# Well Stimulation Proposed Rule: Economic Analysis and Initial Regulatory Flexibility Analysis

U.S. Bureau of Land Management

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# 1. Executive Summary

## 1.1 Introduction

The Bureau of Land Management (BLM) estimates that roughly 90 percent of wells currently drilled on Federal and Indian lands are stimulated using hydraulic fracturing techniques. Hydraulic fracturing facilitates the production of oil and gas where there is no flow or the resource is trapped within reservoir rock. However, the technique is not without controversy. The public and other groups have expressed concerns that hydraulic fracturing and the expansion of oil and gas drilling into new parts of the country pose adverse impacts to water quality and safety.

The BLM hosted public forums in 2011 where panelists and the audience expressed support for improved surface operations and the disclosure of fracturing fluid components. The Secretary of Energy's Advisory Board Subcommittee on Natural Gas has also recommended public disclosure of the chemicals used in fracturing fluids, broader use of water quality sampling before drilling new wells, and progressive standards for wellbore construction. A number of states have passed legislation requiring the disclosure of fracturing fluids.[1]

The BLM has regulatory authority for hydraulic fracturing, found in 43 CFR 3162.3-2; however, the current regulation is inadequate in several respects. Current regulation separates fracture operations into "routine" and "non-routine" operations, but it does not define the difference, thus creating confusion among operators, stakeholders, and others. As a result, the BLM receives a small number of Notice of Intent Sundry proposals for hydraulic fracturing operations on BLM-managed lands even though these operations are common. Also, the regulation is 30 years old and does not reflect the many changes to technology and industry best practices that have occurred since that time. As such, it does not present standards for wellbore integrity even though such standards exist. Lastly, current regulations do not require the disclosure of the chemicals used in fracturing fluids and other information necessary for the BLM to effectively manage the nation's resources on Federal and Indian Lands.

As part of the regulatory process, the BLM conducted this economic analysis to estimate the benefits and costs of the proposed regulatory changes. The results indicate that the proposed rule is not economically significant according to the criteria in Executive Order 12866.

[1] "Natural Gas: More States Require Disclosure of Fracking Chemicals" (January, 23, 2012). Greenwire.

However, in accordance with Executive Order 12866, the Office of Management and Budget (OMB) has determined that the rule is significant, since it would require operators to provide information to the BLM regarding well stimulation activities that they are currently not required to submit. As such, it might raise novel policy issues.

## 1.2 Results

The analysis estimates the effects of the proposed regulations over a baseline scenario, where no action is taken. It also examines an alternative to the proposed regulations. It considers the removal of the requirement for operators to line pits when using pits to store fracturing fluids.

The analysis considers impacts occurring over a ten-year period. The benefits, costs, and net benefits presented in this section are discounted at 7% and 3%. Results are presented as annualized values.

**Proposed Regulations (Preferred Approach)**

*Benefits*

Under the proposed regulations, it is assumed that the regulations would remove much of the risk associated with potential wellbore integrity issues and unlined pits. The change in social benefits from the baseline scenario is positive. Because monetization of the reduction of risk associated with potential wellbore integrity is a difficult issue, this analysis is using avoided cost of remediation as a proxy value. If you assume that there is low environmental risk posed by wellbore integrity issues and storage of hydraulic fracturing fluids in unlined pits and the costs of surface and subsurface remediation is low (on the range assumed), then the change in social benefit as a result of the proposed regulation is positive and ranges between $11.70MM and $13.79MM per year using a discount rate of 7% and between $11.74MM and $13.85MM per year using a discount rate of 3%. If you assume that environmental risk are high and remediation costs are high (on the range assumed), then the social benefits of the proposed regulation is positive and ranges between $42.67MM and $50.27MM per year using a discount rate of 7% and between $42.79MM and $50.49MM per year using a discount rate of 3%.

*Costs*

The change in costs over the baseline ranges between $37.34MM and $43.99MM per year using a discount rate of 7% and between $37.44MM and $44.18MM per year using a discount rate of 3%, assuming either low remediation costs and low environmental risks or high remediation costs and low environmental risks.

*Net Benefits*

The change in net benefits for the proposed regulations varies depending on the amount of environmental risk associated with wellbore integrity issues and unlined pits and the level of remediation costs associated with contamination events. Assuming low remediation costs and low environmental risks, the change in net benefits from the baseline is negative and ranges from between -$25.63MM and -$30.20MM per year using a discount rate of 7% and between -$25.70MM and -$30.33MM per year using a discount rate of 3%. Assuming high remediation costs and high environmental risks, the change in net benefits is positive and ranges from between $5.33MM and $6.28MM per year using a discount rate of 7% and between $5.35MM and $6.31MM per year using a discount rate of 3%.

Given the assumptions made about the costs of remediating contamination and the fact that certain benefits were not quantified, the range of estimated outcomes could underestimate the actual net benefits. The analysis makes several assumptions about the occurrence or contamination and the costs of remediating a contamination event. It assumes low and high costs of $42,500 and $1,000,000, respectively, for remediation of a subsurface contamination, and $25,000 and $75,000 for remediation of a surface contamination. Given the uncertainty in estimating these costs, the assumptions used err on the side of understating net benefits. Where net benefits are estimated to be negative, the net benefits could be greater (meaning the net benefits could be less negative or positive).

This analysis also does not capture the potential benefits associated with the disclosure of fracturing fluids. Disclosure might encourage operators to use fewer or safer chemicals in the hydraulic fracturing fluid. Operators disclosing the MIT and wellbore integrity might add more awareness and attention for due diligence to prudent operations. The public would benefit from increased knowledge about the fluids used. This transparency is also likely to benefit scientists, state and Federal agencies, and other organizations that study the potential impacts of well stimulation operations. The BLM would be able to make more informed resource decisions and respond effectively to events where environmental resources have been compromised.

It should be noted that the low cost and risk scenario results in negative net benefits while the high cost and risk scenario results in positive net benefits. This primary difference is not a result of the administrative or operational costs changing between the scenarios. Instead, the difference is due to the valuation of social benefits. If you assume the risk of contamination is greater and the costs of remediation are higher, then the change in benefits of the proposed rule would be greater and offset the change in compliance costs.

**Alternative 1: Removal of Requirement to Line Pits when Operators Use Pits to Store Fracturing Fluids**

*Benefits*

The change in social benefits from the baseline scenario is positive. Assuming low remediation costs and low environmental risks, then the change in social benefit under this alternative is positive and ranges between $0.01MM and $0.02MM per year using a discount rate of 7%. Assuming high remediation costs and high environmental risks, the change in social benefits over the baseline ranges between $7.60MM and $8.95MM per year using a discount rate of 7%.

*Costs*

The change in costs over the baseline ranges between $34.68MM and $40.86MM per year using a discount rate of 7% and between $34.77MM and $41.04MM per year using a discount rate of 3%, regardless of the remediation costs and environmental risks assumptions.

*Net Benefits*

The change in net benefits is negative for this alternative. Assuming low remediation costs and low environmental risks, the change in net benefits range from between -$34.67MM and -$40.84MM per year using a discount rate of 7% and between -$34.76MM and -$41.02MM per year using a discount rate of 3%. Assuming high remediation costs and high environmental risks, the change in net benefits ranges between -$27.08MM and -$31.90MM per year using a discount rate of 7% and between -$27.15MM and -$32.04MM per year using a discount rate of 3%.

**Energy System Impacts**

The proposed regulations are unlikely to affect the investment decisions of firms, or to have any effect on the supply, distribution, or use of energy. The analysis estimates the cost burden per well stimulation and presents it as a portion of the drilling costs per well.

**Small Entity Analysis**

Small entities represent the overwhelming majority of entities operating in the crude oil and natural gas extraction industry. As such, the proposed rule is likely to affect a significant number of small entities. However, after considering the economic impact of the proposed rule on these small entities, the screening analysis indicates that this proposed rule will not have a significant economic impact on a substantial number of small entities. The analysis presents the burden per small entity as a share of a sample of small entity net incomes in 2010.

**Employment Impacts Analysis**

This analysis seeks to inform the discussion of labor demand and job impacts by providing an estimate of the employment impacts of the proposed regulations using labor requirements for the additional administration and operational needs.

This proposed rule would require operators, who have not already done so, to conduct one-time tests on a well or make a one-time installation of a mitigation control feature. In addition, operators would be required to perform administrative tasks related to a one-time event. Compliance with the operational requirements is expected to shift resources within the industry from the operators to firms providing the services or supplies.

Since we anticipate that the number of well stimulations will increase over time, the labor requirements are expected to increase over the outlook period. Depending on the scenario, the annual labor requirements range from about 15 to 18 additional full-time employees (FTE) in 2013. Operators are not expected to reduce investment or employment as a result of increased burden. Note that these impacts are only for the regulated sector. The BLM cannot predict the net national employment impact, i.e., whether the increased employment in the regulated sector comes from previously unemployed workers or is displaces workers actively employed in other sectors.

## 1.3 Organization of this Report

The remainder of this report details the methodology and the results of the analysis. Section 2 presents additional background material. Section 3 describes the framework and methodology for estimating benefits and costs. Section 4 presents the estimated benefits and costs. Section 5 presents the energy system impact, employment impact, and small business impact analyses. Section 6 presents determinations regarding statutory and executive order requirements. Section 7 offers a conclusion. Sections 8 and 9 provide a list of the references and appendix materials, respectively.

# 2. Background

## 2.1 Requirements for Economic Analysis

By statute and executive order, an agency proposing a significant regulatory action is required to provide a qualitative and quantitative assessment of the anticipated costs and benefits of that action. Executive Order 12866 requires agencies to assess the benefits and costs of regulatory actions, and for significant regulatory actions, submit a detailed report of their assessment to the Office of Management and Budget (OMB) for review. A rule may be significant under Executive Order 12866 if it meets any of four criteria. A significant regulatory action is any rule that may:

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities;
- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

When an agency publishes a general notice of proposed rulemaking, 5 U.S.C. 603 requires the agency to perform an initial regulatory flexibility analysis and make it available for public comment.[2] The analysis must describe the impact of the proposed rule on small entities and contain the following information:

- Description of the reasons why action by the agency is being considered;
- Succinct statement of the objectives of, and legal basis for, the proposed rule;
- Description of and, where feasible, an estimate of the number of small entities to which the proposed rule will apply;

[2] An agency must conduct a final regulatory flexibility analysis when it promulgates a final rule, per 5 U.S.C. 604.

- Description of the projected reporting, recordkeeping and other compliance requirements of the proposed rule, including an estimate of the classes of small entities which will be subject to the requirement and the type of professional skills necessary for preparation of the report or record; and
- Identification, to the extent practicable, of all relevant Federal rules which may duplicate, overlap or conflict with the proposed rule.

The initial regulatory flexibility analysis should also contain a description of any significant alternatives to the proposed rule which would accomplish the stated objectives but which would minimize any significant economic impact of the proposed rule on small entities.

## 2.2 Need for Policy Action

The BLM estimates that roughly 90 percent of wells currently drilled on BLM-managed lands are stimulated using hydraulic fracturing techniques. Hydraulic fracturing is a technique used to increase the amount of crude oil or natural gas produced from a reservoir. During a hydraulic fracturing event, an operator will pump a specially blended liquid containing water, chemicals, and other materials into a formation with sufficient pressure to cause the formation to crack, allowing the resource to flow to the wellbore. The fracturing fluid is designed to serve several functions, such as lubricating the fractures and leaving channels open for the hydrocarbon resource to flow to the well.

The public and other groups have expressed strong concerns about the prevalence of hydraulic fracturing and the chemical content of the fluids used in the process. As a follow-up to the Department of the Interior (DOI) forum on hydraulic fracturing on November 30, 2010, the BLM hosted public forums in Bismarck, North Dakota on April 20, 2011; Little Rock, Arkansas on April 22, 2011; and Golden, Colorado on April 25, 2011, to collect broad input on the issues surrounding hydraulic fracturing. Over 600 members of the public attended the forums. Some of the comments frequently heard during these forums included concerns about water quality, water consumption, and a desire for improved environmental safeguards for surface operations. Commenters also strongly encouraged the agency to require public disclosure of the chemicals used in hydraulic fracturing operations on Federal and tribal lands.

Around the time of the BLM's forums, at the President's direction, the Secretary of Energy's Advisory Board convened a Natural Gas Subcommittee (Subcommittee) to evaluate hydraulic fracturing issues. The Subcommittee met with industry, service providers, state and Federal regulators, academics, environmental groups, and many others stakeholders. Initial recommendations were issued by the Subcommittee on August 18, 2011. Among other things, the report recommended that more information be provided to the public, including disclosure of the chemicals used in fracturing fluids. The Subcommittee also recommended the adoption of progressive standards for wellbore construction and testing. The initial report was followed by a final report that was issued on November 18, 2011. The final report recommended, among other things, that operators engaging in hydraulic fracturing prepare cement bond logs and undertake pressure testing to ensure the integrity of all casings. These reports are available to the public from the Department of Energy's web site at http://www.shalegas.energy.gov.

The U.S. Environmental Protection Agency (EPA) lists the following as potential impacts of hydraulic fracturing[3]:

- Stress on surface water and ground water supplies from the withdrawal of large volumes of water used in drilling and hydraulic fracturing;
- Contamination of underground sources of drinking water and surface waters resulting from spills, faulty well construction, or by other means; and
- Adverse impacts from discharges into surface waters or from disposal into underground injection wells.

The BLM regulatory authority for hydraulic fracturing is found in 43 CFR 3162.3-2. Under that regulatory provision, "Subsequent Well Operations," if a "routine" hydraulic fracturing operation is performed on an existing well, the operator must provide a sundry report of the operation to the BLM within the 30 days following its performance. For "non-routine" fracturing operations, the operator must seek approval from the BLM authorizing officer before operations begin in addition to the subsequent report required for the "routine" operation. The regulations do not offer a definition regarding the terms "routine" or "non-routine." The current regulations make a distinction between routine fracture jobs and nonroutine fracture jobs. The terms "routine" and "nonroutine" are not defined in 43 CFR 3162.3-2 or anywhere else in BLM regulations, making this distinction functionally difficult to apply and confusing for both the

[3] EPA (2012). "Natural Gas Extraction – Hydraulic Fracturing."

agency and those attempting to comply with the regulations. These regulations were established in 1982.

Since the current regulations do not require operators to demonstrate wellbore integrity and disclose the plans for and results of the well stimulation operations, there is greater potential for negative externalities to occur. Wellbores that are constructed inadequately may not sufficiently isolate the wellbore and well fluids from the subsurface water resources or may be more likely to fail during fracturing operations, than wellbores constructed with sufficient and demonstrated integrity. Although the current liability regime allows for remediation of environmental damages associated with hydraulic fracturing, potential difficulties in tracing contamination of underground sources of water to the particular wells that may have contributed to the damage may exist. This potential externality provides conceptual basis for this federal regulatory effort.

Also, the current regulation results in incomplete information being provided to the BLM and the public. As the resource manager, the lack of information restricts the BLM's ability to make informed resource decisions or respond effectively to events where environmental resources have been compromised.

The BLM proposes to revise 43 CFR 3162.3-2 for several reasons. First, the increased use of well stimulation operations over the last decade has generated concerns among the public. Knowing the ingredients of fracturing fluids will help the government better manage and protect valuable resources. Next, 43 CFR 3162.3-2 distinguishes between non-routine fracture jobs and routine fracture jobs but never defines them. Subsequently, operators, stakeholders and others, are confused about which fracturing operations need the BLM's approval. Finally, the regulation is now 30 years old, and many changes to technology and industry standards have occurred since that time and these changes have not yet been addressed in BLM regulations.

## 2.3 Proposed Regulations

As an administrative matter, the proposed rule would amend the authorities section for the BLM's oil and gas operations management regulations at 43 CFR 3160.0-3 to include FLPMA. Section 310 of FLPMA authorizes the Secretary of the Interior to promulgate regulations to carry out the purposes of FLPMA and other laws applicable to the public lands. See 43 U.S.C. 1740. This amendment would not be a major change and would have no effect on lessees, operators, or the public.

The proposed rule would remove the terms “nonroutine fracturing jobs,” “routine fracturing jobs,” and “acidizing jobs” from 43 CFR 3162.3-2(a) and 43 CFR 3162.3-2(b). It would add a new section, 43 CFR 3162.3-3, for well stimulation activities. In the proposed rule, there would be no distinction drawn between what was previously considered nonroutine or routine well stimulations. Prior approval would be required for well stimulation activities, generally in connection with the prior approval process that already is in place for general well drilling activities through the Application for Permit to Drill (APD) process. Operators also will be required to submit cement bond logs before fracturing operations begin. The running of cement bond logs on surface casing, which is currently an optional practice, would now be required for new wells. Existing wells would require mechanical integrity testing prior to hydraulic fracturing.

### 2.3a Definition Additions and Changes

The proposed rule would include six new definitions for technical terms used in the proposed rule. These definitions will improve readability and clarity of the regulations.

The proposed rule intends to add the following definitions:

- Annulus means the space around a pipe in a wellbore, the outer wall of which may be the wall of either the borehole or the casing; sometimes also called the annular space.
- Bradenhead means a heavy, flanged steel fitting connected to the first string of casing that allows suspension of intermediate and production strings of casing, and supplies the means for the annulus to be sealed off.
- Proppant means a granular substance (most commonly sand, sintered bauxite, or ceramic) that is carried in suspension by the fracturing fluid and that serves to keep the cracks open when fracturing fluid is withdrawn after a hydraulic fracture treatment.
- Stimulation fluid means the liquid or gas, and any accompanying solids, used during a treatment of oil and gas wells, such as the water, chemicals, and proppants used in hydraulic fracturing.
- Usable water means water containing up to 10,000 ppm of total dissolved solids.
- Well stimulation means those activities conducted in an individual well bore designed to increase the flow of hydrocarbons from the rock formation to the well bore by modifying

the permeability of the reservoir rock. Examples of well stimulation operations are acidizing and hydraulic fracturing.

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

### 2.3b Section-By-Section Discussion of Proposed Changes

Revised section 3162.3-2(a) would remove the phrase "perform nonroutine fracturing jobs" from the current 43 CFR 3162.3-2(a). The phrase "routine fracturing jobs or acidizing jobs, or" would also be removed from existing section 3162.3-2(b). Well stimulation activities would be addressed under the new proposed 43 CFR 3162.3-3.

Proposed section 3162.3-3(a) would make it clear that this section applies only to well stimulation activities and that all other injection activities must comply with section 3162.3-2. This language is necessary to make the distinction between well stimulation activities and other well injection activities, such as secondary and tertiary recovery operations.

Proposed section 3162.3-3(b) would require the BLM's approval of all well stimulation activity. For new wells, the operator has the option of applying for the BLM's approval in its application for permit to drill (APD). For wells permitted prior to the effective date of this section or for wells permitted after the effective date of this section, the operator would submit a Sundry Notice and Report on Wells (Form 3160-5) for the well stimulation proposal for the BLM's approval before the operator begins the stimulation activity. This section would supersede and replace existing section 3162.3-2(b) that states that no prior approval is required for routine fracturing. This reference in the existing section would be deleted. Also, an operator must submit a Sundry Notice prior to well stimulation activity if the BLM's previous approval for well stimulation is more than five years old, or if the operator becomes aware of significant new information about the relevant geology, the stimulation operation or technology, or the anticipated impacts to any resource. The five-year period is consistent with common state

practices, including those of Montana, Wyoming, and Colorado, which require that operators reconfirm well integrity for fracturing operations through a pressure test every five years.
The BLM understands the time sensitive nature of oil and gas drilling and well completion activities and does not anticipate that the submittal of additional well stimulation-related information with APD applications will impact the timing of the approval of drilling permits. The BLM believes that the additional incremental information that would be required by this rule would be reviewed in conjunction with the APD and within the normal APD processing time frame. Also, the BLM anticipates that requests to conduct well stimulation activities on existing wells that have been in service more than five years will be reviewed promptly. The BLM understands that delays in approvals of operations can be costly to operators and the BLM intends to avoid delays whenever possible. However, as with any operational activity, there may be unforeseen circumstances that may on rare occasions delay approval of APDs. Please specifically comment on the nature and severity of impacts that delays in approvals of hydraulic fracturing operations could cause.

Proposed section 3162.3-3(c)(1) would require a report that includes the geological names, a geological description, and the depth of the top and the bottom of the formation into which well stimulation fluids would be injected. The report is needed so that the BLM may determine the properties of the rock layers and the thickness of the producing formation and identify the confining rocks above and below the zone that would be stimulated.

Proposed section 3162.3-3(c)(2) would require the operator to submit information in the form of a cement bond log, which will help the BLM in its efforts to make sure that water resources are protected. A cement bond log is a tool used to gauge the extent to which water bearing formations are isolated from the casing string. The log is a document that reports the data from a probe of the wellbore that uses sonic technology to detect gaps or voids in the cement and the casing. This log would be used to verify that the operator has taken the necessary precautions to prevent migration of fluids in the annulus from the fracture zone to the usable water horizons. The proposed regulation allows for the use of other evaluation tools acceptable to the BLM in order to allow the substitution of equally effective tools or procedures. For example, an operator could request a variance from the requirements of proposed section 3162.3-3(c)(2) that it submit cement bond logs to prove that the occurrences of usable water have been isolated to protect them from contamination. The BLM could grant a variance to allow for the use of logs other than cement bond logs (e.g., slim array sonic tool, ultrasonic imager tool) if it was satisfied that the alternative logs would meet or exceed the objectives of section (c)(2). The BLM recognizes that the cement bond log would not be available prior to drilling a well. Therefore, when the operator takes advantage of the option to submit its well stimulation information as part of its APD, the cement bond log would be required after approval of the permit to drill and prior to commencing well stimulation activities. Many operators routinely perform cement bond logs for the zones of interest, so the BLM does not expect this step to be a burden for operators. The best available means for the BLM to help 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 useable water, including running cement bond logs on the surface casing.

Proposed section 3162.3-3(c)(3) would require reporting of the measured depth to the perforations in the casing and uncased hole intervals (open hole). This proposed section would also require the operator to disclose specific information about the water source to be used in the fracturing operation, including the location of the water that would be used as the base fluid. The BLM needs this information to determine the impacts associated with operations and the need for any mitigation applicable to Federal and Indian lands. This section would also require the operator to disclose the type of materials (proppants) that would be injected into the fractures to keep them open and the anticipated pressures to be used in the well stimulation operation.

Proposed section 3162.3-3(c)(4), consistent with protecting public health and safety and preventing unnecessary or undue degradation to the public lands, would require operators to certify in writing that they have complied with all applicable Federal, tribal, state, and local laws, rules, and regulations pertaining to proposed stimulation fluids. The BLM will use this information to make an informed decision on the proposed action. This section also would require the operator to certify that it has complied with all necessary permit and notice requirements. The BLM acknowledges that other Federal, state, tribal, and local agencies may have regulatory requirements that would apply to chemical handling, injecting fluids into the subsurface, and the protection of groundwater. It remains the responsibility of the operator to be aware of and comply with these regulatory requirements. The BLM will rely on the operator's certification that it has complied with all of the laws and regulations that apply to its operation.

Proposed section 3162.3-3(c)(5) would require the operator to submit a detailed description of the well stimulation engineering design to the BLM for approval. This information is needed in order for the BLM to be able to verify that the proposed engineering design is adequate for safely conducting the proposed well stimulation.

Proposed section 3162.3-3(c)(5)(i) would require the operator to submit to the BLM an estimate of the total volume of fluid to be used in the stimulation.

Proposed section 3162.3-3(c)(5)(ii) would require the operator to submit to the BLM a description of the range of the surface treating pressures anticipated for the stimulation. This information is needed by the BLM to verify that the maximum wellbore design burst pressure will not be exceeded at any stage of the well stimulation operation.

Proposed section 3162.3-3(c)(5)(iii) would require the operator to submit to the BLM the proposed maximum anticipated injection pressure for the stimulation. This information is needed by the BLM to verify that the maximum allowable injection pressure will not be exceeded at any stage of the well stimulation operation.

Proposed section 3162.3-3(c)(5)(iv) would require the operator to submit to the BLM the estimated or calculated fracture length and height anticipated as a result of the stimulation, so that the BLM can verify that the intended effects of the well stimulation operation will remain confined to the petroleum-bearing rock layers and will not have unintended consequences on other rock layers, such as aquifers.

Proposed section 3162.3-3(c)(6) would require the operator to provide information pertaining to the handling of recovered fluids that will be used for the stimulation activities for approval. This information is being requested so that the BLM has all necessary information regarding chemicals being used in the event that the information is needed to help protect health and safety or to prevent unnecessary or undue degradation of the public lands.

Proposed section 3162.3-3(c)(6)(i) would require the operator to submit to the BLM an estimate of the volume of fluid to be recovered during flow back, swabbing, and recovery from production facility vessels. This information is required to ensure that the facilities needed to process or contain the estimated volume of fluid will be available on location.

Proposed section 3162.3-3(c)(6)(ii) would require the operator to submit to the BLM the proposed methods of managing the recovered fluids. This information is needed to ensure that the handling methods will adequately protect of public health and safety.

Proposed section 3162.3-3(c)(6)(iii) would require the operator to submit to the BLM a description of the proposed disposal method of the recovered fluids. This is currently required by existing BLM regulations (i.e., Onshore Order Number 7, Disposal of Produced Water, (58 FR 47354). This information is requested so that the BLM has all necessary information regarding disposal of chemicals used in the event it is needed to protect the environment and human health and safety and to prevent unnecessary or undue degradation of the public lands. The BLM specifically requests comments on whether the operator should be required to submit as part of the Sundry Notice application additional information about how it will dispose of waste streams not specifically addressed in this proposal.

Proposed section 3162.3-3(c)(7) would require the operator to provide, at the request of the BLM, additional information pertaining to any facet of the well stimulation proposal. For example, the BLM may require new or different tests or logs in cases where the original information submitted was inadequate, out of date, or incomplete. Any new information that the BLM may request will be limited to information necessary for the BLM to ensure that operations are consistent with applicable laws and regulation. Such information may include, but is not limited to, tabular or graphical results of a mechanical integrity test, the results of logs run, the results of tests showing the total dissolved solids in water proposed to be used as the base fluid, and the name of the contractor performing the stimulation. This provision would allow the BLM to obtain additional information about the proposed well stimulation activities. For example, after initial cementing activities, an operator may be asked to perforate the well casing and squeeze cement into the areas with inadequate cement bonding. In this case, the BLM may ask for additional information to show that the corrective action was successful and to ensure that the corrective work addressed any cement bonding deficiencies. The BLM wants to ensure that any additional information requested under this provision is the least burdensome to operators as possible while still accomplishing the goal of protecting the public lands and resources; therefore, the BLM is specifically requesting public comment on how this may be best achieved.

Proposed section 3162.3-3(d) would require the operator to perform a successful mechanical integrity test before beginning well stimulation operations. This requirement is necessary to help ensure the integrity of the wellbore under anticipated maximum pressures during well stimulation operations.

Proposed section 3162.3-3(d)(1) would require the mechanical integrity test to emulate the pressure conditions that would be seen in the proposed stimulation process. This test would show that the casing is strong enough to protect water and other subsurface resources during well stimulation activities.

The proposed section 3162.3-3(d)(2) would establish the engineering criteria for using a fracturing string as a technique during well stimulation. The requirement to be 100 feet below the cement top would be imposed to ensure that the production or intermediate casing is surrounded by a competent cement sheath as required by Onshore Order Number 2. The 100 foot requirement is required by some state statutes (e.g., Montana Board of Oil and Gas Conservation, section 36.22.1106, Hydraulic Fracturing) and is a generally accepted standard in the industry. Testing would emulate the pressure conditions that would be seen in the proposed stimulation process in order to ensure that the casing used in the well would be robust enough to handle the pressures.

Proposed section 3162.3-3(d)(3) would require the use of the pressure test time requirement of holding pressure for 30 minutes with no more than 10 percent pressure loss. This requirement is the same standard applied in Onshore Order Number 2, Drilling, (53 FR 46790) Section III.B.h., to confirm the mechanical integrity of the casing. This language does not set a new standard in the BLM's regulations. This test, together with the other proposed requirements, would demonstrate if the casing is strong enough to protect water and other subsurface resources during well stimulation activities. The BLM believes that all of these tests are important to show that reasonable precautions have been taken to ensure the protection of other resources during well stimulation activities.

Proposed section 3162.3-3(e)(1) would require the operator to continuously monitor and record the pressure(s) during the well stimulation operation. The pressure during the stimulation should be contained in the string through which the stimulation is being pumped. Unexpected changes in the monitored and recorded pressure(s) would provide an early indication of the possibility that well integrity has been compromised. This information is needed by the BLM to ensure that well stimulation activities are conducted as designed. This information would also show that stimulation fluids are going to the formation for which they were intended.

Proposed section 3162.3-3(e)(2) would require the operator to orally notify the BLM as soon as possible, but no later than 24 hours following the incident, if during the stimulation operation the annulus pressure increases by more than 500 pounds per square inch over the annulus pressure immediately preceding the stimulation.  Within 15 days after the occurrence, the operator must submit a Subsequent Report Sundry Notice (Form 3160-5, Sundry Notices and Report on Wells) to the BLM containing all details pertaining to the incident, including corrective actions taken.  This information is needed by the BLM to ensure that stimulation fluids are going into the formation for which they were designed.  The BLM also needs to obtain reasonable assurance that other resources are adequately protected.  An increase of pressure in the annulus of this amount could indicate that the casing had been breached during well stimulation.  Consistent with the BLM's Onshore Order Number 2, Drilling Operations, the operator must repair the casing should a breach occur.

Proposed section 3162.3-3(f) would require the operator to store recovered fluids in tanks or lined pits.  This provision grants flexibility for the operator to choose using either a lined pit or a storage tank, whichever the operator determines is the least burdensome or costly option for the storage of flowback fluid.  The BLM is proposing this requirement because flowback fluids could contain hydrocarbons from the formation and could also contain additives and other components that might degrade surface and ground water if they were to be released without treatment.  This provision is consistent with existing industry practice and American Petroleum Institute (API) recommendations for handling completion fluids (including hydraulic fracturing fluids) (see Section 6.1.6 of API Recommended Practice 51R, Environmental Protection for Onshore Oil and Gas Production Operations and Leases, First Edition, July 2009).  Section 302(b) of the Federal Land Policy and Management Act (43 U.S.C. 1732(b)) states that "In managing the public lands, the Secretary shall, by regulation or otherwise, take any action necessary to prevent unnecessary or undue degradation of the public lands."  In addition, existing BLM regulations at 43 CFR 3161.2 requires that "all operations be conducted in a manner which protects other natural resources and the environmental quality."  Because the use of lined pits or tanks for the storage of recovered fluids are methods that best and reasonably protect the public lands from spills or leaks of recovered fluids, the BLM believes that this provision is in keeping with FLPMA's mandate to prevent unnecessary or undue degradation of the public lands and the BLM regulation's requirement to protect environmental quality.

Additional conditions of approval for the handling of flowback water may be placed on the project by the BLM if needed to ensure protection of the environment and other resources.

The BLM specifically requests comments on whether this rule should impose additional requirements that would require tanks or lined pits for drilling fluids and any other fluids associated with well stimulation operations. The BLM recognizes the ongoing efforts of states to regulate hydraulic fracturing operations. In implementing this rule, the BLM intends to avoid duplication of existing state requirements and will continue to engage states in cooperative efforts to avoid duplication. Please comment on whether this proposed provision would be duplicative of provisions of state rules and whether it is unnecessarily burdensome.

Proposed section 3162.3-3(g) would require the operator to submit to the BLM the post-operation data on a Subsequent Report Sundry Notice (Form 3160-5, Sundry Notices and Report on Wells) following the completion of the stimulation activities. The BLM would determine if the well stimulation operation was conducted as approved. This information would be retained by the BLM as part of the individual well record and would be available for use when the well has been depleted and the plugging of the well is being designed.

Proposed section 3162.3-3(g)(1) would require reporting of the actual measured depth to the perforations and open hole interval. This information identifies the producing interval of the well and will be available for use when the well has been depleted and plugging of the well is being designed. Specific information as to the actual source of water, including location of the water being used as the base fluid, is required because the BLM needs the information to determine the impacts associated with operations and the need for any mitigation applicable to Federal and Indian lands.

Proposed section 3162.3-3(g)(2) would require the operator to submit to the BLM the actual total volume of fluid used, including water, proppants, chemicals, and any other fluid used in the stimulation(s) in order for the BLM to maintain a record of the stimulation operation as actually performed.

Proposed section 3162.3-3(g)(3) would require the operator to submit to the BLM a report of the surface pressure at the end of each stage pumped and the rate at which the fluid was pumped at the completion of each stage (i.e., just prior to shutting down the pumps). In addition to the information provided for the individual stages, the pressure values for each flush stage must also be included. This information is needed by the BLM for it to ensure that the maximum allowable pressure was not exceeded at any stage of the well stimulation operation.

Proposed sections 3162.3-3(g)(4) and (5) would require the operator to identify to the BLM the stimulation fluid by additive trade name and additive purpose, the Chemical Abstracts Service Registry Number, and the percent mass of each ingredient used in the stimulation operation. This information is needed in order for the BLM to maintain a record of the stimulation operation as performed. The information is being required in a format that does not link additives (required by 3162.3-3(g)(4)) to chemical composition of the materials (required by 3162.3-3(g)(5)) to minimize the risk of disclosure of any formulas of additives. This approach is similar to the one the State of Colorado adopted in 2011 (Colorado Oil and Gas Conservation Commission Rule 205A.b2.ix – xii). The BLM intends to place this information on a public web site and is working with the Ground Water Protection Council in an effort to integrate this information into the existing website known as FracFocus.org. The disclosure of the fluids used in hydraulic fracturing would only be required after the fracturing operation has taken place.

Proposed section 3162.3-3(g)(6) would require the actual, estimated, or calculated fracture length and height of the stimulation(s) to be reported to the BLM so that it can verify that the intended effects of the well stimulation operation remain confined to the petroleum-bearing rock layers and will not have unintended consequences on other rock layers or aquifers. This section would require the operator to show that the well stimulation activity was successfully implemented as designed and that the integrity of the well was maintained during stimulation.

Proposed section 3162.3-3(g)(7) would allow the operator flexibility to report online the information listed in proposed sections 3162.3-3(g)(1) through 3162.3-3(g)(6) by attaching a copy of the service company contractor's job log or report, provided the information required is adequately addressed. The operator is responsible for ensuring the accuracy of any information provided to the BLM, even if originally drafted by a third party.

Proposed section 3162.3-3(g)(8), would require operators to certify they have complied with all applicable Federal, state, tribal, and local laws, rules, and regulations pertaining to the stimulation fluids that were actually used during well stimulation operations. The proposed section would also require that the operator certify that it has complied with all necessary permit and notice requirements. This information would be retained by the BLM as part of the well record and be available for use when the well has been depleted and closure of the well is being designed.  The information is also needed for the BLM to fulfill its obligation to prevent unnecessary or undue degradation of the public land.

Proposed section 3162.3-3(g)(9) would require operators to certify that wellbore integrity was maintained throughout the operation.  This information is needed because the BLM has a mandate to protect human health and safety and prevent contamination of the environment.

Proposed section 3162.3-3(g)(10) would require the operator to provide information describing the handling of the fluids used for the stimulation activities, flow-back fluids, and produced water.  The operator must also report how it handled those fluids after operations were completed.

Proposed section 3162.3-3(g)(10)(i) would require the operator to report the volume of fluid recovered during flow back, swabbing, or recovery from production facility vessels.

Proposed section 3162.3-3(g)(10)(ii) would require the operator to report the methods of managing the recovered fluids.

Proposed section 3162.3-3(g)(10)(iii) would require the operator to report the disposal method of the recovered fluids.  This section also makes it clear that the fluid disposal methods must be consistent with Onshore Order Number 7, Disposal of Produced Water (58 FR 47353). This information is needed so that the BLM can help protect human health and safety and prevent the contamination of the environment.  The BLM also needs to confirm that the disposal methods used are those that were approved and conform to the regulations.

Proposed section 3162.3-3(g)(11) would require the operator to submit documentation and an explanation if the actual operations deviated from the approved plan.  Understanding the complexities of well stimulation, the BLM expects there to be slight differences between the proposed plan and the actual operation.

Proposed sections 3162.3-3(h) and (i) would notify the operator of procedures it needs to follow to identify information required to be submitted under this section that the operator believes to be exempt, by law, from public disclosure.  If the operator fails to specifically identify information as exempt from disclosure by Federal law, the BLM will release that information. The BLM may also release information which the operator has marked as exempt if the BLM determines that public release is not prohibited by Federal law after providing the operator with no fewer than 10 business days' notice of the determination.  All other information submitted by the operator will become a matter of public record.

Proposed section 3162.3-3(j) would provide the operator with a process for requesting a variance from the minimum standards of this regulation. Variances apply only to operational activities and do not apply to the actual approval process. The proposed regulation would make clear that the BLM has the right to rescind a variance or modify any condition of approval due to changes in Federal law, technology, regulation, field operations, noncompliance, or other reasons. The BLM must make a determination that the variance request meets or exceeds the objectives of the regulation. For example, an operator could request a variance from the requirements of proposed section 3162.3-3(c)(2) that it submit cement bond logs to prove that the occurrences of usable water have been isolated to protect them from contamination. The BLM could grant a variance to allow for the use of logs other than cement bond logs if it was satisfied that the alternative logs would meet or exceed the objectives of section (c)(2). This variance provision is consistent with existing BLM regulation such as Onshore Order Number 1 (see section X. of Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases; Onshore Oil and Gas Order Number 1, Approval of Operations (72 FR 10308, 10337).

Revised section 3162.5-2(d) would remove the references to fresh water and remove the phrase "containing 5,000 ppm or less of dissolved solids." This revision would require the operator to isolate all usable water. This language does not set a new standard in the BLM's regulations. Since 1988, Onshore Order Number 2, Drilling Operations, (53 FR 46790) Section II.Y. has defined usable water and Onshore Order Number 2, Drilling Operations, Section III.B. has required the operator to "protect and/or isolate all usable water zones." Section 3162.5(d) was not revised when Onshore Order Number 2, Drilling Operations, was promulgated, which has led to some confusion in implementing and interpreting the regulations.

### 2.3c Alternative Approaches

<u>Alternative 1: Removal of Requirement to Line Pits when Operators Use Pits to Store Fracturing Fluids</u>

In addition to the preferred approach, the BLM also considered an alternative to the proposed regulation which would remove the requirement for operators to use lined pits if they choose to use pits to store hydraulic fracturing fluids. This alternative was considered since the percentage of operators who use pits is expected to be lower, relative to the number of operators using storage tanks. Results of this alternative are presented in Table 4 and Table 5.

Other Alternative Approaches Considered

The BLM considered alternatives to direct regulation. Executive Order 13563 reaffirms the principles of Executive Order 12866 and requires that agencies, among other things, "identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public."

The use of economic incentives, such as user fees or marketable permits, is not a good option for this particular subject area. User fees are monies paid to the government to recover the costs of providing the regulatory good or service or for access to the resource. Marketable permits provide efficiencies when the compliance costs vary by producers, such that there are efficiency gains in having certain producers attain more of the emissions reductions, but be compensated otherwise, through the sale of pollution allowances to other producers where reductions are more costly than the price of a permit. This is not the case with the requirements considered in the proposed action and alternatives. The unit costs of the requirements do not vary significantly across wells or producers. Also, a unit of potential environmental degradation and remediation costs are not uniform across wells, events, and geographic areas (unlike, for example, a ton of $CO_2$ which disperses in the atmosphere).

The preferred approach promotes performance standards rather than design standards in its variance language. The BLM chose to include a provision that allows an operator to request a variance if it can attain the same standards established by the proposed regulation but in a different manner. The BLM would consider alternatives if an operator could show that intent and requirements of the proposed rule would be met using an alternate approach. The variance request, like the sundry forms, would be subject to BLM approval. From an efficiency standpoint, variances are important because they allow operators to use technology or other improvements to meet requirements in a more efficient or cost effective manner. This analysis does not quantify the benefits or costs of this provision; however, the provision would likely increase the net benefits of the proposal by reducing the costs.

In the proposed approach, the BLM has provisions for disclosure of hydraulic fracturing fluids. This requirement is informational in nature, rather than direct regulation on the part of the BLM. OMB Circular A-4 describes informational measures as follows:

If intervention is contemplated to address a market failure that arises from inadequate or asymmetric information, informational remedies will often be preferred. Measures to improve the availability of information include government establishment of a standardized testing and rating system (the use of which could be mandatory or voluntary), mandatory disclosure requirements (e.g., by advertising, labeling, or enclosures), and government provision of information (e.g., by government publications, telephone hotlines, or public interest broadcast announcements). A regulatory measure to improve the availability of information, particularly about the concealed characteristics of products, provides consumers a greater choice than a mandatory product standard or ban.

Specific informational measures should be evaluated in terms of their benefits and costs. Some effects of informational measures are easily overlooked. The costs of a mandatory disclosure requirement for a consumer product will include not only the cost of gathering and communicating the required information, but also the loss of net benefits of any information displaced by the mandated information. The other costs also may include the effect of providing information that is ignored or misinterpreted, and inefficiencies arising from the incentive that mandatory disclosure may give to overinvest in a particular characteristic of a product or service.

Where information on the benefits and costs of alternative informational measures is insufficient to provide a clear choice between them, you should consider the least intrusive informational alternative sufficient to accomplish the regulatory objective. To correct an informational market failure it may be sufficient for government to establish a standardized testing and rating system without mandating its use, because competing firms that score well according to the system should thereby have an incentive to publicize the fact.

## 2.4 Federal and Indian Oil and Gas Leasing Activity

The BLM Oil and Gas Management program is one of the most important mineral leasing programs in the Federal government. There were 49,173 Federal oil and gas leases covering 38,463,410 acres at the end of fiscal year (FY) 2011. For FY 2011, there were 90,452 producible and service drill holes and 96,606 producible and service completions on Federal leases.[4]

**Table 1: Federal and Indian Oil and Gas Cases[5]**

| | Producing | Non-Producing |
|---|---|---|
| FY 2008 | | |
| Federal Cases | 19,215 | 5,200 |
| Indian Cases | 2,614 | 125 |
| Total Cases | 21,829 | 5,325 |
| FY 2009 | | |
| Federal Cases | 19,409 | 4,081 |
| Indian Cases | 2,693 | 254 |
| Total Cases | 22,102 | 4,335 |
| FY 2010 | | |
| Federal Cases | 19,995 | 3,523 |
| Indian Cases | 2,576 | 392 |
| Total Cases | 22,571 | 3,915 |

Source: BLM, Automated Fluid Mineral Support System (AFMSS), FY-2010 Inspection and Enforcement Strategy

Production accountability and revenue collection are now the responsibility of the DOI Office of Natural Resources Revenue (ONRR) though the figures cited below were originally reported by the Minerals Management Service or the Bureau of Ocean Energy Management, Regulation and Enforcement. For FY 2011, onshore Federal oil and gas leases produced about 98 million barrels of oil, 2.97 billion Mcf of natural gas, 2.55 billion gallons of natural gas liquids, and approximately $2.7 billion in royalties. The production value of the oil and gas produced from public lands exceeded $23 billion. Oil and gas production from Indian leases was almost 20 million barrels of oil, 255 million Mcf of natural gas, and 143 million gallons of natural gas liquids, with a production value of $2.7 billion and generating royalties of $433 million.

[4] U.S. Department of the Interior, Bureau of Land Management, www.blm.gov, Oil and Gas Statistics.
[5] An AFMSS case can be a lease, unit participating area, communitized agreement, or other agreement.

**Table 2: Federal and Indian Oil and Gas Production and Royalties, Fiscal Year 2011**

| | Sales Volume | Sales Value ($MM) | Royalty ($MM) |
|---|---|---|---|
| Federal Leases | | | |
| Oil (bbl) | 97,721,813 | $8,374 | $1,111 |
| Gas (Mcf) | 2,974,916,041 | $12,556 | $1,360 |
| NGL (Gal) | 2,551,994,725 | $2,474 | $254 |
| Subtotal | | $23,404 | $2,725 |
| | | | |
| Indian Leases | | | |
| Oil (bbl) | 19,550,536 | $1,571 | $271 |
| Gas (Mcf) | 255,401,453 | $950 | $145 |
| NGL (Gal) | 143,404,729 | $167 | $18 |
| Subtotal | | $2,687 | $433 |

Source: ONRR, Federal Onshore Reported Royalty Revenue, Fiscal Year 2011 and American Indian Reported Royalty Revenue, Fiscal Year 2011

## 2.5 Industry Classifications

Most crude oil and natural gas entities are classified under North American Industry Classification System (NAICS) 211. This proposed rule directly affects entities classified within the Crude Petroleum and Natural Gas Extraction (211111), Natural Gas Liquid Extraction (211112), and the Drilling of Oil and Natural Gas Wells (213112) industries. Other industries include various distribution or transportation, storage, or support activities for oil and gas operations industries.

## 2.6 Unconventional Development

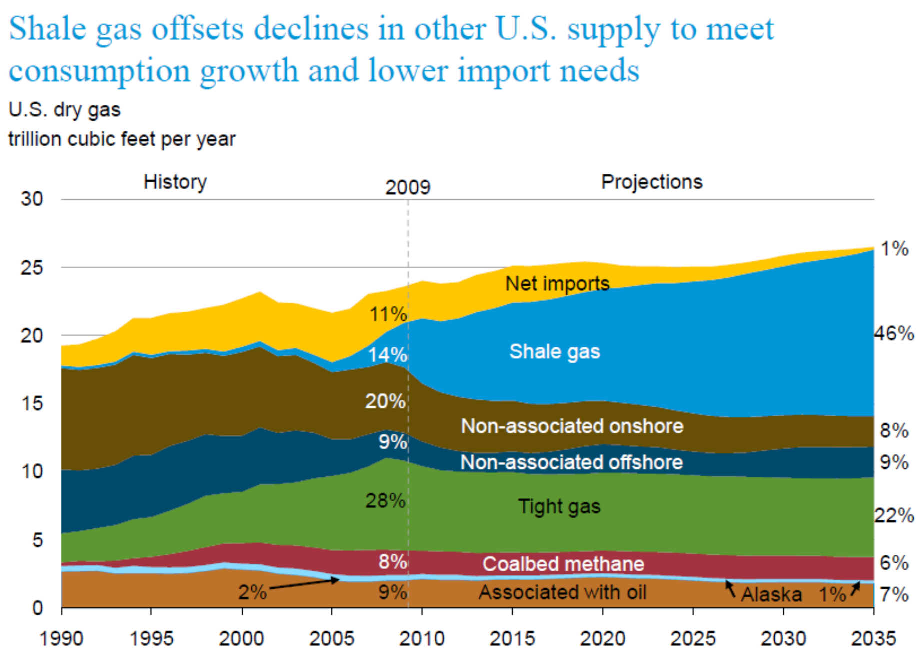
The proposed rule affects crude oil and natural gas producers conducting well stimulation operations. Well stimulations and hydraulic fracturing have grown increasing common in the United States over the past decade with the development of advanced drilling techniques, including horizontal drilling and sidetrack drilling. Horizontal drilling allows the production operation to reach a larger portion of the pay zone and ultimately recover more of the resource. For sidetrack drilling, operators drill horizontally off to the side of a plugged or abandoned vertical well.

Figure 1 displays the North American shale plays, while Figure 2 shows the increasing share of consumption needs that shale gas is expected to meet in the future.

**Figure 1: North American Shale Plays, EIA**


Source: Energy Information Administration based on data from various published studies.
Updated: March 21, 2011

**Figure 2: Expected Growth of Shale Gas**




Source: Richard Newell, EIA. June 21, 2011. "Shale Gas and the Outlook for U.S. Natural Gas Markets and Global Gas Resources. Paris.

## 2.7 Well Stimulation Process

Well stimulation techniques, including hydraulic fracturing of oil and gas wells, are used by oil and gas producers to increase oil and natural gas volumes available to the Nation. After drilling into hydrocarbon bearing rocks, producers use hydraulic fracturing to increase the effective permeability of the oil and gas bearing strata and increase oil and gas production from the well. Hydraulic fracturing involves the injection of fluid under high pressure to create or enlarge fractures in the reservoir rocks. In the fracturing process, a "proppant" such as sand is deposited in the fractures to keep the fractures from closing after the fracturing pressure is released. The proppant-filled fractures become conduits for fluid migration from the reservoir to the wellbore and are subsequently brought to the surface. Hydraulic fracturing allows hydrocarbons to move more freely into the well bore so that they can be brought to the surface for consumption.

Water and sand often make up 98 to 99 percent of the fluid used in hydraulic fracturing. In addition, chemical additives are generally used. Chemicals serve many functions in hydraulic fracturing. Some chemicals may limit the growth of bacteria and others prevent corrosion of the well casing. Chemicals are used to ensure that the work is effective and efficient. The exact formulation of the fluid varies depending on the rock formations, the well, and the requirements of the operator.

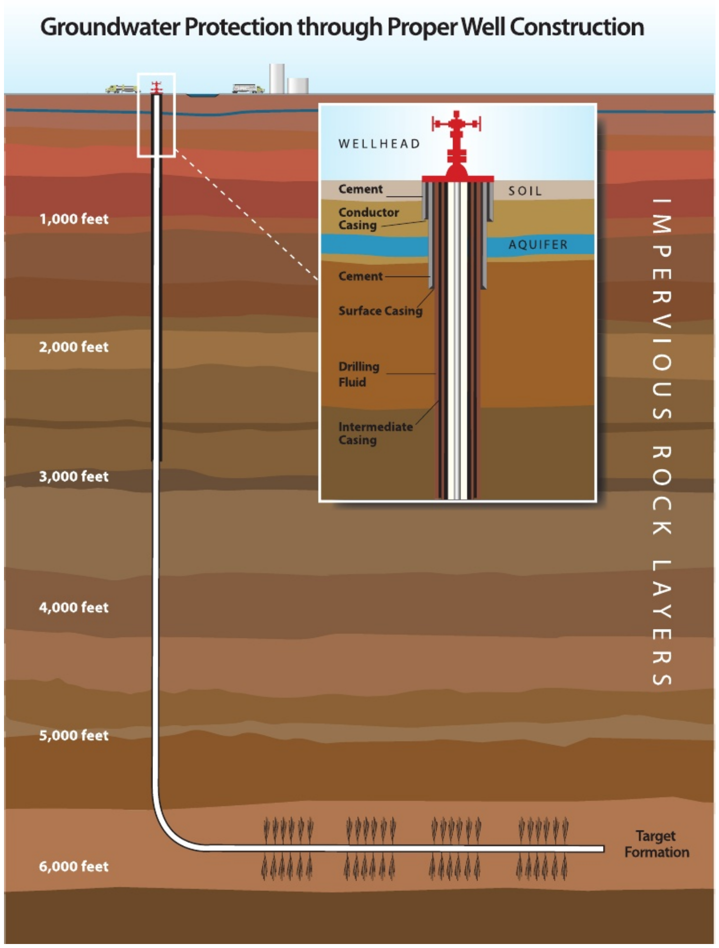
The number of stimulated wells has steadily increased over the years as technology has improved. These improvements allow geologic formations that were once thought to be incapable of production to produce in commercial quantities.

An important component to the production of the resource and to environmental safety is the casing that encases the well bore. "Casing prevents contamination of groundwater from oil production, prevents water encroachment into the well, and also enhances the structural integrity of the hole, preventing collapse as it passes through weak rock or rock containing fluids."[6]

Figure 3 shows how surface casing and cement layers protect the aquifer.

[6] Downey, 107. Casing is important for oil and gas wells.

**Figure 3: Horizontal Hydraulic Fracturing Operation**




Source: API (2010). “Freeing Up Energy.”

## 2.8 Industry Guidelines on Well Construction and Integrity

The American Petroleum Institute (API) provides guidelines for well construction and integrity for hydraulic fracturing operations in the API Guidance Document HF1 (2009). Topics covered in the guidelines include but are not limited to general principles, protecting groundwater and the environment, casing guidance, and well logging and other testing.

Well integrity is critical to protecting the environment and facilitating recovery of the resource. The guidance states, “Maintaining well integrity is a key design principle and design feature of all oil and gas production wells. Maintaining well integrity is essential for the two following reasons: 1) To isolate the internal conduit of the well from the surface and subsurface environment. This is critical in protecting the environment, including the groundwater, and in enabling well drilling and production; and 2) To isolate and contain the well's produced fluid to a production conduit within the well."[7]

*Protecting Groundwater and the Environment*

The combination of steel casing and cement sheaths protect groundwater by isolating the contents within the well from the groundwater aquifers. "The primary method used for protecting groundwater during drilling operations consists of drilling the wellbore through the groundwater aquifers, immediately installing a steel pipe (called casing), and cementing this steel pipe into place…. The steel casing protects the zones from material inside the wellbore during subsequent drilling operations and, in combination with other steel casing and cement sheaths that are subsequently installed, protects the groundwater with multiple layers of protection for the life of the well."[8]

*Casing Guidance and Well Logging*

The surface casing protects the groundwater aquifers by isolating well fluids within the well. "The surface hole is typically drilled to a predetermined depth based on consideration of the deepest groundwater resources and pressure control requirements of subsequent drilling. The surface hole should be drilled using air, freshwater, or freshwater-based drilling fluid. The setting depth can be from a few hundred feet up to 2000 ft deep or more. The surface casing is usually set at a depth sufficient to ensure groundwater protection. State regulations dictate the minimal setting depth of surface casing, and the vast majority of states require the casing to be set below the deepest groundwater aquifer. At a minimum, it is recommended that surface casing be set at least 100 ft below the deepest USDW encountered while drilling the well. It is recommended that the surface casing be cemented from the bottom to the top, completely isolating groundwater aquifers."[9]

Well logging is a common practice of operators and may be conducted multiple times while drilling a well. "Well logs are critical data gathering tools used in formation evaluation, well design, and construction. Also, various types of mechanical integrity and hydraulic pressure tests can be used to assess well integrity during the construction of the well."[10]

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[7] API (2009), pg. 1.
[8] Ibid, pg. 2.
[9] Ibid, pg. 11.
[10] Ibid, pg. 8.

After cementing the casing, logs may be run within the well. A cement bond log “measures the presence of cement and the quality of the cement bond or seal between the casing and the formation.”[11] Logs are important in “determining that the well drilling construction is adequate and achieves the desired design objectives.”[12]

*Pressure Testing*

The API recommends pressure testing on the surface casing. The proposed rule establishes that Mechanical Integrity Tests must be performed at specified pressures. This is consistent with API guidelines, which state, “After the surface casing cement has achieved the appropriate compressive strength and prior to drilling out, the surface casing should be pressure tested (commonly known as a casing pressure test). This test should be conducted at a pressure that will determine if the casing integrity is adequate to meet the well design and construction objectives.”[13]

[11] Ibid, pg. 9.
[12] Ibid, pg. 10.
[13] Ibid, pg. 11.

# 3. Estimating Benefits and Costs

## 3.1 Theoretical Framework

This analysis attempts to capture the potential benefits and costs that would result if the BLM implemented the proposed rule. As such, the current operating environment is the reference point from which the change is measured. Potential costs and benefits rely on the number of well stimulation events estimated to occur in the future on BLM-managed lands. Those estimates depend on a number of factors likely including, but not limited to, future oil and gas prices, the number of applications to drill, the number of wells completed, and the portion of wells that are stimulated.

The potential benefits of the proposed regulations include reduced surface and subsurface contamination. For the base case, where no action is taken, it is assumed that a certain number of well stimulation events may result in contamination and thus pose a cost to society. The proposed rule is designed to identify potential issues concerning wellbore integrity and other deficiencies in the design of well stimulation operations, thereby reducing the likelihood of contamination events. Because monetization of the reduction of risk associated with potential wellbore integrity is a difficult issue, this analysis is using avoided cost of remediation as a proxy value. An operator should identify potential issues with the wellbore once it runs and analyzes the results of the tests. If potential issues exist, the operator is likely to address the problem before submitting the NOI Sundry, rather than have its NOI Sundry disapproved. Requirements to address these issues are covered under BLM's Onshore Order Number 1.

Estimating the benefits is uncertain and subject to assumptions about the number of deficiencies, likelihood of contamination if a deficiency was present, and extent of damage. One way to measure the benefits is by estimating the cost to internalize the contamination, which may include the restoring a source of drinking water or remediation of an aquifer.

Under the proposed regulations, it is assumed that the contamination events assumed to occur in the base case would be avoided, and thus the remediation costs that would likewise be avoided. As such, the social benefit would be zero, but the change in social benefits from the base case to the proposed regulation scenario would be positive. The difference in costs and benefits from the base case to the proposed case represents the net benefits of the proposed rule.

The current regulations make a distinction between routine fracture jobs and nonroutine fracture jobs. However, the terms "routine" and "nonroutine" are not defined in 43 CFR 3162.3-

2 or anywhere else in BLM regulations, making this distinction functionally difficult to apply and confusing for both the agency and those attempting to comply with the regulations. The BLM estimates that about 20 percent of current well stimulations are considered "non-routine" for which the BLM receives a Notice of Intent Sundry prior to the stimulation operation. The proposed rule would require BLM approval for all well stimulation events. For each event, operators would obtain the BLM's approval prior to the event and submit a Subsequent Report Sundry within 30 days of the event. In most cases, the operator may seek approval for the stimulation operation at the same time that it submits the APD. Other information would be required if an incident occurs during a fracturing operation or if the BLM determines that there is a need for additional information.

Administrative costs include only the additional burden posed by the requirements. For operators, this burden includes the submission of forms and supporting documentation that are not currently required. The reporting requirements would also pose an additional burden on the BLM, since it would review an additional number of sundry forms and additional information per form. The efficiency of processing applications relies on operators submitting complete and adequate information. The BLM understands the time sensitive nature of oil and gas drilling and well completion activities and does not anticipate that the submittal of additional well stimulation-related information with APD applications will impact the timing of the approval of drilling permits. The BLM believes that the additional incremental information that would be required by this rule would be reviewed in conjunction with the APD and within the normal APD processing time frame. Also, the BLM anticipates that requests to conduct well stimulation activities on existing wells that have been in service more than five years will be reviewed promptly. The BLM understands that delays in approvals of operations can be costly to operators and the BLM intends to avoid delays whenever possible. However, as with any operational activity, there may be unforeseen circumstances that may on rare occasions delay approval of APDs.

Particularly relevant to the disclosure requirement in the Subsequent Report Sundry, the BLM would not disclose any information that is propriety under Federal law. The protection of proprietary information is important so that a company's trade secrets are not revealed to its competitors. Any information that is not proprietary is available for public disclosure.

The proposed rule seeks to achieve benefits by making more information available to the public about the chemicals injected in well stimulation fluids, while protecting trade secrets. The information that would be submitted to the BLM under this section would generally be made available to the public. The proposed rule, however, would allow an operator to identify specific information that it believes is protected from disclosure by Federal law, and to substantiate those claims of exemption. Under existing law, the BLM may nonetheless make that information available to the public, but only if it determines that the information is not protected by Federal law, and provides not less than ten business days notice to the operator prior to releasing the information.

Furthermore, the disclosure mechanism in the proposed rule would require a table of the additives by trade name and the purpose for which they are included in the well stimulation fluid. It would also require a separate table listing all the chemicals used by the Chemical Abstracts Service Registry Number. This design will inhibit reverse-engineering of specific additives.

Operational costs include any additional logs, tests, or other procedures needed to submit all documents required as additional information that are not currently required. Depending on the well and the operator, these tests or other requirements may be currently conducted or practiced pursuant to other permits, general well testing, etc. For example, operators planning to conduct well stimulations on new wells are almost certainly expected to run MITs at the higher pressures specified in the proposed rule rather than the lower pressures specified in existing regulations. Thus, the requirements of the rule with regards to MITs on new wells should not pose any cost burden to operators.

There are other benefits that are difficult to quantify in monetary terms though they certainly exist. The disclosure requirement might encourage operators to use fewer chemicals in the hydraulic fracturing fluid. The public would benefit from increased knowledge about the fluids used. Increased transparency is also likely to benefit scientists, state and Federal agencies, and other organizations that study the potential impacts of hydraulic fracturing operations. The BLM would have more information with which to make resource management decisions or respond to incidents. Furthermore, the numerical comparison of costs and benefits does not include the benefits to water users from avoiding harms that could not be compensated by alternate water supplies.

The analysis further explores an alternative which would not require operators to line pits when they are used to store fracturing fluid. Operators do not typically use pits to store hydraulic fracturing fluids either prior to or after a well stimulation event. Rather, operators typically store the fluids in storage tanks, especially with deeper wells that require more water for the fracturing process. Examination of this alternative assumes that the removal of these requirements would result in potential contamination and pose a social cost.

## 3.2 Methodology

This analysis presents costs and benefits expected to occur over the next 10 years, from 2013 to 2022. This period of analysis was chosen because 10 years is the length of the primary lease term on BLM-managed lands. Net benefits are discounted using 7 and 3 percent discount rates. The analysis presents a range of expected outcomes since the number of well stimulation events occurring in the future is highly variable and subject to future conditions.

The proposed regulation is designed to reduce the risk that well stimulation events may pose to the environment. Any contamination event that occurs is expected to require remediation. Since the remediation costs are uncertain, the analysis makes assumptions about remediation costs which may underestimate the true costs of remediation. The analysis assumes two scenarios: a low remediation cost – low environmental risk scenario and a high remediation cost – high environmental risk scenario. The benefits, while representing the value of risk reduction, will underestimate or overestimate the true benefits if the true risk of well stimulation operations varies from the assumptions.

### 3.2a Data

The number of well stimulations expected to occur on BLM-managed lands is estimated as a percent of new well completions, which in turn is estimated using the historical relationship between well completions and approved APDs. The number of approved APDs is estimated using EIA commodity price projections in the Annual Energy Outlook (AEO) 2012 Early Release Overview.

Private wages are based on Bureau of Labor Statistics (BLS) data. The base private wage is calculated using the average 2010 hourly wage of first-line supervisors/managers of construction trades and extraction workers[14] at 80% and the average hourly wage of executive secretaries and administrative assistants[15] at 20%. BLM wages are based on Office of Personnel Management (OPM) data for a GS grade 12, step 1 with no locality adjustment.

Costs for the MITs are estimated for older wells that would require MITs. New wells should already have MITs performed under existing regulations. Although this proposed rule

[14] Mining, Quarrying, and Oil and Gas Extraction (NAICS code 21).
[15] Administrative and Support Services (NAICS 561).

requires testing at higher pressure, this poses no additional cost burden to operators. Service costs for MITs were quoted from industry sources.

Costs for running CBLs on surface casings are estimated for wells that are assumed to require them. Currently, operators do not typically run CBLs on surface casings. The costs of running a CBL vary widely depending on the distance that the service firm must travel to the well site. Service costs were quoted from industry sources.[16]

The proposed rule requires operators to use storage tanks or lined pits to hold the flowback of fracturing fluids during the fracturing operation. The majority of producers, especially those on deeper wells where larger volumes of water are needed, currently use storage tanks to hold fracturing fluids before and after the fracturing process. The proposed rule would not pose a burden to those producers. Some producers on smaller fracturing jobs may use a reserve pit, typically used to hold drilling mud during drilling operations, to hold fracturing fluid as well, but in general these pits are too small to hold the volume of fluid used for fracturing. The requirements of the proposed rule would require these operators to use a lined pit or a storage tank. Service costs were quoted from industry sources.[17]

Remediation actions may vary widely depending on the contamination event. For the low remediation cost – low risk scenario, the analysis uses the cost of drilling a new water well as a proxy for the cost of remediating a subsurface contamination.[18] For the high remediation cost – high risk scenario, the analysis uses an assumed cost that would proxy for the remediation of the contaminated aquifer. The Federal Remediation Technologies Roundtable makes a number of case studies available on its website.[19] It provides a description of the contamination event and source, and remediation efforts and costs. This analysis assumes a cost of $1M to remediate contamination to an aquifer. Estimates of total remediation costs also vary depending on the number of contamination events, which rely on assumptions made about the likelihood of contamination occurring on the number of wells where the requirements or tests are not conducted.

Table 3 lists the assumptions used in the analysis.

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[16] The average cost of an MIT and CBL is estimated to be $10,000 and $9,000, respectively, although the ranges of prices that BLM was quoted varied.
[17] Estimated at $0.24 per square foot of lining. The amount of lining required varies by well and the cost of lining depends on the thickness and other properties that vary by the use of the pit.
[18] The BLM received estimates ranging from $35,000 to $50,000, depending on the depth.
[19] http://www.frtr.gov/

## Table 3: List of Base Year Assumptions

| Input | Low Remediation Costs – Low Environmental Risk | High Remediation Costs – High Environmental Risk |
|---|---|---|
| Proportion of wells that are stimulated | 0.900 | 0.900 |
| Proportion of wells needing MIT | 0.200 | 0.200 |
| Proportion of wells needing CBL on the surface casing | 0.975 | 0.975 |
| Proportion of wells where tests would reveal subsurface risk | 0.010 | 0.050 |
| Likelihood of subsurface contamination if subsurface risk | 0.010 | 0.050 |
| Avg remediation of subsurface contamination | 42,500 | 1,000,000 |
| Proportion of wells needing storage tank or lined pit | 0.150 | 0.150 |
| Proportion of wells where tanks or lining would remove surface risk | 1.000 | 1.000 |
| Likelihood of surface contamination if surface risk | 1.000 | 1.000 |
| Avg remediation of surface contamination | 25,000 | 75,000 |
| Avg incremental cost per MIT | 0.000 | 0.000 |
| Avg cost per MIT | 10,000 | 10,000 |
| Avg cost per CBL | 9,000 | 9,000 |
| Avg cost of lining pit | 6,000 | 6,000 |
| Priv - Percent of current HF operations that are "non-routine" | 0.200 | 0.200 |
| Priv - Percent of current HF operations that provide SR Sundry | 1.000 | 1.000 |
| Priv - Hours to prepare per NOI Sundry | 8.000 | 8.000 |
| Priv - Current hours to prepare NOI Sundry | 8.000 | 8.000 |
| Priv - Hours to prepare per SR Sundry | 8.000 | 8.000 |
| Priv - Current hours to prepare SR Sundry | 8.000 | 8.000 |
| Priv - Hourly wage | 30.950 | 30.950 |
| BLM - Hours to review per NOI Sundry | 5.000 | 5.000 |
| BLM - current hrs to review NOI | 2.000 | 2.000 |
| BLM - Hours to review per SR Sundry | 3.000 | 3.000 |
| BLM - current hrs to review SR | 1.000 | 1.000 |
| BLM – Hours to webpost per disclosure | 1.000 | 1.000 |
| BLM - Hourly wage | 28.450 | 28.450 |

### 3.2b Discounted Present Value

There is a time dimension to estimates of potential benefits and costs. The potential events described, if they occur at all, may be in the distant future. The further in the future the benefits and costs are expected to occur, the smaller the present value associated with the stream of costs and benefits. As such, future costs and benefits must be discounted.[20] The discount factor is then used to convert the stream of costs and benefits into "present discounted values." When the estimated benefits and costs have been discounted, they can be added to determine the overall value of net benefits.

The OMB's basic guidance on the appropriate discount rate to use is provided in OMB Circular A-94. The OMB's Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The OMB considers the 7 percent rate as an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector.

OMB Circular A-4 also states that a 3 percent discount rate should be used for regulatory analyses and provides an explanation of the use of the discount rate as follows: "The effects of regulation do not always fall exclusively or primarily on the allocation of capital. When regulation primarily and directly affects private consumption (e.g., through higher consumer prices for goods and services), a lower discount rate is appropriate. The alternative most often used is sometimes called the 'social rate of time preference.' This simply means the rate at which "society" discounts future consumption flows to their present value."

### 3.2c Uncertainty

The benefits and costs provided in this analysis are indeed estimates and come with uncertainty. Estimated costs and benefits rely on the number of well stimulation events occurring in future years and those estimates are uncertain. This analysis estimates the number of future well stimulation events using regression models and future projections of commodity prices.

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[20] Discount factor = $1/(1+ r)^t$ where r is the discount rate and t is time measured in years during which benefits and costs are expected to occur.

Assuming the number of well stimulation events is known, though administrative costs are more easily estimated, the operational costs required by producers to comply with the regulations are subject to assumptions about the number of wells that would require such expenditures.

Further uncertainty lies in the estimation of remediation costs. For the purposes of this analysis, a range of assumed average costs of remediating both subsurface and surface contaminations are used. This assumption may be too low or too high in the real world, depending on the location, severity, consequences, duration of the contamination, and if a causal link between the source and contamination can be made.

This analysis does not quantify other benefits that are undoubtedly relevant, such as the benefit that disclosing the components of fracturing fluids will have on the public health research. It is also uncertain what additional benefits, if any, would result from the disclosure requirements, for instance, if companies find substitutes for the chemicals in the fracturing fluids.

## 4. Results

This section presents the results of the analysis. Table 4 and Table 5 show a summary of the changes in benefits, costs, and net benefits, expected to occur as a result of the proposed regulations or the alternatives examined over the baseline scenario. To annualize the change in benefits, costs, and net benefits of the proposal and alternatives, the analysis calculates the annualized value (AV) as $AV = [PDV * r]/[1 - (1+r)^{-10}]$, where PDV is the present discounted value of the benefits, costs, or net benefits over 10 years and "r" is the discount rate. All results are presented in 2012 dollars.

**Table 4: Annualized Value of Net Benefits of the Proposed Regulations and Alternatives (7% Discount Rate; $MM)**

| | **Low Remediation Cost/ Low Environmental Risk** | | **High Remediation Cost/ High Environmental Risk** | |
|---|---|---|---|---|
| **Proposed Regulations** | | | | |
| Social Benefits | 11.70 | 13.79 | 42.67 | 50.27 |
| Costs | 37.34 | 43.99 | 37.34 | 43.99 |
| **Net Benefits** | **-25.63** | **-30.20** | **5.33** | **6.28** |
| | | | | |
| **Alternative 1: No Requirement for Lined Pits** | | | | |
| Social Benefits | 0.01 | 0.02 | 7.60 | 8.95 |
| Costs | 34.68 | 40.86 | 34.68 | 40.86 |
| **Net Benefits** | **-34.67** | **-40.84** | **-27.08** | **-31.90** |
| | | | | |
| **Estimated Number of Well Stimulations** | **Low** | **High** | **Low** | **High** |
| Total | 31,328 | 37,015 | 31,328 | 37,015 |
| Annual Average | 3,133 | 3,701 | 3,133 | 3,701 |

**Table 5: Annualized Value of Net Benefits of the Proposed Regulations and Alternatives (3% Discount Rate; $MM)**

| | Low Remediation Cost/ Low Environmental Risk | | High Remediation Cost/ High Environmental Risk | |
|---|---|---|---|---|
| **Proposed Regulations** | | | | |
| Social Benefits | 11.74 | 13.85 | 42.79 | 50.27 |
| Costs | 37.44 | 44.18 | 37.44 | 44.18 |
| **Net Benefits** | **-25.70** | **-30.33** | **5.35** | **6.31** |
| **Alternative 1: No Requirement for Lined Pits** | | | | |
| Social Benefits | 0.01 | 0.02 | 7.62 | 8.99 |
| Costs | 34.77 | 41.04 | 34.77 | 41.04 |
| **Net Benefits** | **-34.76** | **-41.02** | **-27.15** | **-32.04** |
| **Estimated Number of Well Stimulations** | **Low** | **High** | **Low** | **High** |
| Total | 31,328 | 37,015 | 31,328 | 37,015 |
| Annual Average | 3,133 | 3,701 | 3,133 | 3,701 |

## 4.2 Proposed Regulations (Preferred Option)

Results contained in this section represent the estimates for the preferred regulatory action described in this report in Section 2.3.

*Benefits*

Under the proposed regulations, it is assumed that the regulations would remove much of the risk associated with potential wellbore integrity issues and unlined pits. The change in social benefits from the baseline scenario is positive. If you assume that there is low environmental risk posed by wellbore integrity issues and storage of hydraulic fracturing fluids in unlined pits and the costs of surface and subsurface remediation is low (on the range assumed), then the change in social benefit as a result of the proposed regulation is positive and ranges between $11.70MM and $13.79MM per year using a discount rate of 7% and between $11.74MM and $13.85MM per year using a discount rate of 3%. If you assume that environmental risks are high and remediation costs are high (on the range assumed), then the social benefits of the proposed regulation is positive and ranges between $42.67MM and $50.27MM per year using a discount rate of 7% and between $42.79MM and $50.49MM per year using a discount rate of 3%. Tables 7 and 8 (below) show the annual change in benefits over the baseline.

Note that the figures for the estimated benefits of the proposed rule do not include such benefits as avoiding harm to water users that cannot be compensated by later providing alternative water sources. The increase in information about additives could aid water users when they consider the potential effects of well stimulation operations and constituent chemicals.

*Costs*

The costs include both costs to the industry and the BLM under this alternative. Costs include operational tests that demonstrate wellbore integrity and those associated with lining open pits in the instances where operators use pits instead of storage tanks.

The change in costs over the baseline ranges between $37.34MM and $43.99MM per year using a discount rate of 7% and between $37.44MM and $44.18MM per year using a discount rate of 3%, assuming low remediation costs and low environmental risks. The change in costs ranges between $37.34MM and $43.99MM per year using a discount rate of 7% and between $37.44MM and $44.18MM per year using a discount rate of 3%, assuming high remediation costs and high environmental risks. Tables 7 and 8 (below) show the annual change in costs over the baseline. Table 9 shows the annual administrative costs associated with the proposed regulation.

*Net Benefits*

The change in net benefits for the proposed regulations varies depending on the amount of environmental risk associated with wellbore integrity issues and unlined pits and the level of remediation costs associated with contamination events. Assuming low remediation costs and low environmental risks, the change in net benefits from the baseline is negative and ranges from -$25.63MM and -$30.20MM per year using a discount rate of 7% and between -$25.70MM and -$30.33MM per year using a discount rate of 3%. Assuming high remediation costs and high environmental risks, the change in net benefits is positive and ranges between $5.33MM and $6.28MM per year using a discount rate of 7% and between $5.35MM and $6.31MM per year using a discount rate of 3%. Tables 7 and 8 (below) show the annual change in net benefits over the baseline scenario.

Given the assumptions made and the fact that certain benefits were not quantified, the range of estimated outcomes could underestimate the actual net benefits, meaning, where net benefits are estimated to be negative, the net benefits would be greater (or less negative).

This analysis also does not capture the potential benefits associated with the disclosure of fracturing fluids. For example, disclosure might encourage operators to use fewer or safer chemicals in the hydraulic fracturing fluid. The public would benefit from increased knowledge about the fluids used. This transparency is also likely to benefit scientists, state and Federal agencies, and other organizations that study the potential impacts of well stimulation operations. The BLM would be able to make more informed resource decisions and respond effectively to events where environmental resources have been compromised.

Also, the variance language might also enable operators to reduce costs, in which case, these estimates may overestimate the actual costs and underestimate the change in net benefits.

It should be noted that the low cost and risk scenario results in negative net benefits while the high cost and risk scenario results in positive net benefits. The primary difference is not a result of the administrative or operational costs changing between the scenarios. Instead, the difference is due to the valuation of social benefits. If you assume the risk of contamination is greater and the costs of remediation are higher, then the change in benefits of the proposed rule would be greater and offset the change in compliance costs.

Table 6 illustrates how the annual costs per well stimulation do not vary greatly between the cost and risk scenarios and how the benefits do. The average annual cost per well (including administrative and operational costs) is estimated to be about $11,833. However, the average annual benefit ranges more widely, between $3,754 and $13,688. The uncertainty about risk and damages causes this variability. The net benefit ranges from -$8,079 to $1,855 on a per well stimulation basis.

**Table 6: Annual Average Change in Benefits, Costs, and Net Benefits Per Well Stimulation**

| **Low Remediation Cost - Low Environmental Risk (Assumed Subsurface Remediation Action is Drilling a New Water Well)** | |
|---|---|
| Benefits | 3,754 |
| Costs | 11,833 |
| **Net Benefits** | **-8,079** |
| **High Remediation Cost - High Environmental Risk (Assumed Subsurface Remediation Action is to Remediate the Aquifer)** | |
| Benefits | 13,688 |
| Costs | 11,833 |
| **Net Benefits** | **1,855** |

**Table 7: Change in Benefits, Costs, and Net Benefits of the Proposed Regulations from the Baseline Scenario ($MM)**
**High Remediation Cost - High Environmental Risk**

| **Low EIA Price Scenario** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **Total** | **AV** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Benefits - Undiscounted | 41.60 | 41.61 | 41.92 | 41.98 | 42.37 | 42.91 | 43.36 | 43.59 | 44.25 | 45.20 | | |
| Benefits - 7% Discount | 38.88 | 36.34 | 34.22 | 32.03 | 30.21 | 28.60 | 27.00 | 25.37 | 24.07 | 22.98 | 299.70 | 42.67 |
| Benefits - 3% Discount | 40.39 | 39.22 | 38.36 | 37.30 | 36.55 | 35.94 | 35.25 | 34.41 | 33.92 | 33.63 | 364.98 | 42.79 |
| Costs - Undiscounted | 36.40 | 36.41 | 36.68 | 36.73 | 37.07 | 37.55 | 37.94 | 38.14 | 38.72 | 39.55 | | |
| Costs - 7% Discount | 34.02 | 31.80 | 29.94 | 28.02 | 26.43 | 25.02 | 23.63 | 22.20 | 21.06 | 20.11 | 262.23 | 37.34 |
| Costs - 3% Discount | 35.34 | 34.32 | 33.57 | 32.64 | 31.98 | 31.45 | 30.85 | 30.11 | 29.68 | 29.43 | 319.36 | 37.44 |
| Net Benefits - Undiscounted | 5.20 | 5.20 | 5.24 | 5.25 | 5.30 | 5.36 | 5.42 | 5.45 | 5.53 | 5.65 | | |
| Net Benefits - 7% Discount | 4.86 | 4.54 | 4.28 | 4.00 | 3.78 | 3.57 | 3.37 | 3.17 | 3.01 | 2.87 | 37.46 | 5.33 |
| Net Benefits - 3% Discount | 5.05 | 4.90 | 4.80 | 4.66 | 4.57 | 4.49 | 4.41 | 4.30 | 4.24 | 4.20 | 45.62 | 5.35 |
| **Reference EIA Price Scenario** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **Total** | **AV** |
| Benefits - Undiscounted | 47.12 | 48.14 | 49.25 | 49.70 | 50.48 | 51.17 | 51.75 | 52.12 | 52.91 | 53.99 | | |
| Benefits - 7% Discount | 44.04 | 42.05 | 40.20 | 37.92 | 35.99 | 34.10 | 32.23 | 30.33 | 28.78 | 27.44 | 353.09 | 50.27 |
| Benefits - 3% Discount | 45.75 | 45.38 | 45.07 | 44.16 | 43.55 | 42.85 | 42.08 | 41.14 | 40.55 | 40.17 | 430.71 | 50.49 |
| Costs - Undiscounted | 41.23 | 42.13 | 43.10 | 43.49 | 44.17 | 44.77 | 45.28 | 45.60 | 46.30 | 47.24 | | |
| Costs - 7% Discount | 38.53 | 36.79 | 35.18 | 33.18 | 31.49 | 29.83 | 28.20 | 26.54 | 25.18 | 24.01 | 308.95 | 43.99 |
| Costs - 3% Discount | 40.03 | 39.71 | 39.44 | 38.64 | 38.10 | 37.50 | 36.82 | 36.00 | 35.48 | 35.15 | 376.87 | 44.18 |
| Net Benefits - Undiscounted | 5.89 | 6.02 | 6.16 | 6.21 | 6.31 | 6.40 | 6.47 | 6.51 | 6.61 | 6.75 | | |
| Net Benefits - 7% Discount | 5.50 | 5.26 | 5.03 | 4.74 | 4.50 | 4.26 | 4.03 | 3.79 | 3.60 | 3.43 | 44.13 | 6.28 |
| Net Benefits - 3% Discount | 5.72 | 5.67 | 5.63 | 5.52 | 5.44 | 5.36 | 5.26 | 5.14 | 5.07 | 5.02 | 53.84 | 6.31 |

Note: AV means Annualized Value

**Table 8: Change in Benefits, Costs, and Net Benefits of the Proposed Regulations from the Baseline Scenario ($MM)**
**Low Remediation Cost - Low Environmental Risk**

| **Low EIA Price Scenario** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **Total** | **AV** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Benefits - Undiscounted | 11.41 | 11.41 | 11.50 | 11.51 | 11.62 | 11.77 | 11.89 | 11.96 | 12.14 | 12.40 | | |
| Benefits - 7% Discount | 10.66 | 9.97 | 9.39 | 8.78 | 8.29 | 7.84 | 7.41 | 6.96 | 6.60 | 6.30 | 82.20 | 11.70 |
| Benefits - 3% Discount | 11.08 | 10.76 | 10.52 | 10.23 | 10.02 | 9.86 | 9.67 | 9.44 | 9.30 | 9.23 | 100.10 | 11.74 |
| Costs - Undiscounted | 36.40 | 36.41 | 36.68 | 36.73 | 37.07 | 37.55 | 37.94 | 38.14 | 38.72 | 39.55 | | |
| Costs - 7% Discount | 34.02 | 31.80 | 29.94 | 28.02 | 26.43 | 25.02 | 23.63 | 22.20 | 21.06 | 20.11 | 262.23 | 37.34 |
| Costs - 3% Discount | 35.34 | 34.32 | 33.57 | 32.64 | 31.98 | 31.45 | 30.85 | 30.11 | 29.68 | 29.43 | 319.36 | 37.44 |
| Net Benefits - Undiscounted | -24.99 | -25.00 | -25.18 | -25.22 | -25.45 | -25.78 | -26.05 | -26.19 | -26.58 | -27.15 | | |
| Net Benefits - 7% Discount | -23.36 | -21.83 | -20.56 | -19.24 | -18.15 | -17.18 | -16.22 | -15.24 | -14.46 | -13.80 | -180.04 | -25.63 |
| Net Benefits - 3% Discount | -24.26 | -23.56 | -23.05 | -22.41 | -21.96 | -21.59 | -21.18 | -20.67 | -20.37 | -20.21 | -219.25 | -25.70 |
| **Reference EIA Price Scenario** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **Total** | **AV** |
| Benefits - Undiscounted | 12.92 | 13.20 | 13.51 | 13.63 | 13.85 | 14.03 | 14.19 | 14.29 | 14.51 | 14.81 | | |
| Benefits - 7% Discount | 12.08 | 11.53 | 11.03 | 10.40 | 9.87 | 9.35 | 8.84 | 8.32 | 7.89 | 7.53 | 96.84 | 13.79 |
| Benefits - 3% Discount | 12.55 | 12.45 | 12.36 | 12.11 | 11.94 | 11.75 | 11.54 | 11.28 | 11.12 | 11.02 | 118.13 | 13.85 |
| Costs - Undiscounted | 41.23 | 42.13 | 43.10 | 43.49 | 44.17 | 44.77 | 45.28 | 45.60 | 46.30 | 47.24 | | |
| Costs - 7% Discount | 38.53 | 36.79 | 35.18 | 33.18 | 31.49 | 29.83 | 28.20 | 26.54 | 25.18 | 24.01 | 308.95 | 43.99 |
| Costs - 3% Discount | 40.03 | 39.71 | 39.44 | 38.64 | 38.10 | 37.50 | 36.82 | 36.00 | 35.48 | 35.15 | 376.87 | 44.18 |
| Net Benefits - Undiscounted | -28.31 | -28.92 | -29.59 | -29.86 | -30.33 | -30.74 | -31.09 | -31.31 | -31.79 | -32.43 | | |
| Net Benefits - 7% Discount | -26.46 | -25.26 | -24.15 | -22.78 | -21.62 | -20.48 | -19.36 | -18.22 | -17.29 | -16.49 | -212.11 | -30.20 |
| Net Benefits - 3% Discount | -27.48 | -27.26 | -27.08 | -26.53 | -26.16 | -25.74 | -25.28 | -24.72 | -24.36 | -24.13 | -258.74 | -30.33 |

Note: AV means Annualized Value

## Table 9: Administrative Costs of the Proposed Regulations (in Dollars, Undiscounted)

| **Low EIA Price Scenario** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|---|---|---|---|---|---|
| **Operator Compliance** | | | | | | | | | | |
| Notices of Intent (Sundry) | 481,655 | 481,725 | 485,334 | 485,995 | 490,538 | 496,825 | 501,953 | 504,663 | 512,341 | 523,316 |
| **Total Private Administrative Cost** | **481,655** | **481,725** | **485,334** | **485,995** | **490,538** | **496,825** | **501,953** | **504,663** | **512,341** | **523,316** |
| **BLM Review** | | | | | | | | | | |
| Notices of Intent (Sundry) | 318,226 | 318,272 | 320,657 | 321,093 | 324,095 | 328,249 | 331,637 | 333,427 | 338,500 | 345,751 |
| Subsequent Reports (Sundry) | 30,395 | 30,400 | 30,627 | 30,669 | 30,956 | 31,353 | 31,676 | 31,847 | 32,332 | 33,024 |
| Webposting | 86,474 | 86,487 | 87,135 | 87,254 | 88,069 | 89,198 | 90,119 | 90,605 | 91,984 | 93,954 |
| **Total BLM Administrative Cost** | **435,096** | **435,159** | **438,419** | **439,016** | **443,120** | **448,799** | **453,432** | **455,879** | **462,815** | **472,730** |
| **Ref EIA Price Scenario** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** |
| **Operator Compliance** | | | | | | | | | | |
| Notices of Intent (Sundry) | 545,550 | 557,377 | 570,212 | 575,398 | 584,460 | 592,410 | 599,128 | 603,385 | 612,565 | 625,029 |
| **Total Private Administrative Cost** | **545,550** | **557,377** | **570,212** | **575,398** | **584,460** | **592,410** | **599,128** | **603,385** | **612,565** | **625,029** |
| BLM Review | | | | | | | | | | |
| Notices of Intent (Sundry) | 360,441 | 368,255 | 376,735 | 380,161 | 386,149 | 391,401 | 395,840 | 398,652 | 404,717 | 412,952 |
| Subsequent Reports (Sundry) | 34,427 | 35,174 | 35,984 | 36,311 | 36,883 | 37,385 | 37,808 | 38,077 | 38,656 | 39,443 |
| Webposting | 97,946 | 100,069 | 102,374 | 103,305 | 104,932 | 106,359 | 107,565 | 108,329 | 109,978 | 112,215 |
| **Total BLM Administrative Cost** | **492,814** | **503,498** | **515,092** | **519,777** | **527,963** | **535,144** | **541,213** | **545,058** | **553,352** | **564,611** |

## 4.3 Alternative 1: No Requirement for Lined Pits

*Benefits*

Under this alternative, it is assumed that the regulations would remove much of the risk associated with potential wellbore integrity issues. The change in social benefits from the baseline scenario is positive. Assuming low remediation costs and low environmental risks, then the change in social benefit under this alternative is positive and ranges between $0.01MM and $0.02MM per year using discount rates of 7% and 3%. Assuming high remediation costs and high environmental risks, the change in social benefits over the baseline ranges between $7.60MM and $8.95MM per year using a discount rate of 7% and from $7.62MM and $8.99MM per year using a discount rate of 3%. Since there is no requirement to use lined pits, the benefits in this alternative come from well integrity.

*Costs*

The costs include both costs to the industry and the BLM under this alternative. Costs include operational tests that demonstrate wellbore integrity, but not those costs associated with lining open pits in the instances where operators use pits instead of storage tanks.

The change in costs over the baseline ranges between $34.68MM and $40.86MM per year using a discount rate of 7% and between $34.77MM and $41.04MM per year using a discount rate of 3%, assuming either low remediation costs and low environmental risks or high remediation costs and low environmental risks.

*Net Benefits*

The change in net benefits is negative for this alternative. Assuming low remediation costs and low environmental risks, the change in net benefits from the baseline is negative and ranges from -$34.67MM and -$40.84MM per year using a discount rate of 7% and between -$34.76MM and -$41.02MM per year using a discount rate of 3%. Assuming high remediation costs and high environmental risks, ranges from -$27.08MM and -$31.90MM per year using a discount rate of 7% and between -$27.15MM and -$32.04MM per year using a discount rate of 3%.

**Table 10: Change in Benefits, Costs, and Net Benefits of Alternative 1 from the Baseline Scenario ($MM)**
**High Remediation Cost - High Environmental Risk**

| Low EIA Price Scenario | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | Total | AV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Benefits - Undiscounted | 7.41 | 7.41 | 7.47 | 7.48 | 7.55 | 7.64 | 7.72 | 7.76 | 7.88 | 8.05 | | |
| Benefits - 7% Discount | 6.92 | 6.47 | 6.09 | 5.70 | 5.38 | 5.09 | 4.81 | 4.52 | 4.29 | 4.09 | 53.37 | 7.60 |
| Benefits - 3% Discount | 7.19 | 6.98 | 6.83 | 6.64 | 6.51 | 6.40 | 6.28 | 6.13 | 6.04 | 5.99 | 65.00 | 7.62 |
| Costs - Undiscounted | 33.81 | 33.82 | 34.07 | 34.12 | 34.44 | 34.88 | 35.24 | 35.43 | 35.97 | 36.74 | | |
| Costs - 7% Discount | 31.60 | 29.54 | 27.81 | 26.03 | 24.55 | 23.24 | 21.94 | 20.62 | 19.56 | 18.68 | 243.57 | 34.68 |
| Costs - 3% Discount | 32.83 | 31.88 | 31.18 | 30.31 | 29.70 | 29.21 | 28.65 | 27.97 | 27.57 | 27.34 | 296.63 | 34.77 |
| Net Benefits - Undiscounted | -26.40 | -26.41 | -26.60 | -26.64 | -26.89 | -27.23 | -27.52 | -27.66 | -28.09 | -28.69 | | |
| Net Benefits - 7% Discount | -24.68 | -23.06 | -21.72 | -20.32 | -19.17 | -18.15 | -17.14 | -16.10 | -15.28 | -14.58 | -190.20 | -27.08 |
| Net Benefits - 3% Discount | -25.63 | -24.89 | -24.35 | -23.67 | -23.20 | -22.81 | -22.37 | -21.84 | -21.53 | -21.35 | -231.63 | -27.15 |
| **Reference EIA Price Scenario** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **Total** | **AV** |
| Benefits - Undiscounted | 8.39 | 8.57 | 8.77 | 8.85 | 8.99 | 9.11 | 9.22 | 9.28 | 9.42 | 9.61 | | |
| Benefits - 7% Discount | 7.84 | 7.49 | 7.16 | 6.75 | 6.41 | 6.07 | 5.74 | 5.40 | 5.13 | 4.89 | 62.88 | 8.95 |
| Benefits - 3% Discount | 8.15 | 8.08 | 8.03 | 7.86 | 7.76 | 7.63 | 7.49 | 7.33 | 7.22 | 7.15 | 76.70 | 8.99 |
| Costs - Undiscounted | 38.30 | 39.13 | 40.03 | 40.39 | 41.03 | 41.59 | 42.06 | 42.36 | 43.00 | 43.88 | | |
| Costs - 7% Discount | 35.79 | 34.18 | 32.68 | 30.82 | 29.25 | 27.71 | 26.19 | 24.65 | 23.39 | 22.30 | 286.96 | 40.86 |
| Costs - 3% Discount | 37.18 | 36.88 | 36.63 | 35.89 | 35.39 | 34.83 | 34.20 | 33.44 | 32.96 | 32.65 | 350.05 | 41.04 |
| Net Benefits - Undiscounted | -29.91 | -30.55 | -31.26 | -31.54 | -32.04 | -32.47 | -32.84 | -33.08 | -33.58 | -34.26 | | |
| Net Benefits - 7% Discount | -27.95 | -26.69 | -25.52 | -24.06 | -22.84 | -21.64 | -20.45 | -19.25 | -18.26 | -17.42 | -224.08 | -31.90 |
| Net Benefits - 3% Discount | -29.03 | -28.80 | -28.61 | -28.02 | -27.64 | -27.20 | -26.70 | -26.11 | -25.74 | -25.49 | -273.34 | -32.04 |

Note: AV means Annualized Value

**Table 11: Change in Benefits, Costs, and Net Benefits of Alternative 1 from the Baseline Scenario ($MM)**
**Low Remediation Cost - Low Environmental Risk**

| **Low EIA Price Scenario** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **Total** | **AV** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Benefits - Undiscounted | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | | |
| Benefits - 7% Discount | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.09 | 0.01 |
| Benefits - 3% Discount | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.11 | 0.01 |
| Costs - Undiscounted | 33.81 | 33.82 | 34.07 | 34.12 | 34.44 | 34.88 | 35.24 | 35.43 | 35.97 | 36.74 | | |
| Costs - 7% Discount | 31.60 | 29.54 | 27.81 | 26.03 | 24.55 | 23.24 | 21.94 | 20.62 | 19.56 | 18.68 | 243.57 | 34.68 |
| Costs - 3% Discount | 32.83 | 31.88 | 31.18 | 30.31 | 29.70 | 29.21 | 28.65 | 27.97 | 27.57 | 27.34 | 296.63 | 34.77 |
| Net Benefits - Undiscounted | -33.80 | -33.80 | -34.06 | -34.10 | -34.42 | -34.86 | -35.22 | -35.41 | -35.95 | -36.72 | | |
| Net Benefits - 7% Discount | -31.59 | -29.53 | -27.80 | -26.02 | -24.54 | -23.23 | -21.94 | -20.61 | -19.56 | -18.67 | -243.48 | -34.67 |
| Net Benefits - 3% Discount | -32.82 | -31.86 | -31.17 | -30.30 | -29.69 | -29.20 | -28.64 | -27.96 | -27.55 | -27.33 | -296.52 | -34.76 |
| **Reference EIA Price Scenario** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **Total** | **AV** |
| Benefits - Undiscounted | 0.01 | 0.01 | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | | |
| Benefits - 7% Discount | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.11 | 0.02 |
| Benefits - 3% Discount | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.13 | 0.02 |
| Costs - Undiscounted | 38.30 | 39.13 | 40.03 | 40.39 | 41.03 | 41.59 | 42.06 | 42.36 | 43.00 | 43.88 | | |
| Costs - 7% Discount | 35.79 | 34.18 | 32.68 | 30.82 | 29.25 | 27.71 | 26.19 | 24.65 | 23.39 | 22.30 | 286.96 | 40.86 |
| Costs - 3% Discount | 37.18 | 36.88 | 36.63 | 35.89 | 35.39 | 34.83 | 34.20 | 33.44 | 32.96 | 32.65 | 350.05 | 41.04 |
| Net Benefits - Undiscounted | -38.28 | -39.11 | -40.01 | -40.38 | -41.01 | -41.57 | -42.04 | -42.34 | -42.99 | -43.86 | | |
| Net Benefits - 7% Discount | -35.78 | -34.16 | -32.66 | -30.80 | -29.24 | -27.70 | -26.18 | -24.64 | -23.38 | -22.30 | -286.86 | -40.84 |
| Net Benefits - 3% Discount | -37.17 | -36.87 | -36.62 | -35.88 | -35.38 | -34.82 | -34.18 | -33.42 | -32.95 | -32.64 | -349.91 | -41.02 |

Note: AV means Annualized Value

# 5. Economic Impact Analysis and Distributional Assessments

## 5.1 Energy System Impact Analysis

Executive Order 13211 provides that agencies prepare and submit to the Administrator of the Office of Information and Regulatory Affairs (OIRA), OMB, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines a “significant energy action” as “any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: 1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or 2) that is designated by the Administrator of OIRA as a significant energy action.

This analysis estimates the additional cost burden per well stimulation event and finds that the average burden per stimulation is about $11,833 in 2013.

The BLM believes that the additional cost per well stimulation resulting from this proposed rule is insignificant when compared with the drilling costs in recent years, the production gains from hydraulically fractured wells operations and the net incomes of entities within the oil and natural gas industries.

Table 14 presents drilling costs per well for a range of wells from 1998 to 2007. The data clearly show that drilling costs increased during this time. Using the estimates for the average burden per well stimulation and the average cost of drilling wells in 2007, the annual costs of this proposed rule represents about 0.3% of the drilling cost of a well.

As such, the proposed regulations are unlikely to have an effect on the investment decisions of firms, and the rule is unlikely to affect the supply, distribution, or use of energy.

Alternative 1 poses slightly lower costs (about $10,958 in 2013) than the proposed (favored) regulations on a per well stimulation basis.

**Table 14: Per Well Costs of Crude Oil and Natural Gas Wells Drilled**

| Year | Crude Oil, Natural Gas, and Dry Wells Drilled (Nominal $) | Crude Oil Wells Drilled (Nominal $) | Natural Gas Wells Drilled (Nominal $) |
|---|---|---|---|
| 1998 | 769,100 | 566,000 | 815,600 |
| 1999 | 856,100 | 783,000 | 798,400 |
| 2000 | 754,600 | 593,400 | 756,900 |
| 2001 | 943,200 | 729,100 | 896,500 |
| 2002 | 1,054,200 | 882,800 | 991,900 |
| 2003 | 1,199,500 | 1,037,300 | 1,106,000 |
| 2004 | 1,673,100 | 1,441,800 | 1,716,400 |
| 2005 | 1,720,700 | 1,920,400 | 1,497,600 |
| 2006 | 2,101,700 | 2,238,600 | 1,936,200 |
| 2007 | 4,171,700 | 4,000,400 | 3,906,900 |

Source: EIA (2012), "Costs of Crude Oil and Natural Gas Wells Drilled"

## 5.2 Employment Impact Analysis

Executive Order 13563 reaffirms the principles established in Executive Order 12866, but calls for additional consideration of the regulatory impact on employment. It states, "Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation." An analysis of employment impacts is a standalone analysis and the impacts should not be included in the estimation of benefits and costs.

This analysis seeks to inform the discussion of labor demand and job impacts by providing an estimate of the employment impacts of the proposed regulations using labor requirements for the additional administration and operational needs.

This proposed rule would require operators, who have not already done so, to conduct one-time tests on a well or make a one-time installation of a mitigation control feature. In addition, operators would be required to perform administrative tasks related to a one-time event. Compliance with the operational requirements would shift resources within the industry from the operators to firms providing the services or supplies. For example, the requirement for a CBL on the surface casing represents a burden to the operator but a benefit to the company running the log.

This analysis calculates the labor requirements anticipated for compliance. Since the BLM anticipates that the number of well stimulations will increase over time, the labor requirements increase over the outlook period, albeit slightly. Under both risk and cost scenarios, the labor requirements for operators to meet additional administrative and operational needs are estimated to be about 15 to 18 FTE in each of the next three years. The results appear in the Appendix. Note that these impacts are only for the regulated sector. The BLM cannot predict the net national employment impact, i.e., whether the increased employment in the regulated sector comes from previously unemployed workers or is displaces workers actively employed in other sectors.

Another area of interest is the extent to which the financial burden is expected to change operators' investment decisions. If the financial burden is not significant and all other factors are equal, then one would expect operators to maintain existing levels of investment and employment. As with the results in the Section 5.1, the BLM believes that the proposed rule would result in an additional cost per well stimulation that is small and will not alter the investment or employment decisions, of firms. Therefore, considering the labor requirements and that operators would not likely reduce investment, the BLM anticipates an overall net gain in employment.

For alternative 1, the labor requirements are about 15 to 18 FTE in each of the next three years.

### 5.3 Small Business Impacts Analysis

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, or small not-for-profit enterprises.

The BLM reviewed the Small Business Administration (SBA) size standards for small businesses and the number of entities fitting those size standards as reported by the U.S. Census Bureau in the 2007 Economic Census. Using the Economic Census data, the BLM concludes that about 99% of the entities operating in the relevant sectors[21] are small businesses in that they employ fewer than 500 employees. Also, within these relevant sectors, small firms account for 74% of the total value of shipments and receipts for services, 86% of the total cost of supplies,

[21] NAICS codes: 211111 - Crude Petroleum and Natural Gas Extraction, 211112 - Natural Gas Liquid Extraction, and 213111 - Drilling Oil and Gas Wells.

78% of the total capital expenditures (excluding land and mineral rights), and 67% of the paid employees (see Tables 15 through 19).

Small entities represent the overwhelming majority of entities operating in the crude oil and natural gas extraction industry. As such, the proposed rule is likely to affect a significant number of small entities. To examine the economic impact of the rule on small entities, the BLM performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity net incomes.

Under the cost and risk scenarios, the average cost per entity in 2013 is estimated to represent between 0.002% and 0.22% of the 2010 net incomes of the sampled companies, depending on the AEO commodity price forecasts. The proportions do not change substantially over the outlook period. The results appear in the Appendix.

For alternative 1, the average cost per entity in 2013 is estimated to represent between 0.002% and 0.21% of the 2010 net incomes of the sampled companies, depending on the AEO commodity price forecasts.

**Table 15: Number of Firms by Firm Size and NAICS, 2007**

| NAICS | NAICS Description | SBA Size Standard | All Firms | < 20 Employees | 20-99 Employees | 100-499 Employees | > 500 Employees |
|---|---|---|---|---|---|---|---|
| 211111 | Crude Petroleum and Natural Gas Extraction | 500 | 5,964 | 4,905 | 820 | 197 | 42 |
| 211112 | Natural Gas Liquid Extraction | 500 | 296 | 171 | 114 | 11 | 0 |
| 213111 | Drilling Oil and Gas Wells | 500 | 2,109 | 1,454 | 439 | 180 | 36 |
| Total firms | | | 8,369 | 6,530 | 1,373 | 388 | 78 |
| *Percent of total* | | | | *78.03%* | *16.41%* | *4.64%* | *0.93%* |

**Table 16: Total Value of Shipments and Receipts for Services ($1000) by Firm Size and NAICS, 2007**

| NAICS | NAICS Description | SBA Size Standard | All Firms | < 20 Employees | 20-99 Employees | 100-499 Employees | > 500 Employees |
|---|---|---|---|---|---|---|---|
| 211111 | Crude Petroleum and Natural Gas Extraction | 500 | 212,783,171 | 27,779,989 | 63,673,010 | 58,879,619 | 62,450,553 |
| 211112 | Natural Gas Liquid Extraction | 500 | 42,321,678 | 6,920,098 | 27,110,810 | 8,290,770 | 0 |
| 213111 | Drilling Oil and Gas Wells | 500 | 22,512,322 | 631,501 | 4,011,228 | 8,382,350 | 9,733,440 |
| Total firms | | | 277,617,171 | 35,331,588 | 94,795,048 | 75,552,739 | 72,183,993 |
| *Percent of total* | | | | *12.73%* | *34.15%* | *27.21%* | *26.00%* |

**Table 17: Total Cost of Supplies ($1000) by Firm Size and NAICS, 2007**

| NAICS | NAICS Description | SBA Size Standard | All Firms | < 20 Employees | 20-99 Employees | 100-499 Employees | > 500 Employees |
|---|---|---|---|---|---|---|---|
| 211111 | Crude Petroleum and Natural Gas Extraction | 500 | 37,755,041 | 5,709,734 | 11,650,183 | 12,335,810 | 8,059,314 |
| 211112 | Natural Gas Liquid Extraction | 500 | 31,129,919 | 4,858,309 | 19,948,706 | 6,322,904 | 0 |
| 213111 | Drilling Oil and Gas Wells | 500 | 6,576,675 | 246,328 | 1,012,247 | 2,567,116 | 2,027,623 |
| Total firms | | | 75,461,635 | 10,814,371 | 32,611,136 | 21,225,830 | 10,086,937 |
| *Percent of total* | | | | *14.33%* | *43.22%* | *28.13%* | *13.37%* |

**Table 18: Total Capital Expenditures (except land and mineral rights) ($1000) by Firm Size and NAICS, 2007**

| NAICS | NAICS Description | SBA Size Standard | All Firms | < 20 Employees | 20-99 Employees | 100-499 Employees | > 500 Employees |
|---|---|---|---|---|---|---|---|
| 211111 | Crude Petroleum and Natural Gas Extraction | 500 | 87,551,089 | 9,714,838 | 26,003,272 | 33,504,207 | 18,328,772 |
| 211112 | Natural Gas Liquid Extraction | 500 | 1,965,593 | 513,229 | 1,058,819 | 393,545 | 0 |
| 213111 | Drilling Oil and Gas Wells | 500 | 6,532,941 | 157,959 | 1,049,920 | 2,519,731 | 2,013,806 |
| Total firms | | | 96,049,623 | 10,386,026 | 28,112,011 | 36,417,483 | 20,342,578 |
| *Percent of total* | | | | *10.81%* | *29.27%* | *37.92%* | *21.18%* |

**Table 19: Number of Paid Employees by Firm Size and NAICS, March, 2007**

| NAICS | NAICS Description | SBA Size Standard | All Firms | < 20 Employees | 20-99 Employees | 100-499 Employees | > 500 Employees |
|---|---|---|---|---|---|---|---|
| 211111 | Crude Petroleum and Natural Gas Extraction | 500 | 143,054 | 23,928 | 34,791 | 37,717 | 33,454 |
| 211112 | Natural Gas Liquid Extraction | 500 | 7,389 | 1,014 | 4,907 | 1,468 | 0 |
| 213111 | Drilling Oil and Gas Wells | 500 | 106,859 | 6,375 | 20,122 | 41,616 | 37,420 |
| Total firms | | | 257,302 | 31,317 | 59,820 | 80,801 | 70,874 |
| *Percent of total* | | | | *12.17%* | *23.25%* | *31.40%* | *27.55%* |

Note: Where range provided, employee data were estimated to be in middle of range.

# 6. Statutory and Executive Order Reviews

## 6.1 Executive Order 12866 Regulatory Planning

In accordance with the criteria in Executive Order 12866, the Office of Management and Budget has determined that this rule is a significant regulatory action.

The rule will not have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. However, the rule may raise novel policy issues because of the proposed requirement that operators provide to the BLM information regarding well stimulation activities that they are not currently providing to the BLM.

## 6.2 Executive Order 13132 Federalism

Under Executive Order 13132, this proposed rule would not have significant Federalism effects. A Federalism assessment is not required because the proposed rule would not have a substantial direct effect on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. The proposed rule would not have any effect on any of the items listed. The proposed rule would affect the relationship between operators, lessees, and the BLM, but would not impact states. Therefore, under Executive Order 13132, the BLM has determined that the proposed rule would not have sufficient Federalism implications to warrant preparation of a Federalism Assessment.

## 6.3 Executive Order 13175 Consultation and Coordination with Indian Tribal Governments

Subject to Executive Order 13175, the BLM may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal Government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the BLM consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement.

Under Executive Order 13175, the President's memorandum of April 29, 1994, ''Government-to-Government Relations with Native American Tribal Governments'' (59 FR

22951), and 512 Departmental Manual 2, the BLM evaluated possible effects of the proposed rule on federally recognized Indian tribes.  The BLM approves proposed operations on all Indian onshore oil and gas leases (except those excluded by statute).  Therefore, the proposed rule has the potential to affect Indian tribes.  In conformance with the Secretary's policy on tribal consultation, the Bureau of Land Management held four tribal consultation meetings to which over 175 tribal entities were invited.  The consultations were held in:

- Tulsa, Oklahoma on January 10, 2012;
- Billings, Montana on January 12, 2012;
- Salt Lake City, Utah on January 17, 2012; and
- Farmington, New Mexico on January 19, 2012.

The purpose of these meetings was to solicit initial feedback and preliminary comments from the tribes.  Comments from tribes will be received and consultation will continue as this rulemaking proceeds.  To date, the tribes have expressed concerns about the BLM's Inspection and Enforcement program's ability to enforce the terms of this rule; previously plugged and abandoned wells being potential conduits for contamination of ground water; and the operator having to provide documentation that the water used for the fracturing operation was legally acquired.  The BLM will further address these concerns during the drafting of the final rule.

## 6.4 Executive Order 13211 Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs (OIRA), OMB, a Statement of Energy Effects for certain actions identified as significant energy actions.  Section 4(b) of Executive Order 13211 defines a "significant energy action" as "any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: 1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or 2) that is designated by the Administrator of OIRA as a significant energy action.

The BLM estimated the additional cost per well stimulation resulting from this proposed rule and compared it with the average cost of drilling wells in 2007. The additional cost represents about 0.3% of the drilling cost of a well.

As such, the proposed regulations are unlikely to have an effect on the investment decisions of firms, and the rule is unlikely to affect the supply, distribution, or use of energy. The proposed rule is unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the proposed rule is not a "significant energy action" as defined in Executive Order 13211.

## 6.5 Regulatory Flexibility Act and Small Business Regulatory Enforcement Fairness Act of 1996 (5 U.S.C. 601-612)

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a significant number of small entities (SISNOSE). Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

The BLM reviewed the Small Business Administration (SBA) size standards for small businesses and the number of entities fitting those size standards as reported by the U.S. Census Bureau in the 2007 Economic Census. Using the Economic Census data, the BLM concludes that about 99% of the entities operating in the relevant sectors are small businesses in that they employ fewer than 500 employees. Also, small firms account for 86% of the total cost of supplies and 78% of the total capital expenditures (excluding land and mineral rights).

Small entities represent the overwhelming majority of entities operating in the crude oil and natural gas extraction industry. As such, the proposed rule is likely to affect a significant number of small entities. To examine the economic impact of the rule on small entities, the BLM performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity net incomes.

The average cost per entity in 2013 is estimated to represent between 0.002% and 0.22% percent of the 2010 net incomes of the sampled companies, depending on the EIA Annual

Energy Outlook commodity price forecasts.  The proportions do not change substantially over the outlook period.

Therefore, after considering the economic impact of the proposed rule on these small entities, the screening analysis indicates that this proposed rule will not have a significant economic impact on a substantial number of small entities.

## 6.6 Unfunded Mandates Reform Act of 1995 (P.L. 104-4)

This proposed rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any one year.  Thus, the proposed rule is also not subject to the requirements of sections 202 or 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments, because it contains no requirements that apply to such governments, nor does it impose obligations upon them.

## 7. Conclusion

This analysis presents potential effects that would result from the proposed rule. These effects are measured as the change from the baseline scenario, that which would likely occur absent of the regulation. In addition to an examination of the favored option, the BLM presents as an alternatives the proposed regulations without the requirement for those operators who use pits to line them (alternative 1).

The preferred regulation is estimated to result in a positive change in net benefits over the baseline scenario when it is assumed that there is high environmental risk and high remediation costs associated with well stimulation operations and hydraulic fracturing. These additional net benefits are calculated to be between about $5.33MM to $6.28MM, annually, using a 7% discount rate, when assuming that the risks posed from well integrity issues are high and the remediation costs of contamination are high. Of course, whether those assumptions for risks and costs are “high” is a source of uncertainty, given the variety of potential impacts and range of costs. If the average cost of remediating a subsurface contamination event is greater than $1 million, then the net benefits calculated in this analysis are underestimated. The additional net benefits are negative when assuming that risks are low and the remediation required for a subsurface contamination would be to simply drill a new water well. In many cases, this assumption does not hold.

Alternative 1 does not approach the change in net benefits estimated under the other alternatives.

For the preferred approach, the estimated costs per well stimulation is not significant when compared against the costs of drilling an oil and gas well. The average cost per well stimulation is estimated to be about $11,833 in 2013, which represents about 0.3% of the cost drilling a well.

The analysis also measures the employment impacts by estimating the labor requirements for the additional administration and operational needs. The labor requirements were estimated to be between 15 and 18 FTE over the next three years. The proposed regulations are not expected to alter investment decisions or reduce production.

## 8. References


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## 9. Appendix

The appendix provides a list of tables, A-1 through A-7, for the high remediation cost – high environmental risk and low remediation cost – low environmental risk scenarios, as follows: