COMMENTS ON BLM'S HYDRAULIC FRACTURING RULEMAKING PROPOSAL

August 22, 2013

Via e-filing on www.regulations.gov

Mr. Neil Kornze
Principal Deputy Director
Attn: Regulatory Affairs
Bureau of Land Management
United States Department of the Interior
20 M Street SE
Room 2134LM
Washington, DC 20003

Re: RIN 1004-AE26. ***Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands*****, proposed rule published in the Federal Register on May 24, 2013 (78 Fed. Reg. 31,636).**

Dear Mr. Kornze,

On September 10, 2012, the Independent Petroleum Association of America ("IPAA") and the Western Energy Alliance (the "Alliance") submitted comments on an initial version of regulations that the Bureau of Land Management ("BLM") proposed relating to oil and gas well stimulations. IPAA is the leading, national upstream trade association representing thousands of oil and natural gas producers and service companies. The Alliance represents over 400 members in all aspects of environmentally responsible exploration and production of oil and natural gas on federal and Indian lands across the western states.

This submission supplements our previous comments and addresses the revised version of the proposed rule. These comments are filed on behalf of IPAA, the Alliance, the Association of Energy Service Companies, the International Association of Drilling Contractors, the International Association of Geophysical Contractors, the National Stripper Well Association, the Petroleum Equipment Suppliers Association, the US Oil & Gas Association, and the following organizations (collectively, the "Associations"):

Arkansas Independent Producers and Royalty Owners Association
California Independent Petroleum Association

Coalbed Methane Association of Alabama
Colorado Oil & Gas Association
East Texas Producers & Royalty Owners Association
Eastern Kansas Oil & Gas Association
Florida Independent Petroleum Association
Illinois Oil & Gas Association
Independent Oil & Gas Association of New York
Independent Oil & Gas Association of West Virginia
Independent Oil Producers Agency
Independent Oil Producers Association Tri-State
Independent Petroleum Association of New Mexico
Indiana Oil & Gas Association
Kansas Independent Oil & Gas Association
Kentucky Oil & Gas Association
Louisiana Oil & Gas Association
Michigan Oil & Gas Association
Mississippi Independent Producers & Royalty Association
Montana Petroleum Association
National Association of Royalty Owners
Nebraska Independent Oil & Gas Association
New Mexico Oil & Gas Association
New York State Oil Producers Association
North Dakota Petroleum Council
Northern Alliance of Independent Producers
Northern Montana Oil and Gas Association
Ohio Oil & Gas Association
Oklahoma Independent Petroleum Association
Panhandle Producers & Royalty Owners Association
Pennsylvania Independent Oil & Gas Association
Permian Basin Petroleum Association
Petroleum Association of Wyoming
Southeastern Ohio Oil & Gas Association
Tennessee Oil & Gas Association
Texas Alliance of Energy Producers
Texas Independent Producers and Royalty Owners Association
Utah Petroleum Association
Virginia Oil and Gas Association
West Virginia Oil and Natural Gas Association

Collectively, these groups represent the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts. It is the members of these groups that the proposed regulations will most significantly affect. Independent producers drill about ninety-five percent of American oil and natural gas wells, produce about fifty-four percent of American oil, and more than eighty-five percent of American natural gas.

In addition to the specific comments made herein, we support those comments that the participants identified above may submit separately.

We ask that BLM carefully consider the concerns discussed in these comments. We request that BLM rescind or significantly amend the proposed rule to eliminate requirements without a sound technical foundation, reduce overlap with state and tribal requirements, and better balance costs and benefits.

POLICY CONCERNS

Sixteen months into the rulemaking process, BLM remains unable to provide a supportable reason to impose its additional layer of regulations on top of those laws States already enforce. For the high cost this rule will impose on the industry – $345 million per year – what benefit will the public receive? For the disincentive this rule will create to invest in federal and tribal oil and gas leases, to whom will the tribes and the taxpayers turn for the lost leasing and royalty revenue? BLM has been unable to answer these questions. BLM should recognize that states are already regulating hydraulic fracturing admirably. The only imperative to adopt this rule is an arbitrary desire "to do something." The Associations oppose the rule because each of the reasons BLM suggests for adopting the rule is without basis in fact.

States Are Regulating Hydraulic Fracturing Effectively

BLM has assured the public that it is mindful of the capabilities of state regulators. "The BLM acknowledges that many States do have regulations in place; however, not all of the States that contain Federal lands under the BLM's jurisdiction have hydraulic fracturing regulations."[1] This statement provides no basis for the rule.

According to the *Public Lands Statistics* for Fiscal Year 2012, BLM approved 4,256 applications for permit to drill ("APDs") on public lands in 17 states.[2] Of that number, over ninety-eight percent of the wells approved were in just seven states: California, Colorado, Montana, North Dakota, New Mexico, Utah, and Wyoming. Since the beginning of 2010, six of these states have revised their regulations specifically to address public concerns over hydraulic fracturing. The seventh, California, is in the process of amendment.

State	Citation	Eff. Date
Montana	Mont. Admin. R. 36.22.608, 36.22.1015, 36.22.1016, 36.22.1106, 36.22,1010 (2013).	8/26/11
North Dakota	N.D. Admin. Code 43-02-03-27.1 (2012).	4/1/12
Colorado	Colo. Code Regs. §§ 404-205, 404-205A, 404-305.e(1)(A),	7/1/09

[1] 78 Fed. Reg. 31,636, 31,644 (May 24, 2013).

[2] *See* Bureau of Land Mgmt., *Pub. Land Statistics* (2012) at 118, Table 3-16, available at: http://www.blm.gov/public_land_statistics/.

State	Citation	Eff. Date
	404-316C, 404-317, 404-341, 404-903, 404-904 (2013).	
New Mexico	N.M. Code R. 19.15.16.19 (2013).	2/15/12
Utah	Utah Admin. Code r.649-3-39 (2013).	11/1/12
Wyoming	55-3 Wyo. Code R. §§ 45(d)(iv), 45(d)(vi), 45(f), 45(g) (LexisNexis 2012).	Adopted 6/8/10
California	Cal. Dep't of Conservation, Div. of Oil, Gas, and Geothermal Res., Pre-Rulemaking Discussion Draft (2012), *available at* http://www.conservation.ca.gov/dog/general_information/Documents/121712DiscussionDraftofHFRegs.pdf.	Issued 12/18/12

Of the ten states that accounted for less than two percent of the APDs approved, nearly all have amended their regulations to address public concerns regarding hydraulic fracturing.

State	Citation	Eff. Date
Alabama	Ala. Admin. Code r. 400-3-8-.03; Ala. Admin. Code r. 400-1-9-.04.[3]	10/16/07
Alaska	Alaska Admin. Code tit. 20, §§ 25.005, 25.280, 25.283, 25.990 (2013).	Changes Proposed 1/17/2013
Arizona	Ariz. Admin. Code §§ 12-7-108, 12-7-122,12-7-140 (2013).	1/19/94, 1/2/96, 7/15/02
Louisiana	La. Admin. Code tit. 43:XIX § 118 (2013).	10/20/11
Mississippi	26-2 Miss. Code R. § 1.26 (2013).	3/4/13
Nevada	S.B. 390, 77th Sess. (Nev. 2013).	10/1/13
Ohio	Ohio Admin. Code 1509.01–1509.99 (2013). S.B. 315, 129th Gen. Assemb. (Ohio 2012).	8/1/12 9/12/12

[3] On August 1, 2013, the State Oil and Gas Board of Alabama granted a motion to adopt Rule 400-1-9-.04 (regulating hydraulic fracturing) and to amend Rule 400-3-8-.03 (regulating hydraulic fracturing of coal beds). *See* State Oil & Gas Bd. of Ala., Results of Meeting (July 30 - Aug. 1, 2013), available at: http://www.gsa.state.al.us/documents/hearings_results/2013-8-1.pdf.

Oklahoma	Okla. Admin. Code §§ 165:10-3-4, 165:10-3-10, 165:10-7-16, 165:10-21-22 (2013).	7/1/13
South Dakota	S.D. Admin. R. 74:12:02:19 (2013).	4/22/13
Texas	16 Tex. Admin. Code §§ 3.13, 3.29, 3.99, 3.100 (2013); .	1/2/12 1/1/2014

Other important states with significant oil and gas development activity, but with two or fewer approved APDs on public lands in FY 2012 -- Pennsylvania and West Virginia -- both have robust regulations governing hydraulic fracturing. In short, there is no gap in the regulation of hydraulic fracturing justifying BLM's proposed rule.

We have carefully reviewed the administrative record for this rulemaking. It is highly significant what the rulemaking record lacks. BLM cannot point to a single instance where there was an environmental problem related to hydraulic fracturing that BLM's proposed rule would have prevented where state regulation did not adequately address the issue. So the problem with BLM's position is not simply that states have hydraulic fracturing rules on the books, but rather that the proposed rule does not provide any benefit commensurate with the costs it will impose. BLM has no evidence that its costly proposed rule will be any more effective in practice than state regulations protecting water and other environmental values.

There Is No Evidence that Hydraulic Fracturing Has Contaminated Groundwater

The chief concern BLM has identified in support of its promulgation of a hydraulic fracturing rule is a public "concern about whether fracturing can lead to or cause the contamination of underground water sources[.]"[4] This concern has been the subject of frequent technical reports, finding not only that hydraulically stimulated fractures in deeper formations have not penetrated drinking water aquifers, but also that principles of petrophysics indicate it is highly unlikely that such fractures could ever reach aquifers. These are facts that BLM must take into account in its rulemaking to avoid an unlawfully arbitrary rule.

Preliminary results from the most recent study were reported on July 19, 2013. In this study, the National Energy Technology Laboratory is monitoring a group of Marcellus Shale wells in Greene County, Pennsylvania. The Associated Press reported that "[d]rilling fluids tagged with unique markers were injected more than 8,000 feet below the surface at the gas well bore but weren't detected in a monitoring zone at a depth of 5,000 feet. The researchers also tracked the maximum extent of the man-made fractures, and all were at least 6,000 feet below the surface."[5]

Other studies and statements of public officials are well-known to BLM and are summarized here.

[4] 78 Fed. Reg. 31,636, 31,636 (May 24, 2013).

[5] K. Begos, "DOE Study: Fracking Chemicals Didn't Taint Water" (July 19, 2013), available at http://bigstory.ap.org/article/ap-study-finds-fracking-chemicals-didnt-spread.

Author	Statement	Citation
Sally Jewell, Secretary of the Dep't of Interior	"I know there are those who say fracking is dangerous and should be curtailed, full stop. That ignores the reality that it has been done safely for decades and has the potential for developing significant domestic resources and strengthening our economy and will be done for decades to come."	Real Clear Energy website, *The Daily Bulletin* (May 20, 2013)
Lisa Jackson, former U.S. Environmental Protection Agency ("EPA") Administrator	"In no case have we made a definitive determination that [hydraulic fracturing] has caused chemicals to enter groundwater."	You Tube: Fox News Channel Clip (Apr. 30, 2012)
Lisa Jackson, former EPA Administrator	"I'm not aware of any proven case where [hydraulic fracturing] itself has affected water."	You Tube: Fox News Channel Clip (May 24, 2011)
Ken Salazar, former Secretary of the Dep't of Interior	"There's a lot of hysteria that takes place now with respect to hydraulic fracking, and you see that happening in many of the states… My point of view, based on my own study of hydraulic fracking, is that it can be done safely and has been done safely hundreds of thousands of times."	Energy in Depth recording of Ken Salazar speaking in front of the U. S. House of Representatives (Feb. 15, 2012)
Dr. Stephen Holditch, Dep't of Petroleum Engineering, Texas A&M University; member of DOE's SEAB Shale Gas Production Subcommittee	"I have been working in hydraulic fracturing for 40+ years and there is absolutely no evidence hydraulic fractures can grow from miles below the surface to the fresh water aquifers."	Written Testimony before U.S. Senate Committee on Energy & Natural Resources (Oct. 4, 2011)
Dr. Mark Zoback, Professor of Geophysics, Stanford University; member of DOE's SEAB Shale Gas Production Subcommittee	"Fracturing fluids have not contaminated any water supply and with that much distance to an aquifer, it is very unlikely they could."	"Extracting natural gas from shale can be done in an environmentally responsible way, says Stanford researcher on government panel," Louis Bergeron, *Stanford Report* (Aug. 30, 2011)
Warner, *et al.*	"The integration of multiple geochemical and isotopic proxies shows no direct evidence of	"Geochemical and isotopic variations in shallow

Author	Statement	Citation
	contamination in shallow drinking-water aquifers associated with natural gas extraction from the Fayetteville shale."	groundwater in areas of the Fayetteville shale development, north-central Arkansas, accepted for publication in APPLIED GEOCHEMISTRY (Apr. 25, 2013)
Warner, *et al.*	"The lack of geospatial association with shale-gas wells and the occurrence of this type of saline water prior to shale gas development in the study area…suggests that **it is unlikely that hydraulic fracturing for shale gas caused this salinization and that it is instead a naturally occurring phenomenon that occurs over longer timescales**."	"Geochemical evidence for possible natural migration of Marcellus Formation brine to shallow aquifers in Pennsylvania" at 11963 (May 10, 2012), available at: www.pnas.org/cgi/doi/10.1073/pnas.1121181109
Duke University	"The study found elevated levels of salinity with similar geochemistry to deep Marcellus brine in drinking water samples from three groundwater aquifers, but no direct links between the salinity and shale gas exploration in the region."	"Marcellus Brine Migration Likely Natural, Not Man-Made", *Duke Today* (July 9, 2012)
Boyer, *et al.*	"In this study, statistical analyses of post-drilling versus pre-drilling water chemistry **did not suggest major influences from gas well drilling or hydrofracturing** (fracking) on nearby water wells, when considering changes in potential pollutants that are most prominent in drilling waste fluids."	"The Impact of Marcellus Gas Drilling on Rural Drinking Water Supplies" at 4, *The Center for Rural Pennsylvania* (Oct. 2011)
New York State Dep't of Environmental Conservation	"A supporting study for this dSGEIS concludes that it is highly unlikely that groundwater contamination would occur by fluids escaping from the wellbore for hydraulic fracturing. The 2009 dSGEIS further observes that regulatory officials from 15 states recently testified that groundwater contamination as a result of the hydraulic fracturing process in the tight formation itself has not occurred."	"Revised Draft Supplemental Generic Environmental Impact Statement On The Oil, Gas and Solution Mining Regulatory Program" (dSGEIS), Executive Summary at 11 (Sept. 7, 2011)
Ohio Dep't of Natural Resources, Mineral Resources Management	"Although an estimated 80,000 wells have been fractured in Ohio, state agencies have **not identified a single instance where**	"State Review of Oil and Natural Gas Environmental

Author	Statement	Citation
	groundwater has been contaminated by hydraulic fracturing operations."	Regulations, Inc. (STRONGER)," *Ohio Hydraulic Fracturing State Review* (Jan. 2011)
MIT Energy Initiative	"In the studies surveyed, **no incidents are reported which conclusively demonstrate contamination** of shallow water zones with fracture fluids."	"The Future of Natural Gas" at 40, MIT Study (2010)
U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory	"[B]ased on over sixty years of practical application and a lack of evidence to the contrary, there is nothing to indicate that when coupled with appropriate well construction[,] the practice of hydraulic fracturing in deep formations endangers ground water. There is also a **lack of demonstrated evidence that hydraulic fracturing conducted in many shallower formations presents a substantial risk of endangerment to ground water**."	"State Oil and Natural Gas Regulations Designed to Protect Water Resources" at 39 (May 2009), available at: http://www.gwpc.org/sites/default/files/state_oil_and_gas_regulations_designed_to_protect_water_resources_0.pdf.
U.S. EPA	"Although thousands of CBM wells are fractured annually, **EPA did not find confirmed evidence** that drinking water wells have been contaminated by hydraulic fracturing fluid injection into CBM wells."	"Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs Study," Office of Water, Office of Ground Water and Drinking Water (4606M), EPA 816-R-04-003, Executive Summary at 1 (June 2004)
U.S. Geological Survey	"Comparative analyses demonstrated that **maximum and median chloride concentrations for data from this study were below that of historical (prior to gas production) chloride concentrations,** and, more importantly, that **chloride concentrations for wells less than 2 miles from gas-production wells were not significantly different from chloride concentrations more than 2 miles from gas-production wells.** Additionally, groundwater-quality data collected	"Shallow Groundwater Quality and Geochemistry in the Fayetteville Shale Gas-Production Area, North-Central Arkansas, 2011" U.S. Geological Survey, Scientific Investigations Report 2012–5273 (January 2013)

Author	Statement	Citation
	for this study indicated that groundwater chemistry in the shallow aquifer system in the study area is a result of natural processes, controlled by geochemical rock-water interaction and microbially mediated redox reactions."	
U.S. Geological Survey	"A study that examined the water quality of 127 shallow domestic wells in the Fayetteville Shale natural gas production area of Arkansas found **no groundwater contamination associated with gas production**, according to a report released today by the U.S. Geological Survey."	"No Contamination from Fayetteville Shale Exploration Found in Sampled Wells" U.S. Geological Survey Release (January 9, 2013)
CardnoEntrix	"Groundwater beneath the Inglewood Oil Field is not a source of drinking water, although the water quality must meet the standards for such a source. Groundwater beneath the Baldwin Hills is geologically isolated from the surrounding Los Angeles Basin and any water supply wells. Routine tests by the water purveyor show the community's water supply meets drinking water standards, including the period of high-rate gravel packs and conventional hydraulic fracturing, as well as the first high-volume hydraulic fracture in September 2011. In addition, the Inglewood Oil Field has an array of groundwater monitoring wells to measure water quality. Apart from arsenic, which is naturally high in groundwater of the Los Angeles Basin, the analyzed constituents meet drinking water standards. **Before-and-after monitoring of groundwater quality in monitor wells did not show impacts from high-volume hydraulic fracturing** and high-rate gravel packing."	"Hydraulic Fracturing Study: PXP Inglewood Oil Field" at 2-3 (Oct. 10, 2012)
U.S. Government Accountability Office	"**Fractures created during the hydraulic fracturing process are generally unable to span the distance between the targeted shale formation and freshwater bearing zones** … When a fracture grows, it conforms to a general direction set by the stresses in the rock, following what is called fracture direction or orientation. The fractures are most commonly vertical and may extend laterally several hundred feet away from the well, usually growing upward	"Information on Shale Resources, Development, and Environmental and Public Health Risks" at 46-49, GAO-12-732 (Sept. 2012)

Author	Statement	Citation
	until they intersect with a rock of different structure, texture, or strength. These are referred to as seals or barriers and stop the fracture's upward or downward growth… In addition, regulatory officials we met with from eight states – Arkansas, Colorado, Louisiana, North Dakota, Ohio, Oklahoma, Pennsylvania, and Texas – told us that, based on state investigations**, the hydraulic fracturing process has not been identified as a cause of groundwater contamination** within their states."	

The vast majority of wells completed by hydraulic fracturing involve geological formations thousands of feet below drinking water aquifers. And improvements in the technology of fracturing have allowed a similar record of safety over the last decade in shallow gas reservoirs as well.

Pioneer Natural Resources USA, Inc., for example, operates 2,400 wells in the Colorado portion of the Raton Basin. These wells are in the main coal bed methane wells, producing gas from up to 20 coal seams at depths ranging from 3,500 feet to as shallow as 450 feet from the surface. EPA has reported the results of Pioneer's fracturing program. "Analysis of data from 2,273 Pioneer [hydraulic fracturing] jobs since late 2001 shows that more than 12,000 individual hydraulic fracture stages were executed. . . . To date, with more than 12,000 stages pumped, there have been no instances where Pioneer's hydraulic fracture fluids or pressures impacted underground sources of drinking water."[6]

Furthermore, at the depths at which most hydraulic fracturing is conducted, petrophysics dictates that the energy hydraulic fracturing disperses into a rock formation tends to spread more horizontally than vertically. "A number of factors control the height growth of a fracture, but the relative difference between the stresses in and around the fracture is the most important factor. Fractures tend to remain in low stress vertical regions that effectively 'lock in' or 'trap' the fracture and keep it from breaking into higher stress rock."[7] In other words, how a fracture spreads is "dictated by the in situ stress that exists at the hydraulic fracture location . . . . Fractures will propagate in the same direction all across a field."[8]

[6] H. Macartney, "Hydraulic Fracturing in Coal Bed Methane Development, Raton Basin, Southern Colorado, USA," U.S. Environmental Protection Agency, PROCEEDINGS OF THE TECHNICAL WORKSHOPS FOR THE HYDRAULIC FRACTURING STUDY: WELL CONSTRUCTION AND OPERATION at 70, EPA 600/R-11/046 (May 2011).

[7] T. Beard, "Fracture Design in Horizontal Shale Wells – Data Gathering to Implementation," U.S. Environmental Protection Agency, PROCEEDINGS OF THE TECHNICAL WORKSHOPS FOR THE HYDRAULIC FRACTURING STUDY: WELL CONSTRUCTION AND OPERATION at 65, EPA 600/R-11/046 (May 2011).

[8] *Id.* at 81.

When this fact is coupled with the fact that rock formations underground are "layered," this combination "makes vertical fracture height growth difficult, thus generally promoting the growth of length over height."[9] An analysis of microseismic studies of fracturing operations in the Barnett Shale has shown that "fracturing does not intrude on the aquifers. There is a limit to how much a fracture can grow vertically, even in the most advantageous conditions."[10]

The most recent analysis of this issue reaches similar conclusions. Hydraulic fracturing operations are brief. Their purpose is to create a zone of lower pressure around the wellbore so that gas and liquids flow toward the well, not up and away from the well. "After an HF stimulation, hydrocarbon extraction creates a low pressure zone that draws fluids toward the target formation, thereby eliminating any potential for upward flow."[11] For that reason, "widespread and rapid upward migration of [hydraulic fracturing] fluid and brine through bedrock is not physically plausible."[12]

There is, in sum, no evidence in the record that regulation through existing state regimes has been inadequate to protect groundwater, the goal BLM expressly seeks here.

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[9] N. Warpinski, "Measurements and Observations of Fracture Height Growth," U.S. Environmental Protection Agency, Proceedings of the Technical Workshops for the Hydraulic Fracturing Study: Well Construction and Operation at 81, EPA 600/R-11/046 (May 2011).

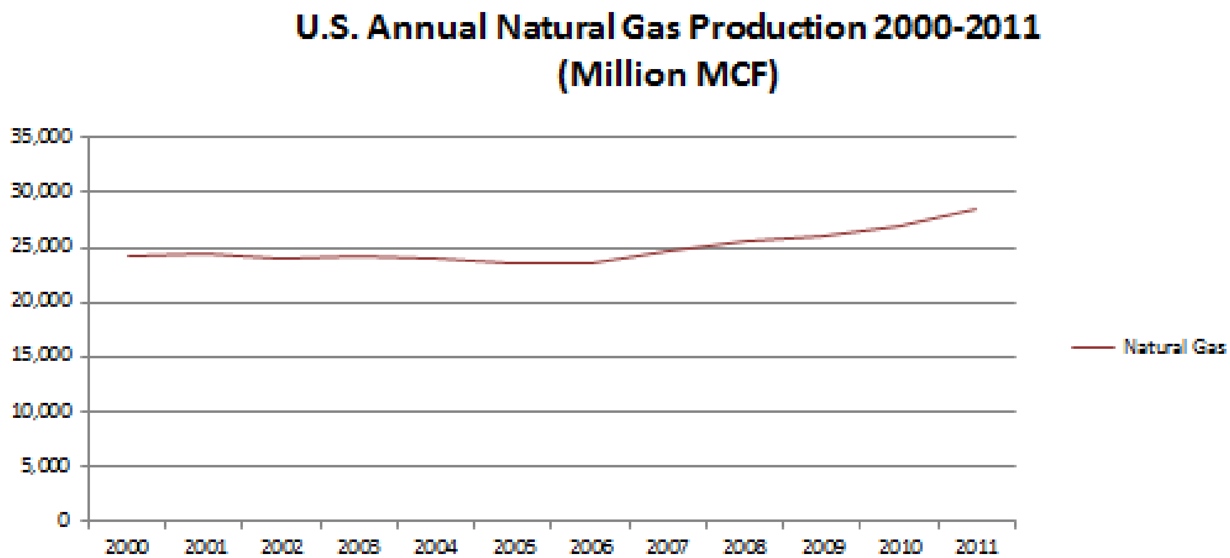
[10] *Id.* at 85.

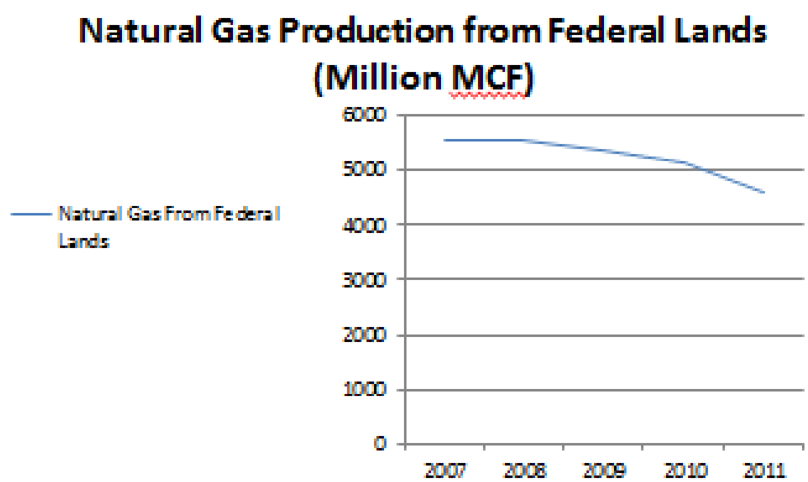
[11] S. Flwelling and M. Sharma, "Constraints on Upward Migration of Hydraulic Fracturing Fluid and Brine," [2013] GROUNDWATER at 2 (accepted for publication June 2013), available at www.NGWA.org.

[12] *Id.*

BLM's Proposal Will Worsen BLM's Already Slow Record in Approving APDs

While national production of crude oil and natural gas has increased, crude oil and natural gas production from federal leases is in decline.





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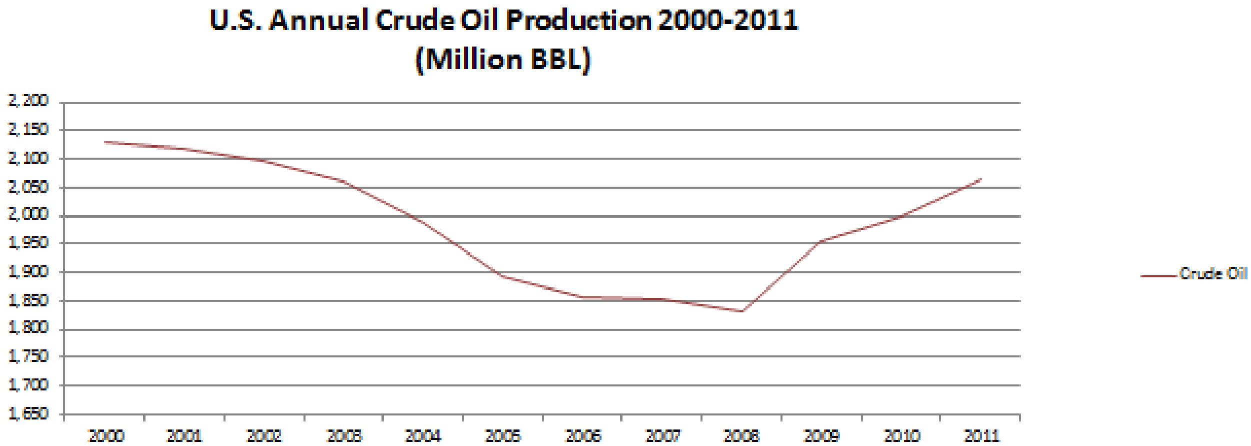

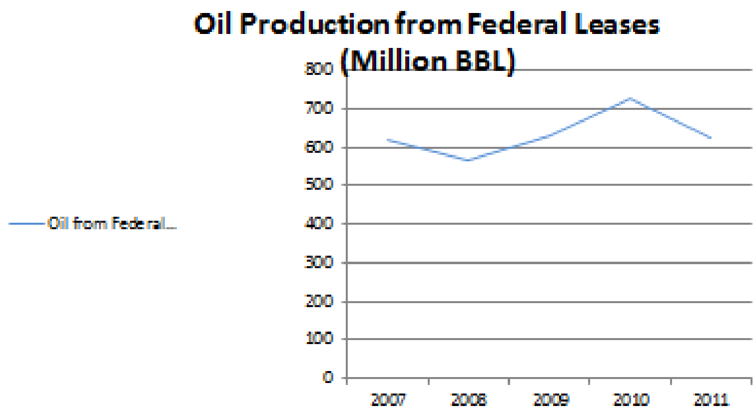

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The obvious question is "why?"

BLM's own statistics reveal inordinate delays between receipt of an APD and approval of it: 162 days in Farmington, New Mexico, 181 days in Dickinson, North Dakota, 211 days in Canon City, Colorado, 215 days in Price, Utah, 226 days in Meeker, Colorado, 233 days in Lander, Wyoming, 271 days in Rawlings, Wyoming, 359 days in Milwaukee, Wisconsin, 518 days in Kemmerer, Wyoming, 635 days in Moab, Utah, and 952 days in Buffalo, Wyoming.[13]

The effect of delays in leasing and permitting have resulted in declining production from federal onshore leases. Operators are investing in lands under private lease, where state permitting is quicker and regulation is more predictable. In Colorado, for example, development of the Niobrara shale thrives in Weld County, but is stymied in Routt County. The chief difference is that the bulk of the leases in Weld County are private, the bulk in Routt County are federal. The proposed rule will only result in driving even more oil and gas investment off the public lands.

[13] S. Zimmerman, *Western Lands and Energy Newsletter* (June 26, 2013), available at http://www.nortonrosefulbright.com/knowledge/publications/100086/western-lands-and-energy-newsletter.

The Associations Support the Use of FracFocus

We support that part of the proposed rule that requires operators to report fluids and additives used in hydraulic fracturing operations on the FracFocus website.[14] FracFocus strikes the proper balance between substantial disclosure of additives used in hydraulic fracturing operations and protection of trade secrets service suppliers develop to improve the quality and safety of those operations. Operators are familiar with FracFocus and have been using the site consistently to disclose chemical usage for the past several years; more than 50,000 wells are currently registered with the site. As the National Energy Technology Laboratory has recognized, FracFocus is a valuable database for the public and for regulators.[15] It is appropriate to require its use for wells drilled on federal and Indian lands.

TECHNICAL CONCERNS

As discussed above, there are significant policy reasons why BLM should not proceed with the proposed rulemaking. Although we firmly believe that this proposed rule is unnecessary, we recognize that it is possible BLM will proceed with the rulemaking. It is therefore our responsibility also to address our numerous concerns regarding both the technical requirements that the rule would impose and the cost-benefit analysis for the proposed rule. These issues are introduced below and more fully discussed in the remainder of this document.

- Oil and gas agencies should continue to identify usable water zones. Currently, state oil and gas agencies and BLM field offices identify the formations that must be protected. This is effective and cost-efficient and should not be changed. Operators should not be required to submit total dissolved solids ("TDS") data or otherwise identify usable water zones. If operators are required to supply the data, the costs would likely be approximately $28.4 million to $42.5 million per year.

- SDWA exemption criteria should be fully incorporated. The proposed protection of "usable water" provisions would exempt water zones that agencies implementing the Safe Drinking Water Act ("SDWA") have formally exempted. If BLM abandons prior practice and adopts the more rigid and expansive definition of "usable water" in the proposal, it must further modify the proposed definition by directly incorporating the SDWA exemption criteria into the proposed rules and by adding water zone flow rates as an exemption criterion. This will allow BLM field offices reviewing Notices of Intent Sundry to determine which zones need to be protected.

- Additional costs for the protection of usable water. The proposed protection of "usable water" provisions are more stringent than the usable water provisions in Onshore Order No. 2, because Onshore Order No. 2 allows separation and segregation of zones and does not require cement behind pipe for every usable water zone. This increased stringency could cost approximately $310 million per year.

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[14] Proposed 43 C.F.R. § 3162.3-3(i)(1).

[15] NETL News Release (Apr. 18, 2013), available at:
http://www.netl.doe.gov/publications/press/2013/130418_hydraulic_fracturing.html.

- Cement evaluation logs ("CELs") for certain casing strings. CELs are not needed for casing strings for which cement is circulated to surface. BLM has failed to establish that CEL data will identify inadequacies in cement jobs that currently-used cement integrity verification measures do not detect. CELs should not be required for casing strings where cement is circulated to surface and should not be relied upon as the sole diagnostic tool to evaluate cement integrity.

- Cement repair provisions will decrease well integrity. The cement repair provisions in the proposed rule rely improperly on an easily-triggered single "indicator" of inadequate cement, overemphasize qualitative CEL data, and do not account for the full suite of diagnostic indicators operators consider to determine whether repairs are needed. As a result, repairs will be required where none are actually needed, a condition that threatens -- not ensures -- wellbore integrity. The proposal should be amended to address these concerns. If the proposal is not amended, BLM must include as part of its economic analysis the costs associated with unnecessary repairs and decreased well integrity.

- Cement repair should not be the remedy of first resort. Even when the evidence suggests that a cement job may be inadequate, other measures should be considered before BLM requires the operator to perforate the casing and perform remedial cementing. It may be more appropriate to test the adequacy of the cement shoe by pressure testing the shoe. It may be more appropriate to require the operator to install an annulus gauge at the surface and monitor the gauge for indications that fluids are increasing pressure in the annulus. BLM should not foreclose practical alternatives to remedial cementing.

- Clarifications are needed for type wells. If a CEL requirement is retained in the final rule, the scope of the "type well" concept should be clarified as generally applying to a "field," meaning a geographical area overlaying one or more hydrocarbon reservoirs. In addition, BLM should allow use of the type well exemption for wells that were not included in the same Group Notice Sundry as the type well.

- Cement monitoring and CEL provisions should not apply to existing wells. As currently drafted, the proposed rule would require cement operations monitoring and CELs before hydraulic fracturing on an existing well that has not previously been hydraulically fractured. Satisfying these requirements will not be possible; therefore, this retroactive requirement will result in the premature abandonment of numerous existing wells. Costs would include capital writeoffs, lost reserves, lost royalties, and replacement well drilling expenses.

- CEL delay costs have been underestimated. BLM is severely underestimating the delays associated with running CELs for surface and intermediate casing strings. The agency's assumed per-hour delay costs also appear to be too low. As proposed, the CEL provisions will result in approximately $7.6 million per year of additional costs.

- No additional cementing for existing wells. BLM should amend the proposed rule to allow existing wells that will be fractured or refractured to continue to meet the protection of groundwater standards in place when the wells were first completed. Without this amendment, BLM will subject many wells to expensive workovers and some to premature retirement. If the cement repair provisions are not amended, BLM must include as part of its economic analysis the costs associated with workovers, lost capital assets, and the drilling of replacement wells.

- <u>Cutoff between flowback and production</u>. BLM requested feedback on when fracturing flowback ends and production begins. There is no reason for BLM to distinguish between fracturing fluid flowback and produced water. From an operational perspective, these fluids are indistinguishable. BLM should use a more realistic nomenclature such as "recovered water" in defining management options for this waste stream. Should BLM insist on drawing such a distinction, however, we do not favor a cutoff based on sales because certain regulatory requirements, such as EPA's emissions standards for the oil and gas sector, may require the sale of oil and gas during flowback. A time-based cutoff, to be determined on a field-by-field basis, would be clearer and simpler.

- <u>Tanks should not be the only recovered fluids option</u>. BLM should retain the current proposed requirement that operators manage recovered fluids in either lined pits or storage tanks. There are economic, environmental, and operational advantages to each and operators should have the flexibility to choose the solution most appropriate under various circumstances. Management in storage tanks is estimated to cost approximately $19.6 million per year and at least $9.4 million more than using temporary lined pits. Costs for long-term storage facilities would be even higher.

- <u>Trade secret protections should be expanded</u>. We endorse the proposed provisions that would allow the submission of data via FracFocus and that would allow protection for trade secret information. The proposed rule affords trade secret protection, however, only to information that would be submitted after a hydraulic fracturing operation. We request that BLM expand the trade secret provisions to information required to be submitted in the Notice of Intent Sundry, such as fracture length and orientation data.

- <u>Costs for fracture modeling</u>. We request that BLM allow the use of fracture data gathered and modeled for similar wells, as opposed to requiring new modeling for every well. If modeling is required for every well, we estimate that annual costs will increase by at least $15.4 million per year or more, depending on the sophistication of the modeling required.

- <u>Deviation reporting should be eliminated</u>. The deviation reporting requirement in the proposed rule will be a significant administrative burden on operators, because natural variation will result in some degree of variation between predicted and observed values with respect to almost every piece of information submitted after a hydraulic fracturing operation. Instead of deviation reporting, BLM should identify any deviations it considers important based on its review of operators' completion reports and then submit those specific concerns to operators for explanation.

- Certification requirements should be more flexible. In light of the nature of oil and gas operations, including the number of contractors involved in drilling and completing a well and the prevalence of trade secret information, the certification requirements require more flexibility than currently proposed. Foremost, service providers -- not operators -- should be required to submit and certify the service provider's own data. In addition, the certification should be based only on data available at the time of certification.

- Variance provisions are too easily revoked or amended. We agree that variance provisions should be included in the final rule and that the BLM should establish a mechanism for states to substitute their existing rules for the BLM's proposed provisions. To ensure both equivalency of standards and predictability, however, the process must be better defined. We are also concerned with BLM's proposal that the agency may revoke or amend granted variances based on a policy change or for "other reasons."

- Total costs of the rule have been underestimated. Based on an economic analysis included in Appendix A, we believe that total costs for the rule are likely to be on the order of approximately $345 million per year or more. BLM has significantly underestimated the costs its proposed rule would impose.

- Benefits analysis is insufficient to support the rule. The purported benefits of the rule are exceedingly uncertain. Although BLM's risk analysis incorporates some numerical assumptions, there appear to be significant errors in the limited amount of numerical data BLM discusses. BLM's arbitrary risk analysis exacerbates its failure to accurately assess the costs associated with the rule.

- Alternatives analysis is inadequate. The alternatives analysis BLM prepared is inadequate because it focuses primarily on whether liners should be required for pits, an issue that the BLM estimates would cost $9 per well (less than 0.03% of total costs). For the alternatives analysis to be meaningful, BLM must at least assess an alternative that does not impose a CEL requirement for surface casing. This requirement alone comprises at least sixty-three percent of BLM's projected costs.

- BLM must comply with statutory and executive order mandates. We estimate that costs will significantly exceed $100 million per year. Because of the costs the rule will impose, BLM is legally required to reconsider and amend its analyses under: (i) Executive Order 13563; (ii) Executive Order 12866 (Regulatory Planning and Review); (iii) the Regulatory Flexibility Act of 1980; (iv) the Small Business Regulatory Enforcement Fairness Act; (v) the Unfunded Mandates Reform Act; and (vi) the National Environmental Policy Act ("NEPA").

- Feedback on deferrals to state and tribal laws. BLM requested feedback on the enforcement challenges associated with BLM's deferral to state or tribal laws and procedures. We believe that BLM could incorporate state and tribal requirements in a manner that would not limit the agency's enforcement powers.

I. PROTECTION OF "USABLE WATER"

BLM's original hydraulic fracturing rule proposal would have eliminated the term "fresh water" from 43 CFR Part 3160, defined "usable water" as generally those containing up to 10,000 parts per million ("ppm") TDS, and replaced a provision requiring the protection of fresh water and water zones with 5,000 ppm or less TDS with a provision requiring the isolation of all usable water zones.

The revised proposal keeps the 10,000 ppm TDS threshold for usable water and clarifies that usable water includes: (i) sources of drinking water that EPA or state law designate expressly; (ii) zones actually used to supply water for agricultural or industrial users; and (iii) zones a state or tribe have designated as requiring protection. The revised proposed rule would exclude from protection those zones designated pursuant to the SDWA as "exempted aquifers" and zones which the state or tribe has designated as exempt from isolation requirements. Usable water zones would be identified "by use of a drill log from the subject well or another well in the vicinity and within the same field."[16]

We have a number of technical concerns with the protection of "usable water" provisions. These concerns are briefly summarized below and then discussed in greater detail in the remainder of this section.

- The "exempted aquifers" provision is largely useless from a practical perspective, because the exemption process is intended for actual injection wells and can be time-prohibitive. BLM should instead incorporate the SDWA exemption criteria into the actual definition of "usable water," in addition to excluding zones that have received a formal SDWA exemption.

- Under current practice, state oil and gas agencies and BLM field offices inform operators about water resources that must be protected, taking into account local geology. In North Dakota, for example, the state requires that surface casing be set at least fifty feet below the base of the Fox Hills formation.[17] For wells drilled in the Jonah Field or to the Lower Fort Union and Lance formations in southeastern Wyoming, the BLM Rock Springs Field Office requires surface casing to a depth of 2,500 feet and production casing with the top of cement 400 feet above the top of the Lance Formation (or above the highest gas sand, whichever is shallower). The proposed rule upsets this locally-sensitive practice and imposes a costly burden for operators to identify all usable water zones, irrespective of localized geographic and geologic considerations. Costs to sample potential usable water zones are estimated to be in the range of \$100,000 to \$150,000 per well. Even if this data is gathered only for type wells, average costs would be approximately \$8,000 to \$12,000 per well.

- Contrary to BLM's assertions, the proposed rule's provisions related to the protection of usable water represent an expansion of Onshore Order No. 2's requirements and will therefore increase costs. Some wells will be unaffected or will need only minor changes

[16] 78 Fed. Reg. 31,636, 31,675 (May 24, 2013).

[17] N.D. Admin. Code § 43-02-03-21.

in casing and cement design, but some may need an entirely new string of intermediate casing. This could be up to the equivalent of 2,350 additional feet of casing at a cost of approximately $310 million. Even if the rule will mandate only the equivalent of 1,000 feet of additional casing, the added cost would still be approximately $132 million.

We request that BLM modify the proposed regulatory definition of usable water to account for existing practice and for consistency with the agency's application of Onshore Order No. 2.

Strike proposed § 3160.0-5 *Usable water* [definition] and replace with:

Usable water means water in those underground formations which a State (for Federal lands) or a tribe (for Indian lands) requires to be protected from oil and gas operations by surface casing.

- The expansion in requirements for the protection of usable water may result in a prohibition on fracturing or re-fracturing existing wells or result in operators having to conduct squeeze cementing operations before conducting hydraulic fracturing operations on these wells.

Background on TDS in Groundwater

To put BLM's proposed use of 10,000 ppm of TDS into a more practical perspective, we begin with a summary of how humans respond to varying concentrations of TDS in water. The World Health Organization has noted the effects of TDS on how palatable water is to humans. The taste of water with less than 300 ppm is rated "excellent," of water with between 300-600 ppm—"good," of water with between 600-900 ppm—"fair," of water with between 900-1,200 ppm—"poor," and of water with greater than 1,200 ppm—"unacceptable."[18] EPA has set a secondary "maximum contaminant level" for TDS at 500 ppm for drinking water.[19]

Recommended maximum levels for TDS for water for crops and livestock are also far below BLM's 10,000 ppm proposed standard. In Colorado, irrigation water exceeding a state guideline of 2,000 ppm is classified as "unsuitable."[20] The North Dakota State University Extension Service advises farmers and ranchers that water quality for animals is "good" if it generally has

[18] World Health Org., "Total dissolved solids in Drinking-water" (2003), available at http://www.who.int/water_sanitation_health/dwq/chemicals/tds.pdf.

[19] EPA, "Secondary Drinking Water Regulations: Guidance for Nuisance Chemicals," available at http://waterepa.gov/drink/contaminants/secondarystandards.cfm.

[20] Bauder, et al., *Water Quality for Irrigated Agriculture - Salinity/Sodicity Focus* at 9, available at: http://waterquality.colostate.edu/documents/irrigationwaterquality.pdf.

less than 2,000 ppm of TDS.[21] Water with 10,000 ppm or more "may cause brain damage or death" in livestock.[22]

One questions what it is about water with 10,000 ppm of TDS that is "usable"? The sole answer is that it is a criterion drawn from EPA regulation of underground injection of potential contaminants under the SDWA. BLM's incorporation of that criterion here represents an arbitrary analogy, because hydraulic fracturing is generally exempt from the underground injection control ("UIC") program promulgated under that statute.

The history of both the SDWA and EPA regulation under that statute reveals three telling points. First, the SDWA itself did not adopt the 10,000 ppm standard. Second, when EPA adopted the standard, it did not do so based on any scientific study of the usability of water with that high a level of dissolved solids. EPA instead selected the figure because it had appeared in a House of Representatives report on the bill.[23] Third, EPA acknowledged that "some aquifers below the 10,000 [ppm] level are so contaminated that as a practical matter they are not potential drinking water sources."[24]

Incorporation of the SDWA's Exclusion Criteria

Under the SDWA, an "underground source of drinking water" is a non-exempt aquifer which supplies any public water system, or contains a sufficient quantity of ground water to supply a public water system, and either currently provides drinking water for human consumption or contains less than 10,000 ppm TDS.[25]

"Exempted aquifers" are those which have been previously determined to meet the following criteria: (i) not serving as a source of drinking water; or (ii) cannot and will not in the future serve as a source of drinking water due to the presence of mineral, hydrocarbon, or geothermal resources, depth or location that makes recovery for drinking water technically or economically impractical, contamination, or location over a Class III well mining area subject to subsidence or catastrophic collapse.[26]

BLM's revised rule references the above provision, but does so in a way that will make little difference to operators. To start, BLM does not incorporate the actual criteria for exempted aquifers into the rule so that operators can consider the criteria when preparing Notices of Intent Sundry, and BLM field offices may refer to the criteria when evaluating those Notices. The agency instead states that zones implementing agencies designate as exempted aquifers under the SDWA are generally excluded from being considered "usable water."

As a result, to avoid protecting a zone that meets the exclusion criteria an operator would have to apply to the EPA or an SDWA-delegated state or tribal agency for a formal exemption. This is a

[21] G. Lardy *et al.*, "Livestock and Water," Table 9 (NDSU Extension Service June 2008).

[22] *Id.*

[23] 41 Fed. Reg. 36730, 36733 (1976).

[24] *Id.*

[25] 40 C.F.R. § 146.3.

[26] 40 C.F.R. § 146.4(a).

lengthy process because it was designed for exemptions allowing long-term injection into a reservoir. This is not a process designed for the protection of non-injection ground water zones.

An example helps to illustrate the practical difficulties of using the current version of the exemption. Suppose there are five zones, A through E, that are technically "usable water" zones, but also meet the exemption criteria and are useless for practical purposes. An operator who wants to use reservoir A for disposal by pumping millions of gallons of produced water and residual associated hydrocarbons into the zone, could apply for and receive an exemption for reservoir A under the SDWA. An operator who simply wishes an exemption from considering these zones "usable water" under the BLM's proposal, and who will not be actively pumping anything into the reservoir, would also have to apply for exemption. And unlike the former operator who would need an exemption only for the injection zone, the latter operator would need to apply for and receive exemptions for all five zones, A through E. This makes the exemption very difficult to use.

We note that BLM likely drafted its exclusion criteria on the assumption that many or even most zones of concern have already been through the SDWA exemption process and that information regarding exempted reservoirs would therefore be readily available to operators. Unfortunately, this is not the case. We contacted EPA and many other delegated SDWA agencies and confirmed that there are no state or federal databases of exempted reservoirs. Further, most exemptions are granted on a well-by-well basis and not on a reservoir-wide basis, so that, even if exemption data were available, it would likely not apply to the vast majority of wells.

The solution to the above issue is for BLM to incorporate the exclusion criteria into the definition of usable water in the proposed rule. This would allow operators and BLM field offices to exclude zones meeting the exclusion criteria without going through a formal exemption process. This would not circumvent the formal exclusion process under the SDWA because operators would not be seeking to actively inject into the excluded formations, making the scope of impacts wholly different. Further, the cement for the production casing across hydrocarbon zones will serve to prevent hydrocarbon migration into the excluded zones.

Finally, we note that BLM should include flow and overall volume as one of the exemption criteria. These are not SDWA exemption criteria, but volume is part of the EPA's definition of "underground source of drinking water." Unless these criteria are added as bases for exemption, "usable water" may include zones that produce very small volumes of water and are useless for all practical purposes, but otherwise meet the usable water definition.

Again, we urge BLM to continue following current practice and adopt the text IPAA has proposed on page 19 of these comments. If BLM refuses, it should at least adopt the following regulatory text concerning usable water:

Definition of Usable Water

Proposed Change to BLM proposed 43 C.F.R. § 3160.0-5:

Usable water means generally those waters containing up to 10,000 parts per million (ppm) of total dissolved solids. The following geologic zones are deemed to contain usable water:[27]

…

(4) Zones known to contain less than 10,000 ppm of total dissolved solids that are not excluded by paragraphs (A), (B), (C), or (D) of this definition. The following geologic zones are deemed not to contain usable water:

(A) Zones from which an operator is authorized to produce hydrocarbons;

(B) Zones designated as exempted aquifers pursuant to the Safe Drinking Water Act;

(C) Zones which the State (for Federal lands) or the tribe (for Indian lands) has designated as exempt from any requirement to be isolated or protected from oil and gas operations; and

(D) Zones which cannot now and will not in the future serve as a source of drinking water because:

(i) It contains insufficient volume or provides insufficient flow to supply a public water system;

(ii) It is mineral, hydrocarbon or geothermal energy producing, or can be demonstrated to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible;

(iii) It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impossible;

(iv) It is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption; or

(v) It is located over a Class III well mining area subject to subsidence or catastrophic collapse.

[27] As discussed above, we believe that defining usable water based on the amount of total dissolved solids is arbitrary and inconsistent with BLM's historic practice. If BLM insists on retaining its proposed definition, however, we offer the regulatory language contained in this box.

Operators Should Not Bear The Compliance Burden of Identifying All Usable Water

As previously noted, the proposed rule will require the protection of "usable water" based on the use of a drill log from the subject well or another well in the vicinity and within the same field. The preamble to the proposed rule states that, as a matter of industry practice, operators typically maintain drill logs identifying usable water zones.[28] This is not correct.

The primary threshold indicator in the proposed definition of "usable water" is a TDS level of 10,000 ppm. No logging tool directly measures TDS. Operators often run resistivity logs for intermediate and production casing[29] and these logs might allow the qualitative identification of high salt content zones. These logs do not, however, directly measure TDS and there are too many variables for the signature these logs record to be converted into accurate TDS data. In fact, when our members apply for an injection permit under the SDWA they are sometimes required to collect a sample of the formation fluid and to then analyze the sample to determine properties such as TDS.

Current practice is not for operators to identify usable water zones for protection and then submit the information to state oil and gas agencies or the BLM field offices for approval, but instead for these agencies to tell operators which zones must be protected. The proposed rule fundamentally alters this practice, placing an increased and substantial burden on operators.

BLM has not identified any data showing that current practice has resulted in a lack of protection for "usable water zones." In the absence of this data, requiring operators to undertake lengthy and expensive projects to individually generate TDS data is unnecessary and inefficient. In many cases, it would require that operators sample multiple water formations to determine whether TDS is above or below 10,000 ppm. In some cases, operators may need to drill a well for the express purpose of sampling water formations.

Based on the above, we request that BLM implement the following rule changes:

Protection of Usable Water

Proposed Change to BLM proposed 43 C.F.R. § 3162.3-3(d)(2):

(2) The operator may include in the Notice of Intent Sundry any water formation or water quality data that the operator believes supports a determination by the authorized officer that a water source is not usable water and is not required to be protected pursuant to 43 CFR § 3162.5-2. Otherwise, the authorized officer will determine usable water based on the zones a State (for Federal lands) or a tribe (for Indian lands) requires to be protected by well casing from oil and gas operations.

Proposed Change to BLM proposed 43 C.F.R. § 3162.5-2(d):

[28] 78 Fed. Reg. 31,636, 31,662 (May 24, 2013).

[29] Resistivity logs are less common for surface casing.

> (d) *Protection of usable water and other minerals*. For each new well, the operator must protect and/or isolate all usable water zones and other mineral-bearing formations which a State (for Federal lands) or a tribe (for Indian lands) requires to be protected by well casing from oil and gas operations and as otherwise consistent with the requirements in Onshore Order Number 2, Drilling Operations, Section III.B. (January 27, 1992, 57 FR 3025).

Costs Associated with the Protection of "Usable Water"

Contrary to the BLM's Assertion, There Will Be Additional Cementing and Casing Costs

BLM maintains that the usable water provisions in the hydraulic fracturing rule will not increase costs for operators because the rule simply updates the rule to be consistent with Onshore Order No. 2. This argument appears to be premised on an incorrect belief that, like the proposed rule, Onshore Order No. 2 requires cement behind pipe across all usable water zones.

Onshore Order No. 2 was published in the Federal Register in November 1988 and addresses drilling operations located on Federal and Indian lands.[30] Among other provisions, Onshore Order No. 2:

- Defines "usable water" to mean "*generally* those waters containing up to 10,000 ppm of TDS." (*emphasis added*)
- Requires that casing and cementing programs "be conducted as approved to protect and/or isolate all usable water zones, lost circulation zones, abnormally pressured zones, and any prospectively valuable deposits of minerals" and requires BLM approval for the use of any isolating medium other than cement.
- Defines "isolating" to mean "using cement to protect, separate, or segregate usable water and mineral resources."

The inclusion of all three words, "protect," "separate," and "segregate," in the definition of "isolating" indicates that Onshore Order No. 2 does not require cement contacting all usable water zones. For example, cement behind the production casing that covers all hydrocarbon productive zones would segregate the hydrocarbon zones from the usable water zones regardless of whether there is cement across all usable water zones.

Additional support is found in BLM's Instruction Memorandum No. 92 (October 31, 1992), which established guidance for oil and gas drilling operations.[31] In the section addressing production casing, the Instruction Memorandum states that the casing string must be cemented so that exposed usable quality water zones "are covered or isolated." The quoted language clearly indicates that isolation, as the word is used in Onshore Order No. 2, is distinct from covering a zone with cement.

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[30] 53 Fed. Reg. 46,798 (Nov. 18, 1988).

[31] Instruction Memorandum No. 92 is available at: http://www.ntc.blm.gov/krc/uploads/247/Drilling%20Manual-Handbook%203160-1.pdf.

Current webpages for BLM field offices in Wyoming further indicate that Onshore Order No. 2 does not require cement behind pipe for all usable water zones. The "Applications for Permit to Drill" webpage for BLM's Kemmerer Field Office in Wyoming states that the cementing program can protect usable water (less than 10,000 ppm TDS) by casing over the usable water entirely *or* by circulating cement above sources of contamination.[32]

In comparison, the proposed hydraulic fracturing rule will impose additional casing and/or cementing costs on operators because, unlike Onshore Order No. 2, the proposed rule would require cement behind pipe across all usable water zones. Even though the proposed rule uses the word "isolate," it uses the word differently than Onshore Order No. 2. This is clear from the requirement to run a CEL for each casing string that protects usable water and from the preamble to the original proposed rule, which stated that "[t]he best available means for the BLM to ensure that well stimulation activities do not contaminate aquifers is to require cement bond logs *for the cement behind the pipe along all areas intersecting usable water*."[33]

Incremental costs associated with the expanded meaning of "isolation" in the proposed rule would include the following:

- Additional cement costs associated with cementing zones that may currently be isolated behind pipe without cement. Costs would result from larger volumes of cement and from the use of lighter, specialty cements to avoid exceeding the fracture pressure of geologic formations.

- Additional casing costs associated with deeper surface or intermediate casing needed to cover and cement over usable water zones that are currently allowed to be isolated behind pipe.

- In some cases, an additional intermediate casing string may be needed where none is currently required. This might be the case where surface casing cannot be extended deep enough to cover all usable water zones due to fluid circulation and geologic constraints. Running an additional casing string would mean additional rig, cementing, and pipe costs. It would also mean that earlier drill bits and casing strings would need to be a larger diameter (and therefore more expensive).

- Multi-stage cementing for wells where covering all usable water zones with a single-stage cement job would result in hydraulic pressures exceeding the fracture point of exposed formations. Multi-stage cementing is more technically complex and requires more time because earlier stages must initially set (so that they do not add to the hydraulic pressure) before later stages are run. The result is additional rig and equipment rental time.

Not all incremental costs would be incurred for all wells. Many wells might not have any incremental casing and cementing costs. Other wells may be subjected to very high additional

[32] The webpage is available at: http://www.blm.gov/wy/st/en/programs/energy/Oil_and_Gas/Onshore_Operations/apdk.html.

[33] 77 Fed. Reg. 27,691, 27,696 (May 11, 2012) (emphasis added).

costs, particularly where fracture pressures limit the amount of cement that can be circulated. Under these circumstances, specialty cements, additional pipe, and multi-stage cementing would be significant costs, as would the additional rig and equipment time needed to implement these additional design factors.

As previously discussed, state oil and gas agencies and the BLM field offices inform our members how deep casing strings need to be set and cemented to comply with Onshore Order No. 2. Operators do not typically sample water zones to develop TDS concentration data. It is therefore not possible to determine the areas in which "usable water" zones are protected under Onshore Order No. 2 without cement behind the pipe.

Applying a conservative estimate, however, and assuming only 2,350 feet of additional pipe as representative of the costs associated with the proposed rule's "usable water" requirement (*i.e.*, as a direct measure of extended casing and additional casing strings and as a surrogate for specialty and other cement costs and increased rig and equipment time), John Dunham & Associates estimates that this measure would increase costs by an average of approximately $87,000 per well and a total of approximately $310 million per year. Even at only 1,000 feet of additional casing, the added costs would total approximately $132 million.

Costs Associated with Identifying Usable Water

As previously noted, BLM has incorrectly assumed that operators have "drill logs" that identify usable water zones. Based on this assumption, BLM's economic analysis does not include costs for the proposed requirement that operators submit in their Notices of Intent Sundry data locating the tops and bottoms of all occurrences of usable water. BLM should either revise the rule to exclude this requirement, or update its economic analysis to reflect the costs that this requirement will impose.

Our members indicate that the cost of obtaining accurate TDS data would be substantial, likely in the range of $100,000[34] to $150,000 to obtain data for a single well. The proposed rule allows the use of water data from "another well in the vicinity," so not all wells would require sampling. If sampling is required for each type well, the cost averaged over all wells would be approximately $8,000 to $12,000 per well. Based on 3,566 wells, the number of hydraulic fracturing operations that BLM estimates to occur in the first year the proposed rule is implemented,[35] this would be approximately $28.4 million to $42.5 million per year.

As previously discussed, we have proposed regulatory language revising the identification of usable water requirement in 43 C.F.R. § 3162.3-3(d)(2) to preserve the currently-used process, by which operators are informed which usable water zones must be protected. If BLM does not accept the proposed revision, we request the following change:

[34] A study prepared at Oklahoma City University, included in comments Devon Energy Corporation submitted on June 24, 2013, indicates that water tests would cost approximately $101,200.

[35] U.S. Bureau of Land Mgmt., *Economic Analysis for Hydraulic Fracturing Rule* at 40; 78 Fed. Reg. 31,636, 31,666 (May 24, 2013).

Removal of Drill Log Data Requirement

Strike the following underscored language from proposed § 3162.3-3(d)(2):

The measured or estimated depths (both top and bottom) of all occurrences of usable water <u>by use of a drill log from the subject well or another well in the vicinity and within the same field</u>;

Complications and Costs for Existing Wells

The proposed rule states that all hydraulic fracturing and refracturing operations must meet the protection of usable water standards.[36] As previously discussed, BLM interprets the new provisions related to the protection of usable water as requiring that cement cover each usable water zone, but this is more stringent compared to the provisions related to the protection of usable water in Onshore Order No. 2.

The problem, then, is that the proposed rule will require existing wells to meet the expanded cementing requirements the rule imposes before these wells can be hydraulically fractured or refractured. Some existing wells already have cement across all usable water zones. Other wells do not have cement behind pipe across all of these water zones, instead protecting them by separation and segregation, consistent with Onshore Order No. 2. For these wells, we are concerned that BLM will require squeeze cementing or, where such operations are infeasible, will not allow fracturing or refracturing at all.

We request that BLM amend the proposed rule to require that existing wells continue to meet the protection of applicable groundwater standards in place when the well was first completed. This could be accomplished by inserting the words "for all new wells" into proposed 43 C.F.R. § 3162.5-2. Without this amendment, BLM will subject many wells (drilled in good-faith reliance on Onshore Order No. 2) to expensive workovers and even premature retirement.

We strongly oppose any rule provision that would needlessly strand significant amounts of reserves and capital resources. This is especially true when the proposed rule upsets justifiable expectations that drilling and cementing in accord with BLM's standards and orders will allow continued use for the reasonable life of an approved well. If BLM proceeds with this rule provision, the agency must capture these costs in its economic analysis. These costs would include workover expenses, loss of reserves associated with premature retirement of wells, and drilling expenses for replacement wells.

II. <u>CEMENT EVALUATION LOGS AND CEMENT REPAIR PROVISIONS</u>

The current version of the BLM's proposal replaces the term "cement bond log" ("CBL") with the more expansive "cement evaluation log." The revised rule also restricts the logging requirement for casing strings contacting "usable water" zones to "type wells," but retains provisions requiring repairs and confirmatory CELs where there is an indication of an inadequate cement job.

[36] 40 C.F.R. § 3162.3-3(b).

We support the substitution of the term CEL because it would afford our members greater flexibility. But we have significant concerns with the provisions dictating when a CEL would be required and how CELs and other data would be used in determining the adequacy of cement jobs. As currently written, the proposed rule encourages activities that will weaken wellbore integrity by requiring cement "repairs" where none are actually needed.

One concern is the requirement that CELs be run for surface casing and other casing strings where cement is circulated to surface. As discussed below, CELs are not a best practice for surface casing because traditional cementing measures, including verification of cement returns at the surface, render them unnecessary. If BLM requires CELs for surface casing and other strings where cement is circulated to surface, it will be imposing significant costs without actually improving the detection of inadequate cement jobs.

We acknowledge that the "type well" concept is an improvement compared to the initial proposal; but the revised provisions are nevertheless unnecessary and expensive. In fact, BLM's justification for limiting CELs to type wells is the inherent efficacy of the measures traditionally used to evaluate cement integrity and formation isolation for casing strings where cement is circulated to surface. Despite this, the BLM retains CELs for type wells without explaining how the required CELs will identify instances of inadequate cement that currently-used measures would not detect.

Another concern is that the cement repair requirements in the proposed rule would be triggered too easily (by any single "indication" of inadequate cement, without regard to other data) and would therefore result in "repairs" where other data, such as pressure tests, demonstrate that proper isolation was achieved. These provisions condition certification following repairs on CEL data, in effect making CEL data the sole determinant of well integrity.

CELs can be misleading when analyzed in the absence of operational cementing data and should not be used as the sole or even primary determinant of whether a cement job is adequate or inadequate. Ignoring pressure tests and other data based on a CEL would cause operators to conduct unnecessary remedial cement squeeze jobs. These jobs would be a needless expense and, worse, would weaken well integrity, increasing the likelihood of future operational issues.

There is No Basis for Requiring CELs When Cement Is Circulated to Surface

CELs are Not Needed Due to Traditional Integrity Verification Measures

Oil and gas operators typically confirm the adequacy of the cement for surface casing by employing most or all of the following measures: (i) using properly spaced centralizers; (ii) using excess cement; (iii) monitoring pressures and flow rates during cementing; (iv) circulating cement to surface; (v) verifying that there is no "fall back" of the cement once pumping stops; (vi) pressure testing the surface casing before drilling out the cement; and (vii) pressure testing the casing shoe after drill out. Indeed, BLM already requires the use of many of these procedures-- Onshore Order No. 2 requires centralization, the circulation of cement to the surface, and the use of top jobs or other remedial cementing measures to assure that cement returns to the surface.

In light of the cement integrity measures noted above, operators do not typically run a CEL for surface casing and might not run a CEL for the intermediate and production strings, particularly where subsequent strings are also cemented to surface. Many intermediate and most production casings strings are not circulated to surface, due to engineering constraints, such as the hydraulic pressure of the cement and the fracture pressure of the formations behind the pipe.

Where cement is not circulated to surface, operators often run CELs as a means of accurately determining the "top of cement." Although CELs provide some information regarding bond integrity, this information is secondary to confirming that the top of cement is where it is expected to be based on the cement job design calculations. Pressure tests coupled with confirming top of cement provide the best indication that cementing was properly executed and that the cement will isolate relevant subsurface formations. In comparison, CEL data can be difficult to interpret properly and often yields false positives (as discussed more fully in the section addressing Wellbore Integrity).

Where cement is circulated to surface and pressure tests are satisfactory, CELs for casing strings that contact "usable water" are unnecessary because CELs do not provide any additional assurance of protection. This is particularly true for casing strings set in vertical or mildly deviated wellbores. Setting casing in a vertical wellbore makes it relatively easy to centralize the casing and to rotate and reciprocate the casing to improve the displacement of drilling mud and the elimination of channels in the annulus.

BLM acknowledges in the preamble to the proposed rule that industry typically does not run CELs for surface casing because the operator can observe the cement in the annulus and use additional cement if needed.[37] We note that the same reasoning applies to subsequent casing strings for which cement is circulated to surface.

BLM also acknowledges that measures such as those noted above are adequate indicators of a proper cement job—sufficiently indicative for BLM to use these alternatives as the basis for BLM's proposal to largely limit CEL requirements to "type wells."[38] We believe that the "type well" concept is a step in the right direction, but only because it reduces the level of burden associated with an unnecessary requirement.

CELs Will Not Improve Integrity

An essential problem with the proposed CEL requirement is that BLM does not establish why this measure is needed given all the other measures that are currently used to confirm that the cement job proceeded as planned and will properly prevent the subsurface migration of fluids. BLM does not discuss or cite any studies or other technical arguments supporting the agency's belief that conducting CELs on surface casing and other casing strings cemented to surface will actually reduce risk by detecting inadequate cement jobs in instances where current measures do not.

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[37] 78 Fed. Reg. 31,636, 31,651 (May 24, 2013).

[38] 78 Fed. Reg. 31,636, 31,652 (May 24, 2013).

BLM stated in the preamble to the initial version of the proposed rule that a Shale Gas Subcommittee report recommended "that operators engaged in hydraulic fracturing prepare cement bond logs and undertake pressure testing to ensure the integrity of all casings."[39] This statement is different in the revised preamble. The revised statement makes no mention of bond logs: "The final report also recommended that operators engaging in hydraulic fracturing undertake pressure testing to ensure the integrity of all casings."[40] The change appears to have been made because BLM's original statement regarding the subcommittee report was incorrect.[41]

BLM likewise cites guidelines the American Petroleum Institute ("API") issued related to hydraulic fracturing operations, stating that the guidance "describes *some* circumstances where CBLs are used to verify adequate cementing."[42] The API guidelines do not mention cement logs in the section specifically devoted to surface casing and state in the section on intermediate casing only that, "[d]epending on the well design, it may be appropriate to run a CBL . . . ."[43] The guidelines do not support CELs for surface casing and indicate that CELs are not universally necessary for intermediate casing.

Relying on the work of George E. King, P.E., BLM estimates in the economic analysis document for the proposed rule that three percent of wells will have an indication of an inadequate cement job.[44] This estimate alone, however, does not constitute support for the proposed CEL requirement; BLM overlooks the critical question, omitting any discussion regarding how many inadequate cement jobs currently go undetected, but would be detected with a CEL. BLM does not discuss the extent to which CELs would reduce risk by improving the detection of inadequate cement jobs compared to the confirmation measures which currently comprise industry's best practices.

It also appears that the BLM was unaware of or discounted Mr. King's other work on cement logs. [45] A more comprehensive review of Mr. King's work reveals that: (i) cement logs will not

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[39] 77 Fed. Reg. 27,691, 27,693 (May 11, 2012).

[40] *Compare* 78 Fed. Reg. 31,636, 31,639 (May 24, 2013).

[41] The Shale Gas Subcommittee report recommended the adoption of "best practices" and then mentioned that pressure testing and cement bond logs should be used to confirm "formation" isolation. The recommendation did not mention surface casing and bond logs for surface casing as a best practice. Equally important, the report used the terms "water reservoirs" or "drinking water resources" for water zones and the word "formation" for the hydrocarbon producing zone. This usage demonstrates that the bond log recommendation in the report concerns the production casing covering the producing hydrocarbon formation and not the casing covering drinking water zones. The report is available at: www.shalegas.energy.gov.

[42] 78 Fed. Reg. 31,636, 31,639 (May 24, 2013) (emphasis added).

[43] The API Guideline document is available at: http://www.api.org/~/media/Files/Policy/Exploration/API_HF1.pdf.

[44] The estimate is located on page 37 of the economic analysis for the proposed rule. The associated footnote references an *EnergyWire* article that cited King's February 2012 paper for the Society of Petroleum Engineers. The original paper is available at: http://fracfocus.org/sites/default/files/publications/hydraulic_fracturing_101.pdf.

[45] Mr. King is an expert in petroleum engineering. His paper on cement bond logs is publically available at: http://gekengineering.com/Downloads/Free_Downloads/Cement_Bond_Log_(CBL)_Overview-DRAFT-2.docx.

predict or confirm pressure isolation; and (ii) the only cement test method that can confirm zone-to-zone isolation is a pressure test.[46]

BLM's benefits analysis for the proposed rule reinforces these conclusions. The agency simply asserts that "the regulations would most certainly reduce risk," even while acknowledging that it is difficult to quantify the level of risk reduction that would be attributable to the regulations as a whole.[47] Not only is it "difficult" to assess the benefits of the rule as a whole, it is also "difficult to attribute benefits to one single test (for instance the CEL) when that is only part of the overall evaluation of wellbore integrity."[48]

BLM has not established that existing practices are insufficient for casing strings cemented to surface and cannot estimate the benefits of requiring CELs for these casing strings. This is because there is no empirical support establishing that the CEL requirement, operating in conjunction with traditional casing cement design and evaluation techniques, will actually enhance well integrity.

BLM appears to believe that there are benefits associated with running CELs for surface casing and other casing strings contacting "usable water." But belief alone is not a legal basis for rulemaking. We urge BLM to remove the CEL requirement for surface casing strings and other strings where cement is circulated to surface and we propose the following revisions to the proposed rule:

> **To Remove the Requirement for Routine Use of CELs**
>
> Strike proposed § 3162.3-3(e)(2) & (3) [requiring cement evaluation logs even without indicators of an inadequate cement job], renumber current proposed paragraphs (4) & (5), and strike the following underscored language from proposed § 3162.3-3(d):
>
> <u>If the type well has not been completed, the cement evaluation log described in paragraph (e)(2) of this section must be provided to BLM before drilling operations may begin on the other wells in the group</u>.

The Cement Repair Requirements Will Compromise Wellbore Integrity

The proposed rule would require that, for any well where there is *an indication* of an inadequate cement job, the operator must report the information to BLM within twenty-four hours and submit a written report within forty-eight hours. As examples of the types of indicators that might suggest an inadequate cement job, BLM references lost returns, cement channeling, gas

[46] These issues are further discussed in the Wellbore Integrity section.
[47] 78 Fed. Reg. 31,636, 31,663 (May 24, 2013).

[48] 78 Fed. Reg. 31,636, 31,664 (May 24, 2013).

cut mud, et al.[49] Before commencing hydraulic fracturing operations, the operator must run a CEL showing that the inadequate cement job has been corrected and must certify the same.[50]

We agree that a CEL may be useful where there are corroborating indications of an inadequate cement job.[51] We have significant concerns, however, that the repair requirements would be too easily triggered, place too much emphasis on CEL data, and would mandate repairs where none are actually needed. Specifically, the current proposal would require repairs based on any single indication of an inadequate cement job without adequately defining what this term means and without consideration of other indicators.

As detailed below, the following revisions are needed: (i) repair assessments and cement adequacy certifications should be based on all of the available data, including pressure test data and an assessment of whether inadequate cement is likely to result in the contamination of "usable water" by subsurface migration; (ii) the term "indication of inadequate cement" should be clarified so that minor issues do not trigger additional investigation or repairs; (iii) clarification that the rule requires only that protected formations be "isolated" from the fractured zone, not that the cement actually cover and be bonded to the formation to be protected; (iv) adoption of objective indicators of cement isolation; and (v) recognition that there can be less costly and more effective alternatives to remedial cementing if a cementing job appears to have been inadequate.

Repair Decisions Should Not Be Based on a Single Indication of Inadequate Cement

BLM's proposed rule presumes that there is an inadequate cement job and mandates repairs based on a single data point. First, the rule states that "*an* indication" of an inadequate cement job triggers the cement repair requirements. Second, the subsequent requirement is that the operator must run a CEL "*showing that the inadequate cement job has been corrected*."

The rule equates an "indication" of an inadequate cement job with proof of an inadequate cement job. And this indication triggers a required certification conditioned on having corrected the inadequate cement. As drafted presently, the certification process does not contemplate the possibility that the original cement job was adequate—there is no allowance for operators to simply demonstrate with other information that the "indication" was incorrect and that repairs are not needed.

The examples of "indicators" that BLM itself provides is illustrative. Observations of lost returns, cement channeling, and gas cut mud do not represent certain or immediate evidence of a poor cement job. Channeling can only be determined through an engineering analysis of the bond log in conjunction with the cementing operations data. Lost returns may occur, but are then regained and the cement tops are subsequently determined to be fine; and this can represent losses in zones above the planned top of cement placement. It is normal for gas cut mud to occur during the shutdown period after circulation and after the rigging up of cementing equipment is

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[49] 78 Fed. Reg. 31,636, 31,652 (May 24, 2013).
[50] 78 Fed. Reg. 31,636, 31,676 (May 24, 2013).

[51] Due to the possibility of false positives, we believe that CEL data should not be used as an indication of inadequate cement *unless* there are other corroborating indicators.

finished. It is the engineering and operational analysis of the entire casing and cementing procedure -- and not any individual factor -- that allows operators to draw meaningful conclusions about the well's integrity.

By basing repair requirements on a single indication of inadequate cement, without regard to other information, the proposed rule will require repairs in circumstances where other data indicate that repairs are not necessary. We therefore request that BLM amend the rule to allow for repair assessments and cement adequacy certifications based on all of the available data, including pressure test data and an assessment of whether inadequate cement is likely to result in the contamination of "usable water" by subsurface migration.

We emphasize that an opportunity to request case-by-case variances, in lieu of objective standards, would be insufficient. Such a requirement would force operators to suspend operations and then wait on formal BLM approval before proceeding with drilling. It is very likely that in many cases the "indication" at issue would be minor and, even though it would be apparent that the issue would not impair wellbore integrity and formation isolation, operators would nevertheless incur delays. These delays will impose costs associated with rig and equipment fees—costs that are not presently included in BLM's economic analysis of the rule.

What is an Indication of Inadequate Cement?—Clarification is Needed

Critical to the application of the proposed rule is the fact that the rule does not define what an "indication of an inadequate cement job" means. The proposed rule provides examples, such as "cement channeling," but does so in an overly general terms that do not provide any meaningful guidance to operators. The proposed rule does not identify what level of gas in mud returns or degree of cement channeling qualifies as an "indicator" and/or renders a cement job "inadequate"? Or whether repairs are required for any length of cement channeling? If a CEL indicates 50 feet of cement channeling in the middle of a 200-foot column of cement, is this an "indicator" that renders the cement job inadequate (despite decades of petroleum engineering experience that the 50 feet of channels will not provide a pathway for fluid to migrate out of the zone)?

BLM's approach overlooks the fact that it only takes one good section of cement for there to be effective isolation. There can be channels for long distances without any detrimental consequences because channels must be continuous to establish a path for fluid migration. Mr. King, the analyst on whom BLM relies, estimates that the amount of channel-free cement required for pressure and fluid isolation is typically less than about fifty feet.[52] Not all channels a CEL might indicate need to be corrected. Equally important, attempts at correcting these channels can reduce integrity by allowing a path for fluids to move from the wellbore into the formation through perforations created to repair the "defect."

Yet as currently written, the rule appears to require cement repairs based on any indication of inadequate cement, no matter how minor and irrespective of whether other data indicate adequate cement. The proposed rule does not account for whether the indicated inadequacy (if real) would actually threaten formation isolation. This means that operators will be required to undertake

[52] *See* King footnote 44 *supra* at 2.

repairs in circumstances where factors beyond a CEL demonstrate that cement is adequate and formation isolation is effective, resulting in unnecessary expense and decreased wellbore integrity.

Except for a "top job," conducting cement repairs involves a "squeeze job." This involves perforating the casing string by detonating explosive charges to puncture the metal, providing pathways through which cement can be pumped into the annulus between the casing and the wellbore. Any damage to the casing decreases its structural integrity and increases the likelihood of future operational issues.

On the rare occasion where there is a continuous channel behind the casing, one which would allow the migration of fluids, perforating the casing and conducting a squeeze job may be prudent—otherwise, doing so is best avoided. In the interest of avoiding unnecessary repairs and preserving wellbore integrity, BLM should clarify the extent to which an "indication" is minor and does not trigger additional investigation and repairs.

CEL Data Should Not Be a Sole or Primary Indicator of Cement Adequacy

The proposed rule's overemphasis on CEL data, even making CELs the only method for confirming isolation and adequate cement, represents a fundamental problem. As previously discussed, any single indication of an inadequate cement job triggers an obligation for operators to run a CEL to demonstrate that the inadequacy was corrected. Even if all other indicators show adequate cement and formation isolation, the rule will require "corrections" and will require a CEL. Worse, as the rule is currently worded, the CEL is the only basis on which an operator can confirm and certify that the cement is adequate.

We do not understand BLM's emphasis on CEL data. CELs are difficult to evaluate absent other cementing measurements and, even when evaluated properly, pose a significant risk of false positive indications of inadequate cement integrity. Each kind of sonic and ultrasonic log used for cement evaluation has limitations, produces results that are open to a range of professional interpretation, and evaluated in isolation poses a significant risk of false positives. These risks are elevated for surface casing because the cement used for surface casing is lighter and has a lower compressive strength, making the acoustic signature more difficult to distinguish from drilling mud.

Cement evaluation logs can provide a risky basis for evaluating the integrity of the cement. The logs do not "see" the cement. The logs merely allow a competent professional to draw inferences about the evenness of the cementing around the pipe, based on readings of sonic or ultrasonic waves passing through the pipe into the cement and the rock beyond. For this reason, API Technical Report 10TR1 cautions that cement bond log interpretation "is *not recommended* as a best practice for cement evaluation."[53] While the amplitude or attenuation of the sound returning to the log's receivers is "often used as a 'bonding indicator' to infer that the cement is 'poorly bonded' or 'well bonded' to the casing[, t]hese 'bonding indices' . . . can be totally misleading."[54]

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[53] API Technical Report 10TR1 at 13 (Sept. 2008).
[54] *Id.* at 14.

Imperfections in the running of the log itself can give misleading indications about the quality of the cement. For example, "[w]hen the [logging] tool is eccentered [off-center] in the casing, the bond log quality is highly questionable."[55] Using evaluation logs on surface casing is especially troublesome. To control quality in evaluation logging, the best practice is to begin by comparing the results recorded from logging a section of casing that is cemented with logging results from a section of uncemented casing, so-called "free pipe."[56] But BLM requires surface casing to be cemented all the way back up to the surface, meaning that there is no free pipe to be logged for comparison.

In an age when computer modeling is relied upon so heavily, there is of course a temptation to look to computer programs that convert cement evaluation log readings into a "cement map." There is risk here as well. "One common problem with cement maps is the use of varying colors to distinguish 'good cement' from 'poor cement.' These colors are based only on a log response and do not reflect the ability of any cement to provide isolation in the well. This problem has led many engineers to misinterpret logs and attempt cement squeezes when they are not necessary."[57] And what is the method for assessing unusual results in cement mapping or in evaluation logs? It is to use the customary data gathered or observed in the cement operation itself. "If the cement job was properly performed, the well had full circulation, the cement was mixed to the proper density and all data from location matches the plan, there is little evidence to believe a cement evaluation log that shows no cement behind pipe."[58]

If BLM must choose a single basis for making a cement certification, it should choose pressure testing. But the better, safer course is to allow certification based on operator assessments of all available information. Unless BLM resolves the issues discussed above, our members will be needlessly required to perform expensive remedial cement squeeze jobs to eliminate channels which may not actually exist. These "repairs" will weaken the structural integrity of well casing strings without improving formation isolation.

One means of resolving some of these issues is for BLM to clarify that the rule requires only that protected formations be "isolated" from the fractured zone, not that the cement actually cover and be bonded to the formation to be protected. This is a reasonable approach that other jurisdictions have adopted. A Louisiana Department of Natural Resources ("LDNR") guideline document for SDWA injection wells, for example, establishes numerical benchmarks for using cement logs to establish cement "isolation."[59] The guidelines require at least a continuous sixty percent cement bond over a minimum interval of cement, with the interval based on the size of the casing.

If BLM continues to insist on CEL data as the sole basis of evaluating repairs following an indication of inadequate cement, establishing criteria like the LDNR benchmarks would give operators an objective standard upon which to base their certifications. Without an objective

[55] *Id.* at 17.
[56] *Id.* at 23, 36, 57, and 73.
[57] *Id.* at 75.
[58] *Id.* at 77.
[59] The LDNR guidelines are available at:
http://dnr.louisiana.gov/assets/OC/im_div/CBL_Guidelines_and_Interpretation_Guide.pdf.

standard, operators will be forced to choose between making "repairs" that they believe unnecessary (and detrimental to well integrity) and possible noncompliance with the rule.

If Retained In the Rule, Type Well Applicability Should Be Expanded and Clarified

BLM is proposing to limit the CEL requirement for casing strings that contact a usable water zone to "type wells" and wells where there is an indication of inadequate cementing. "*Type well* means an oil and gas well that can be used as a model for well completion in a field where geologic characteristics are substantially similar within the same field, and where operations such as drilling, cementing, and hydraulic fracturing are likely to be successfully replicated using the same design."[60]

The type well provision states that CELs for subsequent wells are not required if: (i) the CEL for the type well shows successful cement bonding to protect against downhole fluid cross-migration into water zones; (ii) the subsequent well has the same specifications and geologic characteristics as the type well; (iii) the subsequent well *was approved in the same group sundry notice as the type well*; and (iv) cementing operations monitoring data parallels the type well monitoring data.[61]

To the extent BLM does not simply remove CEL requirements for casing strings where cement is circulated to surface, we generally approve of the type well concept. We nevertheless urge BLM to remove the requirement that subsequent wells undergo a CEL if approved in a different group sundry notice from the type well. There is no technical basis for this limitation—if the other conditions are met, such as similar geologic conditions, the timing of approval should not matter. Operators should be permitted to demonstrate in a subsequent group sundry notice that the existing type well would also be representative of the wells to be approved in the subsequent notice.

BLM should better explain and clarify the type well concept. The preamble to the proposed rule indicates that there might be one type well per field, per operator.[62] The rule should define the term "field" because some oil and gas agencies define a field to mean a single reservoir and others define it to mean a broader geographical area overlaying multiple reservoirs.

Based on definitions applicable in North Dakota, we suggest that BLM define a "field" as "the general area underlain by one or more pools," and to define "pool" as "an underground reservoir containing a common accumulation of oil or gas or both; each zone of a structure which completely separated from any other zone in the same structure is a pool."

Clarification is also needed regarding the amount of variability allowed between a type well and subsequent wells and between the cement operations monitoring data for the type well and a subsequent well. Water formations and hydrocarbon formations are not perfectly horizontal and will vary somewhat in depth and thickness from well to well within a field. As a result, casing

[60] 78 Fed. Reg. 31,636, 31,674 (May 24, 2013).

[61] 78 Fed. Reg. 31,636, 31,676 (May 24, 2013).

[62] 78 Fed. Reg. 31,636, 31,664 (May 24, 2013).

depths may also vary somewhat, as would the cement volumes needed for the casing. Cement operations monitoring data will also vary slightly from one well to another.

BLM should clarify that the type well provisions contemplate a degree of variability between the design and monitoring data for type wells and subsequent wells, provided the variation would not be expected to compromise formation isolation. These determinations would be made based on industry norms, local conditions and circumstances, and operational experience.

Type Well Revisions

If CELs are required, strike proposed § 3160.0-5 *Type well* [definition] and replace with:

Type well, when used in section 3162.3-3(e), means an oil and gas well that can be used as a model for cementing operations in an area in which cementing of casing is likely to be successfully replicated using the same design. *Type well*, when used elsewhere in section 3162.3-3, means an oil and gas well that can be used as a model for well completion in a geographic area or field where geologic characteristics are substantially similar, and where operations such as drilling, cementing, and hydraulic fracturing are likely to be successfully replicated using the same design.

Strike proposed § 3162.3-3(e)(3) and replace with the following:

An operator is not required to run a cement evaluation log on the casings of a subsequent well where an operator submitted a cement evaluation log for a type well that shows successful cement bonding to protect against downhole fluid cross-migration into water zones.

Cement Monitoring and CEL Requirements Should Not Apply to Existing Wells

The proposed rule requires operators to submit cement operations monitoring reports and, for type wells, CELs within thirty days after concluding "hydraulic fracturing operations." The provisions in question do not mention refracturing and it is our understanding that these requirements would not apply to refracturing.[63]

The exemption for refracturing operations, however, is not broad enough to prevent many existing wells from becoming subject to the cement monitoring and CEL requirements. This is because the term "refracturing" applies only to wells that have previously undergone a hydraulic fracturing operation.[64] Existing producing wells that have not previously been fractured and are fractured in the future would be treated as if they are a new well. As a result, operators may be expected to submit cement operations monitoring reports and CELs for these existing wells, if and when those wells are hydraulically fractured in the future.

[63] 43 C.F.R. § 3162.3-3(e) (proposed).

[64] 43 C.F.R. § 3160.0-5 (proposed).

Because the rule was only proposed in mid-2012, and because CELs are not needed for surface casing (and no state requires them), existing wells will not be able to meet the cement monitoring and CEL requirements. This may result in BLM denying approval of proposed hydraulic fracturing operations and the premature abandonment of thousands of wells. In some cases, operators would elect to re-drill the well (at significant cost). In other circumstances, however, the original well was viable only because it intersected multiple reservoirs and could be plugged back from reservoir to reservoir over the life of the well. For many of these wells, re-drilling after early abandonment would not occur, because the reserves recoverable from the remaining reservoirs would not justify the expense of a new well.

The lack of an exemption for existing wells will result in enormous costs which BLM has not assessed. Every premature abandonment will result in a loss of capital assets. Where wells are not re-drilled, operators will lose recoverable reserves and mineral owners will lose royalties. Each and every re-drilled well will cost millions of dollars. We assert that allowing the loss of reserves under these circumstances would be a violation of the agency's legal obligation to manage federal lands and the public's natural resources prudently.

We believe the proposed CEL requirements to be unnecessary for new wells. To allow this requirement to be retroactively applied to existing wells exacerbates the error this requirement poses. As proposed, the rule will improperly preclude operators from realizing the benefit of their interests in the mineral estate without any commensurate public benefit. In the event BLM retains a type well CEL requirement, we urge BLM to adopt the following regulatory revisions:

Hydraulic Fracturing of New Wells

Proposed Change to BLM proposed 43 C.F.R. § 3160.0-5

New well means an oil and gas well for which surface casing was set and cemented on or after [Insert Date 60 Days After Publication in the Federal Register].

Proposed Change to BLM proposed 43 C.F.R. § 3162.3-3(e):

(e) *Monitoring of Cementing Operations and Cement Evaluation Log Before Hydraulically Fracturing a New Well*.

(1) During cementing operations for a new well, the operator must monitor and record the flow rate, density, and treating pressure and submit a cement operation monitoring report to the authorized officer within 60 days after flowback associated with a hydraulic fracturing operation begins. This requirement does not apply to a refracturing operation.

(2) For each new well, the operator must run a cement evaluation log or logs on each casing that protects usable water and the operator must submit those logs to the authorized officer within 60 days after flowback associated with a hydraulic fracturing operation begins, except as provided under (e)(3) of this section. This requirement does not apply to surface casing or to a refracturing

operation. A cement evaluation log is any one of a class of tools that provide an indication of the integrity of annular cement bonding, such as, but not limited to, a cement bond log, ultrasonic imager, variable density logs, microseismograms, cement bond logs with directional receiver array, ultrasonic pulse echo technique, or isolation scanner. An operator may select the tool used to prepare the CEL, as long as it is at least as effective in verifying the integrity of annular cement bonding as is a cement bond log.

Costs Associated with the CEL Provisions

BLM's revised proposal acknowledges that the CEL provisions would impose significant costs on operators, primarily attributable to the additional "waiting-on-cement" time associated with running CELs for surface casing. As discussed below, BLM is significantly underestimating the cost of the CEL provisions.

CEL costs are the largest category in BLM's estimates, comprising about eighty-three percent to eighty-nine percent of the total costs the agency estimates. Most of the cost is associated with CELs for surface casing strings (between about sixty-three percent and seventy-seven percent of total rule costs). Two other categories contribute to the CEL costs: CELs for intermediate casing (between about eight percent and thirteen percent of total rule costs) and CELs following inadequate cementing (between about four percent and six percent of total rule costs).[65]

BLM's cost estimates for CELs depend on many factors. Two of the most significant are: (i) the percentage of wells drilled that are "type wells" for which CELs would be required; and (ii) the amount of additional rig and equipment "idle time" associated with waiting on cement to cure before running CELs.

Type Well Estimate Depends on Removal of the "Same Group Sundry Notice" Limitation

BLM estimates that approximately eight percent of wells will be type wells. Our members are unable to comment effectively on this assumption because BLM has not clearly stated how the concept will be applied in practice. No two wells will be exactly identical, nor will any two sets of cement operations monitoring data.

Given the lack of detail BLM has provided, our comments on this issue are largely confined to requesting that BLM provide an expansive interpretation of the conditions under which a type well will be considered representative of subsequent wells. We expect, however, that any additional commentary from BLM will be consistent with BLM's representation that the agency "is confident that the average number of wells that an operator completes in a field is a good measure . . . ."[66]

We also note that BLM's eight percent estimate is questionable if: (i) a "field" is a single reservoir and not a geographic area overlaying multiple reservoirs; and (ii) BLM limits type well applicability to wells included in the same group sundry notice. In the economic analysis for the

[65] 78 Fed. Reg. 31,636, 31,666 (May 24, 2013).

[66] 78 Fed. Reg. 31,636, 31,664 (May 24, 2013).

proposed rule, BLM states that the number of CELs on surface casing was estimated based on data indicating that each operator completes an average of 12.572 wells in a field (one type well per 12.572 wells is approximately eight percent).

Assuming a field is a geographic area, each operator is likely to submit *at least* two sundry notices in a field, one for an initial exploratory well or small group of such wells and one for a larger development plan submitted after the viability of the operator's leases in the field has been validated. If type wells are limited to the wells included in a single group sundry notice, BLM's eight percent estimate is incorrect. BLM should therefore remove the single group sundry notice limitation for type wells. If the agency does not, it should update its economic analysis to reflect that type wells comprise at least sixteen percent of wells.

BLM Underestimates Rig and Equipment Idle Time

BLM has underestimated the impact of the CEL requirements on rig and equipment idle time. The agency assumed the following:

- For the low-cost case, operators would avoid the costs of idle drilling equipment for 56.47 percent of type wells—the percentage of wells for which it estimates surface casing would be set by a small rig.[67] The CEL requirement would cause an additional 24-hour delay for surface casing on the remaining type wells.

- For the high-cost case, the CEL requirement would cause an additional 24-hour delay for surface casing on all type wells.

- For both cases, the rule would compel CELs for intermediate casing on approximately five percent of type wells, with each CEL for intermediate casing resulting in 48 hours of additional delay.

- Rig and equipment idle costs of $1,900 per hour ($45,600 per day).

BLM should use a 72-hour delay for CELs on both surface and intermediate casing strings, consistent with EPA guidelines for running cement logs for UIC wells.[68] Those guidelines recommend waiting seventy-two hours because cement logs are more likely to show poor bonding if run before the cement achieves maximum compressive strength.

[67] BLM opined that this number might decline in the future as operators seek to avoid idle time by using surface casing rigs on more wells. We do not believe that this is the case. The primary reason to use a smaller rig for surface casing would be because doing so results in lower costs. Yet the fact remains that not all wells are drilled this way; the development cycle and project-specific logistical and operational concerns often result in operators choosing other drilling methods. These same concerns will continue to limit the number of wells that will be drilled using surface casing rigs in the future.

Using multiple rigs can have cost advantages for multi-well projects. For single well development projects, however, the cost of using multiple rigs is comparable to the cost of using a single rig, because of the mobilization and demobilization costs associated with multiple rig operations. Because using multiple rigs does not present any meaningful cost savings to small projects, availability and logistical issues will likely result in small projects continuing to use a single drilling rig.

[68] EPA's guidance is available at: http://www.epa.gov/region8/water/uic/R8UIC-GUIDE34.pdf.

Although it is often possible to run a cement log sooner than seventy-two hours, our members indicate that the repair provisions in the proposed rule will likely compel operators to delay CELs until maximum compressive strength is achieved. This is because the proposed repair provisions can be triggered based on CEL data alone and will not allow operators to interpret the CEL data in conjunction with other data when determining whether cement repairs are needed.

Operators have historically been able to use their operational experience and other data to determine whether indications of channels in a CEL warrant remedial cementing. The proposed rule, in contrast, requires remedial action based on any indication of inadequate cement and without regard to other available evidence. With CEL data (and that data alone) determining whether a cement repair job is needed, operators are likely to wait on maximum compressive strength before logging. This will not remove the possibility of false positives, but could still mean the difference between having or not having to conduct a repair that CEL data indicates might be needed, but other data indicates is unnecessary.

The delay associated with surface casing cement should be *at least* as long as the forty-eight hours BLM assumes for intermediate casing.[69] First, the closer to the surface, the lower the downhole temperature, resulting in longer cure times. Second, the cement used for surface casing tends to be lighter than the cement used for intermediate and production casing due to concerns that the hydraulic pressure of the cement column will fracture a geologic formation and result in loss of circulation and an inadequate cement job. A lighter cement means more time is needed before the compressive strength of the cement is sufficient for the cement's acoustic properties to be distinguishable from the acoustics of liquids, such as drilling mud.

We also note that average rig and equipment rental costs should be higher than $1,900 per hour ($45,600 per day). One of our members reports estimated delay costs of approximately $2,292 per hour ($55,000 per day). Others report delay costs as high as approximately $2,917 per hour ($70,000 per day). Applying BLM's underestimate of surface casing delay time -- only 24 hours -- an economic analysis John Dunham & Associates prepared (included as Appendix A to these comments) estimates that the CEL provisions will still result in approximately $7.6 million of additional costs. Because actual delay times and costs will be much higher, this figure represents a very conservative estimate of the delay costs the propose rule will impose.

The Cement Repair Provisions Will Result in Additional Costs

The expanded repair requirements in the proposed rule will also result in additional costs. We maintain that an indication of inadequate cement should be treated as just that—an indication that merits closer attention. The proposed rule, however, treats an "indication" as a trigger for remedial action. By doing so, it will result in operators undertaking unneeded remedial actions, resulting in rig costs, service company costs, negative impacts to wellbore integrity, and possible future workovers to remedy operational problems associated with decreased casing integrity.

BLM has largely failed to account for the costs of these additional remedial activities. The agency's economic analysis is limited to an estimated $7,000 associated with running a CEL when there is an indication of inadequate cementing. The analysis does not include additional

[69] Section 3.2 of API Technical Report 10TR1 on Compressive Strength also recommends at least forty-eight hours.

rig and equipment time on grounds that "operators must current [sic] remediate to satisfaction." BLM's position appears to be that the rule only requires operators to fix problems and, because Onshore Order No. 2 already requires that operators fix problems, the additional rig time and other remediation costs do not represent new expenses.

The problem is that the proposed rule significantly expands the circumstances in which operators must take corrective actions and BLM has failed to consider the costs of this expansion. As previously discussed, the proposed rule would require remedial actions based on any single "indication" of an inadequate cement job, which is a major change from the remedial requirements in Onshore Order No. 2.

Onshore Order No. 2 provides that remedial action can be required if the surface casing is not cemented to surface, a casing string fails pressure testing, or specified equipment such as centralizers, top plugs, and bottom plugs, are not properly used. Onshore Order No. 2 does not, however, impose remedial actions based on *any* "indication" of an inadequate cement job, such as gas-cut mud or discontinuous cement channels. The proposed rule's repair requirements are too easily triggered and the proposed rule would mandate repairs based on information that would not trigger repairs under Onshore Order No. 2. Perhaps more important, there is a significant risk that the proposed rule will trigger repairs were none are needed, potentially compromising wellbore integrity. BLM must include these expanded costs in its economic analysis and must account for these risks in its rationale in support of the proposed rule.

Operators Cannot Reduce Idle Times By Drilling the Intermediate Hole and Then Logging

In the preamble to the proposed rule and associated economic analysis, BLM states that operators can eliminate additional idle time by not waiting on the cement to achieve the compressive strength needed to run a CEL and instead proceeding to drill the intermediate hole. The surface casing could then be logged at any convenient time before setting intermediate casing. Although this idea was not incorporated into the agency's economic analysis, it reflects a misunderstanding of drilling operations, and therefore deserves comment.

CELs must be run under pressure, generally from approximately 1,000 to 2,000 psi. Because open wellbores cannot function as "pressure vessels," applying pressure in an open hole will simply push fluids into the open formations. Pressures would increase if the operator pumps hard enough, but maintaining a consistently even pressure would be impossible. Failure to maintain an even pressure would impact the acoustic properties in the wellbore making assessment of the log results more difficult.

Although drilling mud is designed to form a filter cake that minimizes fluid movement into and out of open zones, there is some movement of fluid into open wellbores. Gas bubbles can form and then expand as they ascend the mud column and are subjected to decreasing hydraulic pressure. Noise from events such as this will detrimentally impact CEL results, meaning that a CEL run on casing with an open hole below could be useless.

III. RECOVERED FLUIDS MANAGEMENT

National data on "flowback" water from fracturing operations is difficult to assemble. Water injected during hydraulic fracturing does not all return to the surface in short order, but can return over a span of months or years. At some point, flowback becomes hard to distinguish from "produced water," the briny water that has been within the oil and gas bearing formation for millenia. As discussed elsewhere in these comments, there is no meaningful difference in protecting federal and Indian lands from discharges of "flowback" as compared to "produced water" and little, if any, meaningful basis on which to distinguish the two. Under various nomenclature, fluids recovered from oil and gas operations have been the subject of regulation for decades and these regulations are instructive in assessing BLM's proposed rule. BLM should assess this waste stream as "recovered water" rather than search for some arbitrary distinction between "flowback" and "produced water."

In 2009, the Environmental Science Division of Argonne National Laboratory prepared a report, "Produced Water Volumes and Management Practices in the United States" (ANL/EVS/R-09/1 Sept. 2009). Assessing data for calendar year 2007, Argonne estimated that oil and gas operations in the United States produced almost twenty-one billion barrels of water. Although methods of managing the water included evaporation ponds, surface release, offsite commercial disposal or treatment, and beneficial reuse (in addition to reuse in enhanced oil recovery), "[m]ore than 98% of produced water from onshore wells is injected underground. Approximately 59% is injected into producing formations to maintain formation pressure and increase the output of production wells. Another 40% of produced water from onshore wells is injected into nonproducing formations for disposal."[70]

Regulation of water and fluids recovered from oil and gas operations is extensive. Long term underground storage of these fluids is regulated under EPA's UIC program.[71] Use of recovered water for enhanced oil recovery is also subject to UIC constraint[72] and to the control of state oil and gas commissions. Surface discharge of returned water and fluids into waters is regulated under the Clean Water Act's National Pollutant Discharge Elimination System ("NPDES")[73] and state clean water laws. EPA's Effluent Limitations Guidelines for oil and gas extraction regulate discharge of recovered water throughout the country.[74] EPA and states have ample authority to regulate the pretreatment of recovered water sent to "publicly owned [water] treatment works"[75] at "centralized waste treatment facilities."[76] In short, where returned water is not reused, the process of disposal is extensively regulated, and a further role for BLM is unnecessary.

Where recovered water can be reused, the government's role should be to encourage that reuse. Although data on volumes is not readily accessible, reuse of recovered water in fracturing operations is on the rise. In its research in preparation for its 2014 study on hydraulic fracturing, EPA recognized a range of reuse technologies: "direct reuse, onsite treatment (e.g., bag filtration,

[70] Argonne Nat'l Lab., Envtl. Science Div., *Produced Water Volumes & Mgmt. Practices in the U.S.* at 8, ANL/EVS/R-09/1 (Sept. 2009).

[71] 40 C.F.R. Parts 144-149 (2012).

[72] 40 C.F.R. §§ 144.22 & 144.28 (2012).

[73] 33 U.S.C. § 1311(a).

[74] 40 C.F.R. Part 435.

[75] 33 U.S.C. § 1317(b)(1).

[76] 40 C.F.R. Part 437.

weir/settling tanks, third-party mobile treatment systems) and offsite treatment. Offsite treatment, in most instances, consisted of some form of stabilization, primary clarification, precipitation process, and secondary clarification and/or filtration."[77]

The more recent report of the Texas Railroad Commission's Eagle Ford Shale Task Force has quantified the benefits of industry's focus on using less freshwater in fracturing operations in one of America's most prolific shale plays. In a presentation to the Task Force, Dr. Darrell Brownlow reported that while a typical Eagle Ford well required the use of 15 acre-feet of freshwater, "many operators have reported decreasing water consumption to an average of 10-acre-feet . . . of water per well."[78] Some of this reduction is from reliance on gel-based fractures rather than "slickwater" fractures, but some is attributable to reuse of water. The Railroad Commission is also amending its rules on water recycling to facilitate recycling. As of the date of the report, the Railroad Commission has issued permits to fourteen mobile recycling facilities and one stationary facility.[79]

Against this backdrop of regulation and rapid technological innovation, we turn to BLM's proposed regime for recovered water. Under Onshore Order No. 7, BLM currently permits four principal options for disposal. Two options overlap and are redundant of EPA's NPDES and UIC programs. The other two options are the use of lined and unlined pits. Onshore Order No. 7 also allows an operator to propose some fifth alternative to these four. In the proposed rule, BLM would eliminate the options of the fifth alternative and of unlined pits. Under proposed Section 3162.3-3(h), "Storage of all recovered fluids must be in either tanks or lined pits."

Our comments below provide more detailed concerns over this proposed requirement, but, viewed broadly, our great concern is over BLM's movement away from operational flexibility toward rigidity in handling recovered fluids. BLM anticipates the drilling of over 4,000 wells a year to be subject to the new rule. Technology advances far more rapidly than federal regulations change. It is already easy to envision a situation in which an operator uses a mobile treatment facility onsite to condition the water for reuse in the next fracturing operation, with a temporary pit employed for management of the fluid. We urge BLM to maintain a flexible approach to storage of recovered fluids.

The proposed rule would require that recovered liquids be managed in either a lined pit or tanks. BLM has requested feedback regarding whether the rule should require that all recovered fluids be managed in tanks, or that pits should be double-lined and/or equipped with a leak detection system.

We support the current version of the proposed requirements, primarily because the current version of the rule provides operational flexibility regarding whether to use a lined pit or aboveground tanks. Some operators prefer pits and others prefer tanks. Often that preference varies on a project-by-project basis, depending on a wide variety of economic, geographic,

[77] U.S. EPA, "Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources: Progress Report" at 104, EPA 601/R-12/011 (Dec. 2012), available at: www.epa.gov/hfstudy.

[78] Texas RR Comm'n, "Eagle Ford Shale Task Force Report" at 47-48 (March 2013).

[79] *Id.* at 51.

logistical, and environmental factors. Tanks prevent rainwater accumulation from increasing fluid management volumes and can generally be re-used, but also involve large upfront costs and pose a target for lightning strikes. Both storage methods will disturb surface land; but tanks will often impose a larger overall footprint for the same volume of storage.

Tanks do not necessarily reduce the potential for leaks because manifolding tanks together involves more piping than is required to transfer fluids to and from a pit. The increased amount of piping connections poses a release threat, even with the implementation of best management practices to ensure the integrity of transfer lines. Setting, emptying, and removing tanks will also result in increased truck traffic compared to pits. As John Dunham & Associates discusses, the average expected cost for renting storage tanks would be about $11,500 per well (compared to BLM's estimate of $6,000 per lined pit), which totals approximately $19.6 million per year. Based on these numbers, tanks would cost approximately $9.4 million more than the use of lined pits.

Some of our members report even higher costs, in particular where operators are engaged in fluid recovery and reuse operations and must manage a very large volume of water for an extended period of time. In this circumstance, it is relatively common to use a large, central, double-lined pit (with leak detection) designed for long-term use of at least three years. This type of pit would cost approximately $550,000. In comparison, rental charges for an equivalent volume of tank storage would run approximately $36 million over the same three-year period.

One potential advantage of a pit is where the recovered fluid will be used for more than one well. Tanks used for the management of returned fluids typically cannot store the entire volume of fluids returned from the well. A tank's contents must be transferred for disposal throughout the recovery period, thereby making space for operations to continue. In comparison, a pit can generally be sized to handle the entire volume of recovered fluids, which facilitates reuse and decreases impacts on fresh water resources.

Finally, neither double-lined designs nor leak detection systems are needed for short-term, temporary pits. Releases from a liner are typically slow and low in volume, only resulting in significant impacts over the course of years. For some wells, pits may be required only for temporary service, from a few weeks to a few months at the commencement of operations, and not for a period of years. In the very rare event that a leak occurs, it would be discovered upon closure of the temporary pit, at which time the minor impacts associated with the leak can be remediated with relative ease.

IV. PRE-FRACTURING INFORMATION ISSUES

Fracture Modeling

The proposed rule requires operators to obtain an approved Notice of Intent Sundry before conducting a hydraulic fracturing or refracturing operation. The Notice of Intent Sundry must include the estimated or calculated fracture direction, length, and height. Our members are concerned that, to satisfy this information requirement, BLM will expect operators to undertake expensive fracture modeling exercises before fracturing each well.

Operators typically conduct extensive fracture modeling and mapping exercises only when first developing a field. Because these models are expensive and time-consuming, operators will typically use the fracture modeling data gathered for the first several wells in a field to estimate the results of hydraulic fracturing operations for subsequent wells.

A study Oklahoma City University conducted (included in preliminary comments Devon Energy Corporation submitted on June 24, 2013), indicates that simple fracture modeling costs approximately $4,500, which would result in costs of approximately $15.45 million per year if required for every well. Our members inform us that more sophisticated modeling can cost as much as $200,000.

Operators do, of course, calculate the estimated fracture geometry of their wells before conducting hydraulic fracturing operations—what they do not do is engage in extensive modeling for each well, because the similarity of results quickly renders this type of modeling unnecessary. In light of the preceding, we request that the BLM clarify that operators are only required to provide the fracture geometry information that they produce as part of their normal planning for hydraulic fracturing operations and are not required to conduct modeling for the specific purpose of the Notice of Intent Sundry. Suggested regulatory language is set forth below:

> **Fracture Geometry Estimates**
>
> Proposed Change to BLM proposed 43 C.F.R. § 3162.3-3(d)(4)(iv):
>
> (iv) The estimated or calculated fracture direction, length, and height, including the estimated fracture propagation plotted on the well schematics and on a map. The map must be of a scale no smaller than 1:24,000. An operator is not required to conduct additional fracture modeling to satisfy this requirement, but must provide the available information it has generated or used during the design of the proposed fracturing operation; and

To the extent we are misinterpreting the Notice of Intent Sundry requirement, and BLM does not amend the requirement, we note that the rule will impose additional costs that are not reflected in the current version of the economic analysis document for the proposed hydraulic fracturing rule. As noted above, simple modeling will likely result in costs of approximately $4,500 per well and sophisticated modeling can cost as much as $200,000 per well.

Unlimited Discretion to Request Additional Information

The proposed rule states that the "authorized officer may request additional information prior to the approval of the Notice of Intent Sundry" required for the approval of hydraulic fracturing operations.[80] In our comments on the original version of the proposed rule, we noted that this provision gives BLM unlimited discretion and was a power that could easily be abused.

[80] 78 Fed. Reg. 31,636, 31,675 (May 24, 2013).

In the preamble to the revised rule, BLM stated that requests would be limited to the information necessary to ensure permit applications are consistent with the applicable laws and regulations.[81] Although we remain concerned that the information request provision is still exceedingly broad, we appreciate the clarification and request that at least this limiting language be added to the text of the regulatory provision.

V. POST-FRACTURING INFORMATION AND REPORTING ISSUES

BLM has proposed the submission of certain information within thirty days of completing hydraulic fracturing operations. This reporting requirement would include, among other items:

(1) Information regarding fracturing fluid chemicals reported through FracFocus;

(2) The actual, estimated, or calculated fracture length, height, and direction;

(3) The volume of fluid recovered during flowback, swabbing, or recovery from production facility vessels;

(4) Documentation and explanation of deviations from the approved plan; and

(5) A signed certification that "wellbore integrity was maintained" and that fracturing fluid complied with all applicable permitting and notice requirements as well as all applicable federal, state, tribal, and local rules.

Our comments regarding the post-fracturing reporting requirements are in the subsections below. At the end of this section, we have included proposed regulatory language addressing our reporting concerns.

Endorsement of FracFocus/Extension of Reporting Deadline

BLM's revised proposal would allow the use of FracFocus for the submission of post-hydraulic fracturing job information. Because a number of states already require the use of FracFocus, allowing it to be used to satisfy BLM's reporting requirements will reduce compliance burdens.

We do note, however, that the thirty-day period that the proposed rule contemplates for finalizing post-fracturing reports and submitting data to FracFocus is insufficient. A typical well drilling and completion project involves many service companies, each of whom may have elements of the data that must be submitted with the post-fracturing report. Our members are concerned that the process of obtaining data from each of these entities, ensuring the completeness and accuracy of the data, compiling the data into a report, and satisfying certification requirements will not be possible in a thirty-day period. We request that BLM allow sixty days for post-fracture reporting.

[81] 78 Fed. Reg. 31,636, 31,679 (May 24, 2013).

Deviation Identification

We have significant concerns regarding the requirement to identify, document, and explain deviations as part of the post-fracturing report. To start, the term "deviation" is not defined—we assume that it means any difference, no matter how minor, from the approved plan. If this is the case, almost every piece of data included in the post-fracturing report will be a deviation, reflecting the normal, but inconsequential, variability between wells and operations. Cement detected ten feet higher than the calculated top of cement, for example, would be a deviation and would need to be explained, despite posing no wellbore integrity concerns.

Because it would impose significant, but unnecessary, administrative burdens, we strongly oppose the deviation provisions. Even if BLM attempts to make the provisions less burdensome, for example by limiting the provision to "material deviations," operators will have the burden of attempting to divine what the BLM would consider "material," and, if they fail to guess correctly, could face penalties for incomplete reporting. Operators should not shoulder this onus; BLM should instead simply request an explanation and additional information regarding issues it believes may be potentially significant after it has reviewed the completion reports that operators submit.

Certification Requirements

Given the nature of hydraulic fracturing operations, the certification requirements in the proposed rule are unrealistic and inflexible. First, the proposed rule appears to contemplate certification by a single signatory. But in many cases there is no single group within our operators' organizations with overall responsibility for every phase of well drilling, cementing, and completion. A drilling group will typically oversee drilling and cementing, after which a completions group will oversee perforating and hydraulic fracturing. In light of these divisions in responsibility, we request that BLM allow multiple individuals to certify the various aspects over which they will have responsibility.

Second, the proposed rule requires that operators certify that wellbore integrity was maintained before and throughout the hydraulic fracturing operation, but the certification does not include any language limiting the certification to the knowledge of the certifier or to the available information. This means that operators must legally certify wellbore integrity as an absolute factual certainty, even though they cannot directly inspect the thousands of feet of pipe in a well and must necessarily rely on available indicators of integrity, such as pressure testing.

We acknowledge that operators have responsibility for maintaining the integrity of their wells—there are nevertheless limits to what operators should be required to certify and we therefore request that BLM limit the certification requirement to belief and the available information. This will still impose an obligation for operators to conduct a careful inquiry of the available information before certification and will maintain liability for false certifications, but would properly limit the certification to what can be reasonably known.

Third, our members have strong concerns regarding the requirement to certify the submission of information that is known only to service providers. The primary example is information regarding fracturing fluid chemicals. Service companies closely protect this information as a trade secret and, as a result, operators will never have the information necessary to know whether the fracturing fluid used on their wells complies with all applicable laws. More generally, some operators, in particular smaller companies, outsource the entire drilling and completion process to contractors. BLM states that the proposed rule follows the Colorado model on this issue, but because service companies would not certify their own information, in fact, it does not.

We understand and accept that BLM will hold operators responsible for any "incidents" associated with hydraulic fracturing that may occur, even those a contractor may cause. That is not justification, however, for operators to accept responsibility for certifying the accuracy of information service companies provide (or hold as confidential) and over which operators have no control.

We request that BLM allow an operator's contractors to certify compliance regarding areas over which only the contractors have the requisite knowledge. Without this change, operators will be forced to certify compliance in good-faith reliance on the assurances of their contractors. Where those assurances are false, operators could be prosecuted for making a false certification, even though it would be BLM forcing operators to certify issues beyond the operator's actual knowledge and control.

We emphasize that requested change would not result in an enforcement gap. In the event a service company provides inaccurate information, BLM would be able to bring an enforcement action against the service company directly. If BLM does not allow contractors to certify the contractor's own information, we request that BLM amend the proposed rule to require contractors to provide operators with all non-trade secret information required for the post-fracturing report within thirty days of completing the hydraulic fracturing or refracturing operation.

Fourth, as previously discussed, our members are concerned that BLM will require additional modeling of fracture geometry to satisfy the Notice of Intent Sundry requirement for approval of a hydraulic fracturing operation. The same concerns also apply to the submission of fracture geometry information in the post-fracturing report. We request that BLM clarify that no additional fracture modeling is required for purposes of post-reporting and that the reporting requirement be limited to providing such information, "if available." If we are incorrect, and additional modeling would be required, we note that BLM's economic analysis must account for the associated costs.

Finally, in the last section of this document, we discuss the difficulties in distinguishing between fracturing fluid flowback and produced water and note that there is no need for BLM to distinguish between the two. Consistent with those comments, we request that BLM replace the requirement to report the volume of recovered fracturing fluid with a requirement to report the volume of fluids recovered in the first thirty days following the start of flowback. This time-based standard would provide BLM with the information it wants, while avoiding subjective determinations of when fracturing flowback ends.

Post-Fracturing Reporting

Proposed Change to BLM proposed 43 C.F.R. § 3162.3-3(i):

(i) *Information that Must be Provided to the Authorized Officer After Completed Operations*. The information required in paragraphs (i)(1) through (i)(7) of this section must be submitted to the authorized officer within 60 days after beginning flowback subsequent to hydraulic fracturing or refracturing operations. The information is required for each well, even if BLM approved fracturing for a group of wells (see § 3162.3-3(d)). The information required in paragraph (i)(1) of this section must be submitted to the authorized officer through FracFocus, another BLM-designated database, or in a Subsequent Report Sundry Notice (Form 3160-5, Sundry Notices and Reports on Wells). If information is submitted through FracFocus or another designated database, the operator or the operator's designee must specify that the information is for a Federal or an Indian well and the information must be certified in accordance with § 3162.3-3(i)(6). The information required in paragraphs (i)(2) through (i)(7) of this section must be submitted to the authorized officer in a Subsequent Report Sundry Notice. The following information must be submitted:

…

(4) If available, information regarding the estimated or calculated fracture length and height. After the fracturing operation is completed, the operator is not required to conduct additional modeling or calculations of fracture length or height, unless the authorized officer requires additional information in response to an incident.

(5) The following information concerning the handling of recovered fluids:

(i) The estimated volume of fracturing fluid and produced water recovered from the well during the first 30 days of flowback.

(ii) The methods of handling the recovered fluids, including, but not limited to, transfer pipes and tankers, holding pond use, re-use for other stimulation activities, or injection; and

(iii) The disposal method of the recovered fluids, including, but not limited to, injection, hauling by truck, or transporting by pipeline. The disposal of fluids produced during the flowback from the hydraulic fracturing process must follow the requirements set out in Onshore Order Number 7, Disposal of Produced Water, Section III.E. (October 8, 1993, 58 FR 58506).

(6) A certification attesting, based on belief and the available information, that compliance was maintained with the issues identified below in (i) through (vii). Where appropriate due to a division of compliance responsibilities, the certification may be split among multiple signatories. Each signatory must be an employee of the operator or a contractor or agent of the operator and must have knowledge appropriate for making the certification. An operator is not liable for a false certification by a contractor or agent, but

nevertheless remains liable for any noncompliance with the substantive requirements covered by the certification.

(i) Wellbore integrity was maintained prior to and throughout the hydraulic fracturing operation, as required by paragraph (b) of this section;

(ii) Compliance was maintained with the requirements in paragraph (e) of this section;

(iii) Compliance was maintained with the requirements in paragraph (f) of this section;

(iv) Compliance was maintained with the requirements in paragraph (g) of this section;

(v) Compliance was maintained with the requirements in paragraph (h) of this section;

(vi) For Federal lands, the hydraulic fracturing fluid used complied with all applicable permitting and notice requirements as well as all applicable Federal, State, and local laws, rules, and regulations; and

(vii) For Indian lands, the hydraulic fracturing fluid used complied with all applicable permitting and notice requirements as well as all applicable Federal and tribal laws, rules, and regulations.

…

(8) The authorized officer may require the operator to provide documentation substantiating any information submitted under paragraph (i) of this section and may request an explanation regarding information which does not match the approved plan and would therefore reasonably be expected to have a material impact on the protection of usable water.

VI. <u>Exemption of Trade Secrets from Public Disclosure</u>

Although BLM has significantly improved the trade secret provisions in the proposed rule, we remain concerned regarding the lack of a protection mechanism for information submitted to the BLM in a Notice of Intent Sundry seeking approval of a hydraulic fracturing or refracturing operation.

Many of our members consider well development and completion data to be trade secrets. In particular, our members hold fracture geometry information, such as microseismic modeling data and other evaluations, to be protected trade secrets. The problem is that the proposed rule requires inclusion of this information in the Notice of Intent Sundry submitted for approval of a hydraulic fracturing plan,[82] but the proposed rule provides that the submission of information in a sundry notice will be deemed to have waived any protection from public disclosure.[83]

BLM has proposed a mechanism for withholding information based on a claim that the information is exempt from public disclosure. But this provision is inadequate because the cross-references in the exemption provisions indicate that claims can only be made for information submitted following the hydraulic fracturing operation. There is no means of claiming trade secret protection for information required to be included with the Notice of Intent Sundry requesting approval of a hydraulic fracturing operation.[84]

Another concern relates to the disclosure of chemical additives in hydraulic fracturing fluid. First, the chemical constituent information that the proposed rule requires should be revised to limit the information to chemicals that are intentionally added to the fracturing fluid. Second, as currently drafted, the rule could be interpreted as requiring information regarding additives and the maximum concentration of a chemical constituent in each additive, which would jeopardize trade secret information by making it easier to reverse engineer the additive in the event the information is disclosed to the public. BLM should limit the reporting requirement to the maximum ingredient concentration in the overall fracturing fluid, and not the maximum ingredient concentration for each additive. Reporting based on the overall composition of the fracturing fluid is consistent with BLM's objectives to protect usable water while also providing additional protection for legitimate trade secret information.

We request that the BLM adopt the regulatory text below to provide a mechanism for handling trade secret information in a confidential manner.

To Protect Trade Secrets

Proposed change to move "estimated pump pressures" from BLM proposed 43 C.F.R. § 3162.3-3(d)(3) to § 3162.3-3(d)(4):

(3) The proposed measured depth of perforations or the open hole interval and information concerning the source and location of water supply, such as reused or recycled water, or rivers, creeks, springs, lakes, ponds, and wells, which may be shown by quarter-quarter section on a map or plat, or which may be described in writing. It must also identify the anticipated access route and transportation method for all water planned for use in fracturing the well.

(4) A plan for the proposed hydraulic fracturing design that includes, but is not limited to, the following:

(i) The estimated total volume of fluid to be used;

[82] 40 C.F.R. § 3162.3-3(d) (proposed).

[83] 40 C.F.R. § 3162.3-3(j) (proposed).

[84] *See* 40 C.F.R. § 3162.3-3(j) (proposed language cross-references to 43 C.F.R. § 3162.2-3(i), but not 43 C.F.R. § 3162.3-3(d)).

(ii) The estimated pump pressures and anticipated surface treating pressure range;

(iii) The maximum injection treating pressure; and

(iv) The estimated or calculated fracture direction, length, and height, including the estimated fracture propagation plotted on the well schematics and on a map. The map must be a scale no smaller than 1:24,000; and

(v) The estimated vertical distance to the nearest usable water aquifer above the fracture zone;

Proposed change to move "actual pump pressures" from BLM proposed 43 C.F.R. § 3162.3-3(i)(2) to § 3162.3-3(i)(3):

(2) The actual measured depth of perforations or the open-hole interval and the source(s) and location(s) of the water used in the hydraulic fracturing fluid.

(3) The actual pump pressures, actual surface pressure, and rate at the end of each stage of the hydraulic fracturing operation, and the actual flush volume, rate, and final pump pressure.

Proposed change to BLM proposed 43 C.F.R. § 3162.3-3(i)(1):

(i) *Information that Must be Provided to the Authorized Officer After Completed Operations.*

(1) The true vertical depth of the well; for each additive used (including base fluid) the trade name, supplier, and purpose; and for each ingredient intentionally added to the hydraulic fracturing fluid, the name of the ingredient, the Chemical Abstract Service Number (CAS #) if applicable, and the maximum ingredient concentration in the hydraulic fracturing fluid (% by mass).

Proposed change to BLM proposed 43 C.F.R. § 3162.3-3(j):

(j) *Information Exempt from Public Disclosure*.

(1) Information provided in the Notice of Intent Sundry under the requirements of paragraph (d)(4) of this section and in the Subsequent Report Sundry Notice under the requirements of paragraphs (i)(3) and (i)(4) of this section will not be made public for 5 years from the date of filing of the notices. For information required in paragraph (i)(1) of this section that the vendor, service provider, or operator claims to be exempt from disclosure, the person so claiming must submit to the BLM a one-time affidavit that:

(i) Affirms that the information is not publicly available;

(ii) Affirms that the release of the information would likely harm the competitive position of the person or entity claiming the exemption; and

(iii) affirms that the information is not readily apparent through reverse engineering.

Revise proposed § 3162.3-3(j)(2) by striking "operator" and replacing it with "*person or entity that claimed the exemption from public disclosure*."

(3) If the BLM determines that the information is not exempt from public disclosure under 18 U.S.C. § 1905 or other authority, the BLM will provide the person who claimed the exemption 20 business days' notice, beginning the day after the notice is received, of the BLM's intention to disclose the information to the public. The BLM will provide the person who claimed the exemption an opportunity to object to the determination and, if needed, to appeal the overruling of the objection to the Interior Board of Land Appeals under 43 C.F.R. Part 4, subparts A, B, and E.

Revise proposed § 3162.3-3(j)(4) by striking "operator" and replacing it with "*claimant*."…

VII. PROPOSED VARIANCE PROVISIONS

In the preamble to the proposed rule, BLM notes that it intends to allow operators to request case-by-case variances from the proposed rule standards and to also provide a means for BLM to work with states and tribes to issue a variance that would apply to all wells in a field, a basin, a state, or within Indian lands.[85] We generally approve of BLM's proposal to allow case-by-case variances, as well as more generally-applicable variances. We would prefer a general deferral to state programs, or BLM's incorporation of these programs, but the variance provision offers at least the possibility of eliminating overlapping and duplicative requirements on a case-by-case basis as a means of reducing administrative costs and improving efficiencies.

As presently proposed, however, there are a number of problems with the current version of the variance provisions. First, the variance request process is unclear, especially the process by which a state would be able to initiate a process leading to the substitution of state programs for BLM's regulations.

Second, we find the "meet or exceed" criterion BLM proposes to be problematic because, as elsewhere discussed in this document, the current proposal includes requirements that are more stringent than current industry best practices and state standards, but which the BLM has not demonstrated will actually decrease the already low risks associated with hydraulic fracturing. In short, we are concerned that the "meet or exceed" criterion would allow denial of a state's request for recognition of equivalency, unless the state adds unnecessary requirements to match BLM's regulations.

[85] 78 Fed. Reg. 31,636, 31,677 (May 24, 2013).

CELs for casing strings cemented to surface is a prime example of our concern. BLM acknowledges that CELs are generally not run for surface casing strings and no state requires a CEL for surface casing, absent other evidence that cement integrity might be impaired. Under the meet or exceed standard, BLM could deny a state request on grounds that the state's requirements lack a surface casing CEL provision and, therefore, do not meet or exceed BLM's requirements—despite BLM's failure to establish that these CELs will actually and materially decrease risk.

Third, BLM indicates in the preamble to the proposed rule that the possible adoption of state procedures is limited to "operational activities, including monitoring and testing technologies, and do[es] not apply to the actual approval process."[86] BLM does not provide any criteria, however, for determining whether a regulated activity is an "operational activity" or falls rather into the "approval process." Equally important, BLM's approach forsakes the administrative and regulatory efficiencies that could be gained through cooperation with the States. BLM recognizes that "it makes sense for both the BLM and the States or tribes with oil and gas activity to explore ways to coordinate implementation of this revised proposed rule."[87] And BLM acknowledges that there are presently existing agreements that designate certain permitting responsibility for activities within particular states to state agencies.[88] But BLM fails to articulate any basis for its decision to exclude administrative activities from the scope of any equivalency program implemented under the proposed rule. BLM must consider how its current systems used to process drilling permits can be modified to meet its future needs under the proposed rule and should address how those systems can be better integrated with State or tribal databases that are already in place for permitting, inspection and reporting to avoid unnecessary duplication and to promote optimal data management and sharing. To that end, we propose that BLM, through this rulemaking, recognize that its long history of joint regulation of drilling operations in California, Colorado, Montana, North Dakota, New Mexico, Utah, and Wyoming demonstrates that the recent regulatory amendments specifically addressing hydraulic fracturing provide protections equivalent to those BLM proposes in this rule.

Another concern is that the variance provisions give BLM unfettered discretion to revoke or modify a variance. The regulatory text provides that the variance can be modified based simply on a change in policy or even for "other reasons." This is extraordinarily broad language that does not provide any factual criteria that BLM must meet before modifying or revoking a variance. Without objective criteria, the variance process fails to provide operators with a reasonable assurance that regulatory requirements will not arbitrarily change and result in stranded capital resources and lost reserves, in the form of wells that may no longer be completed or produced, due to a modified or revoked variance.

In light of the above issues, we are proposing the following regulatory process and text. The proposed text does not address Indian lands, but we are supportive of tribal autonomy in the event the tribes favor a similar process for requesting an equivalency determination.

[86] 78 Fed. Reg. 31,636, 31,660 (May 24, 2013).
[87] 78 Fed. Reg. 31,636, 31,644 (May 24, 2013).
[88] 78 Fed. Reg. 31,636, 31,645 (May 24, 2013) (citing an agreement "for Permitting and Oil and Gas Operations on BLM and National Forest Service Lands in Colorado").

Variance Requests and Equivalency Determinations

Proposed Change to BLM proposed 43 C.F.R. § 3162.3-3(k):

(k) *Operator Requests for a Variance from the Requirements of this Section*. An operator may make a written request to the authorized officer for a variance from the requirements under this section. The BLM encourages submission using a Sundry Notice (Form 3160-5, Sundry Notices and Reports on Wells).

(1) A request for a variance must specifically identify the regulatory provision(s) of this section for which the variance is requested. The request must explain why the operator needs the variance and how the operator will satisfy the objectives of the regulation from which the variance is sought.

(i) After considering the objectives of the regulation, the authorized officer may approve the request, approve the request in part, or deny the request. The authorized officer's action is subject to State Director review under section 3165.3(b) of this title.

(ii) A variance under this section does not constitute a variance to provisions of other regulations, laws, or orders.

(2) Upon determining that a previously-granted variance no longer satisfies the objectives of the regulation, written notice and justification to the operator, and a 30-day opportunity to respond, the authorized officer may rescind or modify a variance granted under subsection (k)(1). The authorized officer's action is subject to State Director review under section 3165.3(b) of this title.

New proposed 43 C.F.R. § 3162.3-3(l):

(l) *State Requests for an Equivalency Determination*. A State may request that the BLM allow operators of federal leases within the boundaries of the state to comply only with that State's regulatory and programmatic requirements instead of the standards set forth in sections 3162.3-3 and 3162.5-2.

(1) The State shall submit a written request identifying the requirements and prescriptions that the State believes should be employed, as well as the BLM regulations that would be supplanted. The State may identify whichever of its regulations and standards it considers relevant and may identify all of the standards set forth in this section, or only a subset of the BLM standards.

(i) The State shall include in the request information from the prior two calendar years concerning instances of contamination of usable groundwater or of surface waters used for drinking, irrigation, or livestock, directly resulting from hydraulic fracturing or refracturing operations.

(ii) Upon receipt of a request, the BLM shall publish notice of the request in the Federal Register and provide the public 30 days opportunity for comment.

(iii) The BLM will grant the request unless it determines that the requirements identified by the State are not reasonably equivalent to the BLM requirements identified in the request and would materially increase the risk of impaired cement integrity or the contamination of usable groundwater or of surface waters used for drinking, irrigation, or livestock, as a direct result of hydraulic fracturing or refracturing operations.

(iv) The BLM's determination in response to the request may be appealed by any affected person to the Director, BLM. The Director's response to the appeal will be final agency action for purposes of the Administrative Procedure Act.

(2) *Equivalency Deemed Approved.* Because they have standards in place meeting all of the objectives of this section, the following States with significant oil and gas activity on public lands are deemed to have been granted a full determination of equivalency from the requirements of the BLM's regulations in this section: California, Colorado, Montana, North Dakota, New Mexico, Utah, and Wyoming. This determination does not apply to oil and gas operations on lands subject to the trust responsibility of the Bureau of Indian Affairs.

(3) *Reconsideration of Equivalency Determinations*.

(i) Any affected person may petition the BLM to reconsider an equivalency determination, provided the State has modified one or more of the provisions included in the equivalency determination and the petitioner provides reasonable grounds, supported by credible evidence, that the modifications would materially increase the risk of impaired cement integrity or the contamination of usable groundwater or of surface waters used for drinking, irrigation, or livestock, as a direct result of the activities regulated in this section.

(ii) If not granted within 60 days, a petition to reconsider an equivalency determination shall be deemed denied. The BLM may also deny a petition to reconsider before the end of the 60-day period by sending written notice to the petitioner. Denial of a petition to reconsider may be appealed by the petitioner to the Director, BLM. The Director's response to the appeal will be final agency action for purposes of the Administrative Procedure Act.

(iii) Upon granting a petition for reconsideration, the BLM shall provide written notification to the petitioner and the State and allow the State at least 90 days to respond. After the end of the 90 days, or such longer period granted by the BLM, the BLM shall publish in the Federal Register its proposed decision on whether to revoke the equivalency determination and shall provide at least 30 days for public comment. Following the public comment period, the

BLM will revoke the equivalency determination only if it determines that the modifications to the state program materially increase the risk of impaired cement integrity or the contamination of usable groundwater or of surface waters used for drinking, irrigation, or livestock, as a direct result of hydraulic fracturing or refracturing operations.

(iv) The BLM's determination to revoke or not revoke an equivalency determination may be appealed by any affected person to the Director, BLM. The Director's response to the appeal will be final agency action for purposes of the Administrative Procedure Act.

VIII. ADMINISTRATIVE ISSUES

Delays for Issuance of Permits

The approval process that the proposed rule would implement will result in additional significant delays in oil and gas projects conducted on federal and tribal lands. BLM already fails to meet statutory mandates for issuing drilling permits. There is no reason to believe that the addition of more requirements will not make this problem worse. Delays will still occur even though BLM is no longer proposing approvals for other types of stimulations, such as acid treatments.[89]

BLM recognizes that delays in approvals can be costly for operators, but the agency does not anticipate that the submittal of additional hydraulic fracturing-related information with drilling applications will significantly impact the timing of the approval of drilling permits.[90] BLM's own statements contradict this position:

> The processing of NOI Sundry, SR Sundry, and variance requests associated with the rule would pose additional burden to the BLM; however, it is unclear the extent to which the BLM can meet the additional burden with existing capacity. An additional 8.44 FTE of workload is estimated to be required to meet the administrative burden of the rule in the first year of implementation.[91]

BLM must account for the costs associated with these delays in its assessment of the costs and benefits of the rule.

According to John Dunham & Associates' economic analysis (see Appendix A), a one-week delay would result in average costs of about $1,580 per well, based on an interest rate of only seven percent. This equals to over $5.63 million in additional costs per year. Given the amount of data that BLM intends to review, delays may very well be longer and costs higher.

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[89] We agree with the BLM's proposal to exclude these types of stimulation operations from the scope of the proposed rule.

[90] 78 Fed. Reg. 31,636, 31,648 (May 24, 2013).

[91] 78 Fed. Reg. 31,636, 31,666 (May 24, 2013).

IX. THE ECONOMIC ANALYSIS IS INADEQUATE AND THE RULE IS ARBITRARY AND CAPRICIOUS

The economic analysis for the proposed hydraulic fracturing rule is woefully deficient. As previously discussed in our comments on the substantive provisions of the rulemaking, BLM has underestimated the costs of virtually every aspect of the proposed rule. The cost deficiencies are numerous and significant, so those discussions will not be repeated here. We note only that total costs appear to be on the order of approximately $345 million.[92]

The remainder of this section discusses problems with BLM's assessment of the proposed rule's benefits and deficiencies in the agency's evaluation of alternatives to the rule. Without significant revisions, we believe that that the economic analysis renders the proposed rule arbitrary and capricious.

Purported Benefits are Exceedingly Uncertain

BLM asserts that, "[w]hile the potential benefits of the rule are more challenging to monetize than the costs, they are significant."[93] Exactly how the agency reaches this conclusion is unclear, given that most of the preamble discussion regarding the benefits framework is devoted to declarations of what the agency does not know. For example:

- "The primary challenge in monetizing benefits lies in the quantification of a risk that is largely unknown."[94]

- "There are limitations in using the BLM data on undesirable events for this [benefits] analysis." "As such, there is difficulty in quantifying the level of risk reduction that would be attributed to the regulations, even though the regulations would most certainly reduce risk."[95]

- "Damage, in general, is unknown . . . ."[96]

- "Further uncertainty lies in the estimation of benefits and the cumulative effect of the rule's provisions on mitigating the potential risks of hydraulic fracturing operations. This rule has specific provisions that would help operators and the BLM better identify potential issues in wellbore integrity and fracturing design, before operations begin.

[92] This figure, taken from the economic analysis that John Dunham & Associates prepared (attached as Appendix A) does not include certain costs elements. Among other examples, water testing costs of approximately $28.4 million to $42.5 million per year and fracture modeling costs of approximately $15.45 million per year are not included in John Dunham & Associates' assessment.

[93] 78 Fed. Reg. 31,636, 31,663 (May 24, 2013) (emphasis added).

[94] 78 Fed. Reg. 31,636, 31,663 (May 24, 2013).

[95] 78 Fed. Reg. 31,636, 31,663 (May 24, 2013).

[96] 78 Fed. Reg. 31,636, 31,663 (May 24, 2013).

However, it is difficult to attribute benefits to one single test (for instance the CEL) when that is only one part of the overall evaluation of wellbore integrity."[97]

- "Thus far, all reported events of groundwater contamination that attribute the cause of a contamination event to well stimulation operations have not been confirmed."[98]

BLM makes no attempt to discuss the extent to which the requirements of the rule will produce the "significant" benefits of the rule, as compared to the regulatory framework already in place. BLM notes "incident rates" and potential damages (see below) as a means of describing the potential risks that the rule will mitigate, but that is all the agency attempts to quantify.

BLM seems to be relying on the concept that more requirements necessarily means a reduction in risk. Often, however, existing measures are appropriate and additional regulations and requirements will result in no significant change, other than increased burdens on the regulated community. This is precisely the case here. BLM has a regulatory duty to explain how and to what extent the additional requirements it seeks to impose will produce actual benefits—merely stating the agency's confidence that it will be so is insufficient—and this insufficiency renders the rulemaking arbitrary and capricious.

Errors in the Numerical Data Discussed in BLM's Benefits Analysis

Although BLM does not attempt to provide a numerical value of the monetary benefit it believes will result from the proposed rule, the agency's economic analysis document does purport to provide a range of possible incident frequencies and incident costs. Unfortunately, there are a number of significant errors in the BLM's estimates. We submit that these errors are so fundamental as to render BLM's economic analysis procedurally inadequate and the rule itself arbitrary and capricious.

Incident Rates are Inappropriate

The economic analysis document for the proposed rule states that the likelihood of a "minor incident" associated with hydraulic fracturing is 2.7 percent and the likelihood of a "major incident" is 0.028 percent. It is readily apparent that neither number accurately reflects hydraulic fracturing incident rates. The very fact that these are the best estimates BLM can produce reflects that hydraulic fracturing "incidents" are exceedingly rare.

As an initial matter, we note that BLM's estimated incident rates are not based on data that must be submitted to the agency when "undesirable events" occur, such as accidental spills or releases of hydrocarbon fluids, produced water, hydraulic fracturing flowback fluids, or other substances. As explained in BLM's 2006 Notice to Lessees document (NTL-3A), operators are required to

[97] 78 Fed. Reg. 31,636, 31,664 (May 24, 2013) (emphasis added).

[98] BLM's Environmental Assessment at 26.

notify the agency when undesirable events occur and must then submit a written report that provides the "specific nature and cause of the event."[99]

BLM represents that it has not relied on this undesirable events data because the submissions do not specify whether the undesirable events are associated with hydraulic fracturing operations. The better conclusion is that BLM's own data demonstrates that there are no significant issues associated specifically with hydraulic fracturing (making this rule unnecessary). BLM's Environmental Assessment ("EA") document supports this conclusion. BLM states in the EA: "Thus far, all reported events of groundwater contamination that attribute the cause of a contamination event to well stimulation operations have not been confirmed. Therefore, it is impossible to predict how many contamination events the proposed amendments would prevent . . . ."[100]

BLM's minor incident rate is based on data in a survey the Energy Institute conducted that, according to the BLM, shows that 2.7 percent of oil and gas violations were in a violation category associated with hydraulic fracturing. One problem is that "groundwater contamination (complaints only)" was one of the "violation" categories BLM included as part of the 2.7 percent. First, this category appears to include non-hydraulic fracturing events. Second, including unproven complaints as even a partial basis for a hydraulic fracturing incident rate is unscientific, highly objectionable, and wholly inappropriate.

A more fundamental problem is that, without additional data, the fraction of violations that are associated with hydraulic fracturing operations provides no useful information about the actual number of incidents per year attributable to hydraulic fracturing. Yet BLM still seems to interpret the data as indicating that 2.7 percent of all hydraulic fracturing operations will experience an incident. This extrapolation is analogous to observing that fifty percent of Americans go to church on Sunday and then concluding that the average American goes to church approximately 182 days a year.

BLM's calculated rate for "major incidents" is equally flawed. The major incident rate is based on a *single* incident in 2012 in which the fracture path of one well intersected that of a second well and pushed fluids out of the second well. Approximately 60 barrels of crude oil escaped secondary containment. BLM took this one incident and divided it by the 3,566 hydraulic fracturing events it expects in the first year the rule is implemented. According to BLM, this yielded a rate of 0.028 percent *per year*.

The problem is apparent—hydraulic fracturing operations are not a recent innovation that suddenly commenced in 2012—they have been going on for decades. Indeed, even the unconventional shale plays have been extremely active for a period of years. After decades of

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[99] The Notice to Lessees document is available at: http://www.blm.gov/pgdata/etc/medialib/blm/wo/Information_Resources_Management/policy/im_attachments/2006.Par.34677.File.dat/im2006-061attach1.pdf.

[100] Prominent investigations associated with assertions that oil and gas operations have contaminated groundwater have been retracted. In March 2012, EPA dropped its allegations against Range Resources regarding wells in Parker County, Texas. In July 2012, EPA announced that its sampling of drinking water wells in Dimock, Pennsylvania had determined that there were not levels of contaminants that would require agency action. More recently, in June 2013, EPA decided not to finalize its draft report regarding wells in Pavillion, Wyoming.

operations, BLM references only one incident, yet states that it expects one such incident per year. BLM must either identify other major incidents in other years, or decrease the incident rate based on averaging over a much longer period of time. Again, this incident is the only concrete example of a hydraulic fracturing incident BLM provides in the entire preamble and accompanying economic analysis.

Damage Amounts are Inappropriate

The economic analysis document states that BLM's estimate of the remediation costs for a minor incident is approximately \$15,000. This figure is not derived from any study of "minor incidents" but rather represents the remediation costs associated with the single 2012 incident (see above) on which the agency based its incident rate for *major* events. This is plainly inappropriate—the costs for what BLM describes as a "major incident" should not be used as the basis for damages resulting from a "minor incident."

For major events, BLM states that the Federal Remediation Technologies Roundtable ("FRTR") has a number of case studies on its website, but notes that the FRTR does not list any case studies of events resulting from hydraulic fracturing operations. As documented in the introduction to these comments, this is because there are no demonstrated examples of aquifer contamination associated with hydraulic fracturing operations. BLM then states, without explanation, that its analysis assumes a cost of \$1 million to remediate a contaminated aquifer.

No basis for the \$1 million damages number is provided. The implication is that the value is based on the FRTR case studies, but there is no actual statement that the \$1 million is based on one or more case studies. In fact, there is no discussion of the case studies at all and no description of how the factual circumstances associated with the case studies could be similar to what might be expected from aquifer contamination associated with hydraulic fracturing (should such a future event occur).

BLM also states: "We believe remediation efforts could range from \$15,000 to hundreds of thousands of dollars for an incident that affects the surface environment." This one sentence is the entirety of the agency's "discussion" of major event surface damages. Without a basis, these numbers are meaningless. And without informing the public about the basis, public comment and participation are meaningless. Both as a matter of science and law, BLM must do more. Agency action is only lawful when the action can be upheld on the bases the agency itself articulates. Because BLM has advanced a risk assessment and made assertions related to potential damages without documenting any support for the agency's conclusions, its risk analysis cannot meet the standard the law requires.

Insufficient Alternatives and Other Required Analysis

As documented in these comments, BLM's proposed rule will significantly exceed \$100 million in annual costs, making it a significant regulatory action for which an examination of alternative approaches is necessary. Although BLM makes passing reference to alternatives in the preamble to the rule and in the agency's economic analysis, it has not engaged in any meaningful or legally sufficient analysis of alternatives to the rule that is proposed.

BLM considered only two alternatives to the revised proposal: (i) requiring CELs for all wells; and (ii) requiring CELs for all wells, but eliminating liner and tank requirements for fracturing fluid flowback. Practically speaking, there is only one alternative because almost all operators already use either lined pits or tanks for the management of flowback fluids. It is therefore not surprising that BLM estimates that the average difference in costs between the two alternatives would be only $9 per well.[101] This means that the cost difference between the two alternatives is less than 0.02 percent to 0.03 percent of the costs BLM projects.

For the alternatives analysis to be meaningful, BLM must at least assess an alternative that does not impose a CEL requirement for surface casing and other casing strings where cement is circulated to surface. First, BLM acknowledges that CELs are typically not run for surface casing—such a significant departure from industry best practices surely merits consideration in the alternatives analysis. Second, the surface casing component alone makes up at least sixty-three percent of the costs BLM projects.

Because the costs associated with the proposed rule are much higher than those BLM estimates, well over $100 million per year, BLM must also reconsider its current assessments under the following: (i) Executive Order 13563; (ii) Executive Order 12866 (Regulatory Planning and Review); (iii) the Regulatory Flexibility Act of 1980; (iv) the Small Business Regulatory Enforcement Fairness Act; and (v) the Unfunded Mandates Reform Act. To comply with the National Environmental Policy Act, BLM will also need to reassess its Environmental Assessment and Finding of No Significant Impact, based on, among other considerations, the social impacts attributable to the cost of this expensive rulemaking.

X. OTHER QUESTIONS ON WHICH BLM REQUESTED INPUT

Enforcement Issues Associated with Deference

BLM requested feedback regarding the practical enforcement challenges that would result if BLM deferred to state or tribal laws or procedures. We believe that BLM could write the hydraulic fracturing rules to incorporate state and tribal requirements in a way that would not limit the agency's enforcement powers.

BLM could require by rule, and as a condition of drilling permits, that operators must obtain approvals from the relevant state and tribal oil and gas agencies and must comply with the conditions these approvals impose. In this manner, a violation of the state or tribal approval would also constitute an enforceable violation of BLM's requirements.

Incorporation by reference for the sole purpose of enforceability is relatively common in the regulatory sphere. Many states, for example, have regulations that do nothing more than incorporate EPA emissions standards. By doing so, states make the federal standards a part of state law and ensure that they have authority to independently enforce the standards. Nothing prevents BLM from adopting the same approach.

[101] 78 Fed. Reg. 31,636, 31,666 (May 24, 2013).

Drafted correctly, a federal rule that defers to state and tribal laws and procedures regarding oil and gas operations would also provide the same level of information the states and tribes receive to BLM. BLM would simply need to specify that it receive a copy of required submissions. This would allow BLM to meet its stewardship responsibilities without significantly and needlessly increasing the operators' administrative burdens .

Feedback Regarding When Flowback Ends

BLM requested feedback regarding when fracturing fluid flowback ends and production begins, due to concerns regarding a potential overlap with Onshore Order No. 7's requirements for the storage and management of produced water. BLM asked specifically whether it would be sufficient to base a cutoff on the onset of the production of oil and gas.

There is no reason for BLM to distinguish between fracturing fluid flowback and produced water. From a practical perspective, fracturing fluids injected into an oil and gas formation will mix with the formation fluids. The initial flowback following a hydraulic fracturing operation will primarily be composed of fracturing fluid, because the injected fracturing fluid will have largely displaced the fluids in the near-wellbore environment. As time passes, the fluids will comprise an increasing fraction of native formation fluids. In fact, fracture fluids can be recovered from a well months and even years after flowback is initiated.

If BLM does attempt to distinguish between fracture fluid flowback and produced water, we do not believe that the cutoff should be based on the onset of the production of oil and gas. This is primarily because certain regulations, most notably EPA's New Source Performance Standards for the Oil and Gas Sector (40 CFR Part 60 Subpart OOOO) conflate flowback operations and production operations. In particular, Subpart OOOO will eventually require that operators of hydraulically fractured natural gas wells route to a gas sales line all salable quality gas separated from fracturing flowback fluids as soon as doing so is practicable.[102]

Although we do not believe that BLM can distinguish between fracturing fluid flowback and produced water, and have suggested that BLM use a more realistic term (recovered water), should BLM insist on drawing such a distinction, it would be simpler for BLM to use a time-based cutoff to avoid overlap between the flowback provisions in the proposed hydraulic fracturing rule and Onshore Order No. 7. The cutoff would establish a period of time during which liquids would be managed pursuant to the hydraulic fracturing rule and after which Onshore Order No. 7 would become effective. BLM's authorized officer could establish this cut-off for a particular project, to account for the local geology and the natural variances in the rate of fluid return from field-to-field.

This approach will allow BLM to regulate water management and protect environmental resources in an effective manner that accounts for the unique characteristics of each individual mineral reservoir. To the extent there is any meaningful difference between fluid flowback and produced water, the point where the former concludes and the latter commences is different in each field, because each reservoir returns the majority of stimulation waters at different rates. In the Haynesville shale, for example, stimulation waters are generally returned in thirty days. In

[102] 40 C.F.R. § 60.5375(a)(2).

the Bakken, by contrast, stimulation waters may take more than sixty days to return. As such, any distinction between fluid flowback and produced water must account for the nature of the reservoir.

A time-based approach accounting for the characteristics of the reservoir would allow operators flexibility to develop projects in a manner that is the most sensitive to the economic and environmental concerns the particular project's circumstances present. Some will need to manage large volumes of fluids for only a short period of time. These operators would be able to use a temporary pit that has been lined in accordance with proposed 43 C.F.R. § 3162.3-3(h) and then switch to a smaller pit meeting the requirements of Onshore Order No. 7 to manage the lower volumes associated with the post-flowback period. Operators who will need to manage large volumes of produced water during the productive life of the well might, instead, opt to install a permanent pit meeting Onshore Order No. 7 requirements and use that pit for both immediate fluid flowback and longer-term produced water management.

Our proposed regulatory language for a time-based approach can be found below. We expect that operators who anticipate needing the use of a temporary pit for a longer period of time could request a case-by-case variance, pursuant to 43 C.F.R. § 3162.3-3(k).

Storage of Recovered Fluids

Proposed Change to BLM proposed 43 C.F.R. § 3162.3-3(h):

(h) During an initial period of time, determined by the authorized officer based on expected conditions in the reservoir, storage of all fluids recovered must be in either tanks or temporary lined pits.

(1) The following pits must meet the requirements set out in Onshore Order Number 7, Disposal of Produced Water, Section III.E. (October 8, 1993, 58 FR 58506):

(i) Any pit used for the storage of fluids recovered after the end of the initial period determined by the authorized officer; and

(ii) Any pit used only for the storage of fluids recovered during the initial period, but remaining in service for more than nine (9) months.

(2) The authorized officer may require any other BLM approved method reasonably necessary to protect the mineral resources, other natural resources, and environmental quality from the release of recovered fluids.

Thank you for consideration of these comments,

Dan Naatz
Vice President, Federal Affairs
IPAA

Kathleen Sgamma
Vice President, Public & Government Affairs
Western Energy Alliance

Appendix A:

Economic Assessment by John Dunham & Associates

MEMORANDUM

TO: Kathleen Sgamma, VP of Government & Public Affairs, Western Energy Alliance
FROM: John Dunham, Managing Partner
DATE: July 22, 2013
RE: Business Impact of Revised 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 on federal lands face a plethora of new rules. 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]

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 3,566 projects currently under development in the western states – would **cost at least $345.592 million annually**.[2] The anticipated average cost per well is estimated at $96,913. Table 1 below outlines the estimated costs by source.

Table 1
Revised Cost Calculations

	JDA Estimate	Percent of Total
Initial Delay Costs	$ 5,632,585	1.63%
Administrative Costs	$ 1,765,170	0.51%
Enhanced Casing Costs	$ 310,063,700	89.72%
Cement Log Costs for "Well Types"	$ 2,603,465	0.75%
Cement Log Delay Costs	$ 5,914,436	1.71%
Subtotal	$ 325,979,357	94.32%
Cost of Tanks over Pits	$ 19,613,000	5.68%
Total Costs	$ 345,592,357	100.00%

Proposed Regulation and Background:

In May of 2012, the BLM proposed amendments to current regulations (43 CFR 3160.0-3) that would lead to significantly more permitting and operational expenses for companies drilling and completing oil and gas wells on federal lands. At that time, John Dunham and Associates (JDA) estimated that the regulations would impose costs on operators in excess of $1.284 billion. (See Table 2 on the following page.)

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. Also includes estimated wells subject to the rules due to rework.

2 This figure is based on an average of two models. The first is based on the carrying costs of the project and the second on the discounted lost value of petroleum output. This also includes the costs associated with refracturing operations.

Since that time, the BLM has issued revisions to the proposed rule in response to the comments that it received from industry, environmentalists and the general public. The net result of these changes is that the implementation of the rule could cost the industry substantially less to implement; however, the total annual costs would still be far in excess of $325.9 million, not accounting for the use of water storage tanks over lined pits. The major revisions that the BLM has incorporated into the proposed rule consist of:

- The elimination of provisions to require that all well stimulations, including acid stimulations, undergo the full requirements set forth by the proposed rule;
- The elimination of requirements that companies undertaking oil and natural gas well development submit an application to the BLM for approval prior to completing the well;
- The significant modifications of requirements that cement logs be required on all wells but rather on representative wells and that wells of a "similar type" do not need to undergo this procedure unless it is deemed necessary by the particular well characteristics;
- Substantial changes in the administrative reporting and permitting burden placed on operators by the proposed rule.

Table 2
Initial 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

As a result of these changes, there are substantial differences in the calculation of the cost of the proposed rule from those calculated in June 2012. These are outlined below.

<u>Number of Impacted Wells</u>. The BLM assumes that this rule will apply to approximately 3,566 oil and natural gas wells.[3] Based on pending APD applications, JDA's earlier analysis calculated that 5,058 wells in just the 13 western states would be impacted. Without more detail from the BLM it is difficult to determine where the agency assumes these impacted wells will be located, but most of the federal leaseholds are in the modeled states. Therefore, to ensure that these estimates are moderate, the numbers in this analysis are calculated using 3,566 impacted wells rather than the original 5,058.

<u>The elimination of specific provisions of the rule relating to all stimulation procedures for oil and natural gas wells</u>. This specific provision had been estimated to cost the industry as much as $233,100 per well or about $273 million per year under the initial rule, most of which was due to maintenance activities such as acidization. It is now likely that most of these additional costs

[3] This includes BLMs estimates of reworks that would be covered by the proposed rules.

will not be incurred as the rule would generally not apply to these operations unless they are refracturing operations.

The elimination of the requirement that well operators wait an unspecified amount of time for the BLM to approve completion plans prior to the completion of each well. This provision would have imposed substantial delays on well operators leading to significantly higher drilling and capital costs. In the earlier analysis these delays were estimated to have a cost of $7,557 per well, for a total of $38.327 million. While the rule as now written still does not ensure that a well will be approved after completion, the initial analysis assumed an eventual 100 percent approval rate. Keeping that assumption means that these delay costs would no longer be incurred.

The Cost of Mechanical Integrity Tests. The BLM rejected the idea that the proposed rule would increase the cost of Mechanical Integrity Tests (MIT) since they are already required at some point in the development of each well. JDA`s earlier analysis suggested that additional MIT operations would 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.[4] This would lead to a total cost of $10.116 million under the proposed rule. Assuming that the BLM is correct, and that MITs in excess of those already mandated or required by the specific characteristics of the well would not be required, there would be an additional reduction in costs of $10.116 million compared to JDA's previous analysis.

Initial Delay Costs. The BLM recognizes that it does not have the capacity to implement these regulations with its current staffing levels, but nevertheless stated in the proposed rule that the agency will be able to review the new permits in conjunction with the APD and within "normal APD processing time frames."[5] Considering that the agency already takes an average of 10 months, and often 2 or 3 years to process an APD, it is difficult to determine what a "normal APD time frame" may actually be. While it is unlikely that the additional process would take as long as the current permitting time there will undoubtedly be some delay. If for example, it took the BLM just an extra month to process an APD, the financial cost per well could be as high as $6,770 – a total of nearly $23.016 million. This includes the costs of delayed tax and royalty payments to leaseholders (primarily the federal government).

Assuming that there is only a one week delay period – not an unreasonable assumption considering the amount of paperwork and testing that needs to be completed – the cost of delay would average about $1,580 per well.[6] Even using the lower figure this equals over $5.632 million in additional costs, a figure which is included in this report.

Administrative Costs. The BLM recognized our administrative cost assumption in its revised rule, and therefore, we do not believe that there would be any changes in the administrative burden as a result of the revisions to the rule that would reduce JDA's previously calculated figure. Also, there are no changes to the rule pertaining to the additional time that it would take before the approval of an Application for Permit to Drill (APD). Based on a cost of $495 per

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4 Ibid.

5 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.

6 John Dunham and Associates calculations for the Western Energy Alliance, 2012. Based on an interest rate of 7 percent to match the discount rate used in the BLM analysis.

well and assuming that 3,400 wells would be impacted, administrative costs alone will be $1.765 million.

Modification of the requirements that cement logs be required on all wells to just requiring them on representative wells. This change could lead to substantial savings over the costs of the initial rule; however, the definition of a *type well* is unclear. This could mean that cement logs would still be required on 100 percent of new wells drilled on Federal and Indian lands. Taking the agency at its word that the proposed modifications are designed to simplify the regulatory process and minimize the regulatory burden, it is likely that the actual number would be lower.

According to the BLM in its proposed rule, additional cement logs will only be required on about 8 percent of the wells (representing "type wells.") The BLM states that this is based on Automated Fluid Minerals Support System (AFMSS) data but does not provide substantive information on its calculations. Considering that modern drilling equipment and methods allow many wells to be drilled from the same platform, if one assumes that each of these wells is a *type well*, then it is likely that for every 6 to 8 wells only one cement log would be required. Taking the average of 7 would mean that this requirement would apply to just 14.29 percent of wells drilled on Federal and Indian lands. While this is more than the 8 percent assumed by the BLM, the costs from the smaller number of cement logs will be substantial. The earlier estimated cost of the CBL provision was about $776.734 million. The cost was due to the combination of three factors. First, there is an additional cement log required for the surface casing for nearly every well. Second, the analysis assumed that additional cement log wait times would be required on all wells prior to the initiation of a completion. Last, the initial analysis assumed additional cement logs would be required for intermediate casing strings. Assuming that additional cement logs are required on 8 percent of new wells the new calculated cost from this provision would be $2.603 million rather than the previously calculated $736.774 million.[7]

In addition, there are delay costs associated with the requirement that all wells have a cement log performed on surface casing – something that is rarely done in practice. While the BLM assumes that there would be minimal wait times, the analysis itself suggests that 43.3 percent of all wells are not drilled using a preset rig. In the case where a single rig is being used, it will require a minimum of 24 additional hours of complete downtime waiting for cement to dry.[8] The rental and operational costs for these rigs can vary however, the BLM claims that the cost is as low as $45,600, so the cost of delay is not simply equal to the time value of the money being invested, but rather the cost of the rig equipment itself. Based on the assumption that 24 additional down hours will occur on 43.3 percent of the covered wells, this equals as much as $5.914 million in additional costs.[9] This is in addition to the $2.6 million in additional costs for the CELs on surface and intermediate casing.

Additional Surface and Intermediate Casings. In addition, although the revised rule attempts to clarify the definition of "usable groundwater," it does not eliminate the requirement that for

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7 This includes about $100,000 in costs for a limited number of cement logs on intermediate casings.

8 The BLM assumed 24 hours in its economic impact analysis, and noted that most states require between 8 to 18 hours. Some operators have suggested that the actual downtime would be as high as 72 hours. The 24 hour figure used in this analysis is conservative and agrees with the assumptions used by the BLM. This represents only actual down time where no other work can be done on the well. For the limited number of wells that the BLM assumes will need a cement log for intermediate casings a delay time of 48 hours is used to be consistent with BLMs methodology.

9 This includes about $281,600 in delay costs for intermediate casings.

nearly all wells operators will have to run deeper surface casing, two-stage cementing on the production casing or the addition of an intermediate string of casing. Since ground water levels vary greatly across states, it is difficult to determine exactly how much additional casing will be required for an "average" well.[10] According to the BLM in its Economic Impact paper, there would be no cost related to this provision, since operators already have to protect usable ground water. This statement simply does not make sense. If the provision requires no action, the BLM should see no need for the rule.[11]

The simple fact is that the definition of "usable water" in the proposed rule is extremely broad, and could require operators to run and cement casings to depths far beyond any economically usable water. Current laws in the states require operators to case their wells to protect drinking water aquifers and other "useable" water aquifers, with the recognition that for aquifers to be deemed usable, they should also be economically viable. In North Dakota and Montana for example, water currently needs to be protected to a depth below the Pierre Shale, but the proposed rule could require an extra 3,800 feet of casing and cement in North Dakota in some circumstances.[12] Based on the broadest definition of "usable," in Wyoming water needs to be protected to a level 100 feet below the deepest water well within a one mile radius of an oil or gas well. Generally, drinking water aquifers are above 1,000 feet in Wyoming but there are exceptions.[13]

The initial analysis used an average of approximately 2,350 feet of additional intermediate casing per well in its calculations but further analysis of the rule suggests that this might be a very conservative figure. Some operators have suggested that an additional 8,000 feet of casing may be required under certain circumstances. Using the conservative figure of 2,350 feet per well of additional casing, at a cost of $37 per foot, this would add $310.064 million in costs for something that the BLM admits is not even necessary.[14]

<u>Cost of Tanks over Pits</u>. This was not included in the initial analysis, and JDA has not analyzed this provision of the proposed rule. According to the BLM, the cost of renting storage tanks could be about $6,000 to $17,000 per well, while the cost of lining pits is about $6,000 per pit. Storage tanks (as well as pits) could be used for multiple wells, and there would be development costs associated with both of these options. For simplicity, this analysis assumes that the

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10 It is nearly impossible to develop an exact figure for the additional casing costs required under the proposed rule. The new definition of "usable water" is so broad that in practical terms, casings may be required to be run to significantly deeper depths than may be economically practical (particularly for gas wells located on federal lands.) In addition, calculating an exact figure would require an engineering examination of each of the geologic basins and the well designs in use – something which is not practical based on the available data.

11 In practice, the BLM has deferred to the states in determining what formations require additional casing in order to protect usable water, and the states have had latitude in this process. The proposed rule bases the definition of usable water solely on the total amount of dissolved solids contained in a particular formation.

12 Other areas, such as the Denver-Julesburg Basin would likely require no additional casing since they are already covered by state regulations.

13 Based on well permit data from the Wyoming State Engineer's Office, the deepest domestic ground water well in the state is 10,660 feet deep. See: https://seoweb.wyo.gov/e-Permit/common/login.aspx?ReturnUrl=/e-Permit/Default.aspx

14 This does not suggest that operators do not have an obligation to protect actual drinking water sources; however, it does show that a generalized *one-size-fits-all* rule like the one being proposed by the BEA is both practically and economically inefficient. A prescriptive rule of this nature removes the discretion that state governments have long had in determining whether or not particular formations contained economically viable sources of drinking water. It should also be noted that this figure is highly subjective; however, even if the average estimate for additional casings were just one-third of what is presented here (about 800 feet), the estimated cost of the proposed rule on operators would still be greater than $100 million.

development costs would be equal between pits (which need to be dug) and tanks (which need to be plumbed). It also assumes that a tank and a pit can each be used for a given well and that the tank costs are $11,500 per well (BEA's average), the additional costs across 3,566 wells would be $19.613 million, a figure that is included in this analysis.

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.

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.