constraints are necessary because rescinding or modifying a variance that allowed an innovative technique could result in operations being shut down.

BLM should also clarify the scope of the provision. BLM indicates that variances apply only to operational activities and do not apply to the actual approval process.[46] But that statement still leaves unclear what operational activities can be subject to a variance. For example, can a variance apply to one well, or multiple wells in a basin, or for one operator or for all operators in a basin? The regulatory language should more clearly articulate the scope of the provision.

To further explain the scope of the proposed provision, BLM should provide additional examples of potential variance requests. This will allow industry to better understand the effect of the regulation and also to provide comments to BLM. BLM should provide additional examples of its understanding of this provision so that it can receive meaningful comments on their propriety and adjust the regulation accordingly.

[46] 77 Fed. Reg. at 27, 699.

BLM should also establish clear procedures for obtaining and appealing variance decisions. First, BLM should streamline the administrative process for obtaining variances, especially taking into consideration the time constraints and delays that are likely to occur in BLM's processing of approvals. Inconsistencies between BLM and state well stimulation requirements could further exacerbate delays. A streamlined process for obtaining variances could help mitigate the delays caused by such conflicts. Second, BLM should explicitly establish procedures for operators to challenge decisions to rescind or modify variances.

XIV. Proposed § 3162.5-2(d): Control of Wells

Proposed § 3162.5-2(d) relates to the protection of usable water and "other minerals," and requires isolation of usable water and other mineral-bearing formations. The proposed provision requires operators to conduct tests and surveys of the effectiveness of the measures using procedures approved by the authorized officer. BLM should clarify the requirements of this provision.

First, BLM should identify procedures for implementing this requirement, and should also define the term "authorized officer." Current regulations define "authorized representative," but not "authorized officer. 43 C.F.R. § 3106.0-5. It is not clear whether these are intended to be the same person. Second, BLM should clarify whether the operator is required to run CBLs on surface casings, or whether the provision imposes a requirement on operators to protect mineral formations that are already contaminated.

XV. Conclusion

ANGA, AXPC and USOGA appreciate BLM's efforts in responding to stakeholder concerns in connection with the Proposed Rule as well as the opportunity to provide these comments. While the Associations do not support the Proposed Rule, we welcome the opportunity to provide additional input that can help advance what should be the shared objective of expanding safe and responsible domestic energy development on federal lands to the benefit of our nation's environment, economy, and security.

Sincerely,

Regina Hopper
President and CEO
America's Natural Gas Alliance

V. Bruce Thompson
President
American Exploration & Production Council

Albert Modiano
President
U.S. Oil & Gas Association

Appendix A

Analysis of Bureau of Land Management Proposed Rule Impacts on State and Federal Revenues

By: John Dunham & Associates
September 4, 2012

Submitted as part of comments, filed on September 10, 2012, by ANGA, AXPC, and USOGA on BLM's Proposed Rule to Regulate Hydraulic Fracturing on Public and Indian Lands, 77 Fed. Reg. 27,691 (May 11, 2012) 1004-AE26

Analysis of Bureau of Land Management Proposed Rule Impacts on State and Federal Revenues

Prepared for
America's Natural Gas Alliance

By

John Dunham and Associates

New York

September 4, 2012

The US Department of Interior's Bureau of Land Management (BLM) has issued an 81 page proposal that would require that companies drilling new wells for the extraction of petroleum products submit a plan outlining the details of well completion operations for approval prior to performing them.[1] This rule would require significantly more permitting and operational expenses for companies drilling and completing oil and gas wells on federal lands. While BLM claims that the amendments would not constitute a major change in existing regulations, the new rules would add a large number of new requirements for companies exploring for and producing oil and natural gas on federal and Indian lands.

While many of the requirements are simply clarifications or minor additions to the existing permitting process, other components may add significantly to the cost of drilling and completing an oil or gas well. Obviously there will be additional costs to both operators and to the government simply due to the increase in the administrative burden contemplated by these rules. These additional costs would reduce drilling activity since marginal wells would no longer be financially practical to develop. This is particularly true for wells requiring some sort of work-over or retreatment in order to continue to maximize their output. Since the new regulations will also apply to these wells, operators maintaining many of the current 90,452 producible and service drill holes on Federal leases will also experience greatly increased costs over time.

Based on an analysis conducted for the Western Energy Alliance by John Dunham and Associates,[2] and assuming a best case scenario and examining just the wells currently undergoing the permitting process, these regulations would **cost just over $1.284 billion in 13 western states alone.**[3] The average cost per well is estimated at $253,800. This figure does not even include the cost of the regulations for existing wells that will require re-work or re-stimulation. A conservative estimate of this cost is upwards of $233,100 per well or about $273 million per year. Total aggregate annual costs for new permits and workovers would be at least $1.499 billion and as high as $1.615 billion.[4]

These additional costs will lead to a reduction in new drilling which will impact the economies of the 13 states analyzed. There will be a public sector budgetary impact as well, as less domestic petroleum production will reduce both state and federal taxes and royalty payments. Like any business, drilling for and producing oil and natural gas occurs at the margin, this is textbook economics. By increasing the cost of production by as much as $233,000 per well, these regulations will raise the marginal costs while revenues stay the same. Overall fewer wells will

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1 *Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands*, Bureau of Land Management, Proposed Rule RIN 1004-AE26. Available on-line at: www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&pageid=293916.

2 *BLM Fracing Rule Imposes $1.615 Billion Cost to* Society, Western Energy Alliance, News Release, June 12, 2012. Available on-line at: http://westernenergyalliance.org/wp-content/uploads/2009/05/News-Release-Fracing-Rule-Imposes-1.615-Billion-Cost-to-Society.pdf

3 Arizona, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. The model does not include the impact that this regulation would have in the major petroleum producing state of California, Alaska, Oklahoma, Texas or any of the eastern states that may have significant federal lands. This best case scenario model assumes that the BLM approves 100 percent of all applications and that the industry's cost of capital is only 7 percent,

4 For a detailed discussion of how these cost estimates were derived see, *BLM Fracing Rule Imposes $1.615 Billion Cost to* Society, Western Energy Alliance, News Release, June 12, 2012. Available on-line at: http://westernenergyalliance.org/wp-content/uploads/2009/05/News-Release-Fracing-Rule-Imposes-1.615-Billion-Cost-to-Society.pdf

be drilled. The fact that the costs only apply to wells drilled on Federal lands means that governments will give up royalty and leasehold payments in excess of the overall reduction in oil and natural gas production.[5]

Based on this analysis, the proposed BLM regulations will cost as many as 3,970 anticipated new jobs from increased drilling and production nationally, and will reduce potential federal business and personal tax payments by about $73.4 million. On top of this, we estimate that the federal government will lose as much as $1.1 billion in additional royalties and other payments related to the production of oil and natural gas such as bonus bids and lease rental payments for a total of $1.2 billion.

On top of the federal impact, we estimate that the states (and this includes all 50 states) and their localities will see a reduction in anticipated business and personal tax payments of as much as $40.6 million, with another $1.2 billion in lost additional royalties severance tax and other payments related to the production of oil and natural gas.

In total, the proposed BLM regulations could lead to as many as 3,970 job losses, reduce national GDP growth by $1.2 billion, and cost as much as $2.4 billion in federal, state and local government revenues.

Details on the Cost Estimates:

The Bureau of Land Management does not release detailed statistics on pending permits; however, a good estimate of the number of wells impacted by this proposed rule can be developed based on state permitting information. This analysis examines the economic and fiscal impact of the proposed rule in 13 Western states. Based on data from state regulatory authorities, there are approximately 12,300 oil wells, and 14,100 gas wells currently in the process of receiving a permit, or permitted but not yet drilled. Only some of these wells are on Federal or Indian lands, so not all would be required to go through the extra permitting process. In addition, at the present price for oil and natural gas, not all of the wells are economically viable. In fact, in many areas natural gas wells in particular are being capped because the actual cost of production exceeds the price of gas.

The number of effected wells is based on a linear estimate of the number of permits issued over the past 24 years. In addition, the analysis assumes that no wells will be drilled in states where the average profits from either oil or gas plays are less than zero. Based on these limiting assumptions, the proposed regulation would impact about 1,800 currently proposed oil wells, and about 3,250 gas wells. Table 1 below outlines the number of wells currently waiting for permits or for drilling to commence by state, along with an estimate of impacted wells.

[5] This is because the cost structure for drilling on federal lands is already high. A well that generates $1 million in revenues and costs $900,000 on private land might cost $1.1 million to drill on federal land. By increasing the cost on federal lands to $1.3 million, the regulations will reduce overall production; however, they will not impact production on private lands since they do not change the potential costs or revenues.

Table 1
Estimated Oil and Gas Wells Waiting to Be Permitted or Drilled

	Estimated Total			Estimated Impacted		
State	Oil Wells	Gas Wells	Total Wells	Oil Wells	Gas Wells	Total Wells
Arizona	3	1	4	-	-	-
Colorado	3,187	5,718	8,905	212	380	592
Idaho	-	5	5	-	-	-
Montana	398	240	638	63	-	63
Nebraska	106	11	117	-	-	-
Nevada	14	14	27	-	-	-
New Mexico	4,519	2,564	7,083	700	-	700
North Dakota	1,993	6	1,999	99	-	99
Oregon	-	6	6	-	-	-
South Dakota	22	2	24	1	-	1
Utah	1,392	2,098	3,490	252	380	632
Washington	-	3	3	-	-	-
Wyoming	685	3,461	4,146	491	2,480	2,971
Total	12,318	14,129	26,447	1,818	3,240	5,058

This analysis examines only the current impact of the proposed rules – in that they will impact 5,058 existing permits. Since it is virtually impossible to determine the number of new permits that might be applied for in out years following the implementation of these regulations, no calculations have been made regarding future lost drilling opportunities. Were natural gas prices to rise above their current low levels, the resulting number of wells that could be impacted would increase substantially. Were the Federal government to open more areas for oil and gas exploration and leasing, the number could also increase well beyond what is currently considered in this estimate. Recent research conducted for the American Petroleum Institute and America's Natural Gas Alliance suggests that about 93 percent of gas wells are completed with hydraulic fracture, and of these about 1.6 percent require some sort of workover in a given year.[6] Based on these figures, and the number of wells on Federal leases, it is estimated that as many as 1,346 wells per year will also need some sort of workover that falls under these regulations

Based on the data and assumptions presented in the earlier analysis it is possible to calculate the anticipated cost of the proposed rule on the oil and natural gas industry as it impacts the current permit pool. There are two potential ways to calculate this cost. The first assumes that development stops for a period of time while the permitting/verification process takes place. The capital already tied up in the development of the well during this time can be discounted at a reasonable rate of interest which would represent the direct cost to the driller/producer. A second method assumes that the overall cost of completing a well would remain the same; however, there would be a delay to the producer in realizing a return. Under this model, the value of production over the delay period is discounted back representing a lost return on capital.

[6] Shires, Terri and Miriam Lev-On, *Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production*, prepared by URS Corporation and the LEVON Group for the American Petroleum Institute and American's Natural Gas Alliance, June 1, 2012.

While either method can produce a reasonable assumption for the overall cost of the regulations, the magnitude of the difference between them would be impacted by the current market price of petroleum products and capital. In a market where prices are high, the lost return on capital would produce a higher figure, where in a market where interest rates are relatively high, the cost of capital method would produce a more substantial loss estimate. As such, the average value between these two approaches should serve as a good estimate of the cost of the proposed rule.

Based on the first approach and the assumptions outlined above, the total cost of the proposed rule would be just over $1.225 billion, while the second approach leads to a forecast loss of about $1.342 billion. The arithmetic average of these estimates is $1.284 billion which is John Dunham and Associates' estimate of the overall cost to the oil and gas industry of the proposed rule based on the existing wells in the regulatory pipeline. As mentioned above, the rule will impact future operations, it may also have significant costs as long as the industry continues to operate on Federal leases.

Dividing this estimated cost by the number of impacted wells, provides a per well estimate of the cost of the regulations of about $253,800. Obviously this is an average as the costs for a deep horizontal oil well on the Bakken will be significantly higher than that of a shallower vertical gas well drilled on the San Juan Basin. However, the actual per well costs could rise if the regulations were to eliminate the economic incentive for drilling marginal wells. If that were to happen, only deep, horizontal plays with high expected returns may be drilled on federal lands, and more marginal natural gas leases may simply lie fallow.

Table 2
Summary of Estimated Costs by State

	State	Method 1	Method 2	Average
AZ	Arizona	$ -	$ -	$ -
CO	Colorado	$ 140,597,918	$ 144,944,919	$ 142,771,418
ID	Idaho	$ -	$ -	$ -
MT	Montana	$ 15,676,353	$ 17,450,231	$ 16,563,292
NE	Nebraska	$ -	$ -	$ -
NV	Nevada	$ -	$ -	$ -
NM	New Mexico	$ 167,170,616	$ 169,003,720	$ 168,087,168
ND	North Dakota	$ 25,147,180	$ 33,310,119	$ 29,228,649
OR	Oregon	$ -	$ -	$ -
SD	South Dakota	$ 253,752	$ 286,759	$ 270,256
UT	Utah	$ 150,566,431	$ 159,886,215	$ 155,226,323
WA	Washington	$ -	$ -	$ -
WY	Wyoming	$ 726,475,894	$ 817,064,564	$ 771,770,229
Total	Total 13 States	$ 1,225,888,144	$ 1,341,946,527	$ 1,283,917,335

Costs from Reworking Existing Oil and Gas Wells:

Since the new regulations will also apply to maintenance stimulation of existing wells, operators maintaining many of the current 90,452 producible and service drill holes on Federal leases will also experience greatly increased costs over time.[7] Assuming that wells require stimulation in line with figures recently calculated for the American Petroleum Institute, as many as 1,171 wells in the subject states will require workover in a given year.[8]

Assuming that workovers can be rescheduled to minimize the costs and delays that will come about due to the proposed rules, and that operators already perform integrity tests prior to re-stimulation, these projects will incur additional costs equal to over $233,100 per well for the first re-stimulation event for all existing wells. Since it is difficult to determine the actual number of wells on federal lands that will be cost effective to maintain once these regulations are in effect, this analysis examines the costs for only one year. Assuming, therefore, that 1,171 wells on federal leaseholds will require re-work, the cost of the regulations for just workovers will be almost $273.0 million. This figure will only increase as wells require re-work or new stimulation activities over time.

In sum, the above analysis suggests that these proposed regulations will have a significant impact on the oil and gas production industry even without considering future discounted costs.

Baseline Economic Impact:

Once the overall costs are calculated they can be used to estimate the economic impact of the proposed regulations. These estimates are based again on work conducted for the Western Energy Alliance by John Dunham and Associates.[9] In this case we calculate how these increased costs will affect the baseline economic impact of the industry in each state. The *Western Oil and Natural Gas Industry 2012 Economic Impact Study* estimates the economic contributions made by the oil and gas exploration and production industry to the U.S. economy in 2012. John Dunham and Associates conducted this research, which was funded by Western Energy Alliance. This work used standard econometric models first developed by the U.S. Forest Service, and now maintained by the Minnesota IMPLAN Group. Data came from industry sources, government publications and Dun and Bradstreet, Inc.

The study defines the Western Energy Industry as those firms involved in the exploration, leasing, drilling, completion, production, field services and processing, segments of the oil and gas industry in 13 western states.[10] The study measures the number of jobs in this sector; the wages paid to employees, the value added and total output.

The Western Oil and Natural Gas Industry is a dynamic part of the U.S. economy, accounting for about $51.1 billion in output or roughly 0.3 percent of GDP. Western oil and gas producers directly or indirectly employed approximately 229,100 Americans in 2012. These workers earned almost $15.5 billion in wages and benefits. Members of the industry and their employees

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7 See: US Bureau of Land Management, *Well Stimulation Proposed Rule: Economic Analysis and Initial Regulatory Flexibility Analysis*, at: www.regulations.gov/#!documentDetail;D=BLM-2012-0001-0003.

8 Shires, Terri and Miriam Lev-On, *Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production*, prepared by URA Corporation and the LEVON Group for the American Petroleum Institute and American's Natural Gas Alliance, June 1, 2012.

9 For more detail on the economic impact analysis see *Western Oil and Natural Gas Employs America* at: http://westernenergyalliance.org/employsamerica/

10 Throughout this analysis, the "western states" are defined as: Arizona, Colorado, Idaho, Montana, Nebraska, New Mexico, Nevada, North Dakota, Oregon, South Dakota, Utah, Washington and Wyoming.

paid $5.8 billion in direct federal, state and local taxes, and nearly $7.2 billion in production related levies.

The oil and gas industry includes not only companies that directly drill for and produce oil and natural gas in the western United States, but the operations of hundreds of companies that manage leaseholds, explore for and quantify oil and gas resources, provide field services, and perform initial on-site natural gas refining operations. This includes major integrated energy firms like ExxonMobil and Chevron, but also thousands of smaller companies located throughout the region that provide a range of services from well completion, to drilling, to field reclamation. All told, the firms in the region employ 57,960 people in either on-site operations or at their office locations.

The vast majority of these employees are involved in drilling and production activities. These include a wide range of workers, from roughnecks on the wells, to pipefitters, to skilled chemists that complete wells. In addition, thousands of scientists, geologists, engineers and chemists design the wells and determine how and where they will be drilled. We estimate that there are over 3,900 firms involved in drilling and production activities in the 13 western states[11] that employ nearly 50,400 people.

In addition to these workers, there are hundreds of workers employed by other companies that are directly involved in the production of oil and gas. These include over 910 people working in on-field refining operations that separate usable liquid products from natural gas. Another 3,600 people are involved in field operations including carpenters that set up temporary on-site housing and office facilities, electricians that set up temporary electrical services, and geologists, landscapers and environmental engineers that reclaim drilling sites to their original conditions. As many as 2,400 truck drivers, pipefitters and welders (among others) are directly involved in moving water, sand, and produced petroleum products around the oil fields,[12] and another nearly 700 people work in companies that are involved in the financial side of oil and gas production – providing financing and leasing services.

Other firms are related to the oil and gas production industry as suppliers. These firms produce and sell a broad range of items including pipe, pump jacks, generators, sand, drill-bits and electronics used in the production process. In addition, supplier firms provide a broad range of services, including personnel services, financial services, engineering services, consulting services environmental services, or even transportation services. Finally, a number of people are employed in government enterprises responsible for the regulation of the oil and gas industry. All told, we estimate that the Western Oil and Natural Gas industry is responsible for 57,650 supplier jobs with these firms generating about $12.5 billion in economic activity.

This economic analysis of the oil and gas production industry also takes additional linkages into account. While it is inappropriate to claim that suppliers to the supplier firms are part of the industry being analyzed[13] the spending by employees of the industry and those of supplier firms whose jobs are directly dependent on oil and natural gas sales and production, should surely be included. This spending on everything from housing, to food, to educational services and

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11 Physical locations.

12 This does not include those truck drivers, railroad workers or pipeline operators involved in the distribution of oil and gas from the fields to off-site refineries or tank farms.

13 These firms would more appropriately be considered as part of the supplier firms' industries.

medical care makes up what is traditionally called the "induced impact" or multiplier effect of the industry. In other words, this spending, and the jobs it creates is induced by the exploration and production of oil and gas in the western states. We estimate that the induced impact of the industry is just over $16.0 billion, and generates 113,540 jobs, for a multiplier of about 1.96.[14]

Table 3
Summary of Economic Impact of the Oil and Natural Gas Industry

($ In Billions)	Direct	Supplier	Induced	Total
Output	$22.559	$12.511	$16.006	$51.077
Jobs	57,960	57,650	113,540	229,150
Wages	$5.922	$4.112	$5.464	$15.498
Taxes				$5.834

Translating Costs into Impacts:

An important part of an impact analysis is the calculation of the contribution of the industry to the public finances of the community. In the case of the oil and gas industry, the traditional direct taxes paid by the firms and their employees provide over $5.8 billion in revenues to the federal, state and local governments. In addition to this, producers and leaseholders pay state severance taxes, royalties and lease payments equal to nearly $7.2 billion.[15]

Table 3 above presents a summary of the total economic impact of the industry in the United States. Summary tables for each state are included in the Appendix.

The higher costs imposed by the regulations will directly lead to lower production on federal lands, which in turn will reduce both the economic and fiscal impacts of the industry. This is not a one-to-one relationship, since the higher regulatory costs will not impact all of the production inputs equally.

For this model, we calculated the percentage of production costs accounted for by direct inputs into the process including consulting fees, cement, steel, etc. These percentages were calculated for each direct industry type (for example drilling or field services) and for each of the 13 states based on data from the IMPLAN model.[16]

Once the impact percentages are calculated, they are applied to the changes in costs for each state to derive the loss in new production that would have occurred in the absence of the regulations. Again, this reduction would occur as marginal projects are abandoned due to the

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[14] Often economic impact studies present results with very large multipliers – as high as 4 or 5. These studies invariably include the firms supplying the supplier industries as part of the induced impact. John Dunham and Associates believes that this is not an appropriate definition of the induced impact and as such limits this calculation to only the effect of spending by direct and supplier employees.

[15] This figure is not generated by the economic impact mode. It comes from state departments of revenue, and natural resources, as well as from the US Department of Interior, Bureau of Land Management, and represents data for fiscal year 2011, the last year which is currently available.

[16] IMPLAN was originally developed by the US Forest Service, the Federal Emergency Management Agency and the Bureau of Land Management. It was converted to a user-friendly model by the Minnesota IMPLAN Group in 1993. This model uses the 2010 IMPLAN input/output tables.

higher costs. Since the cost structure of projects on private land are not impacted, there would not be a large offsetting increase in non-federal drilling.[17] Jobs and wages are directly related to the level of production based on an output per employee ratio that is unique to each industry and state. As such lost job growth and wage growth can be calculated based on the existing employee/output and wage/employee ratios.

Table 4
Summary of Economic and Fiscal Cost of Proposed BLM Regulations

	Direct	Supplier	Induced	Total
Jobs	695	1,385	1,893	3,973
Wages	$ 78,883,000	$ 97,577,000	$ 85,413,000	$ 261,873,000
Output	$ 658,144,000	$ 314,132,000	$ 259,178,000	$ 1,231,454,000

	Federal	State/Local	Total
Business/ Personal Taxes	$ 73,367,000	$ 40,579,000	$ 113,946,000
Royalties/ Production Taxes	$ 1,088,130,000	$ 1,190,149,000	$ 2,278,279,000

Just as direct employment and wages are based on production, so too are supplier and induced industry effects. In this case anticipated growth in supplier jobs, output and wages would fall based on the anticipated loss in new production in each of the 13 states, with out-of-state suppliers also being impacted. Induced effects come about due to the re-spending by direct and supplier industry employees so reductions in the anticipated growth of these impacts is directly related to reductions in wages across all direct and supplier categories.

Table 4 above outlines all of these impacts.

Finally, the reductions in expected production will lead to lower growth in tax revenues not only from royalties and severance levies, but also from reduced employment, wages and profits. Business and personal taxes are calculated using the IMPLAN model and reflect changes in anticipated job, wage and output growth. Lower employment levels reduce personal income, social security, property and excise taxes, while reduced drilling activity leads to lower corporate profit and sales taxes.

Reductions in royalty and severance payments are more difficult to calculate, but are based on average production in existing oil and natural gas wells in each state. The economic impact model includes total royalty and severance tax receipts for the federal government and for each state. These are divided by the number of existing producing wells to provide an estimated average royalty/severance tax payment per well.

Since the new regulation will reduce the number of new wells drilled, and therefore the amount of oil and natural gas production, there will be fewer royalty and severance tax payments. This

17 There would be some increase as lower demand for drilling rigs, and crews would reduce costs; however, that is impossible to calculate based on available data.

is estimated by multiplying the average current per well payment by the estimated number of new wells that would not be drilled if the higher costs imposed by the proposed rules were to be realized. Most of the reduction is due to less drilling for natural gas on federal lands simply because the current low price for gas at the wellhead makes many of these projects marginal to begin with.

It should be noted that the estimated royalty payments are based on current per well revenues. Were the wells currently in the permitting process to be more productive on average these payments would be larger; however, if most of the abandoned projects were in fact marginal producers the estimated lost royalty payments could be somewhat lower.

As mentioned above, the reduction in royalty and tax revenues as well as reduced economic activity will also impact individual states, particularly those with significant portions of federal land. Appendix A includes a summary of anticipated employment and economic activity impacts and the corresponding reduction in tax and royalty revenues. These state summaries were developed using the same methodologies and models used for the federal impact assessment.

APPENDIX
Individual States

The Bureau of Land Management's Proposed Rule to Regulate Hydraulic Fracturing on Public and Indian Lands could reduce the number of new wells drilled in Colorado. Considering that federal and Indian lands make up over 40 percent of Colorado's land area, these new rules could put a damper on new energy production in the state.

Based on analysis conducted for the Western Energy Alliance, these regulations could increase production costs on new wells in Colorado by as much as $142.8 million. This will slow the growth of the drilling, field services and production industries throughout the state.

The Economic Impact of the Oil and Natural Gas Industry in Colorado

	Direct	Supplier	Induced	Total
Jobs	16,792	14,585	17,521	48,898
Wages	$2,108,880,000	$1,100,685,000	$2,009,001,000	$5,218,566,000
Economic Activity	$5,259,022,000	$2,803,424,000	$5,210,508,000	$13,272,954,000

The oil and natural gas industry supports as many as 48,900 jobs in Colorado, providing those workers with $5.2 billion in wages. Nearly $835.2 million in state and local tax revenues are generated from oil and natural gas companies, workers and production.

Were the BLM regulations to be implemented, it is expected that as many as 376 new jobs in Colorado would go by the wayside, and that the growth of total economic activity in the state would fall by as much as $109.6 million. This is due to the loss in production from wells currently under consideration. It does not take into account future oil and natural gas plays that could have occurred in the absence of the regulations, which would make the impact even greater.

The Economic Cost of BLM Regulations in Colorado

	Direct	Supplier	Induced	Total
Jobs	113	123	139	376
Wages	$16,194,000	$9,307,000	$15,963,000	$41,464,000
Economic Activity	$44,469,000	$23,705,000	$41,400,000	$ 109,574,200

	State	Federal	Total
Business Taxes	$5,113,000	$6,389,000	$13,349,000
Production Taxes	$13,294,000	$21,977,000	$35,270,000

This reduction in employment and economic activity will result in an estimated loss of $5.1 million in new business and personal tax revenues.

In addition, based on the higher production costs, it is estimated that reduced activity from foregone wells would lead to a $13.3 million loss in potential new state production royalties and taxes.

The Bureau of Land Management's Proposed Rule to Regulate Hydraulic Fracturing on Public and Indian Lands could reduce the number of new wells drilled in Montana. Considering that federal and Indian lands make up almost 35 percent of Montana's land area, these new rules could put a damper on new energy production in the state.

Based on an analysis conducted for the Western Energy Alliance, these regulations could increase production costs on new wells in Montana by as much as $16.6 million. This will slow the growth of the drilling, field services and production industries throughout the state.

The Economic Impact of the Oil and Natural Gas Industry in Montana

	Direct	Supplier	Induced	Total
Jobs	1,845	1,351	1,599	4,796
Wages	$179,840,000	$71,675,000	$126,373,000	$377,888,000
Economic Activity	$934,438,000	$219,395,000	$381,572,000	$1,535,405,000

The oil and natural gas industry supports as many as 4,796 jobs in Montana, providing those workers with $377.9 million in wages. Nearly $91.5 million in state and local tax revenues are generated from oil and natural gas companies, workers and production.

Were the BLM regulations to be implemented, it is expected that as many as 30 new jobs in Montana would go by the wayside, and that the growth of total economic activity in the state would fall by as much as $13.0 million. This is due to the loss in production from wells currently under consideration. It does not take into account future oil and natural gas plays that could have occurred in the absence of the regulations, which would make the impact even greater.

The Economic Cost of BLM Regulations in Montana

	Direct	Supplier	Induced	Total
Jobs	8	12	10	30
Wages	$919,000	$658,000	$792,000	$2,369,000
Economic Activity	$8,573,000	$2,013,000	$2,392,000	$12,977,000

	State	Federal	Total
Business Taxes	$330,000	$671,000	$1,001,000
Production Taxes	$7,097,000	$8,757,000	$15,854,000

This reduction in employment and economic activity will result in an estimated loss of $330,000 in new business and personal tax revenues.

In addition, based on the higher production costs, it is estimated that reduced activity from foregone wells would lead to a $7.1 million loss in potential new state production royalties and taxes.

The Bureau of Land Management's Proposed Rule to Regulate Hydraulic Fracturing on Public and Indian Lands could reduce the number of new wells drilled in New Mexico. Considering that federal and Indian lands make up nearly 46 percent of New Mexico's land area, these new rules could put a damper on new energy production in the state.

Based on an analysis conducted for the Western Energy Alliance, these regulations could increae production costs on new wells in New Mexico by as much as $168.1 million. This will slow the growth of the drilling, field services and production industries throughout the state.

The Economic Impact of the Oil and Natural Gas Industry in New Mexico

	Direct	Supplier	Induced	Total
Jobs	10,819	6,460	6,970	24,248
Wages	$864,835,000	$377,725,000	$699,997,000	$1,942,557,000
Economic Activity	$2,667,498,000	$958,728,000	$1,790,239,000	$5,416,466,000

The oil and natural gas industry supports as many as 24,250 jobs in New Mexico, providing those workers with $1.9 billion in wages. Nearly $1.2 billion in state and local tax revenues are generated from oil and natural gas companies, workers and production.

Were the BLM regulations to be implemented, it is expected that as many as 386 new jobs in New Mexico would go by the wayside, and that the growth of total economic activity in the state would fall by as much as $90.2 million. This is due to the loss in production from wells currently under consideration. It does not take into account future oil and natural gas plays that could have occurred in the absence of the regulations, which would make the impact even greater.

This reduction in employment and economic activity will result in an estimated loss of $3.4 million in new business and personal tax revenues.

The Economic Cost of BLM Regulations in New Mexico

	Direct	Supplier	Induced	Total
Jobs	165	110	111	386
Wages	$13,430,000	$6,421,000	$11,183,000	$31,034,000
Economic Activity	$45,346,000	$16,298,000	$28,600,000	$90,244,000

	State	Federal	Total
Business Taxes	$3,387,000	$6,389,000	$9,776,000
Production Taxes	$123,920,000	$117,563,000	$241,483,000

In addition, based on the higher production costs, it is estimated that reduced activity from foregone wells would lead to a $123.9 million loss in potential new state production royalties and taxes.

The Bureau of Land Management's Proposed Rule to Regulate Hydraulic Fracturing on Public and Indian Lands could reduce the number of new wells drilled in North Dakota. Considering that federal and Indian lands make up nearly 8 percent of North Dakota's land area, these new rules could put a damper on new energy production in the state.

Based on an analysis conducted for the Western Energy Alliance, these regulations could increase production costs on new wells in North Dakota by as much as $29.2 million. This will slow the growth of the drilling, field services and production industries throughout the state.

The Economic Impact of the Oil and Natural Gas Industry in North Dakota

	Direct	Supplier	Induced	Total
Jobs	8,022	5,613	5,825	19,460
Wages	$825,614,000	$337,653,000	$588,999,000	$1,752,266,000
Economic Activity	$2,212,830,000	$843,590,000	$1,503,607,000	$4,560,027,000

The oil and natural gas industry supports as many as 19,500 jobs in North Dakota, providing those workers with $1.8 billion in wages. Nearly $1.5 billion in state and local tax revenues are generated from oil and natural gas companies, workers and production.

Were the BLM regulations to be implemented, it is expected that as many as 58 new jobs in North Dakota would go by the wayside, and that the growth of total economic activity in the state would fall by as much as $13.8 million. This is due to the loss in production from wells currently under consideration. It does not take into account future oil and natural gas plays that could have occurred in the absence of the regulations, which would make the impact even greater.

The Economic Cost of BLM Regulations in North Dakota

	Direct	Supplier	Induced	Total
Jobs	23	17	17	58
Wages	$2,472,000	$1,018,000	$1,767,000	$5,258,000
Economic Activity	$6,672,000	$2,544,000	$4,512,000	$13,727,000

	State	Federal	Total
Business Taxes	$758,000	$1,082,000	$1,840,000
Production Taxes	$63,803,000	$15,473,000	$79,276,000

This reduction in employment and economic activity will result in an estimated loss of $758,000 in new business and personal tax revenues.

In addition, based on the higher production costs, it is estimated that reduced activity from foregone wells will lead to a $63.8 million loss in potential new state production royalties and taxes.

The Bureau of Land Management's Proposed Rule to Regulate Hydraulic Fracturing on Public and Indian Lands could reduce the number of new wells drilled in South Dakota. Considering that federal and Indian lands make up nearly 14 percent of South Dakota's land area, these new rules could put a damper on new energy production in the state.

Based on an analysis conducted for the Western Energy Alliance, these regulations could increase production costs on new wells in South Dakota by as much as $270,256. This will slow the growth of the drilling, field services and production industries throughout the state.

The Economic Impact of the Oil and Natural Gas Industry in South Dakota

	Direct	Supplier	Induced	Total
Jobs	86	71	227	384
Wages	$3,443,000	$3,488,000	$4,536,000	$11,467,000
Economic	$14,556,000	$13,931,000	$18,951,000	$47,438,000

The oil and natural gas industry supports as many as 384 jobs in South Dakota, providing those workers with $11.5 million in wages. Nearly $9.1 million in state and local tax revenues are generated from oil and natural gas companies, workers and production.

Were the BLM regulations to be implemented, it is expected that as many as 2 new jobs in South Dakota would go by the wayside, and that the growth of total economic activity in the state would fall by as much as $238,000. This is due to the loss in production from wells currently under consideration. It does not take into account future oil and natural gas plays that could have occurred in the absence of the regulations, which would make the impact even greater.

This reduction in employment and economic activity will result in an estimated loss of $4,000 in new business and personal tax revenues.

The Economic Cost of BLM Regulations in South Dakota

	Direct	Supplier	Induced	Total
Jobs	0	0	1	2
Wages	$17,000	$18,000	$23,000	$58,000
Economic Activity	$73,000	$70,000	$95,000	$238,000

	State	Federal	Total
Business Taxes	$4,000	$8,000	$12,000
Production Taxes	$412,000	$90,000	$502,000

In addition, based on the higher production costs, it is estimated that reduced activity from foregone wells would lead to a $412,000 loss in potential new state production royalties and taxes.

The Bureau of Land Management's Proposed Rule to Regulate Hydraulic Fracturing on Public and Indian Lands could reduce the number of new wells drilled in U tah. Considering that federal and Indian lands make up nearly 72 percent of Utah’s land area, these new rules could put a damper on new energy production in the state.

Based on an analysis conducted for the Western Energy Alliance, these regulations could increase production costs on new wells in Utah by as much as $155.2 million. This will slow the growth of the drilling, field services and production industries throughout the state.

The Economic Impact of the Oil and Natural Gas Industry in Utah

	Direct	Supplier	Induced	Total
Jobs	4,644	5,102	5,407	15,153
Wages	$438,305,000	$294,920,000	$534,972,000	$1,268,197,000
Economic Activity	$2,005,382,000	$795,255,000	$1,405,169,000	$4,205,806,000

The oil and natural gas industry supports as many as 4,644 jobs in Utah, providing those workers with $438.3 million in wages. Nearly $219.9 million in state and local tax revenues are generated from oil and natural gas companies, workers and production.

Were the BLM regulations to be implemented, it is expected that as many as 450 new jobs in Utah would go by the wayside, and that the growth of total economic activity in the state would fall by as much as $151.3 million. This is due to the loss in production from wells currently under consideration. It does not take into account future oil and natural gas plays that could have occurred in the absence of the regulations, which would make the impact even greater.

The Economic Cost of BLM Regulations in Utah

	Direct	Supplier	Induced	Total
Jobs	89	199	163	450
Wages	$10,591,000	$11,483,000	$16,105,000	$38,179,000
Economic Activity	$78,080,000	$30,964,000	$42,303,000	$151,347,000

	State	Federal	Total
Business Taxes	$5,195,000	$7,754,000	$12,949,000
Production Taxes	$12,236,000	$68,631,000	$80,868,000

This reduction in employment and economic activity will result in an estimated loss of $5.2 million in new business and personal tax revenues.

In addition, based on the higher production costs, it is estimated that reduced activity from foregone wells would lead to a $12.2 million loss in potential new state production royalties and taxes.

The Bureau of Land Management's Proposed Rule to Regulate Hydraulic Fracturing on Public and Indian Lands could reduce the number of new wells drilled in Wyoming. Considering that federal and Indian lands make up nearly 53 percent of Wyoming's land area, these new rules could put a damper on new energy production in the state.

Based on an analysis conducted for the Western Energy Alliance, these regulations could increase production costs on new wells in Wyoming by as much as $771.8 million dollars. This will slow the growth of the drilling, field services and production industries throughout the state.

The Economic Impact of the Oil and Natural Gas Industry in Wyoming

	Direct	Supplier	Induced	Total
Jobs	12,531	7,889	6,304	26,724
Wages	$1,244,916,000	$470,053,000	$723,137,000	$2,438,105,000
Economic Activity	$8,521,038,000	$1,427,172,000	$2,175,327,000	$12,123,537,000

The oil and natural gas industry supports as many as 26,720 jobs in Wyoming, providing those workers with $2.4 billion in wages. Nearly $1.6 billion in state and local tax revenues are generated from oil and natural gas companies, workers and production.

Were the BLM regulations to be implemented, it is expected that as many as 962 new jobs in Wyoming would go by the wayside, and that the growth of total economic activity in the state would fall by as much as $632.4 million. This is due to the loss in production from wells currently under consideration. It does not take into account future oil and natural gas plays that could have occurred in the absence of the regulations, which would make the impact even greater

This reduction in employment and economic activity will result in an estimated loss of $11.6 million in new business and personal tax revenues.

The Economic Cost of BLM Regulations in Wyoming

	Direct	Supplier	Induced	Total
Jobs	296	440	226	962
Wages	$35,259,000	$26,199,000	$25,915,000	$87,373,000
Economic Activity	$474,930,000	$79,545,000	$77,956,000	$632,432,000

	State	Federal	Total
Business Taxes	$11,638,000	$27,524,000	$39,162,000
Production Taxes	$969,387,000	$855,639,000	$1,825,026,000

In addition, based on the higher production costs, it is estimated that reduced activity from foregone wells would lead to a $969.4 million loss in potential new state production royalties and taxes.

Appendix B

Business Impact of Proposed Changes to Well Completion Regulations

By: John Dunham & Associates
June 11, 2012

Submitted as part of comments, filed on September 10, 2012, by ANGA, AXPC, and USOGA on BLM's Proposed Rule to Regulate Hydraulic Fracturing on Public and Indian Lands, 77 Fed. Reg. 27,691 (May 11, 2012) 1004-AE26

MEMORANDUM

TO: Kathleen Sgamma, VP of Government & Public Affairs, Western Energy Alliance
FROM: John Dunham, Managing Partner
DATE: June 11, 2012
RE: Business Impact of Proposed Changes to Well Completion Regulations

As per your request, we have examined the impact of a proposal that would require that companies drilling new wells for the extraction of petroleum products submit a plan outlining the details of well completion operations for approval prior to performing them. The proposed regulation is being promulgated by the US Department of Interior's Bureau of Land Management (BLM) and as currently written would apply only to federal wells on or impacting Federal and Indian lands, or split estate lands. However, this definition is remarkably broad and could potentially be applied to companies drilling on private lands in the western states.[1]

In fact, assuming a best case scenario, where the BLM approves 100 percent of all applications and assuming capital costs of only 7 percent, these regulations – if applied to all projects in the western states – would cost at least $1.226 billion annually based on the carrying costs of the project. Based on the discounted lost value of petroleum output, the proposed regulations would cost about $1.342 billion annually. Averaging these two methods together suggests that a reasonable estimate for the cost of this proposed rule as applied to drilling in the western states is just over $1.284 billion. The average cost per well is estimated at $253,800. This figure does not even include the cost of the regulations for existing wells than will require re-work or re-stimulation. A conservative estimate of this cost is upwards of $233,100 per well or about $273 million per year. **Total aggregate annual costs for new permits and workovers would be at least $1.499 billion and as high as $1.615 billion.**

Proposed Regulation and Background:

The US Department of the Interior, Bureau of Land Management (BLM) recently proposed amendments to current regulations (43 CFR 3160.0-3) that would require significantly more permitting and operational expenses for companies drilling and completing oil and gas wells on federal lands.[2] While BLM claims that the amendments would not constitute a major change in existing regulations, the new rules would add a large number of new requirements for companies exploring for, and producing, oil and natural gas on federal and Indian lands. This rule change would among other things require operators to:

- Provide additional information and meet new requirements for all well stimulation (completion) activity when applying for a permit to drill (APD). A similar application would need to be filed prior to performing additional stimulation on an existing well. The BLM would have to review and verify the additional completions requirements when approving these permits.
- Submit additional cement bond logs for review and approval prior to completing the well.

[1] For the purpose of this analysis the western states include: Arizona, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming

[2] Bureau of Land Management proposed rule RIN 1004-AE26: Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands

- Report the specific source of water used in well completion operations.
- Submit a detailed engineering design and other information related to well stimulation operations to the BLM for approval.
- Submit detailed information related to how they will handle or treat all recovered fluids from well stimulation activities.
- Perform a successful mechanical integrity test prior to commencing any well completion activities.
- Store detail to the agency how recovered fluids are disposed of.

While many of the requirements are simply clarifications or minor additions to the existing permitting process, other components may add significantly to the cost of drilling and completing an oil or gas well. Obviously there will be additional costs to both operators and to the government simply due to the increase in the administrative burden contemplated by these rules. The potential for delay resulting not from any direct operational activity, but rather from waiting for permits and paperwork to be processed, could lead to significant financial costs for both operators and investors.[3] While any additional costs would reduce drilling activity (since marginal wells would no longer be financially practical to develop), were these costs to be high enough they could preclude companies from developing any additional resources on BLM-controlled or impacted land. This is particularly true for wells requiring some sort of workover or retreatment in order to continue to maximize their output. Since the new regulations will also apply to these wells, operators maintaining many of the current 90,452 producible and service drill holes on Federal leases will also experience greatly increased costs over time.[4]

Currently, once a company has obtained a lease for mineral extraction on Federal lands, and once it has completed a lengthy environmental analysis under the National Environmental Policy Act (NEPA) process, it must apply for a permit to actually begin drilling. The Energy Policy Act of 2005 specifies that BLM must approve Applications for Permit to Drill (APD) within thirty days, yet according to Bob Abby, the Director of the Bureau of Land Management, the average permit time is 298 days, [5] and depending on the field office, it is not that uncommon for APDs to take years.[6] In addition, data on the number of actual permits outstanding is not generally available in a timely fashion from BLM, making it difficult to estimate the actual amount of time needed to currently process a permit; however, the agency expects to process 5,500 APDs in fiscal year 2012 under the existing regulatory structure.[7]

Estimated Number of Wells Impacted by the Proposed Regulation:

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3 BLM already takes about 10 months to approve an APD and there is a substantial backlog.

4 See: US Bureau of Land Management, *Well Stimulation Proposed Rule: Economic Analysis and Initial Regulatory Flexibility Analysis*, at: www.regulations.gov/#!documentDetail;D=BLM-2012-0001-0003.

5 Cappiello, Dina, *New process to expedite drilling on public lands*, Associated Press, April 3, 2012. On-line at: www.newsvine.mobi/_news/2012/04/03/11002223-new-process-to-expedite-drilling-on-public-lands

6 Sgamma, Kathleen, Vice President of Government & Public Affairs, Western Energy Alliance, *Testimony Before the House Natural Resources Committee Subcommittee on Energy and Mineral Resources Legislative Hearing on H.R. 4381, H.R. 4382 and H.R. 4383*, April 26, 2012.

7 *Secretary Salazar Visits North Dakota's Oil Boom; Unveils Initiatives to Accelerate Drilling Permits and Leases on Federal Lands*, US Department of Interior, Bureau of Land Management, Press Release, April 3, 2012, available at: www.blm.gov/wo/st/en/info/newsroom/2012/april/nr_04_03_2012.html

The Bureau of Land Management does not release detailed statistics on pending permits, however, a good estimate of the number of wells impacted by this proposed rule can be developed based on state permitting information. This analysis examines the impact of the proposed rule in 13 Western states.[8] Based on data from state regulatory authorities, there are approximately 12,300 oil wells, and 14,100 gas wells currently in the process of receiving a permit, or permitted but not yet drilled. Only some of these wells are on Federal or Indian lands, so not all would be required to go through the extra permitting process. In addition, at the present price for oil and natural gas, not all of the wells are economically viable. In fact, in many areas natural gas wells in particular are being capped because the actual cost of production exceeds the price of gas.

This analysis examines these wells as individual units at the state level. It estimates the number on federal permit lands based on a linear estimate of the number of permits issued over the past 24 years. In addition, the analysis assumes that no wells will be drilled in states where the average profits from either oil or gas plays are less than zero. Based on these limiting assumptions, the proposed regulation would impact about 1,800 currently proposed oil wells, and about 3,250 gas wells. Table 1 below outlines the number of wells currently waiting for permits or for drilling to commence by state, along with an estimate of impacted wells.

Table 1
Estimated Oil and Gas Wells Waiting to Be Permitted or Drilled

	Estimated Total			Estimated Impacted		
State	Oil Wells	Gas Wells	Total Wells	Oil Wells	Gas Wells	Total Wells
Arizona	3	1	4	-	-	-
Colorado	3,187	5,718	8,905	212	380	592
Idaho	-	5	5	-	-	-
Montana	398	240	638	63	-	63
Nebraska	106	11	117	-	-	-
Nevada	14	14	27	-	-	-
New Mexico	4,519	2,564	7,083	700	-	700
North Dakota	1,993	6	1,999	99	-	99
Oregon	-	6	6	-	-	-
South Dakota	22	2	24	1	-	1
Utah	1,392	2,098	3,490	252	380	632
Washington	-	3	3	-	-	-
Wyoming	685	3,461	4,146	491	2,480	2,971
Total	12,318	14,129	26,447	1,818	3,240	5,058

This of course represents only one moment in time. Were natural gas prices to rise above their current low levels, the resulting number of wells that could be impacted would increase substantially. In addition, were the Federal government to open more areas for oil and gas

8 Arizona, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming.

exploration and leasing the number could also increase well beyond what is currently considered in this analysis. In fact, according to a report by the Congressional Research Service oil production on federal on-shore leaseholds was down slightly between 2007 and 2011.[9]

According to the BLM in its cursory examination of the benefits and costs of these proposed regulations, approximately 3,100 wells would be impacted each year. This analysis examines only the current impact of the proposed rules – in that they will impact 5,058 existing permits. No assumptions are made as to future permits on either existing or future leases or costs incurred on existing wells that may need future stimulation or acidization. Recent research conducted for the American Petroleum Institute suggests that about 93 percent of gas wells are completed with hydraulic fracture, and of these about 1.6 percent require some sort of work-over in a given year.[10] Based on these figures, and the number of wells on Federal leases, it is estimated that as many as 1,346 wells per year will need some sort of rework that falls under these regulations

Model Data and Assumptions:

This model was developed for the Western Energy Alliance by John Dunham and Associates (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 in detailed below:

<u>Average Drilling Costs</u> are estimated based on data derived from the US Department of Commerce, Bureau of Economic Analysis, by the Minnesota IMPLAN Group in 2010. These data come from the Input/Output accounts of the United States. These data present detailed figures on the input costs for oil and gas well drilling including wages, capital costs, leasing costs, and costs of various materials and services used in the drilling and completion of oil and gas wells. The data are from 2010. 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 as the wellhead in each state as of 2011 which are the latest data available. Annual average prices and production volumes by state are gathered from the US Department of Energy.[11] Costs are divided between exploration/leasing/permitting, drilling and completion based on the type of input and labor costs are divided based on input commodity and service costs with about 52.4 percent of the drilling/completion cost assumed to be for drilling and the rest for completion.[12]

<u>Production Costs</u> are estimated based on data derived from the US Department of Commerce, Bureau of Economic Analysis by the Minnesota IMPLAN Group in 2010. These data come

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[9] Humphries, Marc, *U.S. Crude Oil Production in Federal and Non-Federal Areas*, Congressional Research Service, March 20, 2012, at: http://cnsnews.com/sites/default/files/documents/CRSreport%20Oil%20Production.pdf

[10] Shires, Terri and Miriam Lev-On, *Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production*, prepared by URA Corporation and the LEVON Group for the American Petroleum Institute and American's Natural Gas Alliance, June 1, 2012.

[11] 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

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

from the Input/Output accounts of the United States. These data present detailed figures on the input costs for oil and gas production including wages, capital costs, leasing costs, and costs of various materials and services used in the exploration/leasing/permitting, production, infrastructure development and reclamation of oil and gas plays. The data are from 2010. 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 as the wellhead in each state as of 2011 which are the latest data available. Annual average prices and production volumes by state are gathered from the US Department of Energy.[13] Costs are divided between different activities based on the type of input and labor costs are divided based on input commodity and service costs.

Anticipated Revenues are based on data from the US Department of Energy. It is simply equal to the annualized price of either oil or natural gas at the wellhead (by state) multiplied by annual production.[14] Revenues per well cannot be derived simply by dividing this by the number of producing wells since oil and gas wells tend to have either a hyperbolic or an exponentially declining production trend. Based on discussions with industry principles, a well will generally not be drilled and put into production unless it can recoup at least the direct drilling costs in the first year after completion. Using this assumption and a simple declining exponential function, the model suggests that about 97 percent of the production occurs in the first 4 years after drilling. The four year production total (multiplied by the current price of either oil or gas) was used to estimate total revenue per well. Operating costs were then multiplied by 4 to reflect the economic life of each well.

The Number of Wells To Be Drilled is 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 as in some stage of pre-production. These are aggregated for each state and the summary results are shown on Table 2 on the following page.

The Number of Producing Wells is also 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 that it is in some stage of production. Water wells, disposal wells, capped wells, injection wells, and other operations not directly used to extract petroleum are not included. A summary of these wells is also included in Table 2 on the following page.

The Number of Wells on Federal Land is estimated based on a linear trend of permits issues by state. These data come directly from the Bureau of Land Management.[15] Based on a linear trend, the BLM will approve 5,841 drilling permits on all Federal land in 2012, of which 87 percent (5,058) will be in the 13 subject states.

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13 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

14 Ibid.

15 *Number of Drilling Permits Approved by Fiscal Year on Federal Lands*, US Department of the Interior, Bureau of Land Management, November 9, 2011. Available on-line at: www.blm.gov/wo/st/en/prog/energy/oil_and_gas/statistics.html

The Number of Wells requiring Rework: is estimated by multiplying the 90,452 existing wells on Federal leases by 87 percent (the estimated percentage in the 13 subject states) and then by 93 percent (the percentage completed using hydraulic fracture) and then by 1.6 percent or the annual rework rate in a given year.[16] Under these assumptions 1,171 wells in the subject states will require re-work in a given year.

Table 2
Summary of Wells Included in The Cost Analysis

	Estimated Number of Wells in			
	Production	Permitting Process	Federal Permit Process	Impacted
Oil	108,753	12,318	1,818	1,818
Gas	92,915	14,129	3,675	3,240
Total	201,668	26,447	5,493	5,058

The Number of Impacted Wells is calculated by taking the number of estimate permits on Federal lands (see above) and dividing them into oil or gas wells based on the overall number of oil versus gas wells in each state that are currently in the permitting process. These figures are then adjusted downward to remove all wells in states where the average oil or gas well would be unprofitable. While this does not mean that individual wells would not be profitable, and therefore subject to this new rule, it does ensure that the estimated costs calculated as part of this analysis are conservatively estimated.

The Discount Rate used in this analysis is 7 percent based on the rate used in the BLMs cursory analysis of the benefits and costs of these regulations.[17] The Federal government recommends that significantly lower discount rates be used in internal analyses; however, the cost of capital for government projects is significantly lower than that for risky ventures like oil and gas exploration, drilling and production. Industry sources have suggested to JDA that a discount rate of 12 to 15 percent is generally standard in the financial decision-making process;[18] however, this could not be independently substantiated. Therefore, this analysis assumes a cost of capital equal to the coupon of non-investment grade corporate bonds as of April 23, 2012.[19]

The Number of Delay Days is invariably difficult to predict since the permit in question currently does not exist. The proposed rule does not propose a limit on the number of days that the BLM can take to either approve or reject the permit. Currently the agency is taking about 10 months to approve a drilling permit, and there is already a substantial backlog. No additional funds to enforce the proposed rule could be found in the FY 2012 Federal Budget, so the agency

16 Shires, Terri and Miriam Lev-On, *Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production*, prepared by URA Corporation and the LEVON Group for the American Petroleum Institute and American's Natural Gas Alliance, June 1, 2012.

17 See: US Bureau of Land Management, *Well Stimulation Proposed Rule: Economic Analysis and Initial Regulatory Flexibility Analysis*, at: www.regulations.gov/#!documentDetail;D=BLM-2012-0001-0003.

18 John Dunham and Associates interviews with various industry principles and staff of drillers, operators, service companies and leaseholders.

19 From Bloomberg.com at: www.bloomberg.com/markets/rates-bonds/corporate-bonds/

will be required to process at least 5,000 expanded permit applications with its current staffing levels. As such it is probably not unreasonable to assume that the approval time for these permits with the additional requirements to add about a third of that of approving the existing drilling permits, and will likely be much longer. In this analysis, it is assumed that the additional permitting time will be about 49 days. This is based on a Monte Carlo analysis using a log-normal function and assuming an average increase in permitting time of 47 days, with on outside change of either zero additional days or 99 additional days (which is one-third of the current permitting time). In addition to this, it is assumed that about 13.5 additional days will be needed in between the drilling of a well and the stimulation process. Again, a Monte Carlo analysis is used which assumes a median of 7 additional days and an outside chance of either zero or 30 days.

Additional Casing Costs will be required under the provision that requires casing to protect the "usable groundwater" where this is defined as water containing 10,000 parts per million of total dissolved solids. This change in definition of usable ground water will require operators to run deeper surface casing, two stage cementing on the production casing or the addition of an intermediate string of casing. Currently this casing is brought down to an average depth of about 2,000 feet, but may now have to be brought down to a depth of 4,000 or even 7,500 feet or deeper depending on conditions. It costs about $37 per foot for casing of this type. Again, using a Monte Carlo simulation it is estimated that each well will require approximately 2,350 feet of additional casing.

Additional Cement Bond Log: The new regulations will require operators to maintain an additional Cement Bond Log for all pipes and other surface operations. This is an analysis which provides a representation of the integrity of the cement job on pipes and is generally only required or used on drill casings. According to the BLM this will be required on about $9,000 per well and will be required on 97.5 percent of covered wells.[20] However, on top of the cost of the CBL, operators will need to ensure that all drilling and field equipment is maintained at the site while the cement cures. Cost estimates provided by companies operating in the Williston, Piceance and San Juan basins suggest that on average the hourly cost for maintaining this equipment on-site (and idle) is as much as $1,950. Costs can be even higher in areas where deep, horizontal wells are being drilled. Assuming that 72 hours of additional delay time is required for the cement to cure this would mean that each well would require an additional $140,400 expense simply to cover the down time for the rig while the operator is completing the CBL, meaning that the total cost for this requirement will be $145,665 per well.

Mechanical Integrity Tests are assumed to be required on 20 percent of wells prior to commencing stimulation operations, and that these tests are assumed to cost approximately $10,000 as per the BLM.[21]

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The Permit Approval Rate is assumed to be 100 percent. This ensures that the estimated cost generated by the model will be the lowest possible. A lower approval rate would result in a

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20 See: US Bureau of Land Management, *Well Stimulation Proposed Rule: Economic Analysis and Initial Regulatory Flexibility Analysis,* at: www.regulations.gov/#!documentDetail;D=BLM-2012-0001-0003.

21 Ibid.

higher cost of the proposed rule. The administrative cost to operators is assumed to be only $495 per well as per the BLM.[22]

Detailed Results – Cost of the Proposed Regulations:

Based on the data and assumptions presented in the prior section it is possible to calculate the anticipated cost of the proposed rule on the oil and natural gas industry. There are two potential ways to calculate this cost. The first assumes that development stops for a period of time while the permitting/verification process takes place. The capital already tied up in the development of the well during this time can be discounted at a reasonable rate of interest which would represent the direct cost to the driller/producer. This method assumes that the well development would continue unabated following the completion of the regulatory process and that production from the well would occur at the same rate and with the same revenues as would have occurred 62.5 days earlier. In such, this model simply represents the additional cost of capital to the producer.

Table 3
Summary of Estimated Costs by State

	State	Method 1	Method 2	Average
AZ	Arizona	$ -	$ -	$ -
CO	Colorado	$ 140,597,918	$ 144,944,919	$ 142,771,418
ID	Idaho	$ -	$ -	$ -
MT	Montana	$ 15,676,353	$ 17,450,231	$ 16,563,292
NE	Nebraska	$ -	$ -	$ -
NV	Nevada	$ -	$ -	$ -
NM	New Mexico	$ 167,170,616	$ 169,003,720	$ 168,087,168
ND	North Dakota	$ 25,147,180	$ 33,310,119	$ 29,228,649
OR	Oregon	$ -	$ -	$ -
SD	South Dakota	$ 253,752	$ 286,759	$ 270,256
UT	Utah	$ 150,566,431	$ 159,886,215	$ 155,226,323
WA	Washington	$ -	$ -	$ -
WY	Wyoming	$ 726,475,894	$ 817,064,564	$ 771,770,229
Total	Total 13 States	$ 1,225,888,144	$ 1,341,946,527	$ 1,283,917,335

A second method can be used to calculate the cost to the industry. Under this method, it is assumed that the overall cost of completing a well would remain the same; however, there would be a delay to the producer in realizing a return. Under this model, the value of production over the delay period is discounted back representing a lost return on capital.

While either method can produce a reasonable assumption for the overall cost of the regulations, the magnitude of the difference between them would be impacted by the current market price of petroleum products and capital. In a market where prices are high, the lost return on capital would produce a higher figure, where in a market where interest rates are relatively high, the cost of capital method would produce a more substantial loss estimate. As such, the average value between these two approaches should serve as a good estimate of the cost of the proposed rule.

22 Ibid.

Based on the first approach and the assumptions outlined above, the total cost of the proposed rule would be just over $1.225 billion, with nearly 60 percent of that coming from operations located on Federal lands in Wyoming. The second approach, which examines the lost value of production, leads to a forecast loss of about $1.342 billion, with Wyoming again accounting for the bulk of this cost. Table 3 on the prior page shows the estimated losses by state based on the two approaches.

The arithmetic average of these estimates is $1,284 billion which is John Dunham and Associates' estimate of the overall cost to the oil and gas industry of the proposed rule based on the existing wells in the regulatory pipeline. As the rule will impact future operations, it may also have significant costs as long as the industry continues to operate on Federal leases. This analysis does not examine future costs nor does it examine costs incurred for additional well stimulation efforts on existing – and either currently producing or capped wells.

Table 4
Cost Component Comparison

		BLM	Percent		JDA	Percent		Difference
Initial Delay Costs	$	-	0.00%	$	56,404,007	4.39%	$	56,404,007
Pre Completion Delay Costs	$	-	0.00%	$	38,326,948	2.99%	$	38,326,948
Administrative Costs	$	3,798,558	6.52%	$	2,503,710	0.20%	$	(1,294,848)
Enhanced Casing Costs	$	-	0.00%	$	439,793,100	34.25%	$	439,793,100
Cement Bond Log Costs	$	44,383,950	76.13%	$	736,773,570	57.38%	$	692,389,620
Mechanical Integrity Test Costs	$	10,116,000	17.35%	$	10,116,000	0.79%	$	-
Total Costs	$	58,298,508	100.00%	$	1,283,917,335	100.00%	$	1,225,618,827

Table 4 above presents these costs in comparison with those documented by the BLM in its cursory analysis of the benefits and costs of the proposed rules. As the table shows, the bulk of the additional costs (about 36 percent) come from the additional well casing that the new rules would require and 56.5 percent from the additional cement bond log. However, the costs related to delays are so substantial that even eliminating the additional casing expense and accepting the government's estimates for Mechanical Integrity Tests and administrative costs as given, the total cost to drillers and operators will still exceed $107 million even if the casing and cement bond log costs were not included.

On a per well basis the regulations will cost about $253,800. Obviously this is an average as the costs for a deep horizontal oil well on the Bakken will be significantly higher than that of a shallower vertical gas well drilled on the San Juan Basin. However, the actual per well costs could rise if the regulations were to eliminate the economic incentive for drilling marginal wells. Were that to happen, only deep, horizontal plays with high expected returns may be drilled on federal lands, and more marginal natural gas leases may simply lie fallow. Table 5 below outlines the costs of the proposed rule based on an average oil/gas well.

Table 5
Cost Component Comparison per Well

	BLM Estimate	JDA Estimate
Initial Delay Costs	$ -	$ 11,151
Pre Completion Delay Costs	$ -	$ 7,577
Administrative Costs	$ 751	$ 495
Enhanced Casing Costs	$ -	$ 86,950
Cement Bond Log Costs	$ 8,775	$ 145,665
Mechanical Integrity Test Costs	$ 2,000	$ 2,000
Total Costs	$ 11,526	$ 253,839

Costs from Reworking Existing Oil and Gas Wells:

Since the new regulations will also apply to maintenance stimulation of existing wells, operators maintaining many of the current 90,452 producible and service drill holes on Federal leases will also experience greatly increased costs over time.[23] Assuming that wells require stimulation in line with figures recently calculated for the American Petroleum Institute, as many as 1,171 wells in the subject states will require re-work in a given year.[24]

Assuming that re-work can re scheduled to minimize the costs and delays that will come about due to the proposed rules, and that operators already perform integrity tests prior to re-stimulation, these projects will incur additional costs related only to:

- Administration and permitting ($495 per well);
- Additional costs to ensure that casings meet the new requirements ($86,950 per well);
- Additional Cement Bond Log costs to ensure that all pipes and surface infrastructure conforms to the new requirements ($145,665 per well);

Based on the assumptions above, operators will incur additional costs equal to over $233,100 per well for the first re-stimulation event for all existing wells. Since it is difficult to determine the actual number of wells on federal lands that will be cost effective to maintain once these regulations are in effect, this analysis examines the costs for only one year. Assuming, therefore, that 1,171 wells on federal leaseholds will require re-work, the cost of the regulations for just workovers will be almost $273.0 million. This figure will only increase as wells require re-work or new stimulation activities over time.

In sum, the above analysis suggests that these proposed regulations will have a significant impact on the oil and gas production industry even without considering future discounted costs.

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23 See: US Bureau of Land Management, *Well Stimulation Proposed Rule: Economic Analysis and Initial Regulatory Flexibility Analysis*, at: www.regulations.gov/#!documentDetail;D=BLM-2012-0001-0003.

24 Shires, Terri and Miriam Lev-On, *Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production*, prepared by URA Corporation and the LEVON Group for the American Petroleum Institute and American's Natural Gas Alliance, June 1, 2012.

About John Dunham and Associates:

John Dunham and Associates is a leading New York City based economic consulting firm specializing in the economics of fast moving issues. JDA is an expert at translating complex economic concepts into clear, easily understandable messages that can be transmitted to any audience. Our company's clients include a wide variety of businesses and organizations, including some of the largest Fortune 500 companies in America, such as:

- Altria
- Diageo
- Feld Entertainment
- Forbes Media
- MillerCoors
- Verizon
- Wegmans Stores

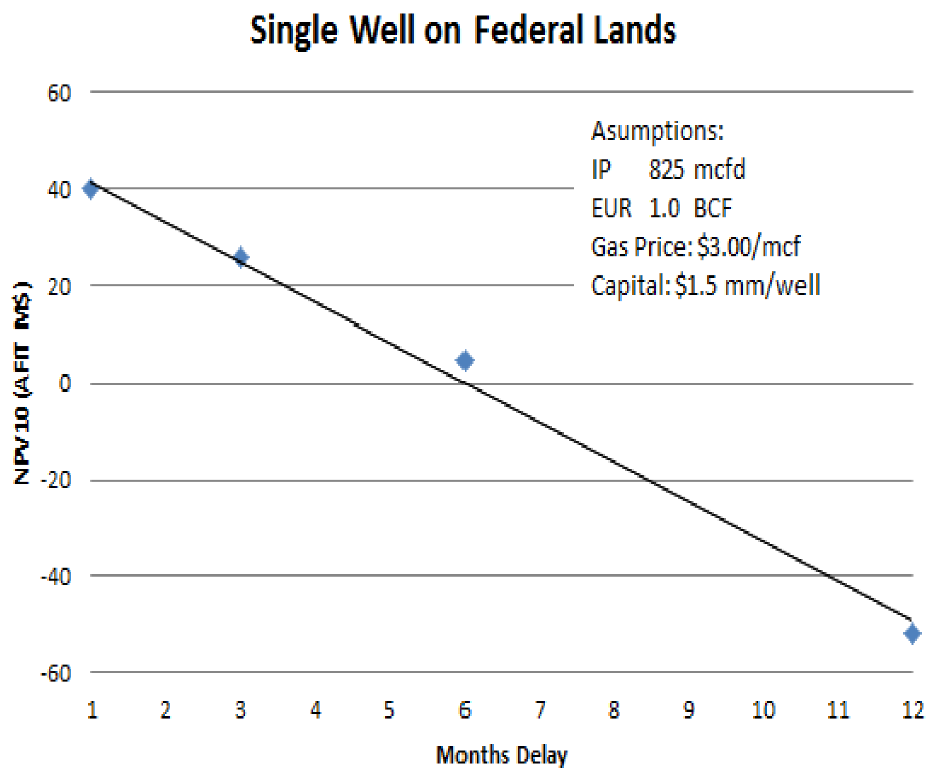
John Dunham is a professional economist with over 25 years of experience. He holds a Master of Arts degree in economics from the New School for Social Research as well as a Masters of Business Administration from Columbia University. He also has a professional certificate in Logistics from New York University. Mr. Dunham has worked as a manager and an analyst in both the public and private sectors. He has experience in conducting cost-benefit modeling, industry analysis, transportation analysis, economic research, and tax and fiscal analysis. As the chief domestic economist for Philip Morris, he developed tax analysis programs, increased cost-center productivity, and created economic research operations. He has presented testimony on economic and technical issues in federal court and before federal and state agencies.

Prior to Phillip Morris John was an economist with the Port Authority of New York and New Jersey, the Philadelphia Regional Port Authority and the City of New York.

Appendix C

Graph of Impact of Delay on Individual Well Cost Over Time (Net Present Value)

Submitted as part of comments, filed on September 10, 2012, by ANGA, AXPC, and USOGA on BLM’s Proposed Rule to Regulate Hydraulic Fracturing on Public and Indian Lands, 77 Fed. Reg. 27,691 (May 11, 2012) 1004-AE26


Single Well on Federal Lands
Asumptions:
IP 825 mcfd
EUR 1.0 BCF
Gas Price: $3.00/mcf
Capital: $1.5 mm/well
NPV/10 (AFIT M$)
60
40
20
0
-20
-40
-60
1
2
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11
12
Months Delay