AUTHENTICATED
U.S. GOVERNMENT
INFORMATION
GPO

FEDERAL REGISTER

Vol. 80 Thursday,
No. 58 March 26, 2015

Part III

Department of the Interior

Bureau of Land Management

43 CFR Part 3160

Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands; Final Rule

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Part 3160

[LLWO300000 L13100000.PP0000 14X]

RIN 1004–AE26

Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands

AGENCY: Bureau of Land Management, Interior.

ACTION: Final rule.

SUMMARY: On May 11, 2012, the Bureau of Land Management (BLM) published in the **Federal Register** a proposed rule titled Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands. Because of significant public interest in hydraulic fracturing and this rulemaking, on May 24, 2013, the BLM published in the **Federal Register** a supplemental notice of proposed rulemaking and request for comment titled Oil and Gas Hydraulic Fracturing on Federal and Indian Lands. The BLM has used the comments on the supplemental proposed rule and the earlier proposed rule in drafting this final rule. Key changes to the final rule include the allowable use of an expanded set of cement evaluation tools to help ensure that usable water zones have been isolated and protected from contamination, replacement of the ''type well'' concept to demonstrate well integrity with a requirement to demonstrate well integrity for all wells, more stringent requirements related to claims of trade secrets exempt from disclosure, more protective requirements to ensure that fluids recovered during hydraulic fracturing operations are contained, additional disclosure and public availability of information about each hydraulic fracturing operation, and revised records retention requirements to ensure that records of chemicals used in hydraulic fracturing operations are retained for the life of the well. The final rule also provides opportunities for the BLM to coordinate standards and processes with individual states and tribes to reduce administrative costs and to improve efficiency.

DATES: This final rule is effective on June 24, 2015.

ADDRESSES:

Mail: U.S. Department of the Interior, Director (630), Bureau of Land Management, Mail Stop 2134 LM, 1849 C St. NW., Washington, DC 20240, Attention: 1004–AE26.

Personal or messenger delivery: Bureau of Land Management, 20 M Street SE., Room 2134 LM, Attention: Regulatory Affairs, Washington, DC 20003.

FOR FURTHER INFORMATION CONTACT: Steven Wells, Division Chief, Fluid Minerals Division, 202–912–7143 for information regarding the substance of the rule or information about the BLM's Fluid Minerals Program. Persons who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339 to contact the above individual during normal business hours. FIRS is available 24 hours a day, 7 days a week to leave a message or question with the above individual. You will receive a reply during normal business hours.

SUPPLEMENTARY INFORMATION:

Executive Summary

The BLM final rule on hydraulic fracturing serves as a much-needed complement to existing regulations designed to ensure the environmentally responsible development of oil and gas resources on Federal and Indian lands, which were finalized nearly thirty years ago, in light of the increasing use and complexity of hydraulic fracturing coupled with advanced horizontal drilling technology. This technology has opened large portions of the country to oil and gas development.

The BLM began work on this rule in November 2010, when it held its first public forum amid growing public concern about the rapid expansion of complex hydraulic fracturing. Since that time, the BLM has published two proposed rules and held numerous meetings with the public and state officials, as well as many tribal consultations and meetings. The public comment period was open for more than 210 days. During this period, the BLM received comments from more than 1.5 million individuals and groups. The BLM reviewed and analyzed these comments based on thoughtful analysis and robust dialogue, which resulted in a rule that is more protective than the previous proposed rules and current regulations. It also strengthens oversight and provides the public with more information than is currently available, while recognizing state and tribal authorities and not imposing undue delays, costs, and procedures on operators. The final rule fulfills the goals of the initial proposed rules: To ensure that wells are properly constructed to protect water supplies, to make certain that the fluids that flow back to the surface as a result of hydraulic fracturing operations are managed in an environmentally responsible way, and to provide public disclosure of the chemicals used in hydraulic fracturing fluids.

The final rule also: (1) Improves public awareness of where hydraulic fracturing has occurred and the existence of other wells or geologic faults or fractures in the area, as well as communicates what chemicals have been used in the fracturing process; (2) Clarifies and strengthens existing rules related to well construction to ensure integrity and address developments in technology; (3) Aligns requirements with state and tribal authorities with regard to water zones that require protection; and (4) Provides opportunities to coordinate standards and processes with individual states and tribes to reduce costs, increase efficiencies, and promote the development of more stringent standards by state and tribal governments.

Various types of hydraulic fracturing have long been used on a relatively small scale to complete or to re-complete conventional oil and gas wells. More recently, hydraulic fracturing has been coupled with relatively new horizontal drilling technology in larger-scale operations that have allowed greatly increased access to shale oil and gas resources across the country, sometimes in areas that have not previously or recently experienced significant oil and gas development. These newer wells can, among other complexities, be significantly deeper and cover a larger horizontal area than the operations of the past. This increased complexity requires additional regulatory effort and oversight.

Rapid expansion of this practice and its complexity have caused public concern about whether fracturing can lead to or cause the contamination of underground water sources, whether the chemicals used in fracturing pose risks to human health, and whether there is adequate management of well integrity and the fluids that return to the surface during and after fracturing operations.

The BLM's regulations that address issues surrounding hydraulic fracturing are at least 25–30 years old, and pre-date the current common use of the practice. In 2011, the Natural Gas Subcommittee of the Secretary of Energy's Advisory Board recommended that the BLM undertake a rulemaking to ensure well integrity, water protection, and adequate public disclosure. Prior to that, in 2009 the American Petroleum Institute published a guidance document titled ''Hydraulic Fracturing Operations-Well Construction and Integrity Guidelines, First Edition,

October 2009,'' commonly known as HF1, to provide guidance and highlight industry recommended practices for well construction and integrity for those wells that will be hydraulically fractured. The purpose of the guidance was to ensure protection of shallow groundwater aquifers and the environment while enabling economically viable development of oil and natural gas resources. More recently, regulations from states, such as Colorado and Wyoming, and professional papers, such as King, George, SPE 152596, (Feb. 2012), focused on the estimation, analyses, and control of risks from hydraulic fracturing operations. All of these factors have led to, and informed, this rulemaking. To ensure that these standards adequately address emerging technological developments and health and environmental protections, the BLM will evaluate the adequacy of this rulemaking 7 years after the date of publication.

Pursuant to the Federal Land Policy and Management Act (FLPMA), Indian mineral leasing laws, and other statutes, the BLM is charged with administering oil and gas operations in a manner that protects Federal and Indian lands while allowing for appropriate development of the resource. The BLM oversees approximately 700 million subsurface acres of Federal mineral estate and carries out some of the regulatory duties of the Secretary of the Interior for an additional 56 million acres of Indian mineral estate across the United States. Currently, nearly 36 million acres of Federal land are under lease for potential oil and gas development in 33 states. As of June 30, 2014, there were approximately 47,000 active oil and gas leases on public lands, and approximately 95,000 oil and gas wells. Like other BLM regulations, this final rule applies to oil and gas operations on public lands (which include split estate lands, *i.e.,* lands where the surface is owned by an entity other than the United States), as well as operations on Indian lands, to ensure that these lands and communities all receive the same level of protection as provided on public lands.

Oil and gas leasing decisions on public lands are made through a thorough, deliberative, and transparent process rooted in Resource Management Plans (RMPs) that cover virtually all BLM-administered public land and related mineral estate. Oil and gas decisions contained within BLM RMPs also apply to lands where the surface is privately owned, but the mineral estate is in Federal ownership. The BLM establishes, amends, and revises RMPs as required by the FLPMA with involvement by the community and stakeholders. As part of the land use planning process, the BLM engages the public in a variety of ways and conducts environmental reviews as required by the National Environmental Policy Act (NEPA), and other applicable natural and cultural resource protection authorities. While the public makes known to the BLM which lands they are interested in leasing, prior to leasing any lands, the BLM undertakes the appropriate NEPA review and provides an opportunity for the public to review and comment on the analyses and documents that the agency prepares.

Existing Requirements

Relevant existing requirements for oil and gas operations are set out at 43 CFR 3162.3–1 and Onshore Oil and Gas Orders 1, 2 and 7. Most of these requirements have been in place for at least 25 years. This final rule will supplement the existing requirements, which will remain in place. On either Federal leaseholds, or Indian lands, an operator may not begin operations until it has filed an Application for a Permit to Drill (APD) with the BLM and received approval from the BLM to commence operations. Existing Federal law requires the BLM to post notices of APDs for oil and gas development on public lands for public inspection for 30 days, during which time the public may express any concerns to the BLM's authorized officer as the agency conducts a site-specific environmental analysis of the proposed well site proposal. Those concerns and other issues identified earlier in the process, or during site examinations, may result in conditions of approval (COA) on the operator's drilling permit that require, forbid, or control specified activities or disturbances. Examples of COAs include providing for road improvements and erosion control measures, or applying seasonal restrictions on some activities. In addition, baseline water testing is a best management practice that the BLM encourages. The BLM may require water testing and monitoring, particularly if water quality impacts are a significant concern based on local conditions, and where the BLM or a cooperating landowner or manager manages the surface estate where testing could yield useful water quality information. This is consistent with what several states, including California, Colorado, and Wyoming, are already doing. The BLM does not post for public inspection notices of APDs for Indian oil and gas leases or agreements because there is no requirement in the Indian leasing statutes similar to that in Section 17 of the Mineral Leasing Act.

Under Onshore Oil and Gas Order 1, Approval of Operations, the location of the well must be identified and important aspects of the proposed operations described. Onshore Order 2 requires all usable water zones to be protected by steel casing and cement, and requires the casing, once in place, to be pressure tested. Casing and cement must meet specific design criteria, which BLM engineers verify as part of the permit review process. When a well is no longer capable of producing, Onshore Order 2 mandates minimum standards for the placement, quality, and verification of cement plugs to ensure that any remaining oil and gas cannot migrate into usable water zones. BLM inspectors witness aspects of drilling and plugging operations to ensure that the operator is in compliance with Onshore Order 2 and the permit to drill.

New Requirements

With this rule, the BLM establishes new requirements to ensure wellbore integrity, protect water quality, and enhance public disclosure of chemicals and other details of hydraulic fracturing operations. The rule requires an operator planning to conduct hydraulic fracturing to do the following:

- Submit detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, the depths of all usable water, estimated volume of fluid to be used, and estimated direction and length of fractures, to the BLM with the APD or a Sundry Notice and Report on Wells (Form 3160–5) as a Notice of Intent (NOI) to hydraulically fracture an existing well;
- Design and implement a casing and cementing program that follows best practices and meets performance standards to protect and isolate usable water, defined generally as those waters containing less than 10,000 parts per million of total dissolved solids (TDS);
- Monitor cementing operations during well construction;
- Take remedial action if there are indications of inadequate cementing, and demonstrate to the BLM that the remedial action was successful;
- Perform a successful mechanical integrity test (MIT) prior to the hydraulic fracturing operation;
- Monitor annulus pressure during a hydraulic fracturing operation;
- Manage recovered fluids in rigid enclosed, covered or netted and screened above-ground storage tanks, with very limited exceptions that must be approved on a case-by-case basis;

• Disclose the chemicals used to the BLM and the public, with limited exceptions for material demonstrated through affidavit to be trade secrets;

• Provide documentation of all of the above actions to the BLM.

Specifically, this final rule will add to existing requirements by providing information to the BLM and the public on the location, geology, water resources, location of other wells or fracture zones in the area, and fracturing plans for the operation before the well is permitted. To ensure well integrity, the final rule will require specified best practice performance standards for all wells, including cement return and pressure testing for surface casing, cement evaluation logs for intermediate and production casing, and remediation plans and cement evaluation logs for any surface casing that does not meet performance standards.

The final rule eliminates the use of ''type wells'' in demonstrating well integrity, and requires that specified best practices be used and demonstrated for all wells, not just a sample well. For surface casing, the final rule does not require a cement evaluation log (CEL) for each well, substituting other equally or more protective performance standards, including cement returns and pressure testing. For any surface casing not meeting these performance standards, an approved remedial plan and CEL will be required. For intermediate and production casing not cemented to the surface, a CEL will be required for all wells.

The final rule will require interim storage of all produced water in rigid enclosed, covered, or netted and screened above-ground tanks, subject to very limited exceptions in which lined pits could be used.

Public disclosure of all chemicals, subject to limited exceptions for trade secret material, will be required after fracturing operations are complete. The existing database, FracFocus (*http://fracfocus.org*), can be used for this disclosure.

FracFocus is managed by the Ground Water Protection Council (GWPC), a non-profit organization of state water quality regulatory agencies, and by the Interstate Oil and Gas Compact Commission (IOGCC), a multi-state government agency charged with balancing oil and gas development with environmental protection. The BLM will continue to work with FracFocus in coordination with the U.S. Department of Energy (DOE) to ensure that the recommendations of the Secretary of Energy's Advisory Board for improvement of the database are made.[1] Specifically, the BLM is in the process of finalizing a Memorandum of Understanding (MOU) with the GWPC to ensure, among other things, that the database can be searched and downloaded easily. In a press release[2] on February 26, 2015 GWPC and the IOGCC, joint venture partners in the FracFocus initiative, announced the release of improvements to FracFocus' system functionality. The new features for 2015 include:

• Reducing the number of human errors in disclosures

• Expanding the public's ability to search records

• Providing public extraction of data in a ''machine readable'' format and

• Updating educational information on chemical use, oil and gas production, and potential environmental impacts.

As a part of the MOU with GWPC, FracFocus will automatically notify the BLM when an operator uploads chemical disclosure information about a Federal or Indian well. The BLM will obtain the information from FracFocus and keep those records in compliance with all pertinent record management requirements.

The BLM developed this final rule with the intention of improving public awareness and strengthening oversight of hydraulic fracturing operations without introducing unnecessary new procedures or delays in the process of developing oil and gas resources on public and Indian lands. Some states, including Alaska, Arkansas, Colorado, Illinois, Michigan, New Mexico, Ohio, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming have regulations in place addressing hydraulic fracturing operations. Operators with leases on Federal lands must comply with both the BLM's regulations and with state operating requirements, including state permitting and notice requirements to the extent they do not conflict with BLM regulations. To address concerns from states and tribes about possible duplicative efforts, the final rule provides that in situations in which specific state or tribal regulations are demonstrated to be equal to or more protective than the BLM's rules, the state or tribe may obtain a variance. Such a variance will allow for enforcement of the more protective state or tribal rule.

For many years, the BLM has maintained a number of agreements with certain states and tribes concerning implementation of the various regulatory programs in logical and effective ways. The BLM will work with states and tribes to establish formal agreements that will capitalize on the strengths of partnerships, and reduce duplication of effort for agencies and operators, particularly by implementing the final rule as consistently as possible with state or tribal regulations.

The provisions in this final rule provide for the BLM's consistent oversight and establish a baseline for environmental protection across all public and Indian lands undergoing hydraulic fracturing. The BLM has analyzed the costs and the benefits of this proposed action in an accompanying Regulatory Impact Analysis available in the rulemaking docket. The BLM estimates that the rule will impact about 2,800 hydraulic fracturing operations per year, but that it could impact up to 3,800 operations per year based on previous levels of activity on Federal lands and growing activity on Indian lands. The BLM estimates that the compliance cost will be about $11,400 per well, or about $32 million per year. On average this equates to approximately 0.13 to 0.21 percent of the cost of drilling a well.

Many of the requirements generally are consistent with industry guidance, the voluntary practice of operators, and some are required by state regulations. So to the extent that industry is already in compliance, the cost of several of the provisions may be overestimated. The improvements also provide significant benefits to all Americans by avoiding potential damages to water quality, the environment, and public health. The rule creates a consistent, predictable, regulatory framework, in accordance with the BLM's stewardship responsibilities for hydraulic fracturing under the FLPMA and the Indian mineral leasing statutes.

I. Background
II. Discussion of the Final Rule and Comments on the Proposed Rules
III. Procedural Matters

I. Background

Well stimulation techniques, such as hydraulic fracturing, are commonly used by oil and natural gas producers to increase the volumes of oil and natural gas that can be extracted from wells. Hydraulic fracturing techniques are particularly effective in enhancing oil and gas production from shale gas or oil formations. Until quite recently, shale formations rarely produced oil or gas in commercial quantities because shale does not generally allow the flow of hydrocarbons to wellbores unless

[1] Secretary of Energy's Advisory Board recommendations can be downloaded from *http://energy.gov/seab/downloads/fracfocus-20-task-force-report.*

[2] *http://www.gwpc.org/major-improvements-fracfocus-announced.*

physical changes to the properties of the rock can be induced. The development of horizontal drilling, combined with hydraulic fracturing, has made the production of oil and gas from shale feasible. Hydraulic fracturing involves the injection of fluid under high pressure to create or enlarge fractures in the reservoir rocks. The fluid that is used in hydraulic fracturing is usually accompanied by proppants, such as particles of sand, which are carried into the newly fractured rock and help keep the fractures open once the fracturing operation is completed. The proppant-filled fractures become conduits for fluid migration from the reservoir rock to the wellbore and the fluid is subsequently brought to the surface. In addition to the water and sand (which together typically make up 98 to 99 percent of the materials pumped into a well during a fracturing operation), chemical additives are also frequently used. These chemicals can serve many functions in hydraulic fracturing, including limiting the growth of bacteria and preventing corrosion of the well casing. The exact formulation of the chemicals used varies depending on the rock formations, the well, and the requirements of the operator.

Some simple types of hydraulic fracturing techniques have been used on a small scale in oil and gas production for decades. However, as discussed in different parts of the preamble, hydraulic fracturing operations in recent years have become more complex, involving the exploration of and production from significantly deeper formations and across much larger subsurface areas through the use of horizontal drilling techniques.

The BLM estimates that about 90 percent of the approximately 2,800 new wells spudded in 2013 on Federal and Indian lands were stimulated using hydraulic fracturing techniques. Over the past 10 years, there have been significant technological advances in horizontal drilling, which is now frequently combined with hydraulic fracturing. This combination, together with the discovery that these techniques can release significant quantities of oil and gas from large shale deposits, has led to production from geologic formations in parts of the country that previously did not produce significant amounts of oil or gas. The expansion of exploration and production across the United States has significantly increased public awareness of hydraulic fracturing and the potential impacts that it may have on water quality and water consumption, and increased calls for stronger regulation and safety protocols. The BLM's engineers and field managers have decades of experience exercising oversight of these wells during the evolution of this technology. This expertise, together with input from the public, industry, state, academic and other experts discussed below, forms the basis for the decision that new rules are needed and for the requirements contained in this rule.

The BLM's existing hydraulic fracturing regulations are found at 43 CFR 3162.3–2. Those regulations were established in 1982 and last revised in 1988, long before the latest hydraulic fracturing technologies were developed or became widely used. The Department of the Interior (Department) held a forum on hydraulic fracturing on November 30, 2010, in Washington, DC, attended by the Secretary of the Interior and more than 130 interested parties. The BLM later 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. More than 600 members of the public attended the April 2011 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 Indian lands. Some commenters from the oil and gas industry suggested changes that would make the implementation of the rule more practicable from their perspective, while others opposed adoption of any such rules affecting hydraulic fracturing on the Federal mineral estate.

Around the time of the BLM's forums, at the direction of President Obama, the Secretary of Energy convened a Shale Gas Production Subcommittee (Subcommittee) of the Secretary of Energy Advisory Board to evaluate hydraulic fracturing issues. The Subcommittee met with industry, service providers, state and Federal regulators, academics, environmental groups, and many other stakeholders. On August 18, 2011, the Subcommittee issued initial recommendations in its ''90-day Interim Report.'' The Subcommittee issued its final report, titled ''Shale Gas Production Subcommittee Second Ninety Day Report'' on November 18, 2011. The Subcommittee recommended, among other things, that more information be provided to the public about hydraulic fracturing operations, irrespective of whether those operations occur on the Federal mineral estate, including disclosure of the chemicals used in fracturing fluids. The Subcommittee also recommended the adoption of stricter standards for wellbore construction and testing. The final report also recommended that operators engaging in hydraulic fracturing undertake pressure testing to ensure the integrity of all casings, as well as the use of FracFocus as a means to report the use of hydraulic fracturing chemicals. These reports are available to the public from the Department of Energy's Web site at *http://www.shalegas.energy.gov*.

On May 11, 2012, the BLM published in the **Federal Register** the initial proposed rule titled ''Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands'' (77 FR 27691). The comment period on the initial proposed rule closed on July 10, 2012. At the request of public commenters, on June 26, 2012, the BLM published in the **Federal Register** a notice extending the comment period for 60 days (77 FR 38024). The extended comment period closed on September 10, 2012. The BLM received over 177,000 comments on the initial proposed rule from individuals, Federal and state governments and agencies, interest groups, and industry representatives.

After reviewing the comments on the proposed rule, the BLM published a supplemental notice of proposed rulemaking on May 24, 2013 (78 FR 31636). The BLM received numerous requests for extension of the comment period on the supplemental proposed rule. Because of the complexity of the rule and well stimulation procedures, the BLM extended the comment period on the rule for 60 days. The closing date of the extended comment period was August 23, 2013. The BLM received over 1.35 million comments on the supplemental proposed rule. Substantive comments on the initial proposed and supplemental proposed rules that informed the BLM's decisions on the final rule are discussed in the section-by-section discussion of this preamble.

This final rule applies to all wells regulated by the BLM, whether on Federal, tribal, or individual Indian trust or restricted fee lands. The lands covered by the rule have not changed since the rule was first proposed.

Tribal Consultation and Coordination With States

Tribal consultation is a critical part of this rulemaking effort, and the Department is committed to making sure tribal leaders play a significant role as the BLM and the tribes work together

to develop resources on public and Indian lands in a safe and responsible way. During the proposed rule stage, the BLM initiated government-to-government consultation with tribes on the proposed rule and offered to hold follow-up consultation meetings with any tribe that desired to have an individual meeting. In January 2012, the BLM held four regional tribal consultation meetings, to which over 175 tribal entities were invited. To build upon established local relationships, the individual follow-up consultation meetings involved the local BLM authorized officers and management, including BLM State Directors. The BLM distributed copies of a draft rule to affected federally recognized tribes in January 2012 and invited comments from affected tribes, which were also considered in developing this final rule. After the issuance of the proposed rule, tribal governments, tribal members, and individual Native American mineral owners were also invited to comment directly on the proposed rule.

In June 2012, the BLM held additional regional consultation meetings in Salt Lake City, Utah; Farmington, New Mexico; Tulsa, Oklahoma; and Billings, Montana. Eighty-one tribal members representing 27 tribes attended the meetings. In these sessions, the BLM and tribal representatives engaged in substantive discussions of the proposed hydraulic fracturing rule. A variety of issues were discussed, including, but not limited to, the applicability of tribal laws, validating water sources, inspection and enforcement, wellbore integrity, and water management, among others. Additional individual consultations with tribal representatives have taken place since that time. Also, consultation meetings were held at the National Congress of American Indian Conference in Lincoln, Nebraska, on June 18, 2012, and at New Town, North Dakota on July 13, 2012.

After publication of the supplemental proposed rule, the BLM again held regional meetings with tribes in Farmington, New Mexico, and Dickinson, North Dakota in June 2013. Representatives from six tribes attended. The discussions included a variety of tribal-specific and general issues. One change resulting from those discussions is the re-drafting of final section 3162.3–3(k) to clarify that tribal and state variances are separate from variances for a specific operator. The BLM again offered to follow up with one-on-one consultations, and several such meetings were held with individual tribes. Several tribes, tribal members, and associations of tribes provided comments on the supplemental proposed rule. The BLM understands the importance of tribal sovereignty and self-determination, and seeks to continuously improve its communications and government-to-government relations with tribes. Responses from tribal representatives informed the agency's actions in defining the scope of acceptable hydraulic fracturing operations. One of the outcomes of these meetings is the requirement in this rule that operators certify to the BLM that operations on Indian lands comply with applicable tribal laws.

In March 2014, the BLM invited tribes to participate in another meeting in Denver, Colorado. Representatives from seven tribes attended. There was significant discussion of issues raised in the comments on the supplemental proposed rule. The BLM subsequently held several consultations with individual tribes.

The BLM has been and will continue to be proactive about tribal consultation under the Department's Tribal Consultation Policy, which emphasizes trust, respect, and shared responsibility in providing tribal governments an expanded role in informing Federal policy that impacts Indian lands.

Several tribal representatives and tribal organizations commented that the hydraulic fracturing rule should not apply on Indian land, or that tribes should be allowed to decide not to have the rule apply on their land (that is, ''opt out'' of the rule). However, the Indian Mineral Leasing Act (IMLA) provides in a pertinent part as follows: ''All operations under any oil, gas, or other mineral lease issued pursuant to the terms . . . of this title or any other Act affecting restricted Indian lands shall be subject to the rules and regulations promulgated by the Secretary of the Interior.'' 25 U.S.C. 396d. The Department has consistently applied uniform regulations governing mineral resource development on Indian and Federal lands. Thus, an ''opt out'' provision would not be consistent with the Department's responsibilities under IMLA, and the final rule does not provide such an option.

There has also been a suggestion that the Secretary should delegate her regulatory authority to the tribes if the tribe has regulations that meet or exceed the standards in the BLM regulation. The IMLA does not authorize the Secretary to delegate her regulatory responsibilities to the tribes, and therefore the final rule does not include a delegation provision. Nonetheless, there are opportunities for tribes to assert more control over oil and gas operations on tribal land by entering into Tribal Energy Resource Agreements under the Indian Energy Development and Self-Determination Act (part of the Energy Policy Act of 2005), and to pursue contracts under the Indian Self-Determination and Education Assistance Act of 1975.

Also, the final rule defers to state (on Federal land) or tribal (on Indian land) designations of aquifers as either requiring protection from oil and gas operations, or as exempt from the requirement to isolate water-bearing zones in section 3162.3–3(b), so long as those designations are not inconsistent with protections required pursuant to the SDWA (also see the definition of ''usable water''). Revised section 3162.3–3(k) provides that for lands within the jurisdiction of a state or a tribe, that state or tribe could work with the BLM to craft a variance that would allow compliance with state or tribal requirements to be accepted as compliance with the rule, for state or tribal provisions that are found to meet or exceed this rule's standards. The BLM would enforce the variance as the Federal rule and the appropriate State or tribe would enforce the variance under its authority.

The BLM will continue its coordination with states and tribes to establish or review and strengthen existing agreements related to oil and gas regulation and operations. During the rulemaking process, the BLM hosted multiple discussions with state governments to enhance coordination with oil and gas permitting, inspection, and enforcement. In August 2013, and then again in March 2014, the Acting Assistant Secretary for Land and Minerals Management invited the Governors and their representatives from those states with significant oil and gas operations, to meet with the BLM and discuss the objectives of the ongoing rulemaking as well as potential options for establishing agreements to assist in implementing the BLM's oil and gas program. The BLM's overall intent for these discussions is to minimize duplication and maximize flexibility though its coordination with states and tribes. We anticipate that these new and improved agreements will reduce regulatory burdens and increase efficiency, while fulfilling the Secretary's responsibilities mandated by statutes as steward for the public lands and trustee for Indian lands. As this rule is implemented, the BLM will continuously review these agreements along with the new variance process allowed by the rule, and consider improvements as necessary.

On Federal lands, the BLM enforces BLM regulations and lease conditions,

and the states enforce their oil and gas regulations. On Indian lands, the BLM enforces Federal regulations and the terms of the leases, and the tribes have the power to enforce their own law.

Disclosure of Chemicals

The BLM is working closely with the GWPC and the IOGCC, in coordination with the DOE, to provide for the disclosure of chemicals in the hydraulic fracturing fluids by the operators to the BLM through the existing public access Web site, *www.fracfocus.org.* As of June 2013, the FracFocus database was upgraded to FracFocus 2.0. These upgrades were designed to enhance several aspects of the site's functionality, such as its search and reports features and geographic information system mapping, for all users. As mentioned earlier, the GWPC and IOGCC, joint venture partners in the FracFocus initiative, announced the release of several improvements to FracFocus' system functionality. The new features are designed to reduce the number of human errors in disclosures, expand the public's ability to search records, provide public extraction of data in a ''machine readable'' format, and update educational information on chemical use, environmental impacts from oil and gas production, and potential environmental impacts. The new self-checking features in the system will help companies detect and correct possible errors before disclosures are submitted. This feature will detect errors verifying that Chemical Abstract Service (CAS) numbers meet the proper format.

As of March 1, 2015, this online database includes information provided by operators concerning oil and gas wells in 20 states, and it is our understanding that a few more states are considering use of this database. It includes information from over 72,700 wells and from more than 500 companies. The list of states currently using FracFocus and the states considering using FracFocus are listed as follows: [3]

States currently using FracFocus	States proposing to use FracFocus
1 Alabama	1 Alaska.
2 California	2 Florida.
3 Colorado	3 Kentucky.
4 Illinois	4 Nevada.
5 Kansas.	
6 Louisiana.	
7 Michigan.	
8 Minnesota.	
9 Mississippi.	
10 Montana.	
11 Nebraska.	
12 North Dakota.	
13 Ohio.	
14 Oklahoma.	
15 Pennsylvania.	
16 South Dakota.	
17 Tennessee.	
18 Texas.	
19 Utah.	
20 West Virginia.	

The Secretary of Energy Advisory Board's Task Force on FracFocus 2.0 has identified a number of areas in which FracFocus needs improvement.[4] The BLM is in continued discussion with the GWPC and expects further progress in ensuring that the site meets key elements addressed by the Task Force report. Specifically, the BLM expects improvement in the database to allow users to search by chemical, well, company, or geography; in quality control; and in the capacity to handle high volumes of information.

The BLM recognizes the efforts of some states to regulate hydraulic fracturing and seeks to avoid duplicative regulatory requirements. It is important to recognize that a major impetus for a separate BLM rule is that states are not legally required to meet the stewardship standards that apply to public lands and do not have trust responsibilities for Indian lands under Federal laws. Thus, the rule may expand on or set different standards from those of states that regulate hydraulic fracturing operations. This final rule encourages efficiency in the collection of data and the reporting of information by allowing operators in states that require disclosure on FracFocus to meet both the state and the BLM requirements through a single submission to FracFocus.

The BLM encourages the public disclosure of all chemicals used in any hydraulic fracturing operation. However, because the identities of some chemicals may be entitled to protection under Federal law as trade secrets, the BLM is allowing that information to be withheld if the operator and any other owner of the trade secret submit affidavits containing specific information explaining the reasons for the claim for protection. If the BLM has questions about the validity of the claim for protection, the BLM can require the operator to provide the withheld information to the bureau, and then would make a determination as to whether the data is properly withheld from the public.

Existing Oil and Gas Development Process

The BLM has an extensive process in place to ensure that operators conduct oil and gas operations in an environmentally sound manner that protects resources. This rule adds specific requirements for hydraulic fracturing operations, which supplement the existing requirements. The following is a description of these existing processes and requirements:

Resource Management Plans. Section 202 of the FLPMA requires the BLM to develop and maintain land use plans (the BLM refers to these plans as Resource Management Plans, or RMPs). The RMP serves as the basis for all land use decisions the BLM makes, including decisions to allow oil and gas leasing, allow oil and gas leasing under certain conditions, or prohibit oil and gas leasing altogether. The RMP applies to public lands, including the Federal mineral estate; however, it does not apply to Indian land or to surface estates managed by other Federal agencies such as the USDA Forest Service. The tribes and other Federal agencies rely on their own planning guidance when determining if their lands are suitable for oil and gas development. The FLPMA also requires that the public be given ample opportunity to participate in the development, maintenance, and revision of land use plans. Regulations implementing the FLPMA (43 CFR 1610.2) require the BLM field offices to publish notices to prepare, amend, or revise RMPs in the **Federal Register** and local newspapers. In addition, the BLM must send notices to groups and individuals who have expressed an interest in being involved in BLM activities or who have participated in the past.

Typically, the first step in the development or revision of an RMP is for the BLM to hold public scoping meetings to identify the primary issues that the BLM should consider and address in the RMP. If, for example, the public identifies tracts of land that are heavily used for recreational activities or that hold special environmental significance, the BLM may consider closing these tracts to oil and gas leasing or placing restrictions on development. Restrictions can include limiting the timing of oil and gas activities to avoid certain impacts, setbacks from sensitive resources, establishing limits on surface disturbance, and prohibiting surface occupancy entirely. Some areas, such as wilderness areas or land within an

[3] See updated FracFocus link: *http://www.fracfocus.org/welcome.*

[4] Secretary of Energy's Advisory Board recommendations (*http://energy.gov/seab/downloads/fracfocus-20-task-force-report*) includes the areas of improvement.

incorporated city, are closed to leasing by law. In addition to public scoping, the BLM coordinates with state, county, and local governments, Indian tribes, and other Federal agencies.

Once various land use options have been developed the BLM generally analyzes the environmental impacts of the alternatives through an Environmental Impact Statement (EIS), which offers additional opportunity for public involvement. For proposed land use decisions, such as keeping areas open for oil and gas leasing, environmental impacts are assessed based on a Reasonable Foreseeable Development (RFD) Scenario that projects the estimated levels and types of industry activity and the associated surface disturbance that might occur during the life of the RMP. Because the RMP and EIS generally cover all the Federal land and mineral estate administered by a BLM field office, the impact analysis is typically done on a broad scale. Mitigation measures developed through the draft RMP and EIS process can be implemented as stipulations on oil and gas leases. In addition to compliance with the National Environmental Policy Act (NEPA), the BLM must comply with the National Historic Preservation Act and the Endangered Species Act (ESA) and engage in a consultation process with the U.S. Fish and Wildlife Service under the ESA, if threatened or endangered species or critical habitat may be affected.

Once a draft RMP and EIS are developed, the public has an additional opportunity to review and comment on the analysis and proposed mitigation measures in the EIS. When all comments have been considered, the BLM develops a final RMP and EIS. The Record of Decision finalizes the RMP, selecting a final action to be adopted from a reasonable range of alternatives and explaining the rationale for the decision. Once the Record of Decision is signed, the BLM makes all land use decisions, including oil and gas development decisions, in accordance with the RMP.

Leasing Process. The next step in the oil and gas development process is the designation of parcels to be offered for lease, and an additional environmental review. Under existing regulations, the public may nominate tracts of land that they would like to see leased. It is far more common, however, for members of the industry to express interest in an area being offered for lease. The BLM first must ensure that the proposed tracts are under Federal jurisdiction and are open to leasing in accordance with the RMP. The next step is to conduct a second NEPA review—typically through an Environmental Assessment (EA)—to address potential impacts that could be caused by oil and gas development within the nominated area. The NEPA review conducted at the leasing stage ''tiers'' from the RMP EIS. In other words, the issues, analysis of potential impacts, mitigation measures, and decisions in the RMP EIS are carried through to the NEPA review conducted at the leasing stage.

An interdisciplinary team consisting of resource specialists develops the NEPA documentation. The interdisciplinary team visits the site to gather on-the-ground data on potential impacts and mitigation measures. After the site visit, an EA is drafted, including coordination with county, state, and Federal agencies, and consultation with Indian tribes, if applicable, in the area proposed for leasing. EAs are posted on the BLM Web site and are available in the public room(s) at BLM field offices for public review and comment, typically for a 30-day period. The BLM reviews and addresses comments received during that 30-day period when it finalizes the EA. Specific mitigation measures are developed in the context of the NEPA review and are included in a notice to potential bidders of an oil and gas lease at a lease sale. If the environmental review concludes with a finding that the proposed lease issuance would result in no significant impacts to the quality of the human environment (FONSI), then the lease parcel can be included in the next scheduled lease sale without any further NEPA analysis. Upon issuance by the BLM, the lease allows the operator to conduct operations on the lease.

Exploration and development requirements. The BLM has existing regulations, including Onshore Oil and Gas Orders, to ensure that operators conduct oil and gas exploration and development in an environmentally responsible manner that protects other resources. These requirements will remain in place and will be supplemented by this final rule.

Existing section 43 CFR 3162.3–1 and Onshore Order 1 require an operator to get approval from the BLM prior to drilling a well. The operator must submit an APD containing all of the information required by Onshore Order 1. This includes a completed Form 3160–3, Application for Permit to Drill or Re-Enter, a well plat, a drilling plan, a surface use plan, bonding information, and an operator certification.

Upon receiving a drilling proposal on Federal lands, the BLM is required by existing section 3162.3–1(g) to post information for public inspection for at least 30 days before action to approve the APD. The information must include: The company/operator name; the well name/number; and the well location described to the nearest quarter-quarter section (40 acres), or similar land description in the case of lands described by metes and bounds, or maps showing the affected lands and the location of all tracts to be leased and of all leases already issued in the general area. Where the inclusion of maps in such posting is not practicable, the BLM provides maps of the affected lands available to the public for review. The public posting is in the office of the BLM authorized officer and in the appropriate surface managing agency office, if other than the BLM. Some field offices also make this information available on the field office Web site. The public may review the posted information and provide any input they would like the BLM to consider during its environmental analysis. If the public has questions and concerns regarding drilling proposals, they can meet with BLM staff and share those concerns.

The drilling plan is a critical, detailed, and multi-faceted component of the APD that allows BLM engineers and geologists to complete an appraisal of the technical adequacy of, and environmental effects associated with, the proposed project. The drilling plan must include:

- Geological information, including the name and estimated tops of all geologic groups, formations, members, and zones as well as the estimated depths and thickness of formations, members, or zones potentially containing usable water, oil, gas, or prospectively valuable deposits of other minerals that the operator expects to encounter, and their plans for protecting such resources.
- Minimum specifications for blowout prevention equipment that will be used to keep control of well pressures encountered while drilling.
- A description of the proposed casing program, including the size, grade, weight, and setting depth of each casing string.
- Detailed information regarding the proposed cementing program, including the amount and types of cement the operator will use for each casing string, which is critical in establishing a barrier outside the casing between any hydrocarbon bearing zones and usable water zones. BLM engineers evaluate the proposed cementing program to ensure that the volume and strength of the cement is adequate to achieve the desired protections.

• Information regarding the proposed drilling fluid and proposed testing, logging, and coring procedures.

• An estimate of the expected bottom-hole pressure and any anticipated abnormal pressures, temperatures, or potential hazards that the well may encounter. BLM geologists and engineers review this information to determine if any other anticipated hazards exist and to ensure that there will be adequate mitigation to address those hazards.

• Other information that may be pertinent, including the directional drilling plan for deviated or horizontal wells so that BLM engineers can look for potential issues with existing wells.

Just as the drilling plan allows the BLM to ensure the down-hole technical adequacy of the proposed project, the surface use plan provides the BLM with information needed to ensure safe operations, adequate protection of the surface resources, groundwater, and other environmental components in areas where the BLM manages the surface.

The surface managing agency must approve surface use plans where the BLM does not manage the surface. The Bureau of Indian Affairs is considered to be the surface management agency for Indian lands. In the surface use plan, operators must also describe any Best Management Practices (BMPs) they expect to use. BMPs are mitigation measures applied to oil and natural gas drilling and production to help ensure that operators conduct energy development in an environmentally responsible manner. BMPs can protect water, wildlife, air quality, and landscapes. The BLM encourages operators to incorporate BMPs into their plans. Information concerning BMPs is available on the BLM's Web site at: *http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices.html*.

Where the BLM manages the surface, the operator's surface use plan should incorporate the BLM's ''Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development,'' which is commonly referred to as ''The Gold Book.'' The BLM developed ''The Gold Book'' to assist operators by providing information on obtaining permit approval and conducting environmentally responsible oil and gas operations. It is available on the BLM's Web site at: *http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices/gold_book.html*.

In general, the surface use plan must include the following:

• Location and description of, as well as maintenance plan for, existing and new roads the operator plans to use to access the proposed well.

• A map showing all known wells, regardless of their status (producing, abandoned, etc.) within a one-mile radius of the proposed location so that the BLM can ensure the proposal does not conflict with any current surface use. The BLM also uses this well information to identify any potential downhole conflicts or issues between the existing wells and the proposed well.

• A map or diagram showing the location of all production facilities and lines the operator will install if the well is successful (a producing well), as well as any existing facilities.

• Information concerning the water supply, such as rivers, creeks, springs, lakes, ponds, and wells that the operator plans to use for drilling the well.

• A written description of the methods and locations it proposes for safe containment and disposal of each type of waste materials that result from drilling the proposed well. The narrative must include plans for the eventual disposal of drilling fluids and any produced oil or water recovered during testing operations.

• A diagram in the surface use plan of the proposed well site layout.

• A plan for the surface reclamation or stabilization of all disturbed areas.

Another component of the APD is proof of adequate bond coverage as required by existing 43 CFR 3104.1 for Federal lands and 25 CFR 211.24, 212.24, and 225.30, for Indian lands. These regulations require the operator or the lessee to have an adequate bond in place prior to the BLM's approval of the APD. If the BLM determines that the current bond amount is not sufficient, the BLM can require additional bond coverage. The BLM determines the need for bond increases by considering the operator's history of violations, the location and depth of wells, the total number of wells involved, the age and production capability of the field, and any unique environmental issues.

Upon receipt of a complete APD, the BLM will schedule an onsite inspection with the operator so that the BLM and operator may further identify site-specific resource concerns and requirements not originally identified in the application.

The onsite inspection team will include the BLM, a representative of any other surface management agency and the operator or permitting agent. When the onsite inspection is on private surface, the BLM will invite the surface owner to attend. The purpose of the onsite inspection is to discuss the proposal; determine the best location for the well, road, and facilities; identify site-specific concerns and potential environmental impacts associated with the proposal; and discuss the conditions of approval or possible environmental BMPs. If the BLM identifies resource conflicts, the BLM has the authority to require the operator to move surface facilities to locations that would reduce resource impacts while still allowing development of the leased minerals.

Site-Specific Environmental Review. After the BLM has reviewed the operator's proposed plans and conducted the onsite inspection, the BLM will prepare an environmental document in conformance with NEPA and its implementing regulations. The extent of the environmental analysis process and the time frame for issuance of a decision will depend upon the complexity of the proposed action and resulting analysis, the significance of the environmental effects disclosed, and the completion of appropriate consultation processes. Regardless of the complexity of the proposed action, the environmental document will always consider the impacts to cultural resources, endangered species, surface water, and groundwater. An interdisciplinary team of BLM resource specialists will conduct the analysis.

The environmental analysis may be conducted for a single well, a group of wells, or for an entire field. The public is welcome to provide input to the BLM for inclusion in the analysis. As discussed previously, the BLM posts notices of all Federal APDs for public inspection in the authorizing office. For large projects, such as field development environmental assessments or environmental impact statements, the BLM will go through public scoping and may issue a draft analysis for public comment prior to completing the final analysis and issuing a decision.

The environmental analysis will identify potential impacts from the proposed action. The BLM will develop any necessary conditions of approval to mitigate those potential impacts. If unacceptable impacts are identified, the BLM will ask the operator to modify its proposal, or the BLM may deny the application. The BLM will attach the conditions of approval to the approved APD that the operator must follow. Examples of conditions of approval include road improvements, additional erosion control, or seasonal restrictions on some activities. In cases where the BLM manages the surface, the BLM may also require baseline water testing prior to drilling.

Compliance with Onshore Oil and Gas Order No. 2. Upon BLM's approval of an APD, the operator may commence drilling of the well. In addition to the approved plan and the conditions of approval, the operator must also comply with the requirements of Onshore Oil and Gas Order No. 2, (Onshore Order 2), which details the BLM's uniform national standards for the minimum levels of performance expected from operators when conducting drilling operations on Federal and Indian lands. Many of the requirements of Onshore Order 2 ensure the protection of usable water.

Onshore Order 2 also requires the operator to:

- Conduct the proposed casing and cementing programs as approved to protect and isolate all usable water zones, lost circulation zones, abnormally pressured zones, and any prospectively valuable deposits of minerals. It also requires the operator to report all indications of usable water.
- Employ technical measures to center the casing in the drilled hole prior to cementing in order to ensure wellbore integrity. It also requires the operator to cement the surface casing up to the surface either during the primary cement job or by remedial cementing, which ensures that all usable water zones behind the surface casing are isolated and protected.
- Wait until the cement for all casing strings achieves a minimum of 500 pounds per square inch (psi) compressive strength at the casing shoe prior to drilling out the casing shoe and utilize proper cementing techniques.
- Pressure test the casing prior to drilling out the casing shoe to ensure the integrity of the casing. The operator must also conduct a pressure integrity test of each casing shoe on all exploratory wells, and on that portion of any well approved for a 5,000 psi blowout preventer. The pressure test ensures the integrity of the cement around the casing shoe.

In addition, Onshore Order 2 identifies the minimum requirements for blowout prevention equipment and the minimum standards for testing the equipment. Proper sizing, installation, and testing of the blowout prevention equipment ensures that the operator maintains control of the well during the drilling process, which is necessary for protection of usable water zones.

Post-Approval Inspections and Reporting. The BLM conducts inspections of drilling operations to ensure that operators comply with the Onshore Order 2 drilling regulations, the approved permit, and the conditions of approval. The BLM drilling inspections consist of two general types of inspections: Technical and environmental. The BLM petroleum engineering technicians conduct technical inspections of the drilling operations such as witnessing the running and cementing of the casing, witnessing the testing of the blowout prevention equipment, and detailed drilling rig inspections. Such inspections also include review of documentation such as the third-party cementing job ticket that describes the cementing operation, including the type and amount of cement used, the cement pump pressures, and the observation of cement returns to the surface, if applicable.

The BLM natural resource specialists conduct environmental inspections of drilling operations that focus primarily on the surface use portion of the approved drilling permit. This includes inspection of the access road, the well pad, and pits. While the BLM does not have the budget or personnel to inspect every drilling operation on Federal and Indian minerals, the BLM conducts inspections in accordance with an annual risk-based strategy to ensure compliance with the regulations, lease stipulations, and permits.

Within 30 days after the operator completes a well, the operator is required by existing regulations to submit a BLM Well Completion or Recompletion Report and Log (Form 3160–4), which provides drilling and completion information. Similar to completion of a new well, an existing well can be recompleted to restore productivity and thus produce oil or gas which would have otherwise been abandoned. This document includes the actual casing setting depths and the amount of cement the operator used in the well, together with information regarding the completion interval between, for example, the top and bottom of the formation, the perforated interval, and the number and size of perforation holes. The operator is also required to submit copies of all electric and mechanical logs. The BLM reviews this information to ensure that the operator set the casing and pumped the cement according to the approved permit.

Compliance with Onshore Oil and Gas Order No. 7. Once a well goes into production, water is often produced with the oil and gas. The water tends to be of poor quality and is not generally suitable for drinking, livestock, or other uses and, therefore, must be disposed of properly. Onshore Oil and Gas Order No. 7 (Onshore Order 7) regulates the disposal of produced water. Under Onshore Order 7, operators must apply to the BLM for authorization to dispose of produced water by injecting the water back into a suitable formation, by storing it in pits, or by other methods approved by the BLM. If the water will be stored in pits, the BLM requires specific design standards to ensure the water does not contaminate the environment or pose a threat to public health and safety.

Post-Drilling Inspections. After a well has been drilled and completed, the BLM continues to inspect the well until it has been plugged and abandoned, and the surface has been rehabilitated. During the production phase of the well, the BLM inspections focus on two primary issues: Production and the environment. The Federal Government (Federal leases) or an Indian tribe or individual Indian allottee (Indian leases) receive a royalty on the oil and gas removed or sold from the lease based on the volume, quality, and value of the oil and gas. Royalties from Federal leases are shared with the state as provided by statute. Production inspections are conducted by the BLM to ensure the volume and quality of the oil and gas is accurately measured and properly reported. Environmental inspections are conducted by the BLM to ensure that wellpads and facilities are in compliance with regulations, Onshore Orders, and approved permits. Environmental inspections include ensuring that pits are properly constructed, maintained, and protected from wildlife; identifying leaking wells or pipelines; ensuring that the wellsite and facilities are properly maintained; and ensuring that proper erosion controls and rehabilitation measures are in place.

Well Plugging, Abandonment and Site Restoration. When a well has reached the end of its economic life, Federal regulations require that it be plugged and abandoned to prevent oil and gas from leaking to the surface or contaminating water bearing zones or other mineral zones. An operator may request well abandonment or the BLM may require it. In either case, the operator must submit a proposal for well plugging, including the length, location, type of cement, and placement method to be used for each plug. The operator must also submit a plan to rehabilitate the surface once the well has been plugged. The goal of surface rehabilitation is to remove obvious visual evidence of the pad and to promote the long-term stability of the site and vegetation.

The BLM inspects both well plugging and surface restoration. Well plugging inspections are completed to ensure the plugs are set in accordance with the

procedure approved by the BLM. The inspector will witness the depth and volume of cement used in a plug as well as the physical verification of the top of a plug. When an operator has completed surface restoration, it will notify the BLM or the surface management agency. The surface protection specialists of the BLM or of the surface management agency will inspect the site to ensure the restoration is adequate. Once the BLM or the surface management agency is satisfied with the restoration efforts, the BLM will approve the operator's Final Abandonment Notice.

The regulations and Onshore Orders that have been in place to this point have served to provide reasonable certainty of environmentally responsible development of oil and gas resources on public lands, but are in need of revision as extraction technology has advanced. The final rule will complement these existing rules by providing further assurance of wellbore integrity, requiring with limited exception public disclosure of chemicals used in hydraulic fracturing, and ensuring safe management of recovered fluids. Taken together these regulations establish baseline environmental safeguards for hydraulic fracturing operations across all public and Indian lands.

II. Discussion of the Final Rule and Comments on the Proposed Rules

As was discussed in the initial and supplemental proposed rules, the BLM is revising its hydraulic fracturing regulations, found at 43 CFR 3162.3–2, and adding a new section 3162.3–3. Existing section 3162.3–3 is retained and renumbered. As stewards of the public lands and minerals and as the Secretary's regulator for operations on oil and gas leases on both public and Indian lands, the BLM has evaluated the increased use of hydraulic fracturing practices over the last decade and determined that the existing rules for hydraulic fracturing require updating.

The FLPMA directs the BLM to manage the public lands so as to prevent unnecessary or undue degradation, and to manage those lands using the principles of multiple use and sustained yield. The FLPMA defines multiple use to mean, among other things, a combination of balanced and diverse resource uses that takes into account long-term needs of future generations for renewable and non-renewable resources. The FLPMA also provides that the public lands be managed in a manner that will protect the quality of their resources, including, but not limited to, ecological, environmental, and water resources. The Mineral Leasing Act and the Mineral Leasing Act for Acquired Lands authorize the Secretary to lease Federal oil and gas resources, and to regulate oil and gas operations on those leases, including surface-disturbing activities.

The Act of March 3, 1909, the Indian Mineral Leasing Act and the Indian Mineral Development Act assign regulatory authority to the Secretary over Indian oil and gas leases on trust lands (except those excluded by statute, *i.e.,* the Crow Reservation in Montana, the ceded lands of the Shoshone Reservation in Wyoming, the Osage Reservation in Oklahoma, and the coal and asphalt lands of the Choctaw and Chickasaw Tribes in Oklahoma). The Secretary has delegated to the BLM her authority to oversee operations on Indian mineral leases through the Departmental Manual (235 DM 1.K), and the Bureau of Indian Affairs' regulations provide that 43 CFR part 3160 applies to oil and gas operations on Indian lands. See 25 CFR 211.4, 212.4, and 225.4. The Secretary also approved the authorities section of the regulations which give the BLM authority under the Indian minerals statutes.

As discussed in the background section of this preamble, the increased use of well stimulation activities over the last decade has generated concerns among the public about hydraulic fracturing and about the chemicals used in hydraulic fracturing. This final rule is intended to increase transparency for the public regarding the fluids used in the hydraulic fracturing process, provide assurance that wellbore integrity is maintained throughout the fracturing process and ensure that the fluids that flow back to the surface from hydraulic fracturing operations are properly stored, disposed of, or treated. The BLM's engineers and field managers have decades of experience exercising oversight of these wells during the evolution of this technology. This expertise, together with input from the public, industry, state, academic and other experts discussed below, forms the basis for the decision that new rules are needed and for the requirements contained in this rule.

The following chart explains the major changes between the supplemental proposed rule and this final rule. A similar chart explaining the differences between the proposed and supplemental proposed rules appears in the supplemental proposed rule at 78 FR 31641 and a chart explaining the differences between the existing regulations and the original proposed rule appears in the proposed rule at 77 FR 27694.

Supplemental proposed regulation	Final regulation	Substantive changes
43 CFR 3160.0–5 Definitions	43 CFR 3160.0–5 Definitions	This final rule makes a series of changes to the definitions section. The term ''master hydraulic fracturing plan'' is added. The definition of a cement evaluation log is moved from § 3162.2–3(e)(2) to the definitions section. The term ''confining zone'' is now defined because that term is used in revised § 3162.3–3(d). The term ''refracturing'' is deleted from this section and the rest of the rule. The term ''usable water'' is updated to remove the requirement to identify usable water only via drill log. The final rule also clarifies the definition of ''usable water''.
43 CFR 3162.3–2 Subsequent Well Operations.	43 CFR 3162.3–2 Subsequent Well Operations.	Paragraph (a) of this section is modified slightly by removing the phrase ''the operator'' because it is redundant.
43 CFR 3162.3–3(a) Hydraulic Fracturing.	43 CFR 3162.3–3(a) Subsequent Well Operations; Hydraulic Fracturing.	The final rule clarifies the application of this rule to wells at various stages of completion on the publication and effective date, and clarifies what sections of the rule apply based on a table which distinguishes leases with approved APDs from leases without approved APDs, as well as leases with approved APDs that do not have wells spudded.
43 CFR 3162.3–3(b) Isolation of Usable Water to Prevent Contamination.	43 CFR 3162.3–3(b) Isolation of Usable Water to Prevent Contamination.	The term ''refracturing'' is deleted.

Supplemental proposed regulation	Final regulation	Substantive changes
43 CFR 3162.3–3(c) When an Operator Must Submit Notification for Approval of Hydraulic Fracturing.	43 CFR 3162.3–3(c) How an Operator Must Submit a Request for Approval of Hydraulic Fracturing.	Paragraphs (c)(1) and (2) of this section are revised non-substantively and for clarity. Paragraph (c)(3) is revised to remove references to refracturing. As in the supplemental proposed rule, the operator may submit the hydraulic fracturing proposal either in the APD or as an NOI. The final rule removes ''type wells'' from this section. In the final rule a request to hydraulically fracture can be submitted for a group of wells in a master hydraulic fracturing plan. Paragraph (c)(4) is added to address and clarify when an operator must submit a new NOI.
43 CFR 3162.3–3(d) What the Notice of Intent Sundry Must Include.	43 CFR 3162.3–3(d) What a Request for Approval of Hydraulic Fracturing Must Include.	Consistent with other changes in this rule, the final rule replaces the procedure for submitting an NOI for multiple wells through a type well submission, and instead allows submission of a master hydraulic fracturing plan. Paragraph (d)(1) is revised to require specific information regarding wellbore geology, including information regarding the formation into which hydraulic fracturing fluids are to be injected, the estimated depths of the confining zones and occurrences of usable water. Paragraph (d)(2) is revised to require a map showing information regarding known or suspected faults and fractures. Paragraph (d)(4) is also revised to require submission of a map showing information about the trajectory of the wellbore and estimated direction and length of the fractures that will be propagated and all existing wellbore trajectories for all wells within one-half mile of the wellbore that will be hydraulically fractured.
43 CFR 3162.3–3(d)(2)	43 CFR 3162.3–3(d)(2)	The final rule deletes the requirement to submit occurrences of usable water by use of a drill log and instead allows flexibility in how to obtain the information.
43 CFR 3162.3–3(d)(3)	43 CFR 3162.3–3(d)(3)	The final rule eliminates the requirement to submit the proposed measured depth of perforations or the open hole interval and estimated pump pressures and makes it clear that the wells referred to in this provision are water supply wells.
43 CFR 3162.3–3(d)(4)	43 CFR 3162.3–3(d)(4)	The final rule combines paragraphs (ii) and (iii) into a revised paragraph (ii) to read ''the maximum anticipated surface pressure that will be applied during the hydraulic fracturing process.'' The revised terminology encompasses the intent of the previous two paragraphs. Supplemental proposed rule paragraph (iv) is now paragraph (iii) and is revised in the final rule, and the word ''calculated'' is deleted, to reinforce the lack of certainty of the information in the APD or NOI at this stage of operations. Supplemental proposed rule paragraph (v) is deleted and replaced with a revised paragraph (iv), which seeks the estimated minimum vertical distance to the nearest usable water aquifer above the fracture zone. New paragraph (v) asks for the measured depth of the proposed perforated or open hole interval. Both the old paragraph (v) and the new paragraph (iv) aim to provide guidance to the BLM on protecting usable water zones.
43 CFR 3162.3–3(d)(5)	43 CFR 3162.3–3(d)(5)	The final rule eliminates some of the specific details of the fluid recovery plan, focusing on estimated volume, proposed handling methods and proposed disposal methods. Further, the timeline is being clarified to better reflect the scope of the plan. This paragraph is also revised by adding a provision asking for information about the handling of recovered fluids between the time of the start of hydraulic fracturing operations and the approval of the disposal of produced fluids under BLM's regulations, which are currently contained in existing Onshore Order 7. Paragraph (i) is revised by eliminating the three circumstances that were listed where the volume of recovered fluid must be estimated, but keeping the requirement to estimate the volume of fluid to be recovered. New paragraph (ii) asks for the proposed methods of handling recovered fluids by cross reference to paragraph (h) of this section, which requires the use of rigid enclosed, covered or netted and screened above-ground tanks to store these fluids (with a limited exception for the use of lined pits). Paragraph (iii) of this section is revised by making clear the methods of handling recovered fluids that must be described in the application.
None	43 CFR 3162.3–3(d)(6)	The final rule includes a requirement for a surface use plan of operations if the hydraulic fracturing operation would cause additional surface disturbance. By reference to paragraph (e), it requires documentation that an adequate cement job occurred for all casing strings designed to isolate usable water.
43 CFR 3162.3–3(d)(6)	43 CFR 3162.3–3(d)(7)	Because of new paragraph (d)(6), the former paragraph (d)(6) is renumbered as paragraph (d)(7), and is revised to make it clear that the requirement may apply to an APD as well as a NOI.

Supplemental proposed regulation	Final regulation	Substantive changes
43 CFR 3162.3(e) Monitoring of Cementing Operations and Cement Evaluation Log Prior to Hydraulic Fracturing.	43 CFR 3162.3–3(e) Monitoring and Verification of Cementing Operations Prior to Hydraulic Fracturing.	The title of this section is revised to better reflect the content of the final rule.
43 CFR 3162.3–3(e)(1)	43 CFR 3162.3–3(e)(1)	This paragraph is revised to make it clear that the information request is for any casing string used to isolate usable water zones. The section is also revised to require that the information be submitted to the authorized officer 48 hours prior to the start of hydraulic fracturing operations unless the authorized officer approves a shorter time.
43 CFR 3162.3–3(e)(2)	43 CFR 3162.3–3(e)(2)	New paragraph (e)(2) replaces supplemental proposed rule paragraph (e)(2) and requires that prior to hydraulic fracturing operations the operator must determine and document that there is adequate cement for all casing strings to isolate usable water. For surface casing, the operator must observe cement returns to the surface and document any indications of inadequate cement following the new requirements of this paragraph. For intermediate or production casing, if the casing is not cemented to the surface, the operator must run a CEL demonstrating that there is at least 200 feet of adequately bonded cement protecting the deepest usable water zone. If the casing is cemented to the surface, then the operator must follow the same requirements as for surface casing established earlier in this section.
43 CFR 3162.3–3(e)(3), (e)(4), and (e)(5).	43 CFR 3162.3–3(e)(3)	Final paragraph (3) combines revised supplemental proposed rule paragraphs (3), (4), and (5). For any well where there is an indication of inadequate cement, the operator must follow the provisions of this paragraph. The operator must notify the BLM of the inadequate cement within 24 hours of discovering it (paragraph (3)(i)) and submit a plan to the BLM requesting approval of remedial action to achieve adequate cement (paragraph (3)(ii)). This section also addresses emergency situations where an operator may request oral approval of remedial action to correct inadequate cement. Such oral approvals must be followed by written notice within 5 business days following oral approval. The operator must also verify that the remedial action was successful with a CEL or other method BLM approves in advance (paragraph (3)(iii)). Consistent with the supplemental proposed rule, the operator must submit a subsequent report for the remedial action including a certification that the remedial action followed the approved plan and was successful (paragraph (3)(iv)). Under paragraph (3)(v), the operator must submit to the BLM the results of the CEL or other testing method that showed that the remedial action was successful at least 72 hours before starting hydraulic fracturing operations.
43 CFR 3162.3–3(f) Mechanical Integrity Testing Prior to Hydraulic Fracturing.	43 CFR 3162.3–3(f) Mechanical Integrity Testing Prior to Hydraulic Fracturing.	Paragraph (1) of this section is revised to include the words ''that will be applied during the hydraulic fracturing process,'' to clarify the timing of the requirement. Paragraph (2) of this section is revised by replacing the word ''treating'' with the word ''surface'' in the second sentence of this paragraph.
43 CFR 3162.3–3(g) Monitoring and Recording During Hydraulic Fracturing.	43 CFR 3162.3–3(g) Monitoring and Recording During Hydraulic Fracturing.	This paragraph has been revised to delete the term ''refracturing,'' and clarifies the actions that operators must take when pressure within the annulus increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation.
43 CFR 3162.3–3(h)	43 CFR 3162.3–3(h) Management of Recovered Fluids.	This section has undergone numerous changes. The final rule requires that fluids recovered be stored in above-ground tanks prior to disposal under BLM's regulations (currently in Onshore Order 7). Paragraphs (1) and (2) specify the very limited conditions under which an authorized officer may approve a lined pit in lieu of a tank.
43 CFR 3162.3–3(i) Information that Must be Provided to the Authorized Officer After Completed Operations.	43 CFR 3162.3–3(i) and (i)(1) Information that Must be Provided to the Authorized Officer After Hydraulic Fracturing is Completed.	The heading of this section is revised to make it clearer. Paragraph (i)(1) of this section is also revised to require the operator to provide information about each additive in the hydraulic fracturing fluid. This will help to account for proppants as well as chemical additives.
43 CFR 3162.3–3(i)(2)	43 CFR 3162.3–3(i)(2), (i)(3), and (i)(5).	This section has been revised to seek only the actual sources and locations of the water used in the hydraulic fracturing fluid. The pressure information requested in the supplemental proposed rule is covered in the final rule by paragraph (3) and the depth of perforations and open hole interval is part of new paragraph (5).
43 CFR 3162.3–3(i)(3)	43 CFR 3162.3–3(i)(3)	The final rule seeks the maximum surface pressure rather than the actual surface pressure and no longer seeks the flush rate or the final pump pressure concentration in the fracturing fluid.

Supplemental proposed regulation	Final regulation	Substantive changes
43 CFR 3162.3–3(i)(4)	43 CFR 3162.3–3(i)(4)	This section requires the report to include the actual, estimated, or calculated fracture length, height, and direction. This section remains as proposed.
None	43 CFR 3162.3–3(i)(5)	New paragraph (5) requires information previously contained in paragraph (2), regarding the actual measured depth of perforations or the open-hole interval.
None	43 CFR 3162.3–3(i)(6)	New paragraph (6) requires operators to report the total volume of fluid recovered between the time that hydraulic fracturing is completed and when the operator starts to report water produced from the well to Office of Natural Resources Revenue (ONRR).
43 CFR 3162.3–3(i)(5)(i)	43 CFR 3162.3–3(i)(7)	The final rule revises this renumbered paragraph to clearly outline the timeframe for reporting information pertaining to fluid recovery.
43 CFR 3162.3–3(i)(5)(ii)	43 CFR 3162.3–3(i)(7)(i)	This final section is renumbered, but is similar to the supplemental proposed rule.
43 CFR 3162.3–3(i)(5)(iii)	43 CFR 3162.3–3(i)(7)(ii)	The final rule would simplify this section by removing the reference to Onshore Order No. 7 and seek information on disposal method, such as injection, recycling, or off-lease storage.
43 CFR 3162.3–3(i)(6)	Deleted	This section is deleted and is unnecessary because the Authorized Officer can always require an explanation of any deviation under (i)(10) of this section.
43 CFR 3162.3–3(i)(7)	43 CFR 3162.3–3(i)(8)	The final rule renumbers this section. Paragraphs (8)(ii) and (8)(iii) are revised to make it clear that the provisions only apply to hydraulic fracturing fluid constituents once they arrive on the lease.
43 CFR 3162.3–3(i)(8)	43 CFR 3162.3–3(i)(9)	The final rule renumbers this section. The well logs and records of adequate cement bonds, including the cement monitoring report and any cement evaluation log, are no longer required to be submitted under this section because this information is covered either in the APD or NOI under paragraph (e) of this section.
43 CFR 3162.3–3(j) Identifying Information Claimed to be Exempt from Public Disclosure.	43 CFR 3162.3–3(j) Identifying Information Claimed to be Exempt from Public Disclosure.	The final rule at paragraph (j)(1) strengthens the affidavit provisions to ensure that operators fully describe and attest to the basis for their claim of exemption from public disclosure for trade secrets. The affidavit must be signed by a corporate officer or the equivalent responsible official of the operator. The affidavit must identify and provide contact information for the owner of the withheld information, if it is not the operator. New paragraph (j)(2) provides that if the operator relies on facts supplied by another entity, it must include an affidavit from a responsible official of that entity verifying those facts. Former paragraph (j)(2) has been renumbered (j)(3) without substantive change. Former paragraph (j)(4) has been renumbered as paragraph (j)(5) and is revised by requiring that the operator maintain records of the information claimed to be exempt from disclosure until the later of the BLM's approval of a final abandonment notice, or 6 years from completion of hydraulic fracturing operations for Indian lands, or 7 years from completion of hydraulic fracturing operations for Federal lands, as is consistent with applicable law. Any subsequent operator is responsible for maintaining access to those records. The final rule also adds a new paragraph (j)(6) to this section requiring the operator to submit the chemical family name or other similar descriptor for information claimed to be exempt from disclosure.
43 CFR 3162.3–3(k) Requesting a Variance from the Requirements of this Section.	43 CFR 3162.3–3(k) Requesting a Variance from the Requirements of this Section.	The final rule revises the variance provisions to allow for individual variances and state/tribal variances in different sections. Most of the substantive information in this section has not changed, but has been re-organized and revised for clarity. One revision to this section is made to make the rule consistent with Onshore Order 1 by clarifying that the decision on whether to approve a variance request is not administratively appealable to either the State Director or to the Interior Board of Land Appeals under 43 CFR part 4.

Section-by-Section Discussion of the Revised Proposed Rule and Discussion of Comments

Comments Addressed in This Rule

In this preamble, the BLM discusses many of the comments received on the supplemental and proposed rules. Commenters provided detailed and helpful information that assisted in framing the issues and ultimately in producing this final rule. The Department does not address every comment in this final rule, because the changes in this rule have mooted some comments on the initial proposed rule and the supplemental proposed rule. Other comments were not central to the evaluation the BLM has undertaken, and thus discussion of those few comments would not contribute to the public's understanding of the reasons for the final rule.

Additionally, not every change in the final rule responds to a specific comment. Some revisions clarify the final rule, and still other revisions allow this final rule to be more effective or reduce inefficiencies.

Section Discussion

As an administrative matter, this rule would amend the authorities section for the BLM's oil and gas operations regulations at 43 CFR 3160.0–3 to include the FLPMA. Section 310 of the FLPMA authorizes the Secretary of the Interior to promulgate regulations to carry out the purposes of the 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.

Section 3160.0–5 Definitions

This section defines terms related to the regulation and the hydraulic fracturing process. The terms annulus, bradenhead, cement evaluation log, confining zone, hydraulic fracturing, hydraulic fracturing fluid, and proppant are used to describe the requirements of the rule. The term ''master hydraulic fracturing plan'' (MHFP) would allow operators to gain certain efficiencies in submitting information to the BLM. The actual process is explained in sections 3162.3–3(c) and (d).

The final rule incorporates several changes to the definitions in section 3160.0–5 from the supplemental proposed rule. The definition of cement evaluation log is added to this section by moving it from section 3162.2–3(e)(2) in the supplemental proposed rule to the definitions section of the final rule. Because the final rule uses the term several times, the BLM decided to add the definition to this section.

The term ''master hydraulic fracturing plan'' is added to take the place of portions of the type well approval in section 3162.3–3(d) of the proposed rule. The final rule retains the ability for operators to submit hydraulic fracturing proposals at the APD or NOI stage for a group of similar wells with a single submission, including the information regarding geology, etc., required in sections 3162.3–3(d)(1) through (d)(7) of this rule. The BLM believes that this will streamline the permitting process without sacrificing the quality of the review. As a matter of current practice, many oil and gas operators use the APD review and approval process to satisfy other BLM approval requirements. For example, the construction of a road to access a drilling location or a pipeline to transport production from a well requires a right-of-way (ROW) in certain cases. Many operators submit their plan of development for their proposed access road or pipeline and a ROW application with their APD. The BLM performs its review of the ROW application at the same time it is reviewing the APD. An MHFP may not be used for the information required to demonstrate well integrity in section 3162.3–3(e). As discussed later, the ''type well'' concept has been eliminated and each well will be required to be demonstrated to meet the performance standards in this rule.

In addition, the requirement that an MHFP only apply to wells in the same field is eliminated primarily because the term ''field'' is not well defined. Instead, in the final rule, an MHFP applies to any well where the geologic characteristics are substantially similar. The geographic area for which an MHFP applies will be at the discretion of the field office. The MHFP is similar in concept to the Master Development Plan (MDP) allowed in Onshore Order 1, although the use of one does not necessarily depend upon the use of the other. The MHFP is specific to the technical aspects of hydraulic fracturing of a group of wells; whereas, the MDP's purposes include encouraging logical field development and ensuring consideration of the environmental effects associated with development of the field in the accompanying NEPA analysis and documentation. The MHFP and MDP can apply to different groups of wells.

The term ''hydraulic fracturing'' was also modified by adding the phrase ''by applying fluids under pressure.'' This change is based on comments seeking clarification of the types of operations that fall under the scope of this rule.

The term ''type well'' was eliminated. The BLM determined that the use of a type well CEL as a model for other wells that were geologically similar was not a statistically valid approach for ensuring wellbore integrity. Because geologic conditions and drilling procedures can vary significantly from well to well, sometimes even for wells drilled from the same pad, a CEL on a single sample well cannot reliably be extrapolated to other wells with any level of confidence. Therefore, the ''type well'' concept, as it applied to CELs, is eliminated in the final rule.

The term ''confining zone'' is added to the final rule because the BLM is requiring the operator to identify both the confining zone and any known faults or fractures that transect the confining zone in the APD or NOI for hydraulic fracturing approval. The definition of confining zone is based on the U.S Environmental Protection Agency (EPA)'s definition under the Underground Injection Control (UIC) program, modified to apply specifically to hydraulic fracturing.

The term ''refracturing'' was eliminated from the final rule because the requirements for permitting, performing, monitoring, and reporting hydraulic fracturing operations are identical whether the well is hydraulically fractured for the first time or any subsequent stimulation.

Usable Water

The BLM made several modifications to the definition of the term ''usable water'' in response to comments received.

The first change in the ''usable water'' definition was to eliminate paragraph (2) from the definition in the supplemental proposed rule because it would be unreasonable to expect an operator to know that other users could be using an aquifer for agricultural or industrial purposes and because an operator would have no way of knowing if other users could be adversely affected by hydraulic fracturing. Decisions on those matters are for state or tribal water regulators, not the BLM. Thus, paragraph (1)(ii) in the final rule defers to State (for Federal lands) or tribal (for Indian lands) determinations that groundwater that does not meet the definition of ''underground sources of drinking water'' (USDWs) in EPA's regulations are nonetheless sources of drinking water that must be protected. The other change was to reorganize the clauses in the definition to separate those items that would be deemed usable water from those items that would not be deemed usable water.

Numerous commenters were confused about the threshold for Total Dissolved Solids (TDS) in usable water. Prior to the publication of this rule, BLM regulations (existing section 3162.5–2(d)) require the operator to ''isolate freshwater-bearing and other usable water containing 5,000 ppm or less of total dissolved solids . . .,'' and Onshore Oil and Gas Order No. 2, Drilling Operations on Federal and Indian Oil and gas leases (53 FR 46798) (Onshore Order 2), section III. B. requires casing and cement to ''protect and/or isolate all usable water zones.'' Usable water is defined in section II.Y of Onshore Order 2 as ''generally those waters containing up to 10,000 ppm of total dissolved solids.'' The requirement in the CFR was inconsistent with the requirement in Onshore Order 2.

This rule corrects the inconsistency between the two by removing the 5,000 ppm standard in 43 CFR 3162.5–2(d) and replacing it with language that is consistent with Onshore Order 2. The requirement to protect and/or isolate usable water generally containing up to 10,000 ppm of TDS has been in effect since 1988, when Onshore Order 2 became effective. This rule does not

substantially modify the requirements in Onshore Order 2, although it clarifies the term by incorporating specific inclusions and exclusions as to what constitutes usable water. The final rule keeps the 10,000 ppm threshold from Onshore Order 2 as the primary determining factor for what constitutes usable water.

Because of the inconsistency between the supplemental proposed rule and existing codified regulations, some commenters were under the impression that this rule was increasing the level of protection for usable water from 5,000 ppm to 10,000 ppm, while other commenters believed that this rule was proposing to decrease the level of protection from 10,000 ppm to 5,000 ppm. Neither impression is true. This rule maintains the 10,000 ppm standard that has been in place since 1988. The BLM still believes that a 10,000 ppm threshold is appropriate because it is consistent with the threshold used as part of the definition of ''underground sources of drinking water'' in EPA regulations implementing the Safe Drinking Water Act (SDWA). The SDWA was enacted in 1974 and is the primary Federal law that ensures the quality of American's drinking water (*www.epa.gov/lawsregs/rulesres/sdwa/*). Specific comments that were based on the erroneous assumption that the BLM was changing the TDS threshold for usable water are summarized as follows. No changes to the final rule were made as a result of these comments.

- Numerous comments expressed concern that the requirement to protect usable water (section 3162.5–2) as defined would result in significantly increased costs because protecting water with TDS levels up to 10,000 ppm would require running casing and cement much deeper than it is currently run. Because the definition of usable water has not substantially changed in this rule, there will be no significant changes in costs of running casing and cement.
- Many commenters thought that there was no use in protecting water zones with TDS levels greater than 5,000 ppm, because water with a TDS higher than 5,000 is not suitable for human, agricultural, or industrial uses. One comment stated that the BLM considers water with TDS levels greater than 5,000 ppm as hazardous to wildlife. This rule does not change the primary criteria for protecting usable water up to 10,000 ppm, which has been in place for the past 26 years. Given the increasing water scarcity and technological improvements in water treatment equipment, it is not unreasonable to assume aquifers with TDS levels above 5,000 ppm are usable now or will be usable in the future.
- Some commenters expressed a concern that the conflicting definitions in Onshore Order 2 and in this rule will cause confusion for operators. There is no conflict between the definition in this rule and the definition in Onshore Order 2. This rule clarifies the term and incorporates specific inclusions and exclusion as to what is deemed to be usable water.

Several comments stated that the cost of running surface casing and cement deep enough to protect all usable water zones, as defined, would significantly increase the cost of drilling wells. This is an erroneous concern. It is not uncommon for deeper usable water zones to be protected with intermediate or production casing, which is allowed under Onshore Order 2 and this rule. No changes to the final rule were made as a result of these comments.

Several commenters suggested changing the definition of usable water to exclude aquifers that are not economical or feasible to use. The commenters said that these would include aquifers that are too deep, too small, too remote, or are not capable of achieving some set flow rate. No changes to the rule were made as a result of these comments. From a practical standpoint, excluding aquifers based on depth, size, location, flow rate, or other characteristics would be difficult in a national rule for several reasons. For example, the depths to which a water user might drill would depend on such factors as the need for water, the availability of other supplies, and the hydrologic characteristics of the aquifer (natural pressures might raise water in a deep well closer to the surface). Excluding aquifers from protection based on some arbitrary flow rate would be impractical. Measuring the flow rate potential of an aquifer would be a time-consuming and expensive process for operators to perform and for the BLM to review. Just as with oil and gas wells, the flow rate potential of a water well can depend on the specific location, depth, and methodology used. Furthermore, a flow rate that is inadequate for one type of use might be adequate for another type of use. State and tribal agencies, and EPA under the SDWA, have the expertise and authority to consider all the factors in characterizing groundwater.

Several commenters questioned the basis for the 10,000 ppm of TDS in the definition. The 10,000 ppm of TDS used in Onshore Order 2 and this rule is based on part of the definition of ''underground source of drinking water'' in EPA's regulations implementing SDWA.

Another change made to this definition in response to comments involved three exemptions from the definition of usable water listed in the supplemental proposed rule. The proposed exclusions in paragraphs (2)(i), (2)(ii), and (2)(iii) of the definition have been modified for clarity and to better reflect the roles of EPA and states and tribes in managing groundwater resources.

The proposed exclusion in paragraph (A) of the definition, regarding hydrocarbon zones, was added to the supplemental proposed rule based on comments received on the initial proposal (77 FR 27691). Some commenters noted correctly that developing minerals from a zone that is also a USDW requires specific authorization under the SDWA. The BLM has edited the exclusion in former paragraph (A) [5] to clarify that the zone which the BLM approves for hydraulic fracturing is not considered to be usable water only if the operator has obtained all necessary authorizations from the EPA, the state (for public lands), or the tribe (for Indian lands), as appropriate, for mineral development in a USDW area.

The BLM received several comments objecting to any exemptions for protecting aquifers, as proposed in the definition of ''usable water'' under 3160.0–5. The commenters stated that it is impossible to predict what will constitute ''usable'' water in the future, especially considering drought and water scarcity. Therefore, they said that the BLM should be very conservative in protecting all groundwater with a TDS of less than 10,000 ppm. The commenters recommended deleting the exemptions under paragraphs (A), (B), and (C) of the usable water definition. The BLM disagrees that all groundwater with a TDS of less than 10,000 ppm must be deemed usable water in this final rule. The TDS is only one parameter in deciding whether water is usable. The amounts of other types of contaminants, depth, and available alternatives are other considerations. The final rule has modified the exemptions in paragraphs (2)(i), (2)(ii), and (2)(iii) of the usable water definition to clarify the central roles of states, tribes, and the EPA in categorizing groundwater and deciding upon the proper level of protection from

[5] For example, any activity authorized under this rule may also require an aquifer exemption for injection activities in the same zone if that zone is regulated by the EPA under the SDWA, even where the zone is not considered to contain usable water under this rule.

hydraulic fracturing operations. Those agencies have the expertise and authority to consider all local factors and to manage groundwater resources.

Some of the commenters suggested that the BLM should incorporate the exemption provisions of the SDWA directly into the definition of usable water instead of relying on designations through the SDWA.

No changes to this provision were made as a result of these comments. The BLM has neither the authority nor jurisdiction to designate groundwater as exempt from protection under the SDWA. Furthermore, the final rule protects usable water, which includes, but is not limited to USDWs. Aquifers that are not USDWs might be usable for agricultural or industrial purposes, or to support ecosystems, and the rule defers to the determinations of states (on Federal lands) and tribes (on Indian lands) as to whether such zones must be protected.

One industry group seemed to favor requiring operators to determine the TDS levels of aquifers already deemed by the state or tribe to require protection, and said that the TDS criterion was arbitrary and capricious, but included the same criterion in its proposed definition. That group's argument against the TDS criterion was that it did not consider other constituents, such as hydrocarbons, heavy metals, microorganisms, or toxic compounds, which would make waters unsuitable for use. The BLM's definition of usable water has for many years used a TDS criterion and TDS is a widely recognized criterion for entities contemplating use of particular waters. In the United States, most users prefer waters containing 10,000 ppm TDS or less.

The BLM agrees that different water users would also be concerned about various other water quality criteria. The most common dissolved solids in most aquifers encountered by oil and gas operations on Federal or Indian lands are salts. Operators can estimate salinity levels from drill logs. Other means of measuring TDS are straight forward and economical. The BLM declines to require operators to test aquifers for hydrocarbons, heavy metals, microorganisms or toxic compounds.

A few commenters mentioned that paragraphs (1) and (3) in the definition in the supplemental proposed rule are irrelevant because they would not occur with TDS levels above 10,000 ppm anyway. Paragraph (1) includes in the definition of usable water all groundwater that meets the definition of USDWs in EPA's regulations. However, the 10,000 ppm of TDS threshold established in the first sentence of the definition is based on part of EPA's regulatory definition of ''underground source of drinking water'' under the SDWA. The commenter concludes, therefore, that paragraph (1) is redundant and unnecessary. Paragraph (3) includes zones designated for protection by a state or a tribe. According to the commenters, however, there are no states or tribes that have designated a TDS threshold higher than 10,000 ppm. While the commenters are correct in their assertions, the BLM must anticipate that, in the future, conditions may change. Given the increasing threat of water scarcity and the advancement of technology, it is foreseeable that a TDS threshold higher than 10,000 ppm may be established under applicable law in the future for aquifers supplying agricultural, industrial, or ecosystem needs. By including these paragraphs in this rule, such zones would automatically be protected from contamination by subsequent hydraulic fracturing without requiring a rule change. No changes to the rule were made as a result of this comment.

Several commenters stated that the BLM has no jurisdiction over the waters of the various states. States and tribes generally administer and regulate rights to use surface water and groundwater within their jurisdictional boundaries. The EPA has authority over USWD in relation to injection wells under the SDWA, although EPA can and does approve states and tribes to implement their programs in lieu of the Federal program. The BLM understands the importance of states and tribes regulating the use of groundwater within their jurisdictions and generally agrees with the commenters. However, the Mineral Leasing Act (30 U.S.C. 181, *et seq.*) gives the BLM the authority to lease oil and gas resources and to regulate the development of those leases. The Indian mineral statutes require the Secretary to regulate oil and gas drilling on Indian trust and restricted lands. This authority extends to the drilling of wells and to subsequent operations on those leases. Of primary importance when drilling or hydraulic fracturing a well is the protection of groundwater. The BLM agrees that regulation of groundwater quality is not within the BLM's authority; however, the protection of those water zones during well drilling and hydraulic fracturing is a key component of the BLM's jurisdiction and responsibility. No changes to the rule were made as a result of these comments.

The BLM received comments both supporting and objecting to paragraph (2) of the definition in the supplemental proposed rule, which included in the definition of usable water, zones in use for supplying water for agricultural or industrial purposes, regardless of TDS concentration, unless the operator could demonstrate that zone would not be adversely affected. The commenters objecting to this provision said that operators are not in a position to know whether aquifers are in actual use, or to prove that hydraulic fracturing operations would not harm the water user, and that BLM should not be making determinations about groundwater use or harm to users. The BLM agrees with those comments and removed paragraph (2) in the final rule as a result.

Commenters supporting paragraph (2) of the definition in the supplemental rule indicated that even if a zone is not required to be protected according to the definition of usable water, because that zone supplies water that is actually being used for agricultural or industrial purposes, the zone is self-evidently ''usable.'' The BLM agrees that an aquifer could be in actual use, even if it exceeds 10,000 ppm TDS. However, the rule defers to the state or tribal agency to make such determinations, as appropriate. Entities using water exceeding 10,000 ppm TDS may ask the appropriate state or tribal agency to designate that zone as usable water, in which case it would have to be isolated and protected from contamination during hydraulic fracturing.

One comment suggested that the BLM—not the operator—should make the determination that hydraulic fracturing would not harm aquifers in use, in paragraph (2) of the definition. The BLM did not make any changes to the rule based on this comment because proposed paragraph (2) has been deleted from the final rule based on other comments received.

The final rule includes a new paragraph (1)(ii) that includes in the definition of usable water ''[u]nderground sources of drinking water under the law of the state (for Federal lands) or tribe (for Indian lands).'' New paragraph (1)(ii) defers to designations of aquifers as sources of drinking by states and tribes, even if the aquifer would not meet the definition of USDW in EPA's regulations. That could occur, for example, if an aquifer cannot supply a public water system, but is used for drinking water by persons not connected to a public water system.

Several commenters found the definition of usable water in the supplemental proposed rule to be

confusing because of the way it was organized. The BLM agrees with this comment and has substantially revised the definition.

Several comments stated that the BLM should eliminate the usable water exemption for zones that states or tribes have designated as exempt (paragraph (4)(C) of the definition of usable water in the supplemental proposed rule). The issue raised by the commenters is that states and tribes typically base their exemptions on water that is unsuitable for drinking, livestock, or irrigation, and not on groundwater-dependent ecosystems. According to the comments, by adopting state or tribal designations, such aquifers would not have to be protected or isolated during hydraulic fracturing operations and this could damage or destroy the ecosystems that are dependent on them.

The BLM did not make any changes to the rule based on these comments for two reasons. First, while the BLM is responsible for preventing unnecessary or undue degradation of resources on public lands and exercising part of the Secretary's trust responsibility for Indian resources, designating the uses of aquifers is a matter for states and tribes, to the extent not otherwise inconsistent with the SDWA.

Second, the BLM does not agree with the commenter's assertion from a practical standpoint. The majority of groundwater-dependent ecosystems would be dependent on relatively shallow groundwater. Shallow groundwater (typically less than 1000 feet deep) is protected by surface casing, regardless. Some commenters said that the criterion of 10,000 ppm TDS exceeds the recommended standard for USDW. The EPA's definition is as follows: Underground source of drinking water (USDW) means an aquifer or its portion ''(a)(1) Which supplies any public water system; or (2) Which contains a sufficient quantity of ground water to supply a public water system; and (i) Currently supplies drinking water for human consumption; or (ii) Contains fewer than 10,000 mg/l total dissolved solids; and (b) Which is not an exempted aquifer'' (40 CFR 144.3).[6]

The rule seeks to protect usable water, which includes, but is not limited to, USDWs. In addition to public water supplies, there are many industrial and agricultural applications that can use water of up to or more than 10,000 ppm TDS. The final rule is not revised as a result of these comments.

Some commenters suggested that the 10,000 ppm TDS criterion could conflict with existing state groundwater standards. However, no commenter has explained how a requirement for oil and gas wells on Federal or Indian lands to verify isolation and protection of aquifers with up to 10,000 ppm TDS will preempt or interfere with states' or tribes' regulation of their ground water quality or quantity. If a state or tribe requires aquifers of lower quality to be isolated and protected, operators would need to comply with those requirements.

Several commenters offered their own definitions of usable water. One suggestion was to incorporate the entire EPA definition of a USDW instead of developing the BLM's own definition. The commenters stated that this would improve consistency and foster cooperation between the EPA and the BLM. The final rule references USDWs as one of the criteria that would constitute usable water. However, USDWs do not necessarily include water zones that have been designated by states or tribes as usable water for agriculture, industry, or other needs. The BLM believes that these zones are also worthy of protection. Therefore, the BLM did not accept this suggestion.

Other suggestions recommended defining usable water as only USDWs or zones designated by states or tribes. In the final rule, the BLM adopted this suggestion in part by eliminating paragraph (2) of the definition in the supplemental proposed rule, which would have also included zones being used for agricultural or industrial purposes, regardless of the TDS level.

One commenter stated that the BLM should require that casing used to isolate usable water be set at least 100 feet below the base of usable water to ensure the usable water zone is protected. Another commenter recommended that corrosive zones and flow zones also be isolated. The BLM did not make any changes to the rule based on this comment because the scope of this rule is hydraulic fracturing. Well drilling, including requirements for casing strings and zone isolation, is regulated by Onshore Order 2 and is based on site-specific downhole conditions.

One commenter recommended that the rule refer to ''established'' usable water zones to add clarity. The BLM did not make any changes to the rule based on this comment because the term ''usable water'' is clearly defined.

Hydraulic Fracturing

Numerous comments objected to the narrow focus of the definition of hydraulic fracturing and suggested that the BLM reinstate the broader definition from the May 2012 proposed rule. Some of the commenters stated that this rule needs to regulate well stimulation and acidization because these operations pose risks similar to those from hydraulic fracturing and because the existing regulations are inadequate to address these risks. The BLM did not revise the rule based on these comments. This rule specifically addresses risks posed by the combination of high pressures, chemical constituents, and procedures used to hydraulically fracture a well. Some commenters said that ''deep hydraulic fracturing'' should be exempt from this rule. The definition of hydraulic fracturing includes all hydraulic fracturing operations regardless of depth. The BLM requires protection and isolation of usable water regardless of depth of the well or depth at which hydraulic fracturing occurs. No changes to the rule were made as a result of these comments.

Several commenters said that the rule should be modified to redefine hydraulic fracturing. Commenters indicated that the definition should include a statement regarding applying fluids under pressure. The BLM agrees and has revised the rule as a result of these comments. The BLM believes that an integral part of hydraulic fracturing is the concept of the application of high pressure, and this position is confirmed by a review of technical literature on hydraulic fracturing as well as consultation with state regulatory agencies. The definition in the final rule has been modified accordingly.

Refracturing

Several commenters suggested that the definition of refracturing should be modified to exempt different stages of a multi-stage fracturing operation. The commenters were concerned that under the definition in the supplemental proposed rule, the BLM could consider each stage as a refracture operation, thereby requiring a separate permit. It is not the intent of the BLM to require a separate permit for each stage of a multi-stage hydraulic fracturing operation and final section 3162.3–3(i) is modified to reflect that a hydraulic fracturing operation is considered to be complete only after the last stage is completed. The BLM did not make modifications to the definition of refracturing as a result of these comments because the definition of refracturing was deleted in

[6] The EPA uses a TDS measurement of mg/l while the BLM uses ppm. While there is a slight difference in the measurements, for practical purposes they would yield very similar results.

the final rule for other reasons discussed in other sections of the preamble.

Several commenters suggested that the rule should be modified to treat refracturing differently than fracturing. The BLM disagrees with these comments because there is no practical purpose in distinguishing ''fracturing'' from ''refracturing.'' The permitting, operational issues, mechanical integrity test requirements, wellbore integrity, disclosure and possible variances for newly drilled wells and older previously fractured wells are the same; therefore, the BLM has removed the term and definition of refracturing in the final rule. The primary purpose of differentiating the two in the proposed rule was to recognize that the information required in section 3162.3–3(e) of the rule may not be available for older wells that would be ''refractured.'' However, upon further deliberation, the BLM determined that would be case for any well where approval for hydraulic fracturing was given subsequent to the drilling and completion of the well, regardless of whether or not the well had been hydraulically fractured previously. Therefore, the definition of refracturing is deleted from the final rule and all references to the term are removed. The requirements for hydraulic fracturing now apply uniformly to all fracturing operations that meet the definition in the rule. Section 3162.3–3(a) in the final rule was modified to allow for cases where hydraulic fracturing is approved subsequent to the drilling and completion of a well.

Several comments recommended that any hydraulic fracturing done within a certain amount of time of a previous fracturing job or that is done under similar conditions as the original hydraulic fracturing, should not be considered refracturing. The BLM did not make any changes based on this comment because the term ''refracturing'' was deleted from the final rule. This rule applies whenever pressure is used to fracture reservoir rock, regardless of how or when the operation occurs relative to a previous hydraulic fracturing.

One comment recommended specifically excluding ''enhanced oil recovery using carbon dioxide'' from the scope of this rule. However, if carbon dioxide or any other gas is used under pressure to fracture reservoir rock, the operation poses much the same risk as if the fracturing was done using a liquid as the fracturing fluid. The term ''fluid'' in the definition of hydraulic fracturing includes both liquids and gases. However, if the carbon dioxide or other fluid is injected not to fracture reservoir rock, but to stimulate production by other means, it would not be a hydraulic fracturing operation.

What constitutes ''completion?''

Several commenters said that the rule should be modified to define what constitutes the completion of hydraulic fracturing operations. The commenters indicated that the supplemental proposed rule would require the submittal of a completion report within 30 days of completion of hydraulic fracturing operations. The BLM did not revise the rule as a result of these comments. The BLM does not believe that a definition of ''completion'' is warranted in the context of these regulations. By definition, hydraulic fracturing ends when pressure is released for the last stage of the operation. It is at this point that the 30-day timeframe would begin for each well that is hydraulically fractured.

CEL Definition

Several commenters said that the term ''micro-seismograms'' should be dropped from the list of CEL tools discussed in supplemental section 3163–3(e)(2). Commenters indicated that the term ''micro-seismogram'' as currently used does not refer to evaluating cement quality and is therefore confusing when included in cement evaluation provisions. The commenters said that conventional cement bond logs (CBL) used for the purposes of evaluating cement integrity around casing can be displayed by a variety of methods. One of those techniques was termed ''micro-seismogram'' (MSG) and referred to the x-y presentation of the entire received signal. Another presentation method, the variable density log (VDL), only displays the amplitude of that signal. Either, or both, of these presentation methods can be used to evaluate the integrity of the cement bond to casing and formation. It is true that the term ''micro-seismogram'' has much broader implications than just cement evaluation, and the rule has been modified as a result of these comments. The CEL discussion has been removed from the regulatory text at proposed section 3162.3–3(e)(2) and placed as a unique definition in the final rule in section 3160.0–5. Further, the CEL definition has been revised to remove any references to ''micro-seismograms.'' The BLM believes that this clarifies the intent of the rule. Additionally, section 3162.3–3(e)(2)(i) has been revised to provide flexibility for the authorized officer to approve other appropriate cement evaluation methods or devices.

Type Well

Numerous commenters suggested that limiting the multiple well permitting, or type well, availability (referred to as Master Hydraulic Fracturing Plan in this rule) to a ''field'' in the definition was too restrictive and would nullify most of the benefits of a group submittal. Some commenters recommended that the BLM should better define what is meant by a ''field''. Commenters offered numerous suggestions on the extent of what an MHFP should cover including ''basin,'' ''pool,'' ''area,'' ''resource play,'' ''geographic area,'' ''geologic formation,'' ''section,'' ''unitized area,'' and ''county.'' The BLM agrees that the term ''field'' is potentially too limiting, and has deleted the requirement that wells included in the scope of an MHFP must be in the same field. However, the BLM disagrees that other terms such as those suggested would be preferable. Therefore, in the final rule, the criteria for the scope of an MHFP are wells that are geologically similar. Under this rule, the decision on the geographic or geologic extent of an MHFP is up to the field office reviewing the application and is based on local geology and drilling practices.

Several commenters asked if there would be any limits on the number of wells or the timeframe over which a multiple well permit could apply to other wells in a group submission for hydraulic fracturing. Under the final rule, the MHFP applies to any number of wells that meet the criteria in the definition of an MHFP and there is no specific timeframe for when wells under an MHFP must be drilled. Decisions regarding the applicability of wells under an MHFP are made at the BLM field office based on local geologic conditions and drilling practices.

Several commenters suggested two definitions of type well: One that would apply to permitting and one that would apply to operations such as running a CEL. The BLM did not revise the rule based on these comments because the term ''type well'' is deleted in the final rule. While the option of permitting a group of wells to be hydraulically fractured is retained in the final rule (now called an MHFP), the requirement to run a CEL on a type well is deleted and replaced with new requirements that will help to ensure adequate cementing and protection of aquifers (see final section 3162.3–3(e)).

The BLM received several comments stating that to be considered a type well, the operator must demonstrate successful replication of operations. No changes to the rule were made as a result of this comment because type

wells are deleted in the final rule. For group submittals under an MHFP, the BLM field offices have the discretion to require individual permitting of wells if the operator is unable to successfully replicate the operations described in an MHFP.

Section 3162.3–2 Subsequent Well Operations

Revised sections 3162.3–2(a) and (b) no longer contain reference to nonroutine or routine fracturing jobs. All other injection activities must still comply with section 3162.3–2, while hydraulic fracturing operations must comply with the requirements under revised section 3162.3–3.

Section 3162.3–3(a) Scope

Section 3162.3–3 lists the requirements concerning all hydraulic fracturing operations and paragraph (a) of this section establishes the conditions under which some wells may be exempted from certain requirements (or ''grandfathered'' in) as a way to transition from the previous regulations to these regulations.

The BLM made several changes to paragraph (a) of the final rule. The term ''refracturing'' is removed from the activities to which this section applies, because the term ''refracturing,'' and all references to it are deleted in the final rule.

In addition, a table is added to this section to clarify how the rule will be implemented with regard to wells in various stages of permitting, drilling, and completion. In general, any well that is drilled after June 24, 2015, or that was drilled more than 6 months before June 24, 2015 must comply with all parts of this rule, including the permitting, cementing, mechanical integrity testing, monitoring, handling and storage of recovered fluid, and reporting requirements. However, in order to reduce the economic and workload impacts of implementing this rule, there are three categories in which an operator can hydraulically fracture a well without submitting a new APD or NOI under sections 3162.3–3(c) and (d).

If an operator has an APD approved within the 2 years immediately prior to June 24, 2015, but has not commenced drilling operations, or has commenced drilling prior to June 24, 2015, but has not completed those operations, or has completed drilling operations within the 6 months immediately prior to June 24, 2015, and commences hydraulic fracturing operations within 90 days after June 24, 2015, the operator does not need to submit a new APD or NOI, or await the approval of the BLM before commencing hydraulic fracturing operations. The operator will need to comply with the provisions of paragraphs (b), (e), (f), (g), (h), (i), and (j) of the rule.

Those provisions are added to paragraph (a) to reduce costs and scheduling conflicts that could arise otherwise, while still ensuring safe and responsible hydraulic fracturing operations. Operators typically schedule hydraulic fracturing services 6 months in advance, though the requirements of every market are different. The BLM determined that the 90 days between publication of this the final rule and its effective date, plus an additional 90 days provided in paragraph (a) will be adequate to accommodate most potential scheduling conflicts. If the operator wishes to conduct hydraulic fracturing more than 90 days after June 24, 2015, under each of these three scenarios, however, the operator must comply with all of the paragraphs in this section, including submission of an application and obtaining approval from BLM to conduct hydraulic fracturing operations.

The final category in the table in paragraph (a) is wells for which drilling operations are completed prior to the effective date of the rule and hydraulic fracturing operations are conducted more than 6 months after the effective date of the rule. Operators would need to obtain the BLM's approval to conduct hydraulic fracturing operations, but not all operators would have the cementing verification records that are required for new wells. Rather than prohibit hydraulic fracturing of wells for lack of documentation not required at the time of construction, the rule provides in section 3162.3–3(e)(1)(ii) that operators must provide the relevant documentation that is available, and that the BLM may require additional testing or verifications on a case-by-case basis. For any existing well, an operator may request approval to conduct hydraulic fracturing operations by submitting an NOI under paragraph (c)(2) of the final rule.

Several commenters stated that the rule should be modified to further clarify the scope of this rule as it relates to injection activities. The commenters indicated that the provisions at this section cloud whether or not the majority of this rule applies to other injection or disposal operations. The BLM has revised the rule as a result of these comments. Injection activities have been removed from this section to avoid any confusion because injection is specifically addressed by existing section 3162.3–2. The BLM believes this change provides the necessary clarity regarding scope.

Section 3162.3–3(b) Isolation of Usable Water

The only change made to this section of the final rule is the deletion of the term ''refracturing'' because it, and all references to it, are removed from the rule. The BLM received no substantive comments on this section.

Section 3162.3–3(c) How To Apply for Hydraulic Fracturing Approval

This section requires an operator to submit a proposal for hydraulic fracturing to the BLM for approval. The operator may submit an application for a single well or for a group of wells under an MHFP. Prior to this rule, the regulations only required an NOI for ''non-routine'' hydraulic fracturing operations. The application requirement in the final rule is a new process. The request for approval of hydraulic fracturing may be submitted with either an APD or as an NOI.

Numerous changes were made to this section in the final rule. The description of how to apply for the hydraulic fracturing of multiple wells is moved from section (d) of the supplemental proposed rule to section (c)(3) of the final rule because it has more to do with the permitting process than the information that an operator must submit to the BLM. This section also references an MHFP instead of a type well, as proposed in the supplemental proposed rule. A discussion of the MHFP is given in the definitions section of the preamble.

The final rule revises some of the conditions under which an operator would have to resubmit a request for approval to hydraulically fracture a well. In the supplemental proposed rule (section 3162.3–3(c)(3)(i)), an operator would not have had to get approval to refracture a well if the refracturing was done within 5 years of the original fracturing approval. The premise of this requirement was that an MIT, required prior to fracturing under section 3162.3–3(f) of this rule, is typically valid for a period of 5 years in some state regulations (*e.g.,* Colorado, Montana, and Wyoming) for MITs. The BLM originally believed that because an MIT was required prior to the original hydraulic fracturing operation, it would not be necessary to re-run the MIT for a period of 5 years after that. However, upon further examination, the BLM determined that the 5-year timeframe for MITs in these state regulations is for the purpose of ensuring wellbore integrity for injection wells under the UIC program and has little relevance to hydraulic fracturing.

The BLM now believes that an MIT should be required prior to any hydraulic fracturing operation because of the high pressures and wellbore configurations used (such as a fracturing string) during hydraulic fracturing operations. Therefore, the final rule is revised to require approval and compliance with all sections of this rule for all fracturing operations, whether the well is being refractured or fractured for the first time (some hydraulic fracturing operations may not have to comply with sections (c), (d), or (e)—see the table in section (a)).

The supplemental proposed rule (section 3162.3–3(c)(3)(i)) would also have required the operator to resubmit an NOI for hydraulic fracturing if fracturing had not commenced within 5 years of the original approval. This requirement is deleted in the final rule because the BLM determined that as long as the proposal for hydraulic fracturing had not changed and there was no new information regarding the geology or potential impacts, the 5-year time frame was unnecessary. If the operator has significant new information about the geology of the area, the stimulation operation or technology to be used or potential impacts, it must submit a new NOI.

The final rule also eliminates paragraph (c)(3)(iii) in the supplemental proposed rule because it dealt with refracturing, a term that is deleted in the final rule along with all references to it.

Some commenters requested that the BLM eliminate the requirement for prior approval of hydraulic fracturing operations, suggesting that it would be unnecessary and costly. As stated in the background section of this rule, the BLM believes this rule is necessary, and prior approval is an essential part of this rule. The information included in the application allows the BLM to evaluate the proposal and to assess the potential impacts of the proposal. Prior approval allows the BLM to mitigate potential impacts through modification of the proposal or by attaching conditions of approval, after compliance with other statutes, such as NEPA.

Several commenters expressed concern that many of the items requested in the application, such as estimated total volume of fluid to be used and anticipated surface treating pressure range, are not known at the time the application is submitted. The BLM recognizes that exact volumes and pressures will not be known at the time the application is submitted, and the provisions at final section 3162.3–3(d) allow flexibility by requiring estimated or anticipated values. The items are necessary to allow the BLM to assess the proposal and ensure adequate storage for the fluids and proper casing strength to withstand the anticipated pressures.

Another commenter suggested eliminating some of the requirements needed for approval because Onshore Oil and Gas Order No. 1, Oil and Gas Operations; Federal and Indian Oil and Gas Leases; Approval of Operations (72 FR 10308) (Onshore Order 1), section III. D. 3, already requires them, and they are included with the APD. As stated in final section 3162.3–3(c)(1), the operator may submit the information required in paragraph (d) of this section with its APD. If the information is already included in the APD, it would not need to be repeated. Another commenter recommended eliminating some of the requirements in the application, since those items will be included in the subsequent report of operations. The information in the application is necessary for the BLM to assess the potential impacts of the proposed operation; additionally, some of the information requested in the application is identified as proposed or estimated. The information required in the Sundry Notice and Report on Wells (Form 3160–5) as a subsequent report (''subsequent report'') is the actual data from the completed hydraulic fracturing operations. No revisions to the rule were made as a result of these comments.

One commenter suggested that the BLM should allow a ''type frack'' approval instead of a type well approval. While the BLM is unclear what the commenter is specifically referring to, the BLM assumes that the commenter means that the hydraulic fracturing operation itself be approved for a group of wells. The BLM believes that the final rule's MHFP submission addresses this comment. The MHFP will allow an operator to describe a generic hydraulic fracturing process for a group of wells by providing the information required in section 3162.3–3(d) for those wells. No changes to the rule were made as a result of this comment.

Numerous commenters objected to permitting hydraulic fracturing for a group of wells. Some of the commenters stated that geologic conditions are too variable to allow any kind of group permitting while other commenters stated that the extent of the grouping should be explicitly defined and that strict limitations should be placed on the maximum allowable extent of an MHFP. The BLM disagrees with these comments because rigid, detailed criteria for what can be considered in an MHFP is not practical in a national rule of general applicability. The local field office must have some flexibility to define the extent of an MHFP based on local geology, drilling practices, and other applicable criteria. No revisions to the rule were made as a result of this comment. The benefits of an MHFP are that it allows the BLM to frontload its analysis of proposed hydraulic fracturing operations in a given area where the geologic characteristics for each well are substantially similar. It also provides early notice to the public of where such operations are being contemplated, and of the scale or intensity of the development. This frontloaded analysis provides the BLM with the tools necessary to perform a more comprehensive and streamlined review of hydraulic fracturing proposals, while maintaining the appropriate standards that ensure wellbore integrity and useable water protection.

Several commenters suggested that exploratory wells could be used as type wells because they were drilled vertically through the target formations and lithologic and reservoir data was obtained from them. Other commenters suggested that wells drilled by other operators could be used as a type well, while some commenters stated that type wells must be drilled by the same operator because drilling practices vary between operators. No revisions to the rule were made as a result of these comments because the requirement to drill a type well in order to receive approval to hydraulically fracture a group of wells with a single permit submittal is deleted in the final rule. The MHFP, which replaces the type well concept, is required to contain the information in sections 3162.3–3(d)(1) through (d)(7); however, the well integrity information required by section 3162.3–3(e) is not required to be included in the MHFP. Rather, the well integrity information required by section 3162.3–3(e) must now be submitted for each well 48 hours prior to commencing hydraulic fracturing. The MHFP only applies to wells drilled by the same operator. Section 3162.3–3(c)(3) states that ''the operator may submit a MHFP,'' thereby eliminating the possibility that an MHFP could apply to wells drilled by multiple operators. The BLM decided to restrict MHFPs to wells drilled by the same operator because doing otherwise would be difficult to administer and the BLM believes that drilling by different operators would only apply in rare instances.

Several commenters asked that the BLM allow the type well concept to include fracture modeling. The MHFP, which replaces the type well concept for permitting, requires all information required in sections 3162.3–3(d)(1)

through (d)(7) to be included in an MHFP. Final section 3162.3–3(d)(4)(iii) requires the operator to submit a map showing the estimated fracture direction and length. Although the final rule does not require fracture modeling, it would fulfill the requirements of this section. No revisions to the rule are made as a result of these comments because the rule already allows fracture estimations or modeling to be applied to a group of wells under an MHFP.

Several commenters stated that the CEL for a type well should be applicable to wells that meet the criteria for group approval, but were submitted under a separate NOI. The BLM did not revise the rule as a result of these comments because the requirements to run CELs on type wells and submit the results of the CEL as part of the group approval package are eliminated in the final rule. Several comments suggested that for group hydraulic fracturing submissions, the operator should be required to certify that the cement, fracturing fluids, and drilling practices for all wells included in the submission comply with the information submitted in the MHFP. The BLM did not incorporate this suggestion into the final rule because a certification is not necessary to ensure compliance with the approved NOI for multiple wells, and because information related to well integrity is now required for each individual well. Any unapproved deviation from the approved NOI and MHFP would be considered a violation and would be enforced under existing subpart 3163, Noncompliance, Assessments, and Penalties. One comment said that the option to permit multiple wells will not help operators who do not drill wells in groups. In the final rule, MHFPs will primarily streamline the permitting process for operators who are hydraulic fracturing multiple wells within an area having similar geology. No revisions to the rule were made as a result of this comment. The fact that not every operator can take advantage of a provision of the rule designed to streamline the process does not make that provision undesirable or unnecessary.

Section 3162.3–3(d) Application for Hydraulic Fracturing

This section specifies that the application must include:

- Information about the geology and the formation, confining zones, usable water (depths estimated), faults and fractures, location of water supply, and transportation method. This information is generally consistent with the requirements in Onshore Order 1;
- Information about the proposed hydraulic fracturing operation, the volume of fluid to be used, the maximum anticipated surface pressure, wellbore trajectory, the estimated direction and length of fractures, and the locations, trajectories, and depths of existing wellbores within a half mile of the wellbore; and
- Information about how the operator will handle recovered fluids, the estimated volume of fluids to be recovered, and the proposed disposal method.

Operators planning to conduct hydraulic fracturing should already possess that information because hydraulic fracturing is a complex operation and would only be conducted pursuant to a plan for performance.

The final rule incorporated several revisions to this section. Requirements relating to an MHFP (referred to as a submission for a group of wells in the supplemental proposed rule) are moved from section (d) to section (c) because section (c) has to do with how to apply for hydraulic fracturing approval. A discussion of the MHFP is given in the definitions section and the response to comments on the type well in the proposed rule are addressed in the discussion of section (c).

Section 3162.3–3(d)(1) in the supplemental proposed rule would have required the operator to identify the geologic formation that would be hydraulically fractured, including measured depths of the top and bottom of the formation. The final rule requires that the operator identify both the measured depths and the true vertical depths of the formation to be hydraulically fractured (paragraph (d)(1)(i)). This section of the final rule also requires the operator to identify the measured and true vertical depths of the confining zone (paragraph (d)(1)(ii)).

The requirement to identify usable water zones is moved from paragraph (d)(2) in the supplemental proposed rule to final paragraph (d)(1)(iii), along with a new requirement to state the measured and true vertical depths of the top and bottom of all usable water zones. The requirement to identify occurrences of usable water with a drill log in the supplemental proposed rule is deleted in the final rule. The BLM determined that it is not always necessary or practical to require a drill log to identify usable water and that there is no reason to be prescriptive about how usable water is identified. The BLM made these changes for several reasons. First, the BLM believes that by grouping all informational requirements relating to wellbore geometry into a single section, the clarity of the regulation is improved. Second, the BLM added a requirement to identify the ''true vertical depth'' of tops and bottoms of all the geologic zones in order to ascertain the vertical separation between zones. Also, under the final rule, the operator is required to identify the confining zone that is capable of preventing fluid migration between the zone that will be hydraulically fractured and any usable water zones.

Section 3162.3–3(d)(2) is revised in the final rule to require the operator to submit a map showing any faults or fractures within one-half mile of the wellbore trajectory that may transect the confining zone. This will allow the BLM to identify and analyze during the permit review process any potential for hydraulic fracturing fluid to migrate outside of the zone being fractured.

Section 3162.3–3(d)(3) in the supplemental proposed rule is separated in the final rule to improve clarity. This section in the supplemental proposed rule contained requirements for down-hole information (*e.g.,* depth of perforations, estimated pump pressures) as well as information on water supply and transportation routes. In the final rule, section (d)(3) is now specific to water supply and transportation routes; downhole information is moved to section (d)(4), which is specific to the technical aspects of hydraulic fracturing.

Several changes are made to supplemental proposed rule section 3162.3–3(d)(4) to improve clarity and to identify potential ''frack hits.'' ''Frack hit'' is a common term for a hydraulic fracturing operation that causes an unplanned surge of pressurized fluid into another well, often resulting in surface spills. The supplement rule required three different pressures to be included in the application: Estimated pump pressure (paragraph (d)(3) in the supplemental proposed rule), anticipated surface treating pressure range (paragraph (d)(4)(ii) in the supplemental proposed rule), and maximum injection treating pressure (paragraph (d)(4)(iii) in the supplemental proposed rule). In the final rule, those three pressures are replaced with a single pressure to be reported: The maximum anticipated surface pressure that will be applied during operations. The BLM determined that this was the clearest and most useful pressure because this will be the pressure at which the MIT must be run under section 3162.3–3(f) of the rule. This change is also made to eliminate the term ''treating,'' which may not be universally understood.

Section 3162.3–3(d)(4)(iii) in the supplemental proposed rule would have required the operator to submit the estimated fracture direction, length, and height, along with a map showing the estimated fracture propagation. The final rule adds several additional requirements to this section that will allow the BLM to determine during the permit review process the potential for ''frack hits.'' In addition to the fracture propagation (including direction and length), the map must also show the trajectory of the wellbore into which hydraulic fracturing fluid will be injected and the trajectory of all existing wellbores and trajectories within one-half mile of the wellbore that will be used for hydraulic fracturing. Additionally, the required map must identify the true vertical depth of each wellbore shown on the map.

Section (d)(4)(v) in the supplemental proposed rule, requiring the estimated vertical distance to the nearest usable water aquifer above the fracture zone, is reworded for clarity. In the final rule, section (d)(4)(iv) requires the estimated minimum vertical distance between the top of the fracture zone and the nearest usable water zone.

Section (d)(5) in the supplemental proposed rule, regarding the handling of recovered fluid, is reworded in the final rule to conform to changes made to section (h). The only period for which information on handling recovered fluid is necessary under the final rule is the period between the completion of hydraulic fracturing operations and the approval of a water disposal plan under Onshore Order 7. A complete discussion of this change is given under section (h) of this preamble.

Section (d)(5)(iii) in the supplemental proposed rule is clarified in the final rule by better defining ''handling'' versus ''disposal.'' In the supplemental proposed rule, disposal included injection, hauling by truck, or transporting by pipeline. The BLM recognizes that hauling by truck or transportation by pipeline are not disposal methods, but transportation methods. In the final rule, the disposal options include injection, storage, and recycling.

Section (d)(6) of the final rule is added to include additional information requirements if the operator requests approval for hydraulic fracturing in an NOI instead of in an APD. One of these requirements (section (d)(6)(i)) is a surface use plan of operations if the hydraulic fracturing operation would include additional surface disturbance. If the request was received as part of an APD, the surface use plan of operations would already be included.

The other requirement is, by reference to paragraph (e), documentation that an adequate cement job was achieved for all casing strings designed to isolate usable water zones.

Pre-Disclosure

A few commenters asked that the volume and chemical composition of flowback water be disclosed in the permit application. Section 3162.3–3(d)(5)(i) of the final rule requires the operator to provide the estimated volume of fluid to be recovered in its application. The projected chemical composition of this fluid is not required. Providing the chemical composition of the recovered fluid would require speculation as to the chemistry of fluids in the target zone, and their reactions, if any, with the hydraulic fracturing fluids and therefore would be impractical to request, and not likely to be useful. The BLM has determined that operators often change the chemical composition of hydraulic fracturing fluids after approval of fracturing operations, in response to such factors as availability of chemicals, changes in vendor, and unexpected geologic conditions. Thus, the reliability of the pre-operational estimated composition of flowback fluids likely will not be known with precision at the application stage. It is important at the approval stage, however, for the operator to show that it has an adequate plan to manage and contain the recovered fluids that would prevent them from contaminating surface water or groundwater without regard to their specific chemical composition. The rule presumes that all recovered fluids would pose hazards to surface or ground water if they are not properly isolated. No revisions to the rule were made as a result of these comments.

Some commenters requested that the BLM require up-front disclosure of the chemicals proposed for use in the hydraulic fracturing fluid and that this information be publicly available. Commenters asserted that chemicals must be disclosed both before and after well stimulation in order to achieve the BLM's goals of protecting public health and the environment. The rule is not revised based on these comments. Analysis of the impacts from hydraulic fracturing is done as part of the NEPA analysis conducted prior to the issuance of permits. The exact composition of the fluid proposed for use is not required because the BLM's goal is to ensure that operators contain all fluids regardless of their composition. All fluids are conservatively treated as if they are hazardous and need to be contained. In undertaking NEPA analysis to support the Bureau's decision to issue a permit, the BLM will assume that the chemicals used in conducting hydraulic fracturing operations may be hazardous. The BLM believes that the post-fracturing disclosures and certifications of chemicals and additives provide adequate information for other purposes, such as to inform the community of the chemicals involved, and to assist in clean-up of any spills.

Several commenters suggested that all of the information required in the subsequent report should be disclosed in the application for hydraulic fracturing approval. The BLM did not make any changes to the rule as a result of these comments because not all of the information required in the subsequent report is relevant or available at the time the operator submits the application. When the proposal for hydraulic fracturing is submitted with an APD, items such as well logs are not available because the well has not yet been drilled.

The original proposed rule required the NOI to contain a certification signed by the operator that the proposed treatment fluid complies with all applicable permitting and notice requirements as well as all applicable Federal, tribal, state, and local laws, rules, and regulations. That requirement was deleted in the supplemental proposed rule. Some commenters supported eliminating this requirement while other commenters requested that the originally proposed requirement be reinstituted. As was stated in the preamble of the supplemental proposed rule, the BLM believes that requiring this certification after the operator has completed hydraulic fracturing operations (see final section 3162.3–3(i)(8)) adequately protects Federal and Indian lands and resources and, therefore, the burden on industry of providing the information and on the BLM of reviewing that information at the application stage is not justified. The commenters requesting the requirement be reinstituted stated the rule removes the first layer of accountability for industry by not even requiring them to say they will comply with permitting, and the lack of certification removes a tool to hold operators accountable to follow the regulations. The BLM disagrees. The operators are required to comply with all applicable laws and regulations, regardless of when the information is submitted. A certification in the NOI does not add any value to the permit and lack of a certification in the notice does not restrain enforcement in the future. Therefore, no revisions to the

rule are made as a result of this comment.

Several comments suggested that the BLM allow a ''master chemical plan'' to be submitted for wells that are proposed for hydraulic fracturing in the same field. According to the commenter, this plan could be used for routine hydraulic fracturing operations to help streamline the permitting process. However, the BLM is not requiring chemical disclosure prior to hydraulic fracturing, so a specific ''master chemical plan'' is unnecessary.

Confining Zone

Numerous comments said that the rule should be modified to add a definition of ''confining zone.'' Additionally, the commenters indicated that the NOI required at 43 CFR 3162.3–3(d) should include the identification of an impermeable confining zone that would protect water sources from vertical migration of hydraulic fracturing fluids and associated brines. The BLM agrees with these comments. The final rule includes a definition of confining zone and a requirement that operators identify the measured and true vertical depths of the top and bottom of the confining zone in their permit application. In addition, in the final rule the operator must identify all known faults and fractures within one-half mile of the wellbore that transect the confining zone. These additions will allow the BLM to further ensure that the hydraulic fracturing fluid will not migrate outside of the intended zone in order to protect usable water.

Several comments asked that the BLM specify a minimum ''vertical buffer'' between the zone that is to be hydraulically fractured and the deepest aquifer. The BLM did not include this requirement in the final rule because the BLM must maintain the flexibility for field offices to review hydraulic fracturing applications on a case-by-case basis and apply site-specific conditions of approval. A minimum vertical distance that is appropriate in one area might be inadequate or overly restrictive in other areas based on the intervening geology. Furthermore, fracking technologies are likely to continue to improve an operator's control over the propagation of fissures.

Master Drilling Plan

Several commenters said that the rule should be modified to allow operators to submit a field-specific casing design and cementing plan and subsequently submit verification of a successful cement job. The BLM did not revise the rule as a result of these comments. This comment addresses the concept of a Master Development Plan (MDP) that is already described in and provided for by Onshore Order 1 for newly drilled wells. The MDP addresses the casing and cementing design of all of the wells within that MDP. Drilling operations and the associated MDP process is outside the scope of this rulemaking.

One commenter suggested that fracture modeling could be done for a group of wells instead of requiring a model for every well. The BLM did not revise the rule as a result of this comment for two reasons. First, neither the proposed rules nor the final rule require fracture modeling. Both allow for submittal of ''estimated'' fracture data. Second, fracture estimates for zones that are in substantially similar geologic regimes could be included in the MHFP under final section 3162.3–3(c).

Use of Estimates

One commenter expressed concern with the use of the term ''estimate'' in the supplemental proposed rule as it pertains to operator submissions under section 3162.3–3(d). The commenter stated that the BLM would be unable to ensure the protection of usable water zones if the operator is allowed to submit estimates. The BLM disagrees with this comment. This provision allows the operator to estimate some items, such as the depth of usable water and the pump pressure, in the APD and NOI. Allowing estimates in the APD and NOI instead of actual information does not compromise the safeguards for protection of usable water. At the time the APD and NOI is submitted, in many instances some of the required information cannot be known for certain, because the well has not yet been drilled. The estimates provide the BLM with sufficient information to evaluate the potential impacts of the planned operation and to ensure that usable water zones are adequately protected. No revisions to the rule are made as a result of this comment.

Changes From Original Proposed Rule

One commenter expressed concern that the changes made to the requirements in the NOI from the original proposed rule to the supplemental proposed rule do not seem designed to provide adequate safeguards for ecological and human resources. The BLM disagrees with this comment. The changes from the original proposed rule to the supplemental proposed rule were based on the comments received from individuals, Federal and state Governments, and agencies, interest groups, and industry representatives. The changes to each section and the rationale for the changes were discussed in the preamble of the supplemental proposed rule. One of the primary goals of the rule is to provide adequate safeguards for resources in and on the public lands and tribal lands, and thus for the persons who use those resources. The BLM believes the changes proposed in the supplemental proposed rule and the provisions of the final rule, along with existing processes for reviewing and approving oil and gas development proposals, accomplish that goal.

Permitting Multiple Wells With an NOI

The supplemental proposed rule would have allowed an NOI to be submitted for a group of wells within the same geologic formation. One commenter suggested that the rule be required to specify the location of all wells where fracturing will take place. The commenter was concerned that if this is not specified, and notice is submitted in the form of a Sundry Notice for a group of wells, the location of each well will not be clear. The BLM disagrees with the commenter. Operators use Sundry Notices (Form 3160–5) to request approval to conduct operations and to subsequently report on operations after they are finished. Sundry Notices are used for all operations, not just hydraulic fracturing, and have been required for many years. The Sundry Notice form itself requires the operator to identify the lease number, the well number, and the location of the well. If a Sundry Notice is submitted for multiple wells, the Sundry Notice must contain a list of all of the wells including the lease number for each well and the legal land description of the location of each well. While this is not explicitly stated in the rule, the Sundry Notice form requires it. No revisions to the rule were made as a result of this comment.

Submission of State/Tribal Data

Numerous commenters said that in states where there is already a regulatory process for hydraulic fracturing, an operator should be allowed to submit the same information to the BLM as it does to the state. Both the supplemental and final rules include provisions that address the commenters concern. The first (section 3162.3–3(d)) allows information submitted in accordance with state law to be submitted to the BLM if the information meets the standards of this rule. The second (section 3162.3–3(k)) allows the BLM to issue a statewide or regional variance to use particular state or tribal regulations and processes for permitting hydraulic fracturing

operations if they meet or exceed the objectives of this rule. Because the commenter's concerns were already addressed in the rule, no changes were made as a result of these comments.

One commenter requested that the BLM clarify the following statement in section 3162.3–3(d): ''If information submitted in accordance with state (on Federal lands) or tribal (on Indian lands) laws or regulations meets the standards prescribed by the BLM, such information may be submitted to the BLM as part of the Sundry Notice.'' This language has been clarified in the final rule. Many of the comments received in response to the initial proposed rule and the supplemental proposed rule were critical of duplication between state or tribal regulations and the supplemental proposed rule. The statement in this section is meant to address those concerns and minimize any duplication. If the information submitted to states or tribes meets the standards in this section, the operator does not need to generate any new information. Operators may submit the information that was generated to meet the state or tribal requirements to the BLM. To better reflect the BLM's intent, the statement has been modified in the final rule for additional clarity, although no substantive change was made to the statement.

Restructure Items for Clarity

Some commenters recommended that sections 3162.3–3(d)(3) and 3162.3–3(d)(4) be restructured to add clarity to the requirements. Commenters said that the information required in section 3162.3–3(d)(3) of the supplemental proposed rule included the proposed measured depth of the perforations or the open-hole interval and included information concerning the source and location of the water to be used during hydraulic fracturing. While this information is still needed, the items are distinct, and therefore should be separate requirements. The BLM agrees with these comments and sections 3162.3–3(d)(3) and 3162.3–3(d)(4) are restructured in the final rule. Section 3162.3–3(d)(3) now requires information concerning the source and location of the water supply. In addition, the requirement for the measured depth of the proposed perforated or open-hole interval is moved to section 3162.3–3(d)(4)(v). The information regarding the proposed perforated interval is now a distinct requirement, and this information relates more closely with the other information required by section 3162.3–3(d)(4).

Identification of Usable Water

Some commenters expressed concern that the requirement to identify usable water zones placed an increased and substantial burden on operators. The commenters stated that the current practice is not for operators to identify ''usable water'' zones for protection and then submit the information to state oil and gas agencies or BLM offices for approval, but instead for these agencies to prescribe to operators which zones must be protected. The commenters' perception of existing requirements is incorrect. Section III.D.3.b. of Onshore Order 1 requires operators to provide the estimated depth and thickness of formations, members, or zones potentially containing usable water, and the operator's plans for protecting such resources. Section III.B. of Onshore Order 2 requires that the proposed casing and cementing programs be conducted as approved to protect and/or isolate all usable water zones. It goes on to require that determination of casing setting depth must be based on all relevant factors, including usable water zones. It also requires that all indications of usable water be reported. This final rule requires the operator to identify the measured or estimated depths (both top and bottom) of all occurrences of usable water. This requirement is consistent with the existing requirements in Onshore Orders 1 and 2 and does not place an increased burden on the operators. No revisions to the rule were made as a result of these comments. The BLM agrees, however, that in many instances state or tribal oil and gas regulators, or water regulators, will be able to identify for operators some or all of the usable water zones that will need to be isolated and protected.

One commenter recommended that the operator must inform the BLM of the locations, geologic formations, and depth of the usable water zones prior to initiating fracking operations. The commenter stated that this is of prime importance to people living in the vicinity of fracking and they need some certainty that the fracking operations will not impact their water resources. The BLM agrees. Some of this information is already required of the operators prior to drilling the well. Section III.D.3.b. of Onshore Order 1 requires operators to provide the estimated depth and thickness of formations, members, or zones potentially containing usable water, and the operator's plans for protecting such resources. The BLM uses this information in the evaluation of the well proposal to ensure that usable water zones are adequately protected by the proper placement of casing and cement. Since this information is already required to be submitted with the APD, it is not repeated in the rule. No revisions to the rule were made as a result of this comment. However, the information that would be required to be submitted as part of this rule will be made available to the public, consistent with the requirements of Federal law.

Some commenters recommended using a research agency such as the United States Geological Survey (USGS) to identify usable water. Other commenters recommended developing Federal and state partnerships to map water resources. The BLM agrees that those entities can be helpful in identifying usable water. However, the BLM cannot mandate their participation. We note that the use of information developed by the USGS or state agencies is acceptable information for operators to use to identify usable water. In many areas, the USGS, state agencies, or tribal agencies have developed water resource maps. Operators may use this information, along with any other available information, including logs from nearby wells, to identify usable water zones. No revisions to the rule were made as a result of these comments.

Section 3162.3–3(d) in the supplemental proposed rule required that the NOI include the measured or estimated depths (both top and bottom) of all occurrences of usable water by use of a drill log from the subject well or another well in the vicinity and within the same field.

Many commenters expressed concern that identification of usable water by drill log is very difficult and expensive. Other commenters stated that the BLM is incorrect to assume that drill logs can be used to identify usable water. The commenters stated that these logs do not directly measure water quality or TDS.

Operators often run resistivity logs for intermediate and production casing, and these logs might allow the qualitative identification of high salt content zones. These logs do not, however, directly measure TDS, and there are too many variables for the signature these logs record to be converted into accurate TDS data. Some commenters expressed concern that the term ''drill log'' is very broad and should be specifically defined. The BLM agrees with these comments. It was not the BLM's intent to mandate a prescriptive method of estimating the depths of usable water. Final section 3162.3–3(d) has been revised and the phrase ''by use of a drill log from the subject well or another well in the vicinity and with the same field,''

has been deleted in the final rule. This change will make the requirement less prescriptive, and it will make it consistent with the existing requirements in section III.D.3.b. of Onshore Order 1.

Section III.D.3.b. of Onshore Order 1 requires operators to provide the estimated depth and thickness of formations, members, or zones potentially containing usable water, and the operator's plans for protecting usable water. It does not specify what information the operator must use to determine the estimated depth of usable water. The expectation is that the operator will use the best available information to estimate the depths of usable water. The expectation in this final rule is the same. Available information could include data and interpretation of resistivity logs run on nearby wells. In many areas, information can be obtained from state or tribal regulatory agencies. Many states have requirements that protect known water zones. For example, the North Dakota Industrial Commission requires that surface casing be set and cemented at a point not less than 50 feet below the base of the Fox Hills Formation (N.D. Admin Code 43–02–03–21 (2012)). The Wyoming Oil and Gas Conservation Commission uses regional water studies to identify known zones with potential to contain usable water such as the Fox Hills Formation in the Powder River Basin of Wyoming and bases its casing requirements on such information. Other information on usable water may be available from local BLM offices. For example, the BLM Pinedale Field Office Web site provides information regarding usable water. That Web site also provides typical casing and cementing designs for different areas under jurisdiction of the Field Office.

Some commenters stated the rule will impose additional casing and/or cementing costs on operators because, unlike Onshore Order 2, the proposed rule would require cement behind pipe across all usable water zones. The commenters state that even though the proposed rule uses the word ''isolate,'' it uses the word differently than Onshore Order 2. The commenters go on to say this is clear from the requirement to run a CEL for each casing string that protects usable water. The BLM disagrees with these comments. The requirements in the supplemental proposed rule are consistent with the requirements in Onshore Order 2. For many wells, the isolation of usable water will be accomplished by setting cement across the usable water zones. However, in some wells, cementing across the usable water zone may not be feasible. In these situations, isolation of the usable water zones from any hydrocarbon bearing formations is warranted. The BLM modified some of the requirements in the final rule to eliminate confusion over the requirement to isolate and protect usable water. In the final rule, a CEL is not required on each string of surface casing that isolates usable water if certain performance standards are met. A few examples of performance standards to be met include cement return to surface, a successful formation integrity test confirming good cement bonding, and no lost circulation or other cementing problems. For wells where a CEL is required, the operator must run a CEL to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone. Meeting this requirement would demonstrate isolation and protection of the usable water zone from the zone to be hydraulically fractured.

Another commenter recommended that all cementing requirements be eliminated from the rule. The commenter asserts that cementing operations are part of drilling operations and information is already submitted to state regulatory agencies for such operations. The commenter asserted that cementing operations have little to do with hydraulic fracturing. The BLM disagrees with this comment. While cementing information is already submitted to state regulatory agencies and the BLM, this rule expands on the requirements by including cement monitoring, cement remediation, and cement evaluation which are all related to protection of usable water from hydraulic fracturing operations. No revisions to the rule were made as a result of this comment.

Identification of Water Sources and Access Routes

Section 3162.3–3(d)(3) requires the operator to identify the anticipated access route for all water planned for use in fracturing the well. One commenter recommended that the BLM require the disclosure of all proposed and existing access routes, including those used to transport proppant (sand), equipment, and chemicals for use in the hydraulic fracturing fluids. The BLM disagrees with this comment. The BLM already requires the operator to submit its proposed access route to the well location in the APD (see Onshore Order 1, section III.D.4.a.). In this rule, the BLM requires the operator to specifically identify the access route for the water to be used in fracturing operations because the access route from the water source may be potentially different from the route approved in the APD. The BLM uses this information provided by the operator to determine potential environmental impacts under NEPA and if a right-of-way to cross public lands is needed, and to assure compliance with other statues such as the FLPMA. All other travel to and from the location should be on the route described in the approved APD. However, the BLM has no authority to require its approval for transportation not on public lands. No revisions to the rule were made as a result of this comment.

Some commenters disagreed with the requirement to provide information concerning the water source and location of water supply because they were unsure what the information would be used for, and others were concerned that the BLM would disapprove or condition the withdrawals, in violation of state authority over water use. Other comments stated that the water source could change and filing a Sundry Notice for the BLM to approve the change is burdensome. The BLM requires this information about the proposed source of the water in order to conduct and document an environmental effects analysis that takes a hard look at the impacts of its Federal action and meets the requirements of NEPA. The BLM has always required operators to file a Sundry Notice for changes to the approved permit—whether it is an APD or an NOI for hydraulic fracturing or for other operations requiring BLM approval. No changes to the final rule were made as a result of these comments.

Some commenters stated that information regarding the water source would have already been provided as part of the APD. The BLM agrees in part. Section III.D.4.e. of Onshore Order 1 requires the operator to identify the location and types of water supply to be used during the drilling operations in the APD. That water supply for such things as mixing drilling mud and cement may or may not be the same as the water supply for hydraulic fracturing operations, which often needs much greater quantities of water, but may be able to use water of different quality. Since the water supply may be different, this information must be included in the application for hydraulic fracturing. No revisions to the rule were made as a result of these comments.

One commenter expressed concern about identifying the source and

location of reused or recycled water. The commenter stated that they will often send produced waters to a centralized recycle or reuse facility. These waters will not have one single source, and once commingled, could not readily be identified as coming from one particular well. The rule does not require the sources of water that the reuse or recycling facility receives. If the water is coming from a centralized recycling facility, identifying the water as reused or recycled, and providing the location of the recycling facility is sufficient for the information required in the permit application.

One commenter requested clarification of the term ''water supply.'' The commenter said it was unclear whether the requirement was requesting the source and location of the water to be used in the hydraulic fracturing operation or if the requirement was requesting the source for drinking water/agricultural water/industrial water in the area. The requirement is referring to the source water used as a base fluid in the hydraulic fracturing operations.

Another commenter recommended that the BLM strengthen the language regarding identification of the water supply to say ''must'' instead of ''may.'' The language in the rule requires the applicant to provide information on the source and location of the water supply, ''which may be shown by quarter-quarter section on a map or plat, or which may be described in writing.'' The BLM believes the rule is clear as written. The applicant must provide the information requested, but they have the option of either showing it on a map or plat, or by describing it in writing. No revisions to the rule were made as a result of these comments.

Hydraulic Fracturing Plan—Water Volume

The BLM received one comment suggesting that the BLM should require the operator to provide the volumes of water to be used during hydraulic fracturing operations in its application. Another commenter asked if section 3162.3–3(d)(4)(i) refers to the volume of hydraulic fracturing fluid or the volume of water from the water supply. Section 3162.3–3(d)(4)(i) requires the submission of the estimated total volume of fluid to be used. This requirement does not specifically require the volume of water. However, since most all of the fracking fluid is water (assuming a water-based fracturing fluid), it is a good indicator of the estimated volume of water to be used. Some hydraulic fracturing operations, however, use other fluids such as nitrogen or carbon dioxide. For these operations, the estimated total volume of fluid would include all fluids, including the nitrogen or carbon dioxide.

Hydraulic Fracturing Plan—Pressures

Several comments suggested clarification of the pressures required in the permit application (supplemental proposed rule section 3162.3–3(d)). In the supplemental proposed rule, paragraph (d)(3) would have required ''estimated pump pressures,'' paragraph (d)(4)(ii) would have required the ''anticipated surface treating pressure range,'' and paragraph (d)(4)(iii) would have required the ''maximum injection treating pressure.'' The commenters expressed some confusion over the need for the three different pressures and also some confusion over the terminology. The BLM agrees with these comments and consolidated the requirements in proposed paragraph (d) to one requirement to provide the ''maximum anticipated surface pressure that will be applied during the hydraulic fracturing process'' (final section 3162.3–3(d)(4)(ii)). The primary reason for requesting this information was to ensure the pressures used during the hydraulic fracturing process were no greater than the pressures used in the MIT (see section 3162.2–2(f)) prior to hydraulic fracturing and to ensure that the wellbore is adequately designed to handle these pressures. Therefore, the requirement for ''pressure ranges'' in the supplemental proposed rule (paragraph (d)(4)(ii)) is not necessary—only the maximum pressure is required for the intended purpose. The phrase ''treating pressure'' is eliminated because the meaning of the word ''treating'' may not be universally understood.

Also in response to these comments, the BLM changed the wording in sections 3162.3–3(f)(1) and (i)(3) of the final rule to match the terminology used in section 3162.3–3(d)(4)(ii).

Hydraulic Fracturing Plan—Fracture Data

The BLM received several comments regarding the submittal of fracture design information. Some commenters fully supported the requirement. These commenters indicated the data is necessary for BLM evaluation. These commenters were in general agreement with the provisions of this section, *e.g.,* fracture length, height, and direction data can be actual, estimated, or calculated.

Some commenters objected to allowing fracture design estimates instead of actual fracturing data and other commenters requested that the data submitted include three dimensional reservoir and fracturing modeling. The primary objective of the additional requirements requested by the commenters was to give the BLM better information to ensure that the fractures would not extend into any usable water zones or intersect other wells (*i.e.,* ''frack hits''). The BLM did not make any changes to the rule as a result of these comments for several reasons. First, information presented in an application is only estimated because actual conditions encountered during the drilling and hydraulic fracturing process can change significantly from the conditions anticipated in the application as operations progress. Therefore, any modeling would be calculated from best estimates of conditions, introducing significant uncertainty in the calculations as to render them no more useful than the estimated fracture data required in the proposed rule. Second, the intent of requiring this information in the hydraulic fracturing application is to give the BLM a general idea of the extent of the fractures as a tool to identify potential hazards such as other wells and to assure that there will be adequate margins of protection for the closest zone containing usable water. Exact calculations, speculative or not, are not required under this section of the final rule. Although no changes to the rule were made directly as a result of these comments, the final rule does expand the informational requirements relating to fractures and potential frack hits. Under the final rule, operators must submit the estimated fracture data on a map that also shows all known wellbore trajectories within one-half mile of the well that is proposed to be fractured.

The BLM also received numerous comments objecting to the requirement to specify the fracture length in the application for hydraulic fracturing. Several commenters stated that expensive modeling would be required to estimate fracture length. As discussed earlier, although it can be used, modeling is not required. The intent of this requirement is to provide the BLM with enough information about the proposed hydraulic fracturing operation that potential hazards, such as other wells and fracture propagation into usable water zones, can be identified and mitigated. Estimated fracture dimensions are sufficient to meet this intent. Because the rule already requires ''estimated or calculated'' fracture data, no changes to the rule were made as a result of the comments.

A few commenters expressed concern about confidentiality of the information

in providing the required details on the estimated fracture length, height, and direction. The BLM believes that the submission of these estimated values would not routinely meet any of the criteria within the Freedom of Information Act regulations (43 CFR part 2) which would require such information to be held as confidential information. The BLM did not revise the rule as a result of these comments.

One commenter said that fracture data has nothing to do with wellbore integrity or protecting groundwater. The BLM disagrees. One of the purposes of submitting fracture estimates is to allow the BLM to analyze hydraulic fracturing proposals for potential interference with other wells. There is a potential for groundwater contamination if high-pressure hydraulic fracturing fluid intersects the drainage radius of another wellbore. The BLM did not revise the rule as a result of these comments.

Meaning of ''Wellbore''

In response to comments, the BLM determined that it should be made clear that the rule was not requiring only the locations of vertical segments of wells. The rule at paragraph (d)(4)(iii)(C) requires submission of a map showing the location of all wellbores within one-half mile horizontally of the wellbore to be hydraulically fractured. A wellbore is not merely the vertical component of a well. A wellbore is commonly understood to be ''[t]he hole made by a well.'' Williams & Myers Manual of Oil & Gas Terms, p.1173 (10th ed. 1997). It thus includes all vertical, directional, and horizontal legs of a well. Thus, any part of an existing well that comes within one-half mile horizontally of the trajectory of the well to be hydraulically fractured (regardless of any difference in depths) must be shown on the map submitted with the operator's application. The information will allow the authorized officer to work with the operator to prevent ''frack hits.''

Distance to Aquifers

The BLM received a few comments regarding the vertical distance from the intended hydraulic fracture zone to the nearest aquifer. One commenter recommended that the rule be revised to require the operator to report the vertical distance from the intended hydraulic fracture zone to the nearest aquifer. The BLM did not revise the rule as a result of these comments since this is already required in final section 3162.3–3(d)(4)(iv) for all requests for approval of hydraulic fracturing.

Some commenters recommended that the rule be modified to clarify the requirement regarding the NOI estimated vertical distance to the nearest usable water aquifer above the fracture zone. The commenters indicated that the BLM should specify if this is the distance between the surface down to the aquifer or the distance between the aquifer to the fracture zone. The BLM agrees that the proposed language was unclear and has modified the rule as a result of these comments. The intent of this section is to estimate the vertical distance between the top of the fracture zone and the nearest usable water zone. The BLM believes that this information is necessary to properly evaluate the potential impacts of a hydraulic fracturing proposal and had revised the language accordingly.

Handling of Recovered Fluids

Some commenters stated that requiring disclosure of proposed methods of handling the recovered fluids prior to drilling is an unreasonable administrative burden for operators when the requirement does nothing to further protect public health and welfare, the environment, nor facilitate efficient production. The BLM disagrees with these comments. The BLM requires the information about the handling of recovered fluids in order to conduct and document an environmental effects analysis that takes a hard look at the impacts of its Federal action and meets the requirements of NEPA and to assure that recovered fluids will not contaminate resources on or in public lands or Indian lands.

Other commenters requested that this section be expanded to include language that requests amounts, locations, facilities for storage, and options for recovering fluids for treatment. The rule requires reporting to the BLM of estimated volumes of recovered fluid along with the proposed methods of handling and disposal of those fluids. The BLM believes the information required in the final rule addresses the commenter's concern and is adequate to assess any potential impacts from the proposed methods of handling the produced fluids and to ensure protection of resources. No changes were made to the final rule based on this comment.

Commenters asked why the estimated chemical composition of the flowback fluid is required, and requested this requirement be struck from the rule. While the original proposed rule required the operator to submit the estimated chemical composition of the flowback fluid, the supplemental proposed rule did not. The rationale for deleting the requirement was discussed in the preamble of the supplemental proposed rule. This final rule does not require the estimated chemical composition of the flowback and therefore the BLM did not revise the rule as a result of these comments.

Additional Data

Some commenters recommended that section 3162.3–3(d)(7), which allows the authorized officer to request additional information prior to the approval of the NOI, be deleted. The commenters expressed concern that the provision creates too much uncertainty for operators and does not include any standards under which the BLM can request additional information. The BLM believes that the provision in the rule is necessary to provide the flexibility essential to regulating operations over a broad range of geologic and environmental conditions. 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 regulations, or that the operator is taking into account site-specific circumstances. Requests for information from the authorized officer are subject to administrative review if an operator believes the directive lacks a proper basis. The BLM did not revise the rule as a result of these comments.

Duplication of State Process

Several commenters stated that many parts of the rule are duplicative of state requirements, and therefore were unnecessary and would increase the regulatory and permitting burdens on operators. Some of the comments were generic while others specifically identified states such as Colorado, New Mexico, and Wyoming. The BLM has determined that the collections of information in the rule are necessary to enable the BLM to meet its statutory obligations to regulate operations associated with Federal and Indian oil and gas leases; prevent unnecessary or undue degradation; and manage public lands using the principles of multiple use and sustained yield; and protect resources associated with Indian lands. The information that states, tribes, or other Federal agencies collect is neither uniform nor uniformly accessible to the BLM. For these reasons, the BLM has determined that the collections in the rule are necessary, and are not unnecessarily duplicative of existing Federal, tribal, or state collection requirements. If the data required by a state is the same as the data required by this rule, it is permissible for the operator to attach it to the APD or NOI required for Federal and Indian lands,

thus substantially reducing the reporting burden for operators.

Timeframes

Some commenters were concerned over possible delays in BLM approval of their applications and requested that the BLM include processing timeframes in the rule. Specific timeframes suggested were from 10 to 30 days. Some commenters recommended that the permit be automatically approved after 30 days. Other commenters did not offer any specific suggestions on timeframes. The BLM did not revise the rule as a result of these comments because the imposition of a timeframe or ''automatic'' approvals could limit the BLM's ability to ensure protection of usable water and other resources. The BLM cannot abdicate its statutorily mandated responsibilities to prevent unnecessary or undue degradation of public lands and to protect Federal and Indian resources by establishing an arbitrary deadline. Furthermore, the BLM has obligations to assure compliance with relevant statutes and Executive Orders, which in some cases would require more than 30 days. As discussed in other sections, however, the rule would make several changes to the permitting process that could reduce the potential for processing delays.

Flowback Fluid

One commenter suggested that the BLM allow the flowback data required in section 3162.3–3(d)(5) of the supplemental proposed rule to be submitted either in the Sundry Notice or through a database. The BLM did not revise the rule because there is no existing database suitable for that purpose and the BLM believes that submission under this final rule is adequate. However, the BLM is considering expanding the use of its Well Information System for electronic submittal of various types of Sundry Notices.

One commenter requested that the BLM require operators to have a water management plan for flowback fluid. No changes to the rule were made as a result of this comment because the BLM requires the equivalent of a water management plan in final section 3162.3–3(d)(5) of the rule.

Approval Standards

Several commenters suggested that the BLM define clear standards for approving or denying an application for hydraulic fracturing. No changes to the rule were made as a result of this comment because the decision to approve or deny a particular application will be made by the authorized officer based on the site-specific conditions for that application and based on whether or not the application complies with this rule and applicable law.

Section 3162.3–3(e) Cement Monitoring

This section requires operators to:

- Monitor and record their cementing operations—This is consistent with industry guidance stressing the importance of using data from reports, logs, and tests to evaluate the quality of a cement job, including drilling reports, drilling fluid reports, cement design and related laboratory reports, open-hole log information including caliper logs, and cement placement information including a centralizer program, placement simulations and job logs, etc.;
- Cement the surface casing to the surface—This is already required by Onshore Order 2 and most state regulations, and is consistent with industry practice;
- For both the intermediate and production casing strings where they serve to protect usable water, the operator must either cement to the surface or run a CEL to demonstrate that there is at least 200 feet of adequately bonded cement between the deepest usable water zone and the formation to be fractured. This is generally consistent with industry guidance and specified in some state regulations. The American Petroleum Institute's (API) guidance titled ''Hydraulic Fracturing Operations-Well Construction and Integrity Guidelines, First Edition, October 2009,'' commonly known as HF1, states that ''if the intermediate casing is not cemented to the surface, at a minimum, the cement should extend above any exposed USDW or any hydrocarbon bearing zone'' and that operators may run a CEL and/or other diagnostic tools to determine the adequacy of the cement integrity and that the cement reached the desired height.

If there is an indication of inadequate cement, the operator must notify the BLM within 24 hours, submit a plan to perform remedial action, verify that the remedial action was successful with a CEL or other approved method, and submit a subsequent report including a signed certification and results of the corrective action.

Section (e)(1) of the final rule is revised to require submission of the cement monitoring report to the BLM at least 48 hours prior to commencing hydraulic fracturing operations, instead of 30 days after the completion of hydraulic fracturing operations, as was proposed in the supplemental proposed rule. The BLM made this change to allow field office engineers time to review the cement monitoring report, consistent with ensuring wellbore integrity. The 48-hour period will allow the BLM sufficient time to review the report, while not creating an unreasonable burden on the operators. In most wells, any usable water is isolated with the surface casing that is set many days or even months before the well reaches total depth, so there is plenty of time for the operator to submit the report. For wells where usable water is isolated by intermediate or production casing, the operator would still have ample time to submit the cement monitoring report. Typically, after the operator completes drilling and cementing operations, the operator moves the drilling rig off the well and moves on a completion rig with hydraulic fracturing following. This transition period will allow the operators sufficient time to submit the cement operations monitoring report at least 48-hour prior to commencing hydraulic fracturing.

For any well completed pursuant to an APD that did not expressly authorize hydraulic fracturing operations, there is a new section 3162.3–3(e)(1)(ii) that requires the operator to submit documentation to demonstrate that adequate cementing was achieved for all casing strings designed to isolate or to protect usable water. The operator must submit the documentation with its request for approval of hydraulic fracturing operations, or no less than 48 hours prior to conducting hydraulic fracturing operations if no prior approval is required pursuant to paragraph 3162.3–3(a). The authorized officer may approve the hydraulic fracturing of the well only if the documentation provides assurance that the cementing was sufficient to isolate and to protect usable water, and may require such additional tests, verifications, cementing, or other protection or isolation operations, as the authorized officer may deem necessary.

This provision would apply to wells subject to the transition period as shown in the table in section 3162.3–3(a), and to other wells that might have been completed as conventional wells or fractured prior to this rule, but subsequently are proposed to be re-completed by hydraulic fracturing. Many if not most operators would have the information required in section 3162.3–3(e)(1)(i), and could readily provide it to the authorized officer. However, if the operator did not maintain all of those records, it could provide the available information to the authorized officer, who could approve the operator's request once there is assurance that the hydraulic fracturing

operation in the well would be consistent with the requirements of proper isolation and protection of the usable water zones.

Sections 3162.3–3(e)(2) and (e)(3) of the supplemental proposed rule were deleted in the final rule and replaced by a new section 3162.3–3(e)(2). The supplemental proposed rule (section 3262.3–3(e)(2)) used a ''type well'' concept and would have required that a CEL be run on all casing strings that protect usable water unless the well was permitted with an NOI for a group of wells, was drilled with the same specifications and geologic characteristics as the type well, the cementing operations monitoring data paralleled the type well, and the type well CEL indicated successful cement bonding (section 3162.3–3(e)(3) of the supplemental proposed rule). The final rule no longer requires a CEL to be run on all casing strings that protect usable water and the type well provisions in the supplemental rule are deleted. Instead, section 3162.3–3(e)(2) of this rule sets performance standards for ensuring adequate cement bonding on all casing that protects usable water and applies to all wells, not just type wells. For casing strings that are cemented to the surface, which includes surface casing, the primary indicator of adequate cement bonding is cement monitoring. This includes such criteria as good returns to the surface, the absence of gas-cut mud, and properly functioning equipment throughout the cement job. The final rule also includes a criterion (10 percent of casing setting depth or 200 feet, whichever is less) for the amount of allowable fall-back. The BLM believes that these criteria will more effectively and less subjectively ensure the protection of usable water on all wells that will be hydraulically fractured than the CEL that would have been required in the supplemental proposed rule.

For intermediate and production casing designed to protect usable water and where cement is not brought to the surface, this final rule requires that a CEL demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone. The supplemental proposed rule would have only required a CEL in this situation if the well was defined as a type well or if there were indications of an inadequate cement job. However, indications of an inadequate cement job are much more difficult to observe when cement is not brought to the surface. Therefore, the final rule requires a CEL on all intermediate or production casing strings designed to protect usable water when the cement is not circulated to the surface. This section also defines the amount of adequately bonded cement necessary to allow hydraulic fracturing, which was not defined in the supplemental proposed rule.

The BLM made several revisions to section 3162.3–3(e)(3) of the final rule (section 3162.3–3(e)(4) of the supplemental proposed rule), which address the course of action an operator must take if there are indications of an inadequate cement job. The final rule explicitly requires the operator to submit an NOI to the BLM for approval of remedial action to address inadequate cementing, where the supplemental proposed rule would have only required the operator to report the remedial action to the BLM. The BLM believes that the final rule's requirement that the operator receive BLM approval prior to remediating inadequate cementing will help to ensure protection of aquifers. The final rule also establishes a procedure for granting approval to take remedial action in emergency situations.

The supplemental proposed rule would have required the operator to submit a written report to the BLM within 48 hours of discovering an inadequate cement job. The final rule requires the submission of an NOI for BLM approval in lieu of the written report and also deletes the 48-hour timeframe. The BLM believes that in most cases prompt submission of an NOI would be in the operator's best interest because they cannot proceed with hydraulic fracturing until the NOI is approved and therefore the 48-hour timeframe is unnecessary. Both the supplemental proposed rule and the final rule require the operator to run a CEL verifying that the remedial action was successful.

Final section 3162.3–3(e)(3) contains revised requirements for what an operator must do if there are indications of an inadequate cement job. In the supplemental proposed rule (section 3162.3–3(e)(4)), prior to commencing hydraulic fracturing, the operator would have been required to notify the BLM within 24 hours, submit a written report within 48 hours, run a CEL showing the inadequate cement had been corrected, and at least 72 hours prior to commencing operations, submit a certification and documentation indicating the cement job had been corrected.

However, the supplemental proposed rule did not have a provision that would have allowed the BLM to review the documentation required or approve a plan for remedial action. The final rule requires the operator to notify the BLM within 24 hours and submit an NOI to the BLM for remedial action along with supporting documentation and logs. This gives the BLM the opportunity to review the documentation and logs submitted to ensure that the remedial action proposed by the operator is appropriate. The requirement to submit an NOI takes the place of the 48-hour written notification in the supplemental proposed rule, although the BLM determined that no timeframe is required because the operator will be required to submit the NOI and receive approval prior to commencing fracturing operations.

Type Well CEL

Very few commenters were supportive of the type well concept for cement evaluation. In the supplemental proposed rule, a type well CEL would have been required to demonstrate successful cement bonding; thereafter, other wells in an approved group would not have been required to have a CEL unless there were indications of inadequate cement. The subsequent wells would also have needed to have the same specifications and geologic characteristics as the type well, and the cementing operations monitoring data would have needed to parallel that of the type well. Many commenters stated that the definition of a type well was too vague. Some commenters wanted the BLM to limit the type well concept to a certain number of wells, to a certain distance between wells, or to a certain time between the hydraulic fracturing of wells. Other commenters recommended requiring a minimum number of successful wells rather than just a single type well. Other commenters wanted the type well concept to be greatly expanded to include all wells within a county or within a geologic basin. Many commenters stated that successful cementing operations on one well were not indicative of subsequent successful cementing of another well, regardless of the proximity. Some commenters wanted a clearer, more specific set of standards and procedures to guide the determination of what constitutes a type well for a given set of wells. Other commenters were critical that the rule did not elaborate upon the meaning of ''substantially similar geological characteristics within the same geologic formation'' (language used in the definition of type well) or the manner in which the BLM makes that determination. Still others expressed concern that the use of type wells assumes that geologic zones are compositionally, texturally, and mechanically homogeneous media, even though this is often not true. Other commenters stated the type well

approach fails to address risk by ignoring fundamental geologic principles and sound engineering practice. Other commenters stated the type well concept allows the BLM to bring significant judgment to the well permitting process rather than specific standards.

After reviewing the comments on the use of type wells, type wells are eliminated from the final rule. The BLM agrees that successful cementing operations on one well are not necessarily indicative of subsequent successful cementing of another well regardless of the proximity or geologic characteristics, and that implementation of the type well concept would be difficult to achieve. Rather than restructure the definition, or develop a specific set of standards, the BLM instead made the decision to eliminate the type well concept and to establish cementing operations monitoring requirements and usable water isolation requirements that apply to every well.

CEL

Numerous commenters objected to the requirement to run a CEL on each casing string that protects usable water. Many of these commenters stated that the use of CELs on surface casing is unprecedented for onshore wells. The commenters pointed out that state regulations do not require CELs on surface casing and that API guidelines do not mention cement logs in the section specifically devoted to surface casing. Many commenters stated that where cement is circulated to the surface and pressure tests are satisfactory, CELs do not provide any additional assurance of protection. Many commenters were concerned about the costs associated with running a CEL on surface casing. Many other commenters said that CELs are not commonly run on surface and intermediate casing unless other indicators of an unsuccessful cement job are present. Many of the commenters were critical that the BLM was relying on the CEL as the ''sole diagnostic tool'' to evaluate cement integrity. Many commenters stated that CEL data can be difficult to interpret properly and often yields false positives. The BLM agrees with many of these comments and has revised the final rule as a result. The final rule does not require a CEL on the surface casing unless there are indications of inadequate cement. Final section 3162.3–3(e)(2)(i) requires that the operator determine that there is adequate cement for surface casing used to isolate usable water zones. The operator must observe cement returns to the surface and document any indications of inadequate cement (such as, but not limited to, lost returns, cement channeling, gas cut mud, failure of equipment, or fallback from the surface exceeding 10 percent of surface casing setting depth or 200 feet, whichever is less). If there are indications of inadequate cement, then under final section 3162.3–3(e)(2), the operator must determine the top of cement with a CEL, temperature log, or other method or device approved by the authorized officer.

Many other commenters recommended that a CEL be required on every string of casing in every well. Commenters expressed concern that anything less would greatly increase the risk of contamination. The commenters were opposed to allowing operators to run CELs on type wells only. The commenters expressed the view that CELs are the only way to ensure adequate cementing of the casing on each well.

Numerous other commenters stated that the best way to confirm the adequacy of a cement job is through proper monitoring of the cementing operations and direct observation of a variety of factors; the most important being cement returns to the surface. Many commenters expressed concern about the reliability of CELs, stating that CEL data can be difficult to interpret properly and often yield false positives. Commenters said that this can lead to unnecessary attempts at remediation, which will actually weaken the wellbore integrity.

Some commenters said that allowing operators to use CELs, rather than just CBLs, alleviates some, but not all of the interpretation concerns. Other commenters stated that CBLs are not effective until the cement has reached a certain compressive strength because CBLs work on the principle of acoustic attenuation. At low compressive strengths, commenters stated that the acoustic properties of cement and water are very similar and it is difficult to delineate between the two when interpreting logs. The commenters went on to state that the problem is also inherent in the CELs, which can sometimes provide a risky basis for evaluating the integrity of the cement. The commenters claim that the logs do not ''see'' the cement. The logs merely allow a competent professional to draw inferences about the evenness of the cementing around the pipe, based on readings of sonic or ultrasonic waves passing through the pipe into the cement and the rock beyond. The commenters quoted API Technical Report 10TR1, September 2008, which cautions that cement bond log interpretation ''is not recommended as a best practice for cement evaluation.''

After further researching these concerns, the BLM agrees that the monitoring of data and direct observations of various factors, including cement return to the surface, are good indicators of an adequate cement job, and the BLM acknowledges the potential difficulties of running and interpreting CELs. As a result, the BLM has determined that requiring CELs on the surface casing of every well will not provide increased protection beyond cement operations monitoring and circulation of cement to the surface. Therefore, the final rule requires operators to monitor their cementing operations, including verification of cement returns to the surface, and to submit the cementing operations monitoring report to the BLM prior to commencing hydraulic fracturing operations.

Some commenters disagreed with the proposed regulation allowing the operator to wait to submit a cement monitoring operations report to the BLM until after completion of the hydraulic fracturing operations. These commenters said that the operator should submit the report to the BLM prior to the commencement of hydraulic fracturing operations. The BLM agrees and revised the rule as a result of these comments. Final section 3162.3–3(e)(1) requires that during cementing operations on any casing used to isolate usable water zones, the operator must monitor and record the flow rate, density, and pump pressure and submit a cement operation monitoring report, including that information, to the authorized officer at least 48 hours prior to commencing hydraulic fracturing operations, unless the authorized officer approves a shorter time. This would allow the BLM time to review the monitoring report to verify compliance with these regulations. If the monitoring report indicates problems with the cementing operations, the operator must correct the issue prior to hydraulically fracturing.

The final rule also has more specific criteria for the operator to follow to determine that there is adequate cement for all casing strings used to isolate usable water zones. Onshore Order 2 (section III.B.1.c.) requires surface casing in all wells to be cemented to the surface. For surface casing, this final rule requires the operator to observe cement returns to the surface and to document any indications of inadequate cement (such as, but not limited to, lost returns, cement channeling, gas cut mud, failure of equipment, or fallback from the surface exceeding 10 percent of

surface casing setting depth or 200 feet, whichever is less). If there are indications of inadequate cement, then the operator must determine the top of the cement with a CEL, temperature log, or other method or device approved by the authorized officer. For intermediate or production casing, this rule requires that if the casing is not cemented to the surface, then the operator must run a CEL to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone. If the casing is cemented to surface, then the operator must follow the surface casing cementing requirements.

The BLM believes that the final rule's requirements described earlier, in conjunction with the casing and cementing requirements of Onshore Order 2, will sufficiently isolate and protect usable water. As discussed earlier, Onshore Order 2 (section III.B.1.c.) requires that the operator cement the surface casing to the surface. Onshore Order 2 (section III.B.1.f.) also requires that the surface casing shall have centralizers on the bottom three joints of casing in order to keep the casing in the center of the wellbore to help ensure efficient placement of cement around the casing string. Onshore Order 2 (section III.B.1.h.) requires the operator to pressure test all casing strings to ensure the integrity of the casing. Onshore Order 2 (section III.B.1.i.) also requires a pressure integrity test of each casing shoe on all exploratory wells and on that portion of any well approved for a 5M (5,000 pounds per square inch) BOPE (blowout preventer equipment). This test insures that a good, leak-tight cement job has been obtained.

Final section 3162.3–3(e) strengthens the requirements that operators must follow when there is an indication of inadequate cementing. The operator must notify the authorized officer within 24 hours of discovering the inadequate cement. For the surface casing, this will likely be immediately following the cementing operations. For intermediate or production casing that is not cemented to the surface, this may not be until after the operator has run the CEL. Early notification will ensure that the BLM is involved with the remediation of the cement. Under the final rule the operator must submit an NOI to the authorized officer requesting approval of a plan to perform remedial action to achieve adequate cement. The plan must include supporting documentation and logs. The BLM will review the plan, work with the operator to modify the plan if necessary, and attach any conditions of approval to the plan. Upon approval, the operator can commence the remedial actions. After completing the remediation process, the operator must verify that the remedial action was successful with a CEL or other method approved in advance by the authorized officer. The operator must submit a subsequent report for the remedial action, including a signed certification that the operator corrected the inadequate cement job in accordance with the approved plan, and the results from the CEL or other method approved by the authorized officer and documentation showing that there is adequate cement. As required by existing section 3160.0–9(c), the subsequent report is due 30 days after the operations are completed. This final rule, however, also requires the operator to submit the results from the CEL or other method approved by the authorized officer at least 72 hours before starting hydraulic fracturing operations. This will provide the BLM the opportunity to verify the remediation process was successful and that will help to ensure adequate protection of aquifers in advance of hydraulic fracturing operations.

Conductor Pipe

Several commenters said that section 3162.3–3(e) should be modified to specify that a CEL requirement does not apply to conductor pipe. The BLM agrees with this comment and has modified the rule at sections 3162.3–3(e)(1) and 3162.3–3(e)(2) to clarify that CELs are only required on casing strings designed to protect usable water. Conductor pipe does not typically protect aquifers. Conductor pipe is a large diameter pipe set to relatively shallow depths which serves as a conduit for all other casings and well operations. The formations close to the surface are often unconsolidated and during the commencement of drilling operations these formations erode or wash out from the circulating drilling muds. The conductor pipe's purpose is to prevent this near-surface erosion from interfering with subsequent drilling and operating activities. Based on the surface formation's conditions, certain wells do not have conductor casing set, in other instances conductor pipe is mechanically driven into the surface formations without any cement, and in other instances the conductor pipe consists merely of corrugated pipe and is cemented with construction cement. One of the roles of the surface casing, the first casing string set, is to protect the near-surface usable-quality waters. Because conductor casing is not designed to protect usable water zones, the CEL requirement does not apply. In addition, the surface casing would be adequately cemented inside the conductor pipe, thus protecting near-surface zones.

What is inadequate cement?

Several commenters stated that section 3162.3–3(e)(2) (proposed section 3162.3–3(e)(4)) regarding indications of inadequate cement should be modified. Commenters indicated that the inadequate cement job criteria listed were not good indicators of an inadequate cement job. The commenters did not offer any suggestions of what would be good indicator(s). The BLM did not revise the rule as a result of this comment. The provision regarding indicators of inadequate cement, at final section 3162.3–3(e)(2)(i), expressly includes the language ''such as, but not limited to'' to indicate that the subsequent list is not an exhaustive list of possible indications of inadequate cement.

The BLM also received comments that this section should be revised to exempt cement fall back from being classified as an indication of inadequate cement. Commenters indicated that there should be a specific exception for those instances where the only remedy is to top-fill cement that has settled in the annulus after curing. The BLM agrees and has revised the rule as a result of these comments. Section 3162.3–3(e)(2) now addresses adequate cement for surface casing or intermediate and production casing separately. Additionally, the BLM believes that the fallback indicator for inadequate cement should incorporate a performance standard. Based on the BLM's experience, 10 percent of surface casing setting depth or 200 feet, whichever is less, is the limit that routine ''top-jobs'' are successfully performed; therefore, the rule has been revised to incorporate this exception as a fall back indicator for inadequate cement. Appropriate remedial operations are to be conducted in either event; however, determination of the cement top via a CEL would not be required under this exception.

Certifications

Numerous commenters stated that the rule provisions dealing with self-certification should be modified. The supplemental proposed rule proposed self-certification statements for remedial cement jobs, wellbore integrity, fluids used, and compliance with laws and regulations.

Some commenters indicated that certifications are unnecessary and require the operator to certify the actions of third parties over whom they

have no direct control; in addition, concern was expressed with the potential liability issues of certification for operations conducted by another party. The BLM did not make any changes to the rule as a result of these comments. By definition, in existing section 3160.0–5, the operator is the entity that is responsible for the operations conducted under the terms and conditions of the lease. As such, the BLM believes it is appropriate that the operator be responsible for all aspects of hydraulic fracturing operations, regardless of the party that conducts the work. The BLM will hold the operator responsible for all actions of third party contractors on a Federal or tribal lease. Requiring the operator to submit the certifications is appropriate and provides added assurance that hydraulic fracturing operations were conducted in compliance with the regulations.

Some commenters objected to the requirement that the operator certify proper execution of remedial cement jobs, the mechanical integrity of casing, and legal compliance related to hydraulic fracturing fluids, among other issues. They asserted that it is impossible for the operator to have one individual who can certify all of those matters and said that the possibility of criminal enforcement is an unreasonable imposition. The BLM disagrees. The operator has always been responsible for everything that occurs on the permitted well site. See existing section 3100.5(a). If an operator uses one or more service contractors for specific tasks, the operator remains fully responsible for those operations. See existing section 3162.3(b). If the operator's contractor, as its agent under existing section 3162.3(b), submits a certification, it is deemed to have come from the operator. Since 1948, the law has provided for criminal liability for certain false statements in public land matters, whether sworn or unsworn. 43 U.S.C. 1212. The certification requirement underscores the importance of operators taking responsibility for reporting accurate information necessary to assure that hydraulic fracturing operations were properly conducted and is intended to ensure that contractor activities on the lease are properly overseen by the operator. The final rule is not revised in response to these comments.

Other commenters were concerned that despite taking all prudent steps, implementing accepted industry standards, and complying with all regulatory requirements in the final rule, the operator could in good faith provide a certification that later in time is found invalid based on circumstances or facts unknown to the operator or that were out of his or her control. The BLM did not make any changes to the rule based on these comments. The BLM would take an operator's diligence and good faith into consideration in exercising enforcement discretion where a certification was later shown to have been in error.

Other commenters said that additional certifications should be required, including fracture propagation and the protection of usable water. The BLM did not make any changes to the rule as a result of these comments. The BLM believes that the subsequent report adequately details fracture design considerations, including fracture propagation. Additionally, usable water considerations are addressed at both the APD and hydraulic fracturing review stages.

Cement Monitoring Report

Several commenters suggested that the rule require the cement monitoring report in paragraph section 3162.3–3(e)(1) to be submitted to the BLM prior to commencing hydraulic fracturing operations. This would give BLM field offices the opportunity to review the report to ensure the cement job was adequate. The proposed rule would have given operators 30 days from the completion of hydraulic fracturing operations to submit the cement monitoring report. The BLM agrees with this comment and revised final section 3162.3–3(e)(1) to require that the report be submitted at least 48 hours prior to commencing hydraulic fracturing operations.

One commenter suggested that the cement contractor's report should be acceptable to the BLM. The requirements of the cement report are detailed in section 3162.3–3(e)(1) of this rule. Any report meeting these requirements would be acceptable to the BLM, including a report submitted by the cement contractor as an agent of the operator. See 43 CFR 3162.3(b). No changes to the rule were made as a result of this comment.

One commenter suggested that the cement monitoring report in section 3162.3–3(e)(1) should be submitted to the BLM within 30 days of cementing, not within 30 days after completion of hydraulic fracturing operations as stated in the supplemental proposed rule. This, according to the commenter, would give the BLM adequate time to review the report prior to hydraulic fracturing. The rule is revised based on other comments to require the cement monitoring report at least 48 hours prior to hydraulic fracturing, which addresses the commenter's concern. In addition, the BLM does not believe that operators would proceed to fracture a well if the monitoring report showed a failure to ensure isolation and protection of usable water, knowing that if the BLM discovered the failure, the operator would be subject to enforcement action.

Section 3162.3–3(f) Mechanical Integrity Test

This section requires the operator to conduct a Mechanical Integrity Test (MIT). The MIT required by this rule is a pressure test of the casing through which the hydraulic fracturing will occur or through the fracturing string (if used). Industry guidance and many state regulations are consistent with this requirement. The API's guidance [7] clearly indicates the need for the MIT. The threshold of 30 minutes with no more than 10 percent loss of applied pressure is used by many states (TX, LA, CO, WY, and others).

Industry guidance on hydraulic fracturing states that the operator should pressure test the production casing. ''Prior to perforating and hydraulic fracturing operations, the production 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.'' (API Guidance Document HF1, First Edition, October 2009) This casing pressure test meets the intent of the MIT required by the rule.

Two changes were made to the MIT requirements in the final rule. The reference to refracturing in the supplemental proposed rule is deleted because the final rule no longer makes any distinction between refracturing and fracturing. The requirement to only perform an MIT on vertical sections of the wellbore in the supplemental proposed rule is also deleted in the final rule. This change ensures that the entire length of casing or fracturing string, not just the vertical section, prior to the perforations or open-hole section of the well, is able to withstand the applied pressure and contain the hydraulic fracturing fluids. In addition, it was unclear to what the term vertical section would apply in a directionally drilled well.

The BLM received numerous comments on performing a successful MIT prior to hydraulic fracturing. These comments ranged from concerns involving need, type wells, MIT reporting, well configurations,

[7] Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, API Guidance Document HF1 (1st ed., Oct. 2009).

terminology, test pressures and finally, alternative testing procedures.

Several commenters stated that the MIT requirement in general is unnecessary and costly. Other commenters indicated that because MITs are already completed as a matter of industry practice prior to any pumping procedure, regulating such procedure is merely bureaucratic and serves no environmental protection. The BLM realizes that many operators perform MITs; however the BLM believes that ensuring casing integrity prior to hydraulic fracturing is essential and that the only way to verify the integrity of the casing is to require a test to the anticipated hydraulic fracturing pressure. An MIT conducted immediately preceding the hydraulic fracturing operation to the specified test pressure would suffice. No change was made to the rule as a result of these comments.

Some commenters were concerned that an MIT would not be required on every well if the type well concept was adopted. As discussed, the proposed type well concept is not included in the final rule. Elimination of the type well concept clarifies any confusion regarding the requirement for an MIT for type wells. The final rule now requires that a successful MIT be performed on every well prior to hydraulic fracturing. The BLM believes that this is the only method that will ensure that each well to be hydraulically fractured demonstrates the appropriate structural capabilities to withstand the intended applied pressures.

Some commenters said that the rule requiring MITs for refracturing should be modified. The commenters stated that the requirement to perform an MIT before refracturing operations is unjustified. The commenter suggested that the BLM should put a timing restriction on when an MIT must be performed when refracturing a well. As previously discussed, the final rule has eliminated the term ''refracturing'' in its entirety. An MIT will be required prior to the first hydraulic fracturing operation in any well, and prior to all subsequent hydraulic fracturing operations in that well. To ensure proper wellbore integrity for protection and isolation of the usable water, an MIT will be required to ensure that an existing well is properly bonded and sheathed to sustain high pressures during a hydraulic fracturing operation. The BLM did not revise the rule as a result of these comments.

Other commenters recommended that the BLM require reporting the results of the MIT prior to hydraulic fracturing. The BLM does not believe that a requirement to report the results of the MIT prior to fracturing is necessary to ensure wellbore integrity. Final section 3162.3–3(f) requires a successful MIT prior to hydraulic fracturing; therefore, if the MIT failed and the operator proceeded with hydraulic fracturing operations, the operator would be in violation of the rule and would be subject to enforcement actions. No revisions to the rule were made as a result of this comment. In addition, final section 3162.3–3(i)(8)(i) requires a certification to be signed by the operator that it had performed a successful MIT under section 3162.3–3(f).

Some commenters recommended that the BLM clarify the requirement for conducting the MIT when the well configuration contains a pressure-actuated valve or sleeve at the end of a lateral completion. The commenters expressed concern that pressure testing this valve or sleeve to maximum anticipated pressure will possibly open the valve or sleeve, causing the pressure test to fail the proposed standard of 30 minutes with no more than a 10 percent pressure loss. The BLM also received comments urging modification to the MIT requirements for open-hole completions. The BLM appreciates the concerns expressed by the commenters. The BLM believes that ensuring casing integrity prior to hydraulic fracturing is essential and the best way to ensure the integrity of the casing is to test to the anticipated hydraulic fracturing pressure. No revisions to the rule were made as a result of these comments. Also, because this is a national rule, it cannot address all the possible wellbore configurations, and the BLM recognizes that certain wellbore configurations may require modifications to perform this test. Many wellbores will require the setting of packers, or other acceptable methods, to isolate existing, sensitive downhole components or open-hole completions. Operators are encouraged to anticipate these complications and provide details to the BLM's authorized officers in their hydraulic fracturing APDs and NOIs.

Several commenters requested clarification regarding at what point in the process should results of the MITs be submitted and for how long must the operator keep the results of the MIT. The final rule was not revised as a result of these comments; however, the rule was reorganized to better reflect the BLM's intent. As required by final section 3162.3–3(i)(9), the MIT results are required to be submitted to the BLM authorized officer, via a subsequent report, within 30 days after the completion of the last stage of the hydraulic fracturing for each well. Existing section 3162.4–1(d) requires that the operator maintain all required records and reports, including MITs, for 6 years from the date that it was generated.

Some commenters said that the rule should be modified to change the term ''MIT'' to ''casing pressure test.'' Other comments asked if the MIT was the same casing pressure test required by Onshore Order 2. The BLM did not make any changes to the rule as a result of these comments. The BLM believes that the term ''Mechanical Integrity Test'' is widely understood by industry, is used by many state regulatory agencies, and accurately describes the test. The MIT required by final section 3162.3–3(f) is not equivalent to either the casing pressure test required by Onshore Order 2, section III.B.1.h., or the casing shoe pressure test as currently required by Onshore Order 2, section III.B.1.i. The MIT is a specific test conducted on a wellbore in its hydraulic fracturing configuration and to the maximum anticipated pressure for the hydraulic fracturing operation being contemplated.

Some commenters suggested various alternative testing pressures or procedures to be used for the MIT. Commenters recommended lower pressures than the proposed rule provided or suggested that alternative methods, including ultrasonic imaging, could be utilized. Final section 3162.3–3(f) requires the operator to perform a successful MIT to not less than the maximum anticipated surface pressure that will be applied during the hydraulic fracturing process. This testing is necessary to help ensure the integrity of the wellbore during hydraulic fracturing operations. This test demonstrates that the casing provides sufficient structural strength to protect usable water and other subsurface resources during hydraulic fracturing operations. The BLM specifically chose the MIT over other alternative tools so that the test could be accomplished without requiring additional equipment, such as ultrasonic imaging tools. No revisions to the rule were made as a result of these comments. However, the BLM may consider a proposal by the operator to use alternative tools to an MIT. If such tools meet or exceed the objectives of performing an MIT, then the BLM may authorize an operator to use such tools as a variance to this requirement.

Commenters suggested alternative MIT failure indicator levels. Section 3162.3–3(f)(3) requires the well to hold the pressure for 30 minutes with no more than a 10 percent pressure loss. As previously pointed out, this test

confirms the mechanical integrity of the casing and is the same ''failure'' standard that the BLM established for drilling operations in Onshore Order 2, section III.B.h.; therefore, this language does not set a new standard in the BLM's regulations. The MIT, together with the other requirements, demonstrate not only the wellbore's structural competency, but that reasonable precautions have been taken to protect usable water and other subsurface resources during hydraulic fracturing operations. Some commenters also indicated that this requirement is duplicative of state requirements and therefore is unnecessary. The BLM acknowledges that although this requirement may be duplicative of some states' requirements, not all of the states to which this final rule is applicable have the same requirements and, therefore, this standard is necessary to protect Federal and tribal lands. Many commenters expressed that the requirement is common industry practice and that they support the requirement. No revisions to the rule were made as a result of these comments.

Section 3162.3–3(g) Monitoring During Hydraulic Fracturing Operations

This section requires the operator to continuously monitor and record the annulus pressure at the bradenhead during the hydraulic fracturing operation.

In the final rule, the BLM removed the term ''refracturing'' from the title of the section because the final rule no longer defines or uses the term ''refracturing.'' The final rule also clarifies that when pressures within the annulus increase by more than 500 psi, the operator must stop fracturing operations and determine the reasons for the increase. Prior to recommencing hydraulic fracturing operations, the operator must perform any remedial action required by the authorized officer and successfully perform an MIT required under paragraph (f) of the rule. The BLM believes that these actions are necessary in these cases to ensure that the integrity of a wellbore is confirmed through an MIT prior to recommencing hydraulic fracturing operations.

One commenter believed that the requirements for the operators in section 3162.3–3(g) of the supplemental proposed rule to continuously monitor and record annulus pressure at the bradenhead were too vague and wanted more specificity in the rule. The commenter also believed that the requirement was unnecessary. The commenter explained that operators already monitor pressures during hydraulic fracturing operations using sophisticated and expensive equipment. Another commenter said that the monitoring requirement could not be achieved because the bradenhead is not accessible. The BLM reviewed the language in the supplemental proposed rule and has determined that the language in this section is clear as written. In fact, the language in this section is very similar to the requirements in Colorado rule 341 (Colorado Oil and Gas Conservation Commission, February, 2014, *http://cogcc.state.co.us/*). Changes in pressure, while not necessarily caused by mechanical failure due to hydraulic fracturing, provide an indication that mechanical failure may have occurred. The BLM appreciates the fact that operators already monitor pressures during hydraulic fracturing using sophisticated equipment. However, as indicated by comments, not all hydraulic fracturing operations utilize the same equipment and therefore specific requirements are necessary. The BLM finds no merit in the comment that the bradenhead is not accessible. Common industry practice is to construct wells that allow bradenhead access. Many states, including Colorado, Wyoming, Montana, and North Dakota, require bradenhead monitoring during hydraulic fracturing, and API guidance, ''Hydraulic Fracturing Operations-Well Construction and Integrity Guidelines, First Edition, October 2009,'' commonly known as HF1, recommends annular pressure monitoring during hydraulic fracturing.

Other commenters recommended that the monitoring should continue on a daily basis for the first 30 days after hydraulic fracturing and then monthly for 5 years thereafter. The BLM disagrees with this comment. Upon completion of pumping the hydraulic fracturing fluids, the wellbore is no longer subject to the pump pressure. Therefore, continual monitoring for wellbore issues caused by the hydraulic fracturing operation is unnecessary. No revisions to the rule were made as a result of these comments.

Some commenters suggested that the reporting requirements of pressure increases by more than 500 psi during hydraulic fracturing operations in the annulus during hydraulic fracturing under section 3162.3–3(g)(2) of the supplemental proposed rule is unnecessary because it duplicates state requirements. Another commenter asserted the need for a more comprehensive regulatory approach for hydraulic fracturing operations in state and tribal lands. The BLM acknowledges that some states have similar requirements, but not all states have the same requirements. Since this rule applies to all Federal and Indian minerals, this requirement is necessary. Even in states that do have a similar requirement, the BLM needs to know about the pressure increase so that the BLM can work closely with the operator to correct the issue and take the appropriate action.

Another commenter recommended that in addition to the oral notification of a pressure increase, written notice should also be required. The BLM believes oral notification is sufficient in this situation. If warranted, the BLM may require additional documentation regarding the pressure increase and the corrective measures that were taken to abate the situation.

One commenter recommended that the BLM adopt the language in the original proposed rule which required the operator to file a subsequent report of the corrective actions taken within 15 days, instead of the language in the supplemental proposed rule which requires the submission of the subsequent report within 30 days of completion of the hydraulic fracturing operations. As stated earlier, the BLM will work closely with the operator following notification of the pressure increase. Since the BLM will be aware of the incident by the oral notification and will be involved with the corrective action from the start, the timing of submission of the subsequent report is not critical to the BLM. The 30-day requirement is consistent with all of the other documentation required to be included in the subsequent report. No revisions to the rule were made as a result of these comments.

One comment made numerous suggestions about additional monitoring that should take place on producing wells. The suggestions include:

- Submit monthly and annual production reports including volume of oil and gas to the BLM;
- Monitor pressure of each well daily for the first 30 days of operation;
- Maintain production and monitoring reports for 5 years;
- Conduct periodic well tests to determine flow rate and pressure;
- Maintain and test wellhead equipment over the life of the well;
- Annually report casing pressures to the BLM and notify the BLM if pressures approach the design limits of the casing;
- Install pressure relief valves, especially on high-pressure or high-volume wells; and
- Monitor all wells for corrosion and potential hazards.

The BLM did not revise the rule as a result of these comments because these comments apply to producing wells whether or not they are hydraulically fractured. The BLM believes that the existing monitoring, maintenance, and reporting requirements for producing wells are adequate. See 43 CFR part 3160, and *http://www.blm.gov/mt/st/en/prog/energy/oil_and_gas/operations/orders.html*.

For example, operators of Federal and Indian wells already must report production to the Office of Natural Resource Revenue (ONRR). Furthermore, the supplemental notice of proposed rulemaking did not propose to amend the onshore orders or other operating regulations.

Several commenters suggested that the rule require operators to notify the BLM if the annular pressure exceeds 80 percent of the casing internal yield rating during hydraulic fracturing. Both the supplemental and the final rules require the operator to notify the BLM if the annular pressure exceeds 500 psi. The BLM determined that the standard for notifying the BLM should be an objective and easily measured parameter. The 500 psi limit can be detected by observing a pressure gauge. A standard based on casing yield ratings as the commenters suggested would be more difficult to detect and implement, especially if the person observing the gauge was not familiar with the weight, grade, and depth of the casing run, or the weight of the mud in the hole. In addition, as part of the BLM's review of hydraulic fracturing applications, the engineer will ensure that a 500 psi increase in annular pressure will not jeopardize the integrity of the casing. No revisions to the rule were made as a result of this comment.

Section 3162.3–3(h) Storage of Recovered Fluids

This section requires operators to manage recovered fluids in rigid enclosed, covered, or netted and screened above-ground tanks. Those tanks may be vented, unless Federal, state or tribal law, as appropriate for the surface estate involved, require vapor recovery or closed-loop systems. The tanks must not exceed a 500 barrel (bbl) capacity unless approved in advance by the authorized officer. In certain very limited circumstances, the operator may apply for approval to use a lined pit.

Tanks that are not enclosed will need to be covered, netted, or screened to exclude wildlife. This is not a new requirement. In 2012, the BLM issued an instructional memorandum to its authorized officers to assure that pits, tanks, and similar structures are netted or screened to prevent entrapment and mortality of wildlife. (See *http://www.blm.gov/wo/st/en/info/regulations/Instruction_Memos_and_Bulletins/national_instruction/2013/IM_2013-033.print.html*.). These mitigation requirements are used to help prevent deaths of animals protected under the Migratory Bird Treaty Act and other laws.

The supplemental proposed rule would have required that recovered fluids be stored in lined pits or tanks unless otherwise required by the BLM. The final rule incorporates two significant changes. First, the BLM decided not to distinguish flowback fluid from produced water. Instead, in the final rule the requirements for the storage of flowback fluid only apply to the interim period between the completion of hydraulic fracturing and the implementation of an approved plan for the disposal of produced water under Onshore Order 7. Fluids produced from the well during this period are referred to as ''recovered fluid'' in the final rule and the term ''flowback'' is deleted from the rule. Second, instead of allowing lined pits or tanks, as proposed in the supplemental proposed rule, the final rule requires that all recovered fluids to be stored in above-ground tanks unless otherwise approved by the BLM in advance of generating recovered fluids. In addition, a list of minimum criteria for the approval of storage in lined pits is included in the final rule.

Pits vs. Tanks

In the supplemental proposed rule, the BLM asked for comments on whether flowback fluids should only be stored in closed tanks. The BLM received comments that both supported and objected to this proposal. Comments supporting a ''tanks only'' approach stated that the risk of impacts to air, water, and wildlife is too great, even if a pit is lined. Those commenters stated that lined pits are still subject to breaching, failure, and leaking. In addition, because pits are open to the atmosphere, fumes from the fluid in the pits can become airborne and cause health and environmental problems. The commenters also raised the possibility of wildlife getting into pits and dying or becoming ill from exposure to the chemical constituents in the fluids. Some of these comments suggested that flowback fluid should only be stored in ''closed systems'' that would not only use tanks, but the tanks would be vapor tight to eliminate the possibility of air contamination.

Many of the comments objecting to a ''tanks only'' approach raised the issue of increased cost if tanks or ''closed systems'' were required. Most of these comments preferred the flexibility of lined pits or tanks, depending on the location or the specific situation. For example, the extra cost of storing flowback fluid in tanks may have no benefits in remote areas where there are no water sources which could be contaminated and no human populations that could be affected by airborne contaminants. Some of the comments suggested that the rule could require geo-textile or composite liners or double-lined pits with leak detection systems in order to reduce the risks of leakage. Other commenters raised the concern of unintended consequences of requiring tanks, such as increased truck traffic.

After reviewing these comments and comments relating to the definition of ''flowback,'' the BLM decided to make a number of modifications to final section 3162.3–3(h). First, because the BLM is not differentiating ''flow back'' fluid from produced water, the requirements in paragraph (h) will only apply to the fluids recovered between the completion of hydraulic fracturing and the implementation of a plan for the disposal of produced water approved under BLM regulations, which currently are in Onshore Order 7. This will ensure that recovered fluids are stored and handled in a way that minimizes the risk of impacts to air, water, and wildlife during the interim period (up to 90 days) while the BLM is reviewing the operator's long-term plan for the disposal of produced water. When the information is available, the BLM highly encourages operators to submit their plans for long-term storage of recovered fluids with their APD or NOI for proposed hydraulic fracturing operations to allow the BLM to evaluate the various aspects of an operator's development proposal under one review process, rather than multiple processes.

Second, the BLM agrees with the comments stating that the storage of flowback, or recovered fluid in pits, poses a risk of impacts to air, water, and wildlife. Therefore, this rule requires storage of recovered fluids in rigid enclosed, covered, or netted and screened above-ground tanks during the interim period before the operator implements a BLM-approved plan for the disposal of produced water under its regulations (currently in Onshore Order 7). The BLM believes that above-ground tanks, when compared to pits, are less prone to leaking, are safer for wildlife, and will have less air emissions. The BLM generally considers tanks as being constructed from a rigid material such as steel or fiberglass. The BLM realizes

that, if enclosed, tanks will still need to be vented to prevent the tanks from bursting or collapsing when filling or emptying the tanks and to compensate for changes in temperature. Venting will release some vapors into the atmosphere. Although a ''closed loop'' system would be approvable, we do not currently have an adequate basis to require such a system nationwide. However, the BLM supports states and tribes that require vapor-recovery or ''closed loop'' systems. Also, from the BLM's observations in the field, many operators already choose to use tanks in lieu of pits for temporary storage of recovered fluids to manage costs and timing of operations, and to control impacts to the environment and any resulting liability.

Third, the BLM agrees with the comments asking for the flexibility to allow lined pits based on site-specific conditions, but believes such exceptions should be limited and rarely granted. As a result, final section 3162.3–3(h)(1) allows the BLM to approve the storage of recovered fluids in lined pits on a case-by-case basis and only if the applicant demonstrates that the use of an above-ground tank is infeasible for environmental or public health or safety reasons only and all of the listed criteria are met. In circumstances where use of above-ground tanks has concomitant impacts to the environment, public health, and safety, the rule allows BLM to exercise its discretion to approve lined pits, but only if they meet all of the listed criteria. These criteria include minimum distances from water sources, public places, and residences, as well as potential floodplain impacts. If approved, the lined pit would be required to be constructed and maintained in accordance with final section 3162.3–3(h)(2), which requires the pit to be properly located, lined with a durable, leak-proof synthetic material and equipped with a leak detection system. Onshore Order 7 already establishes a standard for leak detection systems when disposing of produced water into lined pits. The minimum distances found in this section are similar to requirements found in Title 19, Chapter 15, Part 17 of the New Mexico Administrative Code. The BLM considers the criteria in this section as minimum requirements—if an operator proposes to store recovered fluid in a lined pit that does not meet one or more of these minimum requirements, the BLM would not approve the storage method. However, the BLM has the discretion to deny proposals to use lined pits that meet or exceed the minimum criteria, based on site-specific conditions. In no cases would the BLM allow the storage of recovered fluids in unlined pits.

Moreover, in the BLM's experience, the use of tanks in lieu of pits in high-volume operations limits potential environmental impacts, allows for quicker site preparation, reduces reclamation requirements, eliminates longer term environmental risk, reduces risks of spills or leaks, and increases safety. A tank can be removed in a day and there is no waiting required to recontour and seed the surface for reclamation purposes. The use of tanks for temporary storage of recovered fluids also provides the additional advantage of not requiring any long-term monitoring and mitigation. Pits also require periodic upkeep, monitoring, and fences. Several comments suggested that treatment and injection is the safest and most effective way to dispose of flowback fluids. The BLM did not revise the rule based on these comments because the ultimate disposal of recovered fluids is outside the scope of this rule, and, except for disposal on or in public lands, is outside of the BLM's regulatory authority.

In the BLM's experience, most operators use rigid, truck- or trailer-mounted tanks for temporary storage of recovered fluids, and those tanks are usually no larger than 500 bbl capacity. Large open-topped tanks, often called ''semi-rigid,'' can be susceptible to failures of seams or welds. Failure of a large-capacity tank containing recovered fluids would pose particular risks of harm to humans and wildlife because of the amount of fluid involved. Failures of large-capacity open-topped tanks have been documented. For example, between October 2011 and June 2013, there were five catastrophic failures of large-volume tanks reported to the Colorado Oil and Gas Conservation Commission (none of those tanks contained recovered fluids). Colorado has banned the storage of recovered fluids from such large-volume tanks.[8] For these reasons, the rule provides that tanks used for temporary storage of recovered fluids must not exceed 500 bbl capacity, unless approved in advance by the authorized officer.

Flowback vs. Produced Water

In the supplemental proposed rule, the BLM asked for comments on whether or not the rule should differentiate flowback fluids from produced water and, if so, how the two should be distinguished. Flowback fluids generally refer to the fluids recovered from the well immediately after hydraulic fracturing, presumably containing a high percentage of the fluids injected during hydraulic fracturing. Produced water is generally considered to be water from the hydrocarbon zone that is produced along with oil and gas.

Onshore Order 7 establishes requirements for the handling and disposal of produced water. If this rule did not distinguish flowback fluid from produced water, then Onshore Order 7 could be applied to all water produced from the well, including that water recovered from the well immediately after hydraulic fracturing. If this rule did distinguish flowback fluid from produced water, then unique handling, disposal, and reporting requirements could be imposed for the flowback fluid.

The majority of comments received regarding this issue recommended that the rule not try to distinguish flowback fluid from produced water. The primary reasons given were: (1) There is no way to define the difference between the two; and (2) They are both potentially hazardous and should be treated in the same manner. A minority of comments recommended that the rule establish special handling, disposal, and reporting requirements for flowback fluid. However, no clear or enforceable means of making the distinction was given. Several comments suggested a time-based approach (*e.g.,* flowback would end 10 days after the completion of hydraulic fracturing), while others suggested that the flowback period end when oil and gas production begins.

The BLM considered numerous different criteria on which to differentiate flowback fluid from produced water, including all the methods suggested in the comments. The BLM decided that any method of differentiation would be either arbitrary (*e.g.,* 10 days after the completion of hydraulic fracturing) or difficult to implement. For example, several states define flowback fluid as the fluid recovered prior to the production of oil and gas. However, the time at which the production of oil and gas begins is not always clear, therefore making this alternative difficult to apply. Often, some quantity of oil or gas is produced from the well almost immediately after hydraulic fracturing. In other cases, it might be days or weeks later. ''Production'' could mean whenever measureable amounts of oil and gas are detected in the recovered fluid or it could mean when oil and gas is produced in marketable quantities. Any method based on the quantity or quality of oil and gas production would need to

[8] Link to the Final COGCC Policy: *https://cogcc.state.co.us/RR_Docs_new/Policies/MLVTPolicyFinal20140613.pdf.*

be measured and tracked. Additionally, it is unlikely that the chemical constituency or toxicity of the recovered fluid would change significantly once oil and gas was detected; therefore, there would be no practical reason to make such a distinction.

Ultimately, the BLM decided not to make a distinction between flowback fluid and produced water and all references to the term ''flowback'' were removed in the final rule (sections 3162.3–3(d)(5), (i)(6), and (i)(7)). Instead, the term ''recovered fluid'' is used in the final rule for all fluids coming from the well after a hydraulic fracturing operation is complete. Also Onshore Order 7 generally applies to all recovered fluids, including those fluids recovered immediately after hydraulic fracturing. However, under Onshore Order 7, section III.A., an operator has permission to temporarily dispose of produced water from newly completed wells for up to 90 days, until an application for the disposal of produced water is approved by the authorized officer. This 90-day interim period is typically when the highest percentage of hydraulic fracturing fluid is recovered. The BLM determined that special handling provisions are necessary for fluids recovered during this interim period after hydraulic fracturing and revised section 3162.3–3(h) of the final rule as a result (see the discussion of pits versus tanks under section 3162.3–3(h)).

The BLM also revised the provision for reporting the volume of fluid recovered during flowback, swabbing, or recovery from production vessels in final section 3162.3–3(i)(6). Instead of reporting volumes of ''flowback'' in the subsequent report for an undefined period of time, the BLM determined that the ultimate goal is to have a complete record of all volumes recovered from a well, regardless of how it is defined or when it is recovered. ONRR requires operators to report the monthly volume of all fluids (oil, gas, and water) produced from wells on the Oil and Gas Operations Report, Part A (OGOR A). However, some operators do not start reporting on OGOR A until royalty-bearing quantities of oil and gas are produced, thereby leaving a potential gap in the reporting of recovered fluids. To fill this gap, paragraph (i)(6) in the final rule requires operators to report the volume of fluid recovered between the completion of hydraulic fracturing and the start of reporting on OGOR A. Because the subsequent report is due 30 days after the completion of the last stage of hydraulic fracturing, there may be situations where the subsequent report is filed prior to the start of reporting on OGOR A. In these cases, the operator would have to file an amended subsequent report showing the total volume of fluid recovered prior to the start of reporting on OGOR A.

Refer to Figures A and B for an example of how the BLM will implement the provisions of this rule. Both figures show the flow rate of fluid recovered after hydraulic fracturing over some time period. Typically, the initial flow rate is high and declines over time as the excess pressure caused by hydraulic fracturing is relieved. The area under the flow-rate curve represents the volume of fluid recovered over a given time period. In Figure A, the operator begins reporting produced volumes on OGOR A 10 days after the completion of hydraulic fracturing and submits its subsequent report 20 days after the completion of hydraulic fracturing. Because reporting of recovered volumes on OGOR A precedes submittal of the subsequent report, only that volume recovered between the completion of hydraulic fracturing operations and the start of reporting produced fluids on OGOR A would be reported on the subsequent report—12,000 bbl in this example. The additional 5,000 bbl recovered before the submittal of the subsequent report will be captured by the volumes reported on OGOR A, thereby providing a continuous record of the volume of fluid recovered for the life of the well.

In Figure B, the subsequent report is submitted on its due date (30 days after the completion of hydraulic fracturing), but reporting of produced fluids on OGOR A does not occur until 40 days after the completion of hydraulic fracturing. In this example, the operator would have to submit a supplemental subsequent report showing the total volume of 24,000 bbl recovered between the completion of hydraulic fracturing and the start of reporting on OGOR A.

BILLING CODE 4310–84–P

Figure A

Figure B

BILLING CODE 4310–84–C

Other Flowback Requirements

Several comments suggested that the BLM require that flowback fluid be tested prior to disposal. The BLM did not revise the rule as a result of this comment because disposal of recovered fluids is generally done off-site and under the authority of other agencies such as the EPA (for underground injection). Disposal on Federal or Indian land would be covered under Onshore Order 7.

One commenter suggested that the BLM create a manifest system to assure proper disposal of recovered fluids. While the commenter did not expound on what was meant by a ''manifest system,'' the BLM assumes it to mean a system of formal documented custody transfer ensuring that all flowback fluid removed from the site arrives at its destination (a disposal facility). Onshore Order 7 already requires the operator to submit a copy of the disposal facility's permit, and a right-of-way authorization if the wastewater would travel over Federal or Indian lands off of the lease. Other agencies regulate the transport and disposal of chemical wastes, and this rule does not interfere with those regulatory programs.

One comment suggested that the BLM should get rid of the Onshore Order 7 provision that allows the disposal of pit liquids through evaporation. No revisions to the rule were made as a result of this comment because it cannot be addressed at this final rule stage, but the BLM will evaluate and consider options for updating requirements under all of its existing Onshore Orders. This rule sets standards for the handling of recovered fluid until a disposal plan is approved by the BLM under Onshore Order 7. This rule does not amend Onshore Order 7.

Several commenters suggested that the rule should require the monitoring of constituents of flowback fluid. The BLM did not incorporate this suggestion because the goal of the rule is to contain the recovered fluids regardless of their chemical constituents. Disposal facilities often require an analysis of the fluid to be disposed; however, that is outside the scope of this rule.

Section 3162.3–3(i) Subsequent Report

This section lists information that the operator must submit to the BLM after the completion of a hydraulic fracturing operation and requires a disclosure of the chemicals used during the operation to FracFocus, the BLM, or another database that the BLM specifies.

The BLM strongly encourages operators to submit the chemical disclosure data through the FracFocus database. If data is submitted directly to the BLM, the BLM will upload it to Fracfocus.org. This will meet the goals and requirements of the rule most effectively by providing a direct public disclosure of the chemical additives used in the hydraulic fracturing operation. If the BLM finds that operators are avoiding use of FracFocus without a justification, such as temporary problems with the FracFocus site, the BLM will consider requiring a filing fee for chemical disclosure data submitted directly to the BLM.

Numerous changes are made to this section of the final rule. In the supplemental proposed rule, the 30-day time period for submitting the subsequent report would have begun when hydraulic fracturing operations were complete. In the final rule, the start of the time period begins after the last stage of hydraulic fracturing operations on each well is complete. This change is to clarify that in a multi-stage hydraulic fracturing operation, the operation is not complete until the last stage of hydraulic fracturing on each well is complete.

In section 3162.3–3(i)(1), the final rule clarifies that a description of the base fluid and each chemical added to the hydraulic fracturing fluid must be reported, instead of each chemical used. The BLM made this change to clarify that operators do not have to report chemicals that are found in the water used as a base fluid, whether taken from surface or groundwater, or reuse or recycled water. The word ''description'' is added for clarity.

The downhole information in section 3162.3–3(i)(2) of the supplemental proposed rule is moved to a new section (i)(5) of the final rule for clarity and to be consistent with the informational requirement of section (d)(3). Section (i)(2) of the final rule is now specific to water sources and section (i)(5) is specific to downhole information.

The pressure information in section 3162.3–3(i)(3) of the supplemental proposed rule is changed in the final rule to clarify that the maximum surface pressure at the end of each stage is required. The supplemental proposed rule would have required the ''actual surface pressure,'' which could be ambiguous. The maximum surface pressure is needed for the BLM to ensure that the pressure used in the MIT, as required in section 3162.3–3(f) of the final rule, was not exceeded.

Section 3162.3–3(i)(6) of the final rule redefines the period over which the volume of recovered fluids must be given in the subsequent report. In the supplemental proposed rule (section (i)(5)(i)) the volume of fluid to be included in the subsequent report was the amount recovered during flowback, swabbing, or recovery from production vessels. However, the supplemental proposed rule did not define the flowback period, or the period over which fluid recovery from swabbing or recovery from production vessels would have to be reported. The BLM determined that the goal of reporting recovered fluids is to have a complete history of everything that comes out of the well, regardless of how it is defined. Once an oil and gas well begins producing oil and gas, the monthly volumes of gas, oil, and water produced from each well must be reported on the OGOR A under 30 CFR 1210.102(a). Therefore, the only additional volumes that are needed to provide a complete history of fluids produced after hydraulic fracturing is the water produced immediately after hydraulic fracturing, but prior to the production of oil and gas that would trigger reporting on the OGOR A. If reporting on OGOR A does not start for more than 30 days after hydraulic fracturing—the timeframe in which the subsequent report is due—an amended subsequent report would have to be filed when OGOR A reporting started, showing the total volume of fluid produced since the completion of hydraulic fracturing.

Section 3162.3–3(i)(7) of the final rule (section 3162.3–3(i)(5) of the supplemental proposed rule) is revised to apply only to the handling and disposal of fluids recovered between the completion of hydraulic fracturing operations and the approval of a plan for the disposal of produced water under Onshore Order 7. The supplemental proposed rule would have required information on the handling and disposal of recovered fluids, but did not define what constituted ''recovered fluids.'' In addition, the examples of handling and disposal methods are revised to coincide with the information requirements in the hydraulic fracturing application in section (d)(5).

Section 3162.3–3(i)(7)(i) in the supplemental proposed rule would have required that the operator to certify that wellbore integrity was maintained under section (b) of the rule. Section 3162.3–3(i)(8)(i) of the final rule is reworded so that it is clear that the certification refers to compliance with paragraphs (b), (e), (f), (g), and (h) of this rule.

Section 3162.3–3(i)(9) of the final rule (section 3162.3–3(i)(8) of the supplemental proposed rule) is revised to eliminate the need to submit well logs and records of adequate cement (including CELs) under this section because the operator must already

submit these under other sections of this rule and with the BLM Well Completion or Recompletion Report and Log (Form 3160–4).

Subsequent Report Fracture Data

Several commenters were concerned that the specific fracture dimensions data required by this section (fracture length, height, and direction) could only be obtained through fracture modeling and requested that the BLM allow the use of fracture data gathered and modeled for similar wells, as opposed to requiring new modeling for every well. The BLM did not make any changes as a result of these comments. As provided by this section, fracture length, height and direction data can be actual, estimated, or calculated. The BLM is anticipating only hydraulic fracturing design estimates, and that hydraulic fracturing modeling is not required to meet this requirement. These data are obtained by some operators during the fracturing operation using microseismic fracture mapping, a diagnostic technique that measures created hydraulic fracture dimensions and their azimuth. The purpose of fracture data is to avoid potential interconnectivity between fractured pathways and either existing wellbores, *i.e.,* so called ''frack hits,'' or zones containing usable water.

Several comments suggested that the subsequent report compare the actual fracture dimensions with those estimated in the NOI. The BLM did not make any changes to the rule in response to these comments because the only method of verifying actual fracture dimensions is with a microseismic array, which the BLM is not requiring. The BLM believes that for the purpose of protecting ground water and identifying potential ''frack hits,'' estimated fracture dimensions are adequate. The estimated fracture dimensions are based on actual volume and pressure used during the hydraulic fracturing operation, and knowledge of the perforated string and the geology.

Timeframe for Submittal

Several commenters stated that the BLM should allow 60 days after completion of hydraulic fracturing operations for submitting the completion reports required under section 3162.3–3(i). Some commenters added that it takes the operator some time after the completion of operations to gather the information from their service contractors and to then compile the report accurately prior to submission. One commenter also indicated that for consistency with existing chemical disclosure reporting requirements of a couple of states (Colorado and North Dakota), the timeframe for submittal should be modified to 60 days. Another commenter suggested that the information could be submitted in an annual report. The BLM requirement to submit completion reports within 30 days after completion is consistent with the BLM's existing requirements under Onshore Order 1, section IV.e. Given experience with industry submission of information to the BLM, 30 days has been demonstrated to be an acceptable timeframe for accurate submissions. The BLM did not make any changes as a result of these comments.

''Fluid'' Ambiguity

One commenter suggested that the word ''fluid,'' as it is used in the rule to provide an estimated volume of fluid in the initial submission of hydraulic fracturing proposal under section 3162.3–3(d)(4)(i) and for reporting the volume of fluid recovered under section 3162.3–3(i)(6), is ambiguous. The commenter recommended that the BLM require reporting of the total volume of ''hydraulic fracturing fluid,'' including gas, used or injected into the well, stated in gallons or other appropriate volumetric units of measurement. The BLM recognizes that a fluid includes both liquids and gases and any device employed to measure liquid volume would also measure any suspended or dissolved solids in the liquid. The BLM has defined the term ''hydraulic fracturing fluid'' in section 3160.0–5 in this rule. This should provide the needed clarity. Therefore, under this rule, the word ''fluid'' includes the liquid or gas, and any associated solids used in hydraulic fracturing, including constituents such as water, chemicals, and proppants. The BLM did not revise the rule based on this comment because the wording in the supplemental and final rules addresses the commenter's concern.

Third-Party Certification and Reporting

One commenter stated that the term ''wellbore integrity,'' as used in section 3162.3–3(i)(7)(i) of the supplemental proposed rule is vague and undefined. The BLM agrees with that comment and has deleted the separate reference to ''wellbore integrity'' in the final rule, which is now designated section 3162.3–3(i)(8)(i).

One commenter stated that the BLM should remove the requirement to certify wellbore integrity that cross-references to usable water zonal isolation. The commenter states that section 3162.3–3(i)(7)(i) of the supplemental proposed rule would require that operators certify that well integrity was maintained prior to and throughout the hydraulic fracturing operation, as required by section 3162.3–3(b). Section 3162.3–3(b) directly refers to the performance standard in section 3162.5–2(d) on isolation of all usable water. The commenter stated that isolation of useable water does not ensure wellbore integrity. The BLM agrees. This section of the final rule, which is now designated section 3162.3–3(i)(8)(i), has been rewritten to require the operator to certify that the operator complied with the requirements in paragraphs (b), (e), (f), (g), and (h) of the section.

Another commenter said that operators should not be required to certify that isolation of usable water and mineral zones was achieved, and should only be required to use best efforts to isolate those zones, because isolation cannot be measured directly, but only inferred. The final rule is not revised in response to that comment. Isolation of zones of usable water or minerals is shown or inferred by data indicating that hydraulic fracturing fluids, recovered fluids, or oil and gas have not been lost from the wellbore in or around those zones. It is appropriate to require operators to review the reasonably available data concerning their operations and to certify that the data indicate that zonal isolation was achieved.

A commenter was critical of the certification requirement, arguing that it added nothing because operators are required to comply with all applicable regulations, and that terms such as ''treatment fluid'' and ''wellbore integrity'' are ambiguous. The commenter stated that an operator could in good faith believe that its certification was valid, but later it could be proved that there was an undiscovered problem. Although the BLM agrees that operators must comply with all applicable regulations, the BLM disagrees with the commenter's conclusions. The term ''treatment fluid'' is not used in the regulations. The reference to wellbore integrity has been deleted. The function of the self-certification is to require operators to conduct a good-faith review of the construction and operational data for any indication of problems. Certification of compliance with the requirements in paragraphs (b), (e), (f), (g), and (h) of the section is appropriate.

A commenter said that the requirement for an operator to certify its compliance with applicable law for operations on an Indian reservation is unnecessary and could result in ''serious litigation.'' The BLM disagrees. An operator on an Indian reservation is

responsible for knowing and complying with the applicable tribal and Federal law, just as an operator on non-tribal lands is responsible for knowing and complying with applicable state, local, and Federal law. The certification is an appropriate requirement in exercise of the Secretary's trust responsibilities to assure that the operator has reviewed and verified its own compliance with tribal law. A certificate signed in good faith and following reasonable efforts to verify compliance would not increase any risk of litigation.

One commenter recommended that the rule model its reporting and certification requirements (final section 3162.3–3(i)(1) and (i)(8), respectively) on the Colorado Oil and Gas Conservation Commission (COGCC) Rule 205 and 205A because these rules strike a balance between reporting obligations of operators versus service companies. Rule 205A is specific to hydraulic fracturing and is most relevant to this rule. The BLM did not revise the rule as a result of these comments. The reporting requirements under 3162.3–3(i)(1) and Rule 205A, paragraph b, are very similar. Both require the disclosure of the hydraulic fracturing operations, including the well name, the total volume of water used, and the types and amounts of chemicals used in the operation (with exceptions for trade secrets). Both also require that the information be submitted by the operator (Rule 205A.b(2)). The Colorado rule requires vendors and service companies to provide water volume and chemical data to the operator; however, the operator is ultimately responsible for submitting the information to COGCC. In this respect, this rule is consistent with the Colorado rule. Section 3162.3–3(i)(8) in the final rule requires the operator to certify that it complied with paragraphs (b), (e), (f), (g), and (h) of the rule, and that the hydraulic fracturing fluid constituents comply with all applicable Federal, tribal, state, and local laws, rules, and regulations. There is no corollary requirement in the Colorado rule. The BLM primarily has authority over the parties who hold or operate the lease—the lease being the instrument through which the BLM exercises its authority over the lessee or operator. No changes to the rule were made as a result of this comment.

One commenter said that the rule should be revised to improve the readability of sections 3162.3–3(i)(8)(ii) and (iii), which contain the phrase ''the hydraulic fracturing fluid used complied . . . .'' The commenter indicated that this phrasing makes no sense linguistically since hydraulic fracturing fluid does not comply, the operator complies. The BLM did not revise the rule as a result of these comments. The lead-in section for this certification section of the rule, now designated as section 3162.3–3(i)(8), clearly indicates that the certification signed by the operator contains the information that the hydraulic fracturing fluids used complies with all applicable permitting and notice requirements.

FracFocus

Some of the commenters noted that reporting requirements of the rule would reduce duplication of effort for the operators. They supported the provision in the rule that allows operators in states that require disclosure on FracFocus to meet both the state and BLM requirements through a single submission to FracFocus. The BLM agrees with these comments and did not make any changes to the rule.

Other commenters were critical of FracFocus for not being user-friendly and for not allowing republication or linking with other databases. The BLM has been in discussions with the GWPC, which is responsible for the FracFocus database, to address some of these concerns. As of June 2013, the FracFocus database was upgraded to FracFocus 2.0. Their latest upgrades are explained on their Web site under ''Frequently Asked Questions'' at *www.fracfocus.org/faq.* The BLM is in continued discussion with the GWPC and expects further progress and improvement of the site to ensure an effective chemical disclosure registry for the hydraulic fracture fluids. The BLM did not make any changes to the rule as a result of these comments.

Some commenters suggested that additional information, such as the APD, well status, compliance, volume of fluid recovered, and complaint process, should be reported through the FracFocus submission. While some of this information is available through the BLM, FracFocus only publishes information related to disclosure of chemicals used in hydraulic fracturing fluids. The BLM did not revise the rule as a result of this comment.

Some commenters were critical of FracFocus because of the unknown future condition and long-term reliability of this organization in hosting and retaining the data. A few commenters expressed concern about future funding, access, and data backup issues of FracFocus. Other commenters suggested that the disclosure registry should be searchable across forms and allow for meaningful cross-tabulation of search results. One of the commenters specified that each of the disclosure submissions should have a date stamp showing the actual date of submission to the database and validate/reject the correct/incorrect CAS Registry Numbers of the disclosed chemicals/ingredients when submitted. Another commenter suggested that the BLM should develop a new public disclosure platform tailored to the agency needs. The BLM considered these comments as valuable suggestions and will continue to work to improve any platform used for public disclosure. However, it did not make any changes in the rule because of these comments.

The BLM has reviewed the Secretary of Energy Advisory Board's FracFocus 2.0 Task Force Report, dated March 28, 2014, and its concerns and recommendations for FracFocus improvements as cited earlier in the preamble. Key issues raised include: The ability to search and generate information by chemical, well, company, and geography; quality control of data; and the capacity to handle large volumes of data. The BLM is committed to working with the DOE and FracFocus to ensure these issues are addressed so that public information gathered as a result of this rule is of high quality, accessible, and usable. As mentioned earlier, the GWPC and IOGCC, joint venture partners in the FracFocus initiative, announced the release of several improvements to FracFocus' system functionality. The new features are designed to reduce the number of human errors in disclosures, expand the public's ability to search records, provide public extraction of data in a ''machine readable'' format, update educational information on chemical use, environmental impacts from oil and gas production, and potential environmental impacts. The new self-checking features in the system will help companies detect and correct possible errors before disclosures are submitted. This feature will detect errors verifying that CAS numbers meet the proper format. These improvements to the system will address many of these concerns.

Many commenters addressed the use of the FracFocus database and Web site. Some commenters supported the BLM's proposal to allow submission of data through FracFocus. Other commenters, however, were critical of the proposal. Some commenters were concerned that the ownership of the data on FracFocus and the applicability of public disclosure laws, such as the Federal Freedom of Information Act (FOIA), are unknown. The Federal FOIA does not apply to FracFocus, because it is operated by the GWPC, which is not an

agency of the Federal Government. However, information on FracFocus concerning Federal or tribal wells is public information.

A commenter suggested that the BLM adopt a procedure used in Texas that requires operators to submit to the state commission a copy of the information that they upload to FracFocus. Under this final rule, submission of the required information through FracFocus is optional; an operator may instead submit it directly to the BLM, and the BLM will upload it to FracFocus. The BLM's intent, however, is to reduce the paperwork burden on operators by allowing them to submit information through FracFocus, if they so choose. Thus, in states that require submission on FracFocus, there would be no additional burden of complying with this requirement of the rule.

Some commenters said that using FracFocus would violate an Executive Order requiring new government information to be available to the public in open, machine-readable formats, and the implementing guidance from the Office of Management and Budget. See Executive Order 13642, 78 FR 93 (2013), and Memorandum for the Heads of Executive Departments and Agencies, M–13–13 (OMB 2013). That Executive Order provides, in pertinent part, that the policy of the Executive Branch is that new and modernized Government information resources must be open and machine readable. The order is subject to several conditions, including available appropriations.

That Executive Order does not prohibit the BLM from allowing operators to submit information through FracFocus. The BLM believes that FracFocus is the quickest, most cost-effective way to make the information public. Working with FracFocus to meet the policy goals of the Executive Order, including machine-readable formats, will be more prompt and will use taxpayer dollars more efficiently than would the BLM creating and managing its own database solely for chemical disclosures.

A commenter was concerned that using FracFocus could cause a conflict of interest because the GWPC is a trade association for the oil and gas industry. The BLM disagrees with this comment. The members of GWPC are the state agencies (*www.gwpc.org/state-agencies*) that protect and regulate ground water resources. They do not have a conflict of interest in operating FracFocus to serve as vehicle for operators to submit data to the BLM, or in making that information available to the public.

A commenter said that using FracFocus would fail to meet minimum standards for managing government records. The commenter misconstrues the role of FracFocus. FracFocus will not be the official repository of the chemical information required by the rule. Whether an operator submits information to BLM directly or through FracFocus, the BLM will keep the information in its records. The information will also be available on FracFocus for the benefit of the public and state and tribal agencies.

A commenter raised an issue of implementation and enforcement—that because FracFocus does not show the date that information is uploaded, it will be difficult for the BLM to know if the information was submitted within the time period required by the rule. The BLM will closely monitor FracFocus to ensure that operators submit information in a timely manner consistent with these regulations. The BLM will be working with the GWPC to improve the ability of FracFocus to meet the BLM's needs and of operators on Federal or tribal lands. The final rule is not revised in response to those comments.

Report Route Changes

One commenter expressed concern that operators may change their access route and transportation methods for water used in fracturing wells after the initial approval. The commenter suggested that operators be required to report any changes in approved access routes and transportation methods. Although not explicitly stated, operators are required to follow the approved plan along with any conditions of approval. This requirement includes using the approved access route and transportation method. Any change to the approved plan requires the BLM's approval. The Sundry Notice form itself addresses a change of plans. If the operator has a need to change the access route or transportation methods for water, they must file a change of plans. If the operator does not follow the approved plan along with any conditions of approval, the operator would be in noncompliance with the approval. The BLM would then take enforcement actions under 43 CFR part 3163. No revisions to the rule were made as a result of this comment.

Need for a Subsequent Report

Some commenters stated the information required to be submitted to the authorized officer within 30 days after the completion of the last stage of hydraulic fracturing operations under section 3162.3–3(i), is redundant, unnecessary, and burdensome. The commenters stated that much of the information is provided in the NOI and some of the information is already required with the completion report. The information in the application and the information in the subsequent report serve different purposes. The information in the application allows the BLM to analyze the proposed operations to ensure that there will not be any unnecessary or undue degradation of public lands or breach of trust on Indian lands, and to develop any necessary mitigation to protect resources. The purpose of the subsequent report is to provide information on what was done and how it was done, as compared to how it was planned. Some information, such as the results of the MIT and the cement operations monitoring report, are not included in the APD or NOI, and can only be submitted after the operations are complete. The information included with the subsequent report also differs from the information required with the well completion report. Examples include the results of the MIT and the operator certification that it complied with paragraphs (b), (e), (f), (g), and (h) of the rule prior to and throughout the hydraulic fracturing operation. However, final section 3162.3–3(i)(9) is revised in response to comments pointing out that the proposed requirement to submit well logs and records of adequate cement duplicates a requirement in the well completion report.

Fluid Volume Data

One commenter requested that the total volume of fluid injected during a hydraulic fracturing operation should be reported. Another commenter requested further subcategorization of water volumes, such as surface, subsurface, and recycled water. The BLM did not revise the rule as a result of these comments. During a water-based hydraulic fracturing operation, water and proppant generally make up approximately 98–99 percent of the fluid injected during a fracturing operation and other additives, such as friction reducers, surfactants, gelling agents, and scale inhibitors make up the remaining, usually about 1–2 percent. The difference between total fluid used and volume of water used is insignificant from a volumetric perspective. Other commenters were critical of the fact that the volumes of each chemical were not required to be reported in addition to the percentages of ingredients used. The maximum ingredient mass can be calculated from the percentages of ingredients reported. The BLM did not revise the rule because of these comments.

One commenter suggested that the BLM require operators to report their water usage to a public database to assure that water usage complies with state law and require operators to provide evidence of their water rights. The BLM does not need to see evidence of an operator's water right. Policing water rights is the duty of states and tribes, not the BLM. The rule already requires operators to report the total water volume used for each well. The BLM expects that most operators will report that information through FracFocus. This rule does not preempt any state or tribal law requiring operators to report water usage to another database.

Hydraulic Fracturing Fluid Constituent Data

One commenter stated that the post-fracking reporting requirements should clarify that the chemical disclosure is just for the chemicals added to the hydraulic fracturing fluids and do not include naturally occurring chemicals in the formation. The BLM concurs with this comment and section 3162.3–3(i)(1) is revised to clarify that the operator must submit a description of each additive in the hydraulic fracturing fluids. The chemical disclosure will include each additive in the hydraulic fracturing fluid used by the operator for conducting the hydraulic fracturing operation. Surface or ground water usually includes naturally occurring chemicals and may have pollutants from other sources. Re-used or recycled water will usually not be distilled, but rather have traces of chemicals from prior uses or by-products from processing. Those chemicals are not additives to the hydraulic fracturing fluids and will not be required to be reported as part of the disclosure. If the final rule required expensive chemical analysis of reused or recycled base fluids, it would discourage the use of reused or recycled water and put additional demands on surface or ground waters needed for drinking, agriculture, industry or ecosystems, and would increase the volume of recovered fluids needing permanent disposal. However, even if chemicals are naturally occurring in the formation, the same chemicals need to be disclosed if they are added to base fluid for hydraulic fracturing.

One comment stated that not all chemical compounds have CAS numbers and therefore could not be reported. CAS stands for Chemical Abstracts Service, a division of the American Chemical Society. The CAS number is a unique numerical identifier assigned to every chemical substance described in the open scientific literature. This registry is maintained by CAS and is internationally recognized. The BLM's review of disclosure reports on FracFocus indicates that the chemical substances added to base fluids are registered and have a CAS number. Therefore, the requirement for reporting a CAS number has not been changed. Multiple CAS numbers may be used if multiple chemical constituents are reported for one chemical compound.

Some of the commenters suggested that the BLM require both maximum and actual concentration of chemicals used. The BLM made no change to the rule because of this comment. Considering the objective of the chemical disclosure, the maximum concentration provides the worst case scenario, which is more important for environmental exposure, health, and safety of the operation. Percent by mass of each chemical is required in the hydraulic fracturing fluid to quickly evaluate potential exposure. Also, the actual concentration of chemicals may change as the operator fractures different stages of a single well. Thus, the maximum concentration provides the most useful information toward achieving the goal of protecting groundwater and developing potential response criteria.

A few commenters asserted that listing the maximum concentration of the non-MSDS-listed ingredients within an additive imparts no real value while increasing the risk that the disclosures could be used to reverse-engineer proprietary formulas for hydraulic fracturing additives. The BLM disagrees with this comment. The chemicals listed on Material Safety Data Sheets (MSDS) are believed to be hazardous to workers in an occupational setting as determined by the Occupational Safety and Health Administration (OSHA). Other chemicals which do not require MSDS, however, might be hazardous to humans in an environmental setting (such as in ground water used for drinking) or might be harmful to the environment. Therefore, disclosure of these chemicals, including the maximum concentration, is necessary. Section 3162.3–3(j)(1) of the final rule requires affidavits to validate the trade secret claims. This requirement will allow legitimate exemptions with proper documentation and attestations in compliance with the previously mentioned section. The BLM did not revise the rule as a result of this comment. Several commenters requested disclosure of the volume of proppant to be used along with the location where the proppant was mined or extracted. Final section 3162.3–3(i)(1) is revised to require a description of each additive in the hydraulic fracturing fluid, rather than just each chemical. While section 3162.3–3(i)(1) does not specifically require the volume of proppant to be reported, it does require that each additive to the hydraulic fracturing fluid be reported along with the maximum ingredient concentration in the hydraulic fracturing fluid. Because a proppant is an additive, it must be reported. The volume of proppant can be calculated from the percentages of ingredients reported. The BLM does not believe it to be appropriate to require the location where the proppant was mined or extracted because the BLM would have no authority over proppant extraction if it were not on public land. If it were on public land, it would require a separate authorization unrelated to these regulations. No changes to the rule were made as a result of this comment.

Some commenters asked that the BLM defer to states on matters of disclosure of information, including disclosure of chemicals used in hydraulic fracturing operations. These commenters said that states have the best knowledge of the geology, and have the experience and expertise to make the right decisions. The BLM agrees that state agencies are well-informed and have much experience and expertise, as does the BLM. However, chemical reporting requirements are not dependent on geological conditions. The final rule assures that the BLM, states, and the public will have access to information on the chemicals used in hydraulic fracturing operations on Federal and Indian land without imposing unreasonable burdens on operators.

Handling and Disposal

Several commenters suggested clarifying the language in sections 3162.3–3(i)(7)(i) and (7)(ii) (paragraphs (5)(ii) and (5)(iii) in the proposed rule) to better differentiate handling methods from disposal methods. The commenters pointed out that hauling by truck and transporting by pipeline are not disposal methods. The BLM agrees and modified the requirement to differentiate handling methods (*e.g.,* hauling by truck, holding ponds) from disposal methods (*e.g.,* injection, off-site disposal facility, recycling).

Several comments objected to the requirement that operators report the volume of fluid recovered from production facility vessels. The BLM agrees with this comment and has reworded this requirement in final section 3162.3–3(i)(6). See the preamble discussion under flowback fluids for a further explanation.

One comment requested that the composition of the recovered fluid be required as in the original proposed rule (77 FR 27710). The BLM did not revise the rule as a result of this comment because this was not a requirement in the supplemental proposed rule and because the BLM believes providing such information would not be useful. This rule aims to treat all recovered fluid as potentially hazardous regardless of what the chemical constituents may be.

Deviation From Permit

Numerous commenters stated that the rule should be modified to define what is meant by a ''deviation from the approved plan'' as required in the subsequent report after hydraulic fracturing operations have concluded. The commenters indicated that it is possible for numerous minor deviations to occur while conducting hydraulic fracturing operations, and that the BLM should identify any deviations it considers critical. Other commenters indicated that the BLM should request an explanation and additional information regarding issues believed to be potentially significant after the completion reports have been reviewed. The BLM agrees and has modified the rule as a result of these comments by deleting supplemental section 3162.3–3(i)(6). The BLM believes that due to the nature of hydraulic fracturing operations it is not practical to define, or list, all the myriad of outcomes and has deleted this specific requirement in the final rule. Anomalies or deviations are better handled through implementation, including both policy and training, and BLM engineers will identify and resolve deviations when reviewing completion reports as the BLM handles deviations involving approved APDs. This rule and the operating regulation provides for the authorized officer to request any additional information deemed necessary for review of the post-hydraulic fracturing operation on Federal or Indian leases.

Submission of Logs

Several commenters expressed concern about the requirement under the supplemental proposed rule (section 3162.3–3(i)(8)) requiring operators to submit well logs within 30 days of completion of hydraulic fracturing. A commenter stated this requirement is duplicative of the requirements of the BLM Well Completion or Recompletion Report and Log (Form 3160–4). The commenter stated that all logs are already provided with the completion report. The BLM agrees with this comment. As the commenter pointed out, operators are required to submit all logs with the BLM Well Completion or Recompletion Report and Log. Item 21 of the form requires the operator to specify the type of electric and other mechanical logs run and indicates operators are to submit a copy of each. Item 33 of the form requires the operator to indicate which items have been attached by placing a check in the appropriate boxes. The first box is for electrical/mechanical logs and in parentheses, the operator is reminded that ''1 full set req'd.'' Submission of the completion report and the logs is required by existing section 3162.4–1(b). Since the operators are already required to submit all logs, the requirement in supplemental section 3162.3–3(i)(8) has been deleted in the final rule.

Additional Information

Numerous commenters objected to the requirement in the supplemental proposed rule that the BLM can ask for additional information when reviewing an application for hydraulic fracturing. The commenters stated that this requirement is vague, unnecessary, and could lead to a broad interpretation by local BLM offices. The BLM did not revise the rule in response to this comment because the BLM must have the ability to ask for whatever information it needs to adequately review an application and fulfill our stewardship or trustee obligation. Because geology and operations vary widely, the BLM needs the flexibility to request information relevant to a specific or unique proposal and it would be unworkable for the BLM to list every possible piece of information that would cover all hydraulic fracturing applications.

Pressure

Several comments expressed confusion over which pressure the BLM required in the subsequent report. Supplemental proposed rule section 3162.3–3(h)(2) asked for the actual pump pressure, and section 3162.3–3(h)(3) asked for the actual surface pressure. The BLM agrees that these requirements were confusing and revised the final rule to only require the maximum surface pressure that was applied during the hydraulic fracturing operations. The requirements in this section were also revised to make them consistent with the requirements of the NOI in section 3162.3–3(d).

Section 3162.3–3(j) Information Exempt From Public Disclosure

This section sets out the circumstances and procedure under which operators may withhold information from public disclosure under the rule. An operator may withhold information as exempt from public disclosure only if it identifies a Federal statute or regulation that would prohibit the BLM from disclosing the information if it were in the BLM's possession. The BLM anticipates most if not all exemption assertions will be made under the Federal Trade Secrets Act, 18 U.S.C. 1905, a criminal statute which prohibits Federal employees from divulging trade secrets and other confidential information without authorization. The supplemental proposed rule would have allowed operators to withhold information otherwise required to be submitted by executing an affidavit affirming that the information was a trade secret. The final rule modifies the supplemental proposed rule at section 3162.3–3(j) in several respects. The list of items that the operator must affirm has been expanded to more completely address the factors that are needed to support a claim of exemption from public disclosure. The operator's affidavit must also identify any other entity, such as a contractor or supplier, which would be the owner of the withheld information. The operator must submit an affidavit from such entity that provides any information upon which the operator relies in executing the operator's affidavit. The operator must affirm that it has possession of the withheld information so that BLM would have access to it upon request. A corporate officer, managing partner, or sole proprietor must sign the operator's affidavit. Finally, the operator must maintain the withheld information for the later of the BLM's approval of the final abandonment notice for the well, or for Indian lands, 6 years, or for Federal lands, 7 years, as provided under existing applicable law discussed below. As in the supplemental proposed rule, the BLM may require the operator to provide the withheld information.

The BLM received numerous comments concerning trade secrets and confidential business information. Some commenters were critical of allowing operators to withhold any information from the public. Other commenters were critical of the role of the BLM in deciding whether information would be entitled to protection.

A commenter suggested that the BLM defer to states on the handling of trade secrets claims, asserting that they were state and tribal issues, and should be regulated by those authorities. Further, the commenter believed that states and tribes were better versed in hydraulic fracturing operations, and could be

stricter than the Federal Government. The BLM did not revise the rule in response to this comment. No Federal statute allows the BLM to defer to decisions of states or tribes about what information in the BLM's possession will be released to the public, or what information the BLM would allow operators to withhold from the public.

Some commenters were critical of the supplemental proposed rule for not being the same as state rules on trade secrets. Many states have adopted the Uniform Trade Secrets Act, or have other laws governing protection of proprietary information. Those state statutes do not govern the BLM's compliance with the Federal Trade Secrets Act, and the Federal Trade Secrets Act does not apply to state governments. Thus, the BLM is not in a position to concur or to disagree with a state's ''trade secret list,'' as suggested by a commenter. The BLM understands concerns about duplication of efforts or the potential for inconsistent determinations. If a state agency has released information to the public without restrictions, that information would not qualify as a trade secret and the BLM would not withhold it from the public. Nothing in this rule preempts state or tribal laws requiring disclosure of information or protecting proprietary information.

Several commenters stated that if the BLM continues to allow exemptions from public disclosure for information on chemical identities in the final rule, it should at least require identification of the chemical family of the substance. The commenters stated this basic information does not implicate an operator's trade secrets, but provides at least some information about what types of chemicals were used by the operator in well stimulation. The commenters point out that such a rule is feasible because a number of states require that the chemical family be disclosed where a chemical's identity is withheld as a trade secret. Those states include Arkansas, Colorado, Louisiana, Montana, Oklahoma, Pennsylvania, and Texas. The BLM reviewed numerous hydraulic fracturing disclosure reports in FracFocus. The review revealed that many operators are providing the chemical family name or other similar descriptor for those chemicals that are protected as trade secrets. Those include reports from states that do not have a specific requirement to report on FracFocus, and thus were voluntarily disclosed.

A commenter recommended that the rule require disclosure of the generic chemical name as required under EPA's guidance implementing section 5 of the Toxic Substances Control Act (TSCA). See Instruction Manual for Reporting Under the TSCA § 5 New Chemicals Program, p.33 (EPA 2003). The BLM believes that the generic chemical name that was or should be provided to the EPA under TSCA or other statutes and published in the **Federal Register** would not constitute a trade secret because it is or should be public, and the operator can still withhold the specific chemical identity. The BLM also concludes that requiring the generic chemical name would promote consistency with the EPA's implementation of TSCA and other statutes for confidential chemical information, and thus would be less confusing for owners of information and the public. Therefore, final section 3162.3–3(j)(6) requires the operator to include the generic chemical name for each such chemical. The BLM expects that the generic chemical name submitted pursuant to this rule will be the same as that submitted to EPA; if the generic chemical name is less descriptive than that submitted to EPA, the owner of the information should have a credible explanation for the difference.

The supplemental proposed rule at section 3162.3–3(j)(4) would have required operators to retain in their records the information they claimed to be exempt from disclosure for 6 years, by reference to the existing regulations at 43 CFR 3162.4–1(d). The rule expressly requested comments on whether another retention time would be more appropriate. The BLM received many comments on that topic. A few commenters favored the 6-year retention period, though more favored shorter periods. Many other commenters favored longer retention periods; several favored that records be retained for the life of the well, and a few advocated perpetual retention.

Final rule section 3162.3(j)(5) requires operators to retain information that is withheld from the BLM until the later of the approval of the notice of final abandonment of the well (*i.e.,* the ''life of the well''), or 6 years after the completion of hydraulic fracturing operations on Indian lands, or 7 years after completion of hydraulic fracturing operations on Federal lands. The BLM's need to have access to information about chemicals injected into Federal or Indian minerals may arise at any time. However, a perpetual retention requirement would not be appropriate because an operator's responsibility for a well ends (for purposes of most of the BLM's regulations) when the BLM approves the operator's notice of final abandonment of the well.

A 6-year minimum retention period on Indian lands is not burdensome because operators are already required under the Federal Oil and Gas Royalty Management Act (FOGRMA) and regulations to retain all records for a minimum of 6 years, including records and reports they submit to the BLM. See 30 U.S.C. 1713(b); 43 CFR 3162.4–1(d).

A 7-year minimum retention period is not burdensome because operators on Federal lands are already required under the Federal Oil and Gas Royalty Simplification and Fairness Act of 1996 (FOGRSFA), 30 U.S.C. 1724(f), to retain all records for determining compliance with any regulation with respect to Federal oil and gas leases for 7 years. BLM's regulations at 43 CFR 3162.4–1(d) have not been updated to reflect that statutory obligation, but there is no impediment to this final rule requiring retention of data for a minimum of 7 years. Although FOGRSFA precludes the BLM from requiring longer retention of records pertaining to financial obligations (such as royalties), it does not preclude longer retention of records pertaining to other requirements for onshore oil and gas operations. FOGRSFA does not apply to Indian lands, and therefore the 6-year retention period in 30 U.S.C. 1713(b) applies to those lands.

Requiring trade secret records to be retained for the life of the well, if that life is longer than 6 or 7 years, is fair and reasonable because if an operator withholds the information under the rule (section 3162.3–3(j)(1)) the operator's records of the withheld information may be the only records of the chemicals injected into Federal or Indian minerals. Therefore, the BLM believes that it is necessary to have access to that information for the life of the well, and that the 6-year and 7-year retention periods in the pertinent statutes are minimum requirements with respect to records that do not pertain to financial obligations.

Some commenters said that the rule would fail to protect trade secrets, or that it mandated disclosure, putting the BLM and its employees at risk of lawsuits. The BLM disagrees. This rule, like the supplemental proposed rule, allows operators initially to withhold specific information by submitting an affidavit from the operator demonstrating that the information is protected from disclosure by law. The BLM retains authority to require operators to submit any of the initially withheld information. If the BLM decides that the information is not a trade secret, it would provide advance notice so that the operator or owner of the information could seek a court order

restraining disclosure to the public. The rule provides the same procedural safeguards for hydraulic fracturing information as for all other information obtained by the Department.

Some commenters expressed confusion about who would determine whether identities of chemicals were entitled to be withheld from the public as trade secrets. Under this final rule, in the first instance, the operator would either disclose the information or would withhold specific information and submit an affidavit. If the BLM requested the withheld information, the operator would be required to provide it. The BLM would determine if the information is a trade secret. As described earlier, if the BLM determines that the information is not a trade secret, the operator and owner of the information would have an opportunity to challenge the BLM's determination in Federal district court.

Some commenters were critical of the revised proposed rule for not defining trade secrets. The Federal Trade Secrets Act does not define trade secrets, and does not expressly authorize Federal agencies to define trade secrets. The BLM will make any decisions regarding trade secrets and other confidential information based on relevant Federal judicial opinions. See, *e.g., Canadian Commer. Corp.* v. *Air Force,* 514 F.3d 37, 39 (D.C. Cir. 2008) (''We have long held the Trade Secrets Act . . . is 'at least co-extensive with . . . Exemption 4 of FOIA.' '') (citation omitted); *National Parks & Conserv'n Ass'n* v. *Morton,* 498 F. 2d 765 (D.C. Cir. 1974) (discussing meaning of privileged or confidential commercial or financial information); *Public Citizen Health Research Group* v. *FDA,* 704 F.2d 1280, 1288–89 (D.C. Cir. 1983) (''trade secret'' in exemption 4 means a ''commercially valuable plan, formula, process, or device that is used for the making, preparing, compounding, or processing of trade commodities and that can be said to be the end product of either innovation or substantial efforts'').

Other commenters asserted that 10 business days' notice before releasing information was insufficient, and one said that it would stifle development of more environmentally benign chemicals. The BLM disagrees. Similar to the Department's FOIA regulations, the final rule requires a minimum of 10 business days' notice prior to releasing information determined not to be exempt from disclosure. Cf. 43 CFR 2.33(c). That time is sufficient for the submitter to seek a temporary restraining order from a court. Also, the BLM would give due consideration to all relevant factors, including whether the information is the end product of innovation, in deciding whether the information is a trade secret.

Many commenters objected to the requirement that the operator certify that withheld chemical information is a trade secret. They said that the trade secrets are owned by the service contractors, and that the operator has no knowledge of them or ability to certify. Some said that the BLM should place the burden on the service contractors and not the operator. One commenter said that chemical manufacturers invest great sums in developing their products, and should not have to rely on oil and gas operators (or apparently, service providers) to assert and defend their trade secrets. The BLM disagrees in part. The BLM is aware that the common practice is for operators to engage service companies to conduct hydraulic fracturing services. The existing regulations are clear, however, that an operator cannot use a contract with a third party to escape responsibility for all operations on the permitted well site. See existing section 3162.3(b). Whether or not chemical suppliers or service contractors would ''own'' the information about the chemicals, it is the operator who has voluntarily taken responsibility for all operations in and on its wells, including hydraulic fracturing, and it is the operator who is responsible for submitting all required reports and information. Nonetheless, because the operator will not always be in the best position to declare why certain information should be withheld, the final rule allows the operator to submit an affidavit from the owner of the information attesting to the confidential status of the information in addition to the affidavit required from the operator. When the BLM is deciding whether alleged trade secret information it has received may be disclosed to the public, both the operator and the owner of the information may provide the BLM with any materials that would substantiate a claim of trade secret status, and both the operator and the owner of the information would receive advance notice of any BLM decision that the information is not a trade secret.

Some commenters asked that trade secret protection be extended to other required information, such as elements in the NOI. As with any submission of information to a Federal agency, the submitter may segregate the information it believes is a trade secret, and explain and justify its request that the information be withheld from the public.

Many commenters addressed other issues concerning trade secrets. Some commenters opposed allowing operators to withhold trade secrets from public disclosure. Other commenters asserted that the BLM was arbitrarily ignoring the recommendations of the Secretary of Energy's advisory task force that all chemicals should be disclosed to the public without exception. The BLM has no authority to require public disclosure of information that is entitled to protection under the Federal Trade Secrets Act. There is nothing arbitrary in assuring the compliance of BLM employees with a Federal criminal statute.

Some commenters said that the BLM's authority to promulgate regulations provides the BLM authority to require public disclosure by regulation, obviating protection under the Trade Secrets Act, citing, *e.g., Chrysler Corp.* v. *Brown,* 441 U.S. 281 (1979) [*Chrysler*]. The Supreme Court in *Chrysler* established a three-part test for determining whether an agency rule may exempt information from the Trade Secrets Act: (1) The rule must be substantive; (2) It must be issued in accordance with statutory procedures; and (3) The rule must be based on a statutory grant of authority allowing the agency to disclose privileged information. This rule satisfies parts 1 and 2 of the *Chrysler* test. But the BLM's authorizing statutes do not expressly authorize regulations requiring disclosure of privileged information. Thus, the final rule is not revised in response to those comments.

Some commenters urged the BLM to require operators to submit trade secret information to the BLM, even if the BLM was required to maintain confidentiality, in order to encourage operators to make only good faith claims of trade secret protection. Some commenters said that the BLM should require operators to justify their trade secret claims. Some commenters said that the BLM should individually validate each claim of trade secret status. The BLM believes that the affidavit requirements are sufficient to assure that the vast majority of operators will assert only good faith claims for trade secret protection. But although the BLM will not be individually adjudicating each claim of trade secret status, the BLM agrees with those commenters in part. The BLM has revised the affidavit requirements to address all of the factors that the BLM would need to consider in deciding whether to release the information. The final rule requires the operator to affirm that it or any other owner of the information is in actual competition, identify competitors that would be interested in the withheld information, and affirm that release of the

information would likely cause substantial competitive harm and provide the reasons for that affirmation. If the operator is relying on information from its contractors or suppliers, the operator will need to provide affidavits from those entities supporting that reliance. Although additional supporting facts might be required if the BLM had to decide whether the information is a trade secret, the BLM could request those additional facts. Furthermore, the final rule requires that the affidavit be signed by a corporate officer, managing partner, or sole proprietor of the operator. That will discourage bad-faith assertions of trade secret protection.

A commenter suggested that, in addition to the affidavit, an operator should be required to provide independent verification that the information is a trade secret. The BLM will not require an operator to disclose proprietary information to an industry trade group as suggested by the commenter, in order to assert trade secret protection. Even if it were within the BLM's discretion, it would place industry trade groups in a role they have not requested.

Some commenters suggested that the BLM establish a procedure for citizens to challenge affidavits for withholding trade secret information. The BLM's resources will be better devoted to implementing this rule to assure protection of usable water from hydraulic fracturing fluids than in adjudicating uncontrollable numbers of challenges to affidavits. If the BLM has reason to believe that an affidavit is incomplete or inaccurate, or that it needs the information for any purpose, including a random inspection, it can demand the withheld information and make a determination if it is truly a trade secret. Additionally, the BLM encourages voluntary disclosure of fracturing fluids to the public, as some companies in the oil and gas industry have begun to do. Some commenters urged the BLM to require operators to disclose trade secret information in the event of a medical emergency. Other commenters stated that the material safety data sheets (MSDS) required by the OSHA are adequate for disclosure to medical personnel and first responders. The BLM understands the need for first responders and medical personnel to have complete information about potential chemical exposures in the event of an accident. However, unlike many state laws, the Federal Trade Secrets Act does not include an exception for medical or other emergencies. If the BLM requests the withheld information, and any Federal law required the BLM to provide it to another entity, the BLM would comply with that law. Note though, however, that nothing in this rule exempts operators or their contractors from complying with all applicable regulations of the OSHA, including requirements concerning MSDS. Furthermore, nothing in this rule preempts laws of states and localities (on Federal lands) or of tribes (on tribal land) requiring disclosure of information to first responders or to medical personnel.

Some commenters doubted the BLM's ability to make informed management decisions without complete information about the chemicals being used. The BLM disagrees. The BLM understands that hydraulic fracturing operations will use chemicals that are potentially hazardous. Compliance with this rule will assure that those chemicals are isolated from sources of usable water.

A commenter suggested deleting the ''maximum ingredient concentration in additive (percent by mass)'' requirement, arguing that it would have the effect of creating more trade secret exemptions, and that from an environmental perspective, what matters is the total concentration of a chemical. The BLM believes that the comment has merit, but there are costs and benefits to either approach. On balance, the rule is not revised in response. On the one hand, it is possible that if the rule does not require the percent by mass maximum ingredient concentration, more of the chemicals used in hydraulic fracturing operations would be disclosed because the risk of reverse-engineering would be reduced. On the other hand, the GWPC requests the percent by mass on its FracFocus data sheet and the industry has shown a willingness to furnish that information. As a result, the final rule requires disclosure of the percent by mass. The BLM notes that operators may seek to withhold the percent by mass as a trade secret, and to disclose the identity of the particular chemicals. That could be appropriate where the particular chemicals are not unusual, but the operator believes it has a valuable formula that optimizes the concentrations.

A commenter recommended that trade secret protection be denied unless there were a patent or a patent application pending for the chemicals. The Federal Trade Secrets Act does not have such a restriction and the BLM has no authority to impose one in this regulation. The final rule is not revised in response to that comment.

Some commenters recommended that operators should be able to obtain trade secret protection prior to conducting hydraulic fracturing operations, either in an NOI, or in a ''master chemical plan.'' The BLM disagrees. The BLM is not requiring submission of the identities of chemicals proposed to be used in hydraulic fracturing operations. Only the chemicals actually used in those operations would need to be either disclosed, or withheld by submitting an affidavit. The final rule is not revised in response to those comments.

Some commenters expressed uncertainty about what statute would prohibit disclosure of the identities of chemicals for purposes of final section 3162.3–3(j)(1)(ii). The BLM believes that most claims would be made under the Federal Trade Secrets Act, but the final rule leaves the category open in case any other statute might apply to certain information. The final rule is not revised in response to these comments.

A commenter recommended changing the affirmation required in the affidavit to ''the best of the operator's knowledge at the time.'' The final rule is not revised in response to that comment. Withholding the identities of chemicals injected into Federal or Indian minerals is a privilege, and to earn that privilege the operator must make informed declarations in the affidavit. If the operator is relying on information from a contractor or supplier, the rule requires that the operator provide an affidavit from that entity setting forth that information.

A commenter recommended deleting the affirmation as unnecessary. The BLM disagrees. The BLM believes that the affirmation is appropriate and has not revised the rule in response to that comment.

Some commenters urged that the records of the chemical identities withheld as trade secrets should be retained by the service contractors, not by the operators. As previously explained, operators are responsible for their contractors' actions on the well sites. Maintaining accurate and complete well records with respect to all lease operations is the operator's responsibility. See existing section 3162.4–1(a). Indeed, the admissions in comments that some operators are not currently retaining all information about hydraulic fracturing operations raise concerns. Note though, that nothing in the rule prevents an operator from maintaining the confidential information under a physical or an electronic seal that would notify the owner of the information when it was accessed, as long as the BLM will have access to it upon request.

Furthermore, in response to comments stating that owners of trade secret chemical information would not allow operators to possess it, the final rule provides that an operator will be deemed to be maintaining the required information if it can promptly provide it to the BLM upon request, even if the information is in the custody of its owner. Any successor operator will be responsible for maintaining that access for the retention period in this rule.

Section 3162.3–3(k) Variances

This section allows operators to request a variance from the requirements of this final rule. Variance language is common among BLM regulations. Under this provision, the BLM will consider alternatives if an operator can demonstrate that the objectives of the rule would be met using an alternate approach.

Three changes are made to this section. First, this section is reorganized for clarity, segregating requirements for individual variances and state or tribal variances. Second, this section has been revised to clarify that the authority to approve a variance that applies to all wells within a state or within Indian lands, lies with the State Director. Third, this section has been revised to make paragraph (k)(3) consistent with existing regulations in Onshore Order 1 by adding language stating that the decision on a variance request is not subject to administrative appeal either to the State Director or under 43 CFR part 4.

Numerous commenters said that the rule should be revised to prohibit blanket variances for operators. The BLM did not revise the rule as a result of these comments. No blanket variance provisions for hydraulic fracturing operations exist in the rule. As provided, variances may be granted on a case-by-case basis from a specific provision of the rule, within a state, or on a tribal basis. Individual variances could only be granted where the operator's proposal meets or exceeds the objectives of the rule, and state or tribal variances may only be granted if the state or tribal provisions meet or exceed the objectives of the rule. A variance granted pursuant to this rule would not be an exemption from the goals of this rule, and would not be an abdication of the Secretary's stewardship responsibilities on Federal lands or trust responsibilities on Indian lands.

Numerous commenters stated that the rule should be revised to disallow variances of any kind or that variances should be limited. The BLM did not make any changes as a result of these comments. The BLM believes that it is practical to include a variance provision since the rule cannot contemplate all possible hydraulic fracturing circumstances which may be encountered on a national basis and must include provisions to address those unique or local circumstances, or improved technologies. The BLM believes, however, that variances should only be granted when it is clear that the alternative requirement is equally or more protective than the BLM's rule.

Several commenters indicated that the variance definition is vague and could allow for waiving of hydraulic fracturing requirements. Other commenters requested further clarification or suggested alternative language for this section. The BLM did not revise the rule as a result of these comments. While the rule does not contain a specific variance definition, the variance provisions in the rule are substantially similar to existing provisions in 43 CFR 3162.7–5(b)(9) as well as in Onshore Orders 2 through 7 regarding variances. All hydraulic fracturing operations on Federal or Indian leases must still meet or exceed the objectives of the requirement for which a variance is being requested.

Several commenters said that the rule should be revised to include the procedure and criteria for requesting a variance. The commenters indicated that the rule should provide clarification on the variance-issuance process and expressed concern that the supplemental proposed rulemaking contained no mechanism to notify the public. The BLM did not revise the rule as a result of these comments. Throughout this rulemaking the BLM has been aware that members of the public are concerned about hydraulic fracturing. While specific processing details regarding hydraulic fracturing variances have yet to be developed, the notification process may be made available to the public for statewide and tribal variances. The BLM will post all variances on its Web site.

Several commenters said that the rule should be revised to address how variances will be implemented. Other commenters indicated that all variances should be written; that no oral variances should be allowed. The BLM did not revise the rule as a result of these comments. The final rule specifies the procedural steps for several different variance processes.

Additionally, final section 3162.3–3(k)(1) contains no provision for oral variances. The BLM envisions that the majority of case-by-case variances will be authorized in the same manner as existing variances are authorized and that is via Sundry Notices. Each variance request must contain specific information justifying why a variance is needed. For state or tribal variances, the provisions will depend on the formal agreement between the involved agency and the BLM. It is not possible to envision or regulate all the possibilities and therefore these rules provide flexibility and discretion to the local BLM manager.

Several commenters expressed concern regarding section 3162.3–3(k)(5) in the final rule (paragraph 3162.3–3(k)(4) in the supplemental proposed rule) which allows the BLM the right to rescind a variance. The commenters stated that this is extraordinarily broad language that does not provide any factual criteria that the BLM must meet before modifying or revoking a variance. In their view, the proposed variance process fails to provide operators with a reasonable assurance that regulatory requirements will not arbitrarily change. Commenters also stated that if the variance language remains in the rule, the BLM should be required to provide operators notice of its intent to rescind or modify a variance in writing, provide operators at least 30 days to respond, and provide that any final decision on variances not become effective until at least 30 days after receipt by the operator. The BLM agrees in part. The authorized officer will grant a variance only if the BLM determines that the proposed alternative meets or exceeds the objectives of the regulation for which the variance is being requested. The BLM understands that operators are likely to rely on a variance in planning and executing their operations. A decision to rescind a variance would only occur after a thorough internal process has been undertaken. But if the BLM later determines that a particular variance fails to meet the objectives of the regulation, the BLM must retain the right to rescind that variance. In addition, changes in Federal laws or changes in technology may dictate the need to rescind a variance. While the BLM appreciates the issues raised by the commenters, these concerns do not override the BLM's responsibility to manage the public lands to prevent unnecessary or undue degradation, and to assure proper resource protection on Federal and Indian lands. While no timeframe is described, the rule requires that the authorized officer provide a written justification if a variance is rescinded. The rule does not require prior notification, but it also does not prohibit the local BLM manager from providing prior notification of a rescission of a variance when

appropriate. No revisions to the rule were made as a result of these comments.

State and Tribal Variances

Numerous commenters said that the rule should be revised to establish the process for state-initiated variances. Commenters indicated that the rules lacked specificity in this regard and provided specific language for a ''state equivalency determination'' process which enumerated the steps a state agency would utilize as well as the process that binds the BLM in reviewing and approving such proposals. The BLM did not revise the rule as a result of these comments. State or tribal variances would be approved as a result of discussions among the BLM and the state or tribal agencies, which do not require a rigid process specified in regulations. A state or tribal variance is not a delegation of full or partial regulatory primacy, so a ''state equivalency determination'' process is neither necessary nor appropriate.

One commenter supported section 3162.3–3(k), which allows for the BLM to work in cooperation with a tribe and issue a variance that would apply to all wells within Indian lands or to specific fields or basins within Indian lands. The commenter, however, recommended that the rule be expanded to include the process that tribes would use to initiate a variance. The BLM does not believe the rule needs to be expanded to include the specific mechanism for approving variances with tribes since it may vary from tribe to tribe. The BLM will work cooperatively with any tribe or state to craft variances that would allow technologies, processes, or standards required or allowed by the state or tribe to be accepted as compliance with the rule. Such variances would allow the BLM and the states and tribes to improve efficiency and reduce costs for operators and for the agencies.

Numerous commenters stated that the rule should be revised to provide for statewide exemptions from the hydraulic fracturing rule. Other commenters suggested modifying the variance section so that the BLM's hydraulic fracturing rule should only apply in those states which do not have hydraulic fracturing rules. The BLM did not revise the rule as a result of these comments. The Secretary of the Interior has stewardship responsibilities on public lands and trust responsibilities on Indian land. Accordingly, the BLM is promulgating a rule that governs hydraulic fracturing operations on all Federal and Indian leases. While the BLM does not provide for statewide exemptions from the entire hydraulic fracturing rule, variances may be granted for individual provisions of the rule, if the variance proposal meets or exceeds the objectives of the rule. The BLM encourages formal agreements with state or tribal agencies to avoid overlap and promote cooperation amongst regulatory bodies and to reduce compliance burdens on operators.

Numerous commenters said that the rule should be revised to recognize existing state agency rules. The commenters indicated that under such a provision the need for any variance would then be redundant because all proposals would clear the ''meets or exceeds'' state threshold. The BLM did not revise the rule as a result of these comments. While numerous states have hydraulic fracturing rules in place or are currently contemplating hydraulic fracturing rules, the applicability and content of these rules are not consistent across all BLM-managed public lands in those states. Additionally, certain states do not have hydraulic fracturing rules at all. In addition, state rules may not apply to tribal lands. The BLM will work closely and cooperatively with state and tribal agencies to implement these rules to avoid overlap and duplication where possible. Formal agreements with state and tribal agencies are encouraged.

Numerous commenters said that the rule should be modified to allow for statewide or tribal variances. Commenters indicated that states should regulate hydraulic fracturing operations on all lands within that state by memorandum of understanding. The BLM agrees with those comments in part, and has modified the rule as a result of these comments. The rule has been edited to clarify that there are two types of variances: Individual (or operator-specific), and state or tribal (for wells on all or designated portions of state or tribal lands). As provided, variances may be granted to states and tribes, only if the state or tribal requirements meet or exceed the objectives of the rule. The rule also provides that state or tribal variances maybe initiated by the involved state, tribe, or the BLM.

The BLM may approve a variance under paragraph 3162.3–3(k) from one or more specific requirements of the rule, but not from the entire rule. The variance provision does not allow the BLM to delegate regulation of hydraulic fracturing operations on public or Indian lands to state agencies. Unlike several other environmental statutes, none of the BLM's statutory authorities authorize delegation of the BLM's regulatory duties to state or tribal agencies.

Section 3162.5–2(d) Isolation of Usable Water

The changes to this section conforms the out-of-date language in this section with the Onshore Order 2 requirements. Onshore Order 2 superseded the existing regulations in 1988, because it was promulgated pursuant to notice-and-comment rulemaking. Since the final rule is consistent with Onshore Order 2, it does not represent a change in policy.

The BLM received numerous comments on the subject of usable water. Those comments are addressed under the section 3160.0–5 discussion in this preamble. This section is not revised in the final rule and remains as proposed.

General Comments

Incorporate API Standards

Several commenters recommended that the BLM adopt American Petroleum Institute (API) Guidance Document HF1, First Edition (October 2009) (HF1) instead of developing its own standards. During the development of the rule, the BLM not only considered all comments received but also consulted numerous other sources including API HF–1, state regulations, and academic and professional papers such as King, George, SPE 152596, ''Hydraulic Fracturing 101: What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor, and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells,'' Society of Petroleum Engineers, Hydraulic Fracturing Technology Conference, (Feb. 2012). The BLM does not believe that the rule should incorporate any particular guidance. Although the BLM has carefully considered the API HF1 and HF2 guidance as we developed this rule, the BLM cannot fully incorporate the guidance documents because they do not meet all of the BLM's areas of concern for protection of resources on Federal and Indian lands. Moreover, nothing in this final rule precludes an operator from following recommended industry guidance. See the following table for a comparison of applicable components of API HF1 guidance and the final rule.

Subject	API HF–1	Final rule/Onshore Order 2
Surface casing	Set at least 100′ below lowest USDW (deep water zones can be isolated by intermediate or production casing).	Usable water must be isolated by casing (not necessarily by surface casing).
	Cement to surface	Cement to surface (Onshore Order 2). If no cement to surface, must identify top of cement with CEL or temperature log. If fallback >200 feet or 10 percent of surface casing depth, must identify top of cement with CEL or temperature log. Monitor and record flow rate, density, and pump pressure.
Intermediate casing	Cement above any USDW or hydrocarbon bearing zone.	
	CBL recommended	CEL required if casing is used to isolate usable water and not cemented to surface Monitor and record flow rate, density, and pump pressure if casing used to isolate usable water.
Production casing	Tail cement (the last cement system pumped during primary cementing which covers the lower sections of the well) should be brought 500′ above producing formation. Tail cement should extend above the top of confining formation.	200 feet of adequately bonded cement between the fractured zone and the deepest usable water zone, could be either production or intermediate casing.
	Should consider CBL for cement evaluation	CEL required if casing is used to isolate usable water and not cemented to surface Monitor and record flow rate, density, and pump pressure if casing used to isolate usable water.
All casing	Pressure test	Pressure test (Onshore Order 2).
	Formation integrity test after drilling out	Formation integrity test if exploratory well or if the blowout prevention equipment is 5,000 psi or greater (Onshore Order 2).
	Take remedial action if pressure tests fail	Take remedial action if there are indications of inadequate cement.
Pressure test prior to hydraulic fracturing.	Test all hydraulic fracturing surface equipment	Mechanical Integrity Test: Pressure test casing or fracturing string to maximum anticipated pressure.
Baseline water monitoring	Test water samples from nearby water sources prior to drilling.	
Monitoring during hydraulic fracturing.	During hydraulic fracturing, monitor injection pressure, slurry rate, proppant concentration, fluid rate, and proppant rate.	Monitor and report actual pump pressure, fluid rate, and flush volume.
	Monitor annular pressure (all annuli)	Monitor annular pressure (all annuli).
	Monitor unexplained deviations from plan	Annular pressure increase greater than 500 psi requires corrective action.
	Pressure should not exceed working pressure of weakest component. Relief valve on intermediate casing annulus—set not to exceed working pressure of casing; flowline diverted to lined pit or tank.	
Monitoring after HF	Monitor annular pressure after hydraulic fracturing; assign max/min.	

Enforcement and Implementation of Rules

Several commenters stated that there is concern that the BLM is imposing new rules when the BLM does not have the staffing, budget, or the number of experts needed to implement the rule or requisite expertise to evaluate fracturing proposals, which would cause delays in approvals and decreased Federal and Indian oil and gas production. The BLM does not agree with the assertion regarding the lack of BLM staff expertise. The BLM employs qualified and experienced petroleum engineers and geologists. The BLM understands the time-sensitive nature of oil and gas drilling and well completion activities and does not anticipate that the review of additional information related to hydraulic fracturing with an APD will impact the timing of the approval of drilling permits. The BLM believes that the additional information that would be required by this rule would be reviewed in conjunction with the APD and within the normal APD processing timeframe. If an operator submits a request in an NOI, however, further processing time should be expected. The BLM understands that delays in approvals of operations can be costly to operators and the BLM intends to avoid delays whenever possible. Also, the revisions made from the supplemental rule to final rule would reduce the amount of staff time required to implement the rule and limit any permitting delays. The changes include eliminating the type well concept and the requirement for a CEL to be run and submitted for a type well prior to completing additional wells.

Several commenters said that the rule should be modified to provide enforcement provisions. The commenters stated that the BLM must monitor hydraulic fracturing operations on Federal and tribal lands to ensure compliance with the rules. The BLM did not make any changes as a result of these comments. Monitoring performed by the BLM is a matter of implementation and policy, not regulation, and therefore, revision of the rule for monitoring is not warranted.

Additionally, enforcement is outside the scope of this rulemaking. The rule does not address compliance and enforcement issues because those issues are already covered by existing regulations in subpart 3163. More specifically, existing section 3163.1 addresses the remedies for acts of noncompliance. The remedies include written notices of the violation, assessments, and shut down of operations. Continued noncompliance could lead to civil penalties and possible lease cancellation. See existing section 3163.2. The law also provides for criminal liability for certain false statements in public land matters, whether sworn or unsworn. 18 U.S.C. 1001; 43 U.S.C. 1212.

Commenters also expressed concern that depending on self-reporting by the operators would be unreliable. The BLM, in line with its authority, has historically relied on self-reporting throughout the oil and gas program (*e.g.,* production volumes and completion information). In order to verify the self-reporting, the BLM conducts regular inspections of operations. The BLM conducts inspections in accordance with an annual risk-based strategy to ensure compliance with the regulations. The BLM has a funding request in place that will lead to improved Inspection and Enforcement resources and performance. The BLM's oil and gas program has no greater priority than ensuring that development is done safely and responsibly. No revisions to the rule were made as a result of these comments.

One commenter expressed concern over how the BLM will know if an operator fails to report a wellbore issue. The BLM has a number of mechanisms that would indicate if an operator failed to report a wellbore issue. The BLM routinely conducts inspections of ongoing operations. These inspections consist of witnessing operations, such as the cementing of casing, onsite review of the drillers log at the rig, or the review of documentation such as the third-party cementing ticket. Through witnessing the operation or the review of the documentation, the BLM inspectors can verify that operations were conducted in accordance with the approved plan and that no wellbore issues exist. Operators also must submit a subsequent report as required by final section 3162.3–3(i). BLM staff will review the information included in the subsequent report to identify any deviations from the approved plan, or any indications of wellbore issues. In addition, under final section 3162.3–3(i), the operator must certify that it complied with the paragraphs of the rule that assure wellbore integrity was maintained prior to and throughout the hydraulic fracturing operation. No revisions to the rule were made as a result of this comment.

One commenter recommended that each operator designate one or more individuals to be prosecuted criminally if criminal negligence, fraud, or conspiracy were found in any hydraulic fracturing operation. The commenter also recommended that an independent counsel be appointed to investigate death or disability caused by hydraulic fracturing operations, and a freezing of corporate stock pending such investigation. While criminal liability and criminal investigations are beyond the scope of this rulemaking, any information of potential criminal violations would be appropriately addressed by law enforcement authorities.

Some commenters wanted the BLM to add an appeal process for decisions to condition or to deny a hydraulic fracturing proposal, and wanted rules for the standing of third parties. The Department's regulations already provide procedures for administrative review of adverse decisions by the BLM. E.g., 43 CFR 3165.3(b). Issues of standing to participate in an administrative review or appeal of a BLM decision are beyond the scope of this rulemaking.

Allow State Agencies To Regulate

Several commenters suggested that the rule allow state oil and gas commissions to regulate hydraulic fracturing on Federal and tribal lands. Commenters believed that the BLM rule adds no value, and increases the layers of approval necessary to develop on Federal and tribal land. Other commenters stated that BLM rules duplicate state rules, and that because the states adequately protect and manage hydraulic fracturing, the BLM's rules are unnecessary, add costs and burdens for compliance, and present regulatory inconsistencies when enforced alongside state rules. Several commenters said that hydraulic fracturing should be regulated at the state level because implementing a national rule would be unworkable due to the widely varying geology and techniques used from region to region. Other commenters recommended that in those states which already have an established regulatory process for hydraulic fracturing, operators should automatically be exempt from this rule.

The BLM did not revise the rule as a result of these comments. The BLM recognizes that many states have made efforts to update their hydraulic fracturing regulations in recent years, but those regulations continue to be inconsistent across states. Further, those state rules may not apply to Indian lands. The rule will establish a consistent standard across Federal and Indian lands and fulfill BLM's stewardship and trust responsibilities. In addition, the BLM is not allowed to delegate its responsibilities to the states. The BLM has worked diligently to reduce the compliance burden on operators, and will continue to work with the states and tribes to develop cooperative agreements to help align hydraulic fracturing regulations at the state, Federal, and tribal levels. Although no changes to the rule were made as a result of these comments, final section 3162.3–3(k) establishes a process for state or tribal variances, if the BLM determines that certain state or tribal rules meet or exceed the objectives of this rule.

Several commenters objected to the use of state regulations. Commenters believed that state regulations were uneven and inconsistent, which could present problems for implementation and enforcement of the rule. The BLM did not revise the rule as a result of these comments. The rule applies on all Federal and Indian lands.

Some commenters urged the BLM to defer to state regulations that are more stringent in protecting resources than this rule. All state laws apply on Federal lands, except those that are preempted by Federal law. This rule does not preempt any more stringent state or tribal law. Operators on Federal leases must comply both with this rule and any applicable state requirements, just as they already must comply with both BLM rules and state rules on a variety of drilling and completion issues. For example, if a state law required recovered fluids to be held in above-ground tanks, the BLM would not approve an application to use a lined pit.

Some commenters objected to what they perceived as a suggestion that states do not have adequate regulatory authority. Those commenters are mistaken as to the BLM's intent. This rule is not about state regulatory programs. It is about the Secretary fulfilling her obligations under the statutes that assign to her stewardship over public lands and trusteeship over Indian lands.

Approve Service Companies

Several commenters asked that the BLM regulate service companies. The commenters sought a list of ''approved'' service companies that would constitute the only eligible service companies who

could operate on Federal and Indian land and so that operators would not be compelled to submit chemical disclosure records to a BLM authorized officer. The BLM did not revise the rule because of these comments. The BLM believes the appropriate approach is to establish regulations that would apply to any service company selected by the operator rather than limiting the specific service companies that operate on Federal and Indian lands.

Ban or Restrict Hydraulic Fracturing

Many commenters asked that the BLM ban hydraulic fracturing, unless the chemicals used in hydraulic fracturing can be contained. The BLM did not revise the rule as a result of these comments. The goals of the rule include groundwater protection, wellbore integrity, and chemical disclosure. Chemical management, containment, and public disclosure are core purposes behind the regulation, and the BLM fully intends to contain chemicals used in hydraulic fracturing through this rule.

Numerous commenters called for a moratorium or permanent ban on hydraulic fracturing on Federal and tribal lands. The BLM did not revise the rule as a result of these comments. The BLM has a responsibility under the FLPMA to act as a steward for the development, conservation, and protection of Federal lands, by implementing multiple use principles and recognizing, among other values, the Nation's need for domestic sources of minerals from the public lands. A ban or moratorium would not satisfy the BLM's multiple-use responsibilities under the FLPMA when regulations can adequately reduce the risks associated with hydraulic fracturing operations. Similarly, hydraulic fracturing operations on Indian lands result in substantial benefits to tribes and to individual Indians. By updating the requirements for hydraulic fracturing, this rule protects usable water on Indian lands without a ban or moratorium that could reduce royalty payments and employment. The BLM understands the risks and the environmental impacts of hydraulic fracturing operations, and the BLM believes that those risks and impacts can be managed by the rule. The rule will provide adequate assurance that hydraulic fracturing operations on Federal and Indian lands will continue to provide the Nation with domestically produced oil and gas and at the same time protect public lands and trust resources.

Many commenters asked that the rule require minimum setback distances for hydraulic fracturing operations. Some commenters requested setbacks from sensitive areas, including conservation areas, areas of critical environmental concern, wilderness and roadless areas, wild and scenic river corridors, surface waters, drinking water supplies, homes, schools, hospitals, other buildings, and recreation areas. Some commenters proposed setback distances ranging from 1,000 feet to half a mile. No revisions were made to the rule in response to these comments.

The BLM has processes in place to ensure protection of sensitive areas. For example, the BLM has rules at 43 CFR 3100.0–3(a)(2)(iii) that prohibit the leasing of Federal minerals beneath incorporated cities, towns, and villages, which is where the majority of homes, schools, hospitals, and other buildings are located. In addition, during development of a Resource Management Plan (RMP), the BLM identifies areas needing protection as areas closed to leasing or areas open to leasing, but with stipulations that limit or prohibit surface occupancy. Other sensitive areas are protected by seasonal and controlled surface use restrictions that are also developed during the land use planning process. When specific drilling proposals are received, the BLM conducts onsite inspections, which identify any sensitive areas and/or occupied dwellings. As part of the NEPA review for the specific proposal, the BLM then develops proper mitigation measures to protect these areas. Mitigation could include moving the well location and including site-specific conditions of approval (COAs). In addition, if unnecessary or undue degradation impacts are identified (for public lands), or unacceptable impacts (on Indian lands), which cannot be mitigated, the BLM may deny the proposal. Through existing regulations, the RMP process, and the subsequent site-specific analyses, the BLM has measures in place to ensure protection of sensitive areas, drinking water supplies, and occupied buildings.

Furthermore, state set-back requirements would normally apply on Federal lands, and tribal set-back requirements would apply on tribal lands (see also existing section 3162.3–1(b)). Minimum setbacks are more effective when they are determined and set at a site-specific level rather than in a nationwide rule because the unique circumstances of each drill site can be considered. Since setback requirements are already addressed in existing regulations and internal processes and policy, minimum setback distances are not necessary in this rule.

Cooperative Agreements

Several commenters asked that the BLM pursue cooperative agreements with states in order to establish more local control over hydraulic fracturing. Generally, the commenters believed that states have enhanced knowledge of the hydrological and geological conditions of their local oil and gas resources. The BLM did not make any rule changes based on these comments. The BLM intends to continue to pursue memoranda of understanding with states, and encourage further cooperation at the BLM State and field office level. The BLM cannot, however, delegate its stewardship responsibility to state or local officials, as some commenters suggested. The BLM must make the final decisions provided by statutes and regulations concerning operations on Federal lands and Indian lands. However, the BLM expects that by cooperatively working with states and through the variance process to appropriately consider state and tribal law and rules so as to reduce regulatory redundancies and compliance burdens.

Some commenters asserted that the rule should include a formal memorandum of understanding mechanism whereby state approval of hydraulic fracturing operations would constitute BLM approval. No statute authorizes the BLM to delegate its responsibilities to states. The rule provides for statewide variances that could result in aligning state and BLM requirements to reduce compliance burdens for operators while assuring that resources in and on public lands are protected.

Compliance With Other State and Federal Laws

One commenter asked that the BLM include a statement in this rule requiring operators to comply with other Federal laws and with state laws. Section 3162.3–3(i)(8)(i) of this rule already requires that the operator certify that the hydraulic fracturing fluid constituents complied with all Federal, state, and local laws, rules, and regulations, in addition to other certifications. In addition, the BLM's Federal oil and gas lease form requires the lessee to comply with all applicable laws, and that includes other Federal and state and local laws, rules, and regulations. That requirement is repeated in the existing regulations at sections 3162.1(a) and 3162.5–1(a). No revisions to this rule were made as a result of this comment because the commenters concern is already addressed in the rule and other BLM regulations.

Ensure Chemicals Are Safe

A commenter suggested that the BLM require all chemicals used in hydraulic fracturing on Federal and Indian lands to be proven safe by an independent third party, or otherwise banned from use. The BLM did not revise the rule in response to this comment. The emphasis of this rule is to ensure that hydraulic fracturing fluid is confined to the intended zone and does not contaminate usable water zones, and that recovered fluids do not contaminate surface or ground water. Though this comment is beyond the scope of this rule, the BLM encourages the use of safer chemicals. Developing and using safer chemicals in all stages of hydraulic fracturing activities can help minimize potential environmental and health concerns while promoting greater public confidence.

Need for the Rule

Numerous commenters said that the rule disrupts the balance between environmental protection and energy development. The commenters stated that the rule would negatively affect jobs, revenue, and effective government. The BLM did not revise the rule as a result of these comments. The BLM evaluated these concerns as part of its economic analysis and found the impacts to be nominal in relation to current overall costs of drilling operations. The economic analysis is available upon request.

Several commenters stated that operators currently submit information regarding casing and cementing programs as part of the existing APD process under Onshore Order 1. The commenters stated that the existing regulatory program already ensures well integrity, thereby making the provisions in the supplemental proposed rule unnecessary. The BLM did not revise the rule as a result of these comments. While the APD process does include many similar components regarding casing and cementing specifics related to well construction, this rule addresses specific hydraulic fracturing operational aspects to verify the integrity of the casing that existing rules do not address.

Several commenters said that the rule is unnecessary and offers no change to the existing situation. The commenters indicated that the rule does not increase safety or transparency, and the supplemental proposed rule offered no solution. The BLM disagrees and did not make changes to the rule as a result of those comments. The BLM believes that compliance with these rules will increase transparency of the hydraulic fracturing approval process and provide a means for disclosure to the public of the fluids utilized in the hydraulic fracturing process.

Several commenters said that the BLM had no reason to promulgate the regulations because there was no evidence that hydraulic fracturing operations have caused contamination of groundwater. The BLM disagrees. The need to assure that hydraulic fracturing fluids are isolated from surface waters, usable groundwater, and other wells is clear. The BLM also notes that those commenters' arguments would apply equally to state regulations, which the same commenters champion. The final rule is not revised in response to those comments.

Several commenters stated that the rule is unnecessary because it codifies common industry practice which has been successful in preventing groundwater contamination. The BLM did not make any changes to this rule as a result of these comments because the BLM has the responsibility of ensuring for the public and tribes that specific minimum standards are adhered to, and does not depend upon voluntary compliance.

Several commenters requested that the BLM wait for EPA to complete its study of hydraulic fracturing and its potential impact on drinking water resources before promulgating a rule. The BLM does not believe it is necessary to wait for the EPA study to implement requirements that will help ensure the protection of water resources and the environment. Nothing prevents the BLM from updating its hydraulic fracturing regulations in light of a finalized EPA study. However, it is necessary to have adequate requirements in place without further delay. No revisions to the rule were made in response to this comment.

Implementation or Grandfathering

Many commenters asked whether the rule would apply to existing wells and requested that certain requirements be waived for those wells. The BLM agrees that the rule needs clarity on how it will address existing wells and added a table in section 3162.3–3(a) to specify which section of the rule would apply to which activity and when. Groundwater protection remains one of the principal reasons for applying the rule to all wells, existing or new. The BLM recognizes, however, that it may be impossible for an operator of an existing well to comply with all requirements of the rule. An example of this would be the requirements in section 3162.3–3(e)(1)(i) to monitor the casing and cementing operations, because the casing and cementing activities would have already occurred. Although most responsible operators retain that monitoring data and will be able to submit it to the BLM, not all of the data has been required by existing regulations. To comply with this section for existing wells, section 3162.3–3(e)(1)(ii) requires that the operator submit documentation demonstrating that an adequate cement job was achieved for all casing strings designed to isolate usable water, and provides that the BLM may require additional testing, verification, or other measures necessary to assure that the well will withstand hydraulic fracturing operations.

Several commenters suggested a phased or delayed implementation of the rule to give industry time to comply with the provisions of the new rule. One commenter requested a 180-day implementation period, instead of the 60-day implementation period required by statute and executive order (Congressional Review Act (5 U.S.C. 801–808) and Executive Order 12866). The BLM agrees that a longer implementation time is required given the complexity of the rule, the potential impacts of the rule on industry, the coordination needed with other entities, such as the GWPC for FracFocus, and for the development of internal training and policy. However, the public also expects new requirements for hydraulic fracturing to be implemented in a timely manner. Therefore, the final rule will be effective 90 days after publication in the **Federal Register.** Outreach to industry and the public is also anticipated during this implementation period. The table in section 3162.3–3(a) provides for an additional 90 day phase-in of the requirement to obtain the BLM's prior approval under limited circumstances. No well (existing or otherwise) proposed for hydraulic fracturing after June 24, 2015 will be exempt from paragraphs (b), (e), (f), (g), (h), (i), and (j), the substantive requirements of the rule.

One commenter requested that the term ''New Well'' be added to the definitions section. The commenter recommended the following definition: ''*New well* means an oil and gas well for which surface casing was set and cemented on or after 60 Days after publication in the **Federal Register**.'' The commenter was concerned that existing wells could not meet the cement monitoring and CEL requirements in the supplemental proposed rule. The commenter also suggested the cementing monitoring and CEL requirements should only apply to new wells as defined. The BLM recognizes the potential challenges with

the cement monitoring requirements on existing wells. The BLM, however, did not include a definition for ''New Well'' in the rule. Instead, final section 3162.3–3(a) of the rule clarifies that for wells drilled prior to the effective date of the rule, the operator must provide the documentation required in 3162.3–3(e) or demonstrate to the authorized officer that the casing and cement have isolated usable water zones.

Ban Diesel

Several commenters asked that the BLM completely ban the use of diesel fuel in hydraulic fracturing fluids. The BLM did not make changes as result of these comments. Congress has authorized regulation of the use of diesel fuels in hydraulic fracturing fluid by the Environmental Protection Agency (EPA), Underground Injection Control (UIC) Program. The EPA has provided technical guidance for protecting underground sources of drinking water (USDWs) from potential endangerment posed by hydraulic fracturing operations by requiring a permit under the UIC program where diesel fuels are used. See EPA Underground Injection Control Program Guidance # 84 for issues concerning diesel fuels during hydraulic fracturing operations (79 FR 8451). If, however, a state (on Federal lands) or a tribe (on tribal lands) prohibited the use of diesel, this rule would not ordinarily preempt such regulations.

Bonding

Many commenters requested that the BLM increase liability bonds to account for the increased risk caused by hydraulic fracturing operations. The BLM did not revise the rule as a result of these comments. Existing section 3104.5(b) authorizes the BLM to adjust bond amounts to appropriately reflect the level of risk posed by an oil and gas operation. The BLM may increase the bond amount if there is a history of previous violations, if there are uncollected royalties due, or if the total cost of plugging existing wells and reclaiming lands exceeds the present bond amount based on the estimates determined by the authorized officer. The BLM believes that it has authority under existing regulations to adjust bond amounts to address any increased liability that may be present as a result of hydraulic fracturing operations. The BLM will make a liability determination for hydraulic fracturing on a case-by-case basis and increase the bond amount as necessary.

Prior Approval for All Changes

Many commenters stated that the rule should be modified to require prior approval for all significant changes to the proposed hydraulic fracturing plan. The commenter stated that the regulation only requires that the operator provide notice to the BLM after the hydraulic operations are complete. The BLM did not revise the rule as a result of these comments. The requirements that the commenter is referencing are specific to hydraulic fracturing operations that did not proceed as planned. Any change of plans from any approved permit must be submitted to the BLM for a new approval. This is the same requirement for changes to all authorizations for oil and gas operations, including APDs and Sundry Notices.

One commenter requested that the BLM establish criteria that would rise to the level of a ''change in scope'' that would necessitate the operator filing a subsequent Form 3160–5 Sundry Notice in the event of a change or deviation from the previously approved hydraulic fracturing operation. Too many possible scenarios exist to develop criteria that would address all issues that could arise. The BLM expects the operator to follow the approved plan along with any COAs. The BLM, however, recognizes that the operator may make minor changes in the design criteria prior to the hydraulic fracturing operations. This recognition is already acknowledged in the rule. Many of the items required in the permit application can be estimates (see final section 3162.3–3(d)). For example, the rule requires estimated pump pressures and the estimated total volume of fluid to be used. Slight deviations from these estimates would not trigger the need for a new Sundry Notice. Those items that cannot be estimated, however, such as the location of the water supply or the method of handling the recovered fluids, would have to be disclosed on an additional Sundry Notice requesting changes to the original approval. No revisions to the rule were made as a result of this comment.

Mitigation Measures

Many commenters asked that the rule require a number of specific actions from the operator such as:

- The installation of air and water monitoring equipment on all hydraulic fracturing operations. The commenters stated that more comprehensive monitoring, including air and groundwater quality monitoring, could help build a knowledge base regarding hydraulic fracturing and its effects on the environment;
- Dust abatement on county roads;
- The power washing and inspection of all vehicles entering a well site to prevent non-native invasive plant species from becoming established;
- The installation of sound dampening devices;
- Prohibiting the use of jake (engine) brakes on trucks operating near residential areas;
- Provisions to control stormwater runoff;
- Capturing or controlling greenhouse gas emissions during hydraulic fracturing operations; and
- The prohibition of flaring in sensitive areas.

The BLM did not make any changes to the rule as a result of these comments. First, the requested changes are outside the scope of this rule, which is specific to hydraulic fracturing operations. With the exception of the installation of air and water monitoring equipment, all of the other requested changes would apply to oil and gas operations in general and are not unique or specific to hydraulic fracturing or appropriate to address in a hydraulic fracturing rule. Second, the BLM believes that it is not appropriate to require specific mitigation measures in a national rule of general applicability. Requiring specific actions such air monitoring, dust abatement, or power washing of vehicles is best left to the discretion of the local BLM offices, determined through NEPA analysis on a case-by-case basis and applied as lease stipulations, and conditions of approval in permits to drill, or through best management practices that operators may propose in their APDs. The rule must allow for some degree of flexibility to accommodate the wide range of geologic and environmental conditions encountered on Federal and Indian leases. If water quality or other impacts are anticipated due to hydraulic fracturing operations, the BLM would then develop mitigation measures, such as water quality monitoring, dust emission control, and any other relevant actions on a case-by-case basis. These requirements will be included as specific conditions of approval (COA) in the drilling permit to the extent consistent with the lease rights.

''Frack Hits''

Several commenters expressed general concern over ''frack hits'' (*i.e.,* unplanned interconnectivity of wells during a hydraulic fracturing operation through the underground formations between the well undergoing a fracturing operation and an existing

well), and that the NOI review process should include an area of review to identify nearby wells and fractures, in addition to prescribing reporting, evaluation, and corrective actions for frack hits.

The BLM revised the rule as a result of these comments. As provided in this final rule, hydraulic fracture design, including estimated fracture length and direction data, are required to be submitted as part of the APD or NOI. In addition, the final rule requires the operator to provide a map showing the extent of the fractures along with all known wellbore trajectories within one-half mile of the well that is proposed to be fractured. One purpose of fracture design data is to avoid potential intersection between fractured pathways to existing nearby wellbores. These data will be reviewed during the review process for hydraulic fracturing approval. The provisions of Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases (NTL–3A), March 1, 1979, (44 FR 2204) and other regulations already contain operator obligations for reporting, evaluation, and corrective actions in the event of an environmental release. Enforcement provisions for releases into the environment involving Federal or tribal leases already exist in the regulations and are outside the scope of this rulemaking.

Independent Review of Hydraulic Fracturing

Several commenters stated that the rule should be modified to establish an independent review of hydraulic fracturing proposals. The BLM did not revise the rule as a result of these comments. The BLM has the necessary expertise to properly review hydraulic fracturing proposals.

Public/Landowner Participation

Several commenters stated that the rule should require notice to landowners, communities, and other stakeholders when hydraulic fracturing is proposed. Commenters said that the rule should require notice to parties located at various distances from 500 feet to 10 miles away from the hydraulic fracturing operation. The BLM did not revise the rule as a result of these comments. Public notice of Federal oil and gas operations is already provided to both the public and nearby landowners. By statute and regulations, notice of Federal APDs are publicly posted in BLM field office public rooms for a minimum of 30 days before the BLM issues a permit to drill (see existing section 3162.3–1(g)). Some field offices also make this information available on the field office Web site.

Furthermore, the BLM is working on improvements to make additional information available on a Web site for all Federal APDs in the near future. The information would include the operator name, well name and number, surface location legal land description, the date the BLM received the application, the date the BLM approved the application, the date the well was spudded, and the date the well was completed.

Additionally, surface owners of split estate lands are invited to attend the onsite inspection before an APD is approved, and other agencies and interested parties can request to attend the onsite well inspection. Also, the APD surface use plan of operations lists all wells and water wells within prescribed distances from the proposed wells, which provides additional information to the public about potential concerns. Although stakeholders could assume that any proposed well would be hydraulically fractured, the BLM will be exploring ways to provide additional public notice of proposed hydraulic fracturing operations. Information that would be required to be submitted as part of this rule will be made available to the public, consistent with the requirements of Federal law. Note, though, that the rule does not preempt notification requirements of states (on Federal lands) or tribes (on tribal lands).

Several commenters stated that the rule should be modified to provide for stakeholder participation in the permitting process for hydraulic fracturing operations. The BLM did not revise the rule as a result of these comments. The BLM already provides numerous opportunities for stakeholder participation during the Federal oil and gas leasing process as well as the APD process on Federal lands and stakeholders are specifically invited to participate during the NEPA process.

Ensuring Wellbore Integrity

Several commenters stated that Onshore Order 2 is inadequate to ensure wellbore integrity during hydraulic fracturing operations. According to these commenters, the BLM needs more requirements specific to casing centralization, intermediate and production casing standards, cement types, cement compressive strength, ensuring proper wellbore condition prior to cementing, and ensuring a static wellbore during cementing operations. The BLM did not revise the rule as a result of these comments. Onshore Order 2 provides uniform national standards for the minimum levels of performance expected from operators when conducting drilling operations, including casing design, casing centralization, and cement compressive strength. The BLM reviews each drilling proposal to ensure that operations will meet these minimum standards. If the BLM's review determines that additional requirements regarding casing centralization, cement types, cement compressive strengths, etc., are necessary for wellbore integrity or isolation of usable water, the BLM can require the operator to modify its proposal or add COAs. The BLM believes that the requirements for well drilling, casing, or cementing in Onshore Order 2 along with the new requirements established by this rule are sufficient to assure that wellbores can withstand hydraulic fracturing operations.

Seismicity

Several comments stated that the rule should be modified to limit hydraulic fracturing activities in those areas with seismic zones. The BLM did not revise the rule as a result of these comments. The research on the phenomena of induced seismicity from hydraulic fracturing operations is still ongoing and inconclusive. For hydraulic fracturing operations proposed in seismically active areas or when the BLM determines through the internal and public scoping process that seismic impacts are an issue, risks of induced seismicity would be evaluated through the NEPA analysis, including analysis of the proposed drilling and fracturing operations. These final regulations also require submittal of additional geologic information prior to hydraulic fracturing to help further that review.

Tracers

Several commenters stated that the rule should be revised to require tracer surveys in production and injection wells. The commenters indicated that if tracer efficacy could be validated, then the BLM should require its use. One commenter suggested that some of the constituents in flow back fluid could be used for tracers. The BLM did not revise the rule as a result of these comments. One of the rule's major emphases is the prevention of groundwater contamination from hydraulic fracturing operations through ensuring wellbore integrity and the isolation of usable water zones. Additionally, while the BLM believes that tracers may have value in certain situations, their overall effectiveness is questionable due to dilution and detection issues. These limitations render tracer surveys inappropriate for universal application

for all hydraulic fracturing operations on Federal or Indian lands.

Baseline Monitoring

Numerous commenters asked that the BLM require baseline air and water monitoring prior to hydraulic fracturing. The commenters stated that without baseline air and water quality data, it would be impossible to prove (or disprove) that hydraulic fracturing caused changes in air or water quality. Several commenters noted that the API guidance document on hydraulic fracturing (HF–1) recommends baseline water quality monitoring of both surface and groundwater prior to hydraulic fracturing.

The BLM agrees that baseline air and water quality data and monitoring are good policies with benefits for land managers, the public, and the oil and gas industry, and fully endorses the API guidance with respect to baseline water monitoring. The BLM supports and encourages baseline testing and monitoring, and will require those activities on a case-by-case basis where appropriate, but is not requiring baseline monitoring in this nationwide rule for several reasons. First, there is such a wide variety of hydrogeological conditions that it would be unworkable to establish a single requirement for baseline water monitoring for all Federal and Indian lands. For example, some locations may not have surface or ground water resources, while other locations may have a mix of different types of water resources.

Second, there are many places where the BLM either does not manage the surface above the leased minerals, or the locations where baseline testing and monitoring would be necessary or most useful would be off of BLM-managed land. The BLM has no authority to require air or water quality monitoring on non-Federal lands, and limited authority on non-Federal surface estates (''split estates''). If the final rule were to require baseline testing and on-going monitoring, it would need to have so many exceptions that it would be confusing and of limited value.

Given the fact that the BLM cannot rationally and consistently implement baseline monitoring requirements, no revisions to the rule were made as a result of these comments. Nonetheless, analysis of potential impacts to both air and water quality are common elements of any NEPA review that the BLM prepares on proposals for drilling and hydraulic fracturing operations. If air or water quality impacts are anticipated, then, if not already part of the proposed operation, the BLM could require mitigation measures to address those impacts. These include baseline testing and monitoring that would be developed on a case-by-case basis taking into account local hydrogeologic or airshed factors, plans for field development, land ownership, and existing data and monitoring programs required or implemented by other agencies. These mitigation measures would be imposed as a condition of the BLM's approval for a given project. There are a number of cases where the BLM has required the baseline testing and monitoring of air and water resources as part of its decision to approve the development of oil and gas resources. For example, the Records of Decision (ROD) for the Pinedale Anticline Project Area Environmental Impact Statement (EIS) (see Appendix A–3 at *http://www.blm.gov/wy/st/en/info/NEPA/documents/pfo/anticline.html*), the Pinedale Anticline Project Area Supplemental EIS (see Chapter 4 at *http://www.blm.gov/wy/st/en/info/NEPA/documents/pfo/anticline/seis.html*), and the Greater Natural Buttes Final EIS (see Appendix C at *http://www.blm.gov/ut/st/en/fo/vernal/planning/nepa.html*) include requirements for oil and gas operators to test/identify baseline air and water (surface and subsurface) conditions, and monitor trends in resource conditions throughout the project. Furthermore, if the Federal surface management agency (such as the U.S.D.A. Forest Service) required air or water monitoring as part of the surface use plan, then those requirements would be enforceable.

Some commenters said that BLM could require operators to obtain permission to test water on non-Federal lands. Although states' or tribal police powers may authorize such requirements, the BLM's statutory authority does not extend to non-federal, non-Indian lands, absent a threat to Federal resources. We therefore decline to revise the rule as suggested.

Other comments recommended that the BLM require baseline monitoring of soil, plants, human sickness, and environmental degradation before, during, and after hydraulic fracturing. Additionally, one commenter asked that the BLM provide landowners information on how to test their water to document baseline conditions. The BLM did not revise the rule as a result of those comments. Similar to the recommendation in the API Guidance [9] (section 10.2) for conducting a baseline assessment once the location for a well has been selected and before it is drilled, as part of the NEPA analysis, the BLM examines the baseline condition of the site, evaluates the potential effects of the proposed operation, and suggests mitigation and monitoring needs when necessary. As with baseline water monitoring, the BLM could require monitoring of resources on Federal lands, and with the surface owner's consent on split-estate lands, as a site-specific mitigation measure based on an environmental analysis prepared under NEPA. Although the BLM has expertise in management of Federal lands, monitoring the health of persons or of natural resources on non-Federal lands is entrusted to other local, state, tribal or Federal agencies with appropriate authority and expertise. Similarly, this rule does not attempt to advise landowners or tenants on how to test their water. Other agencies and private consultants have the expertise to provide that advice.

Water Use

Several commenters requested that the rule address the potential stresses on local fresh water supplies. The commenters expressed concern that local fresh water supplies will be diminished by the demand for water for hydraulic fracturing. Some commenters suggested placing restrictions on the use of local fresh water and requiring the use of non-fresh water sources or recycled water to help reduce potential impacts to local fresh water. Other commenters requested the rule include restrictions on water usage. The BLM understands the concerns raised by the commenters. The BLM encourages operators to treat and recycle the water returned after performing hydraulic fracturing along with the water produced from the formation. In fact many operators on public lands are currently considering options of using produced water or recycled water for their hydraulic fracturing operations. The BLM, however, does not have regulatory authority over the use of local fresh water. State and tribal governments, through administration of water rights and permitting water wells, regulate water usage. Existing state and tribal laws require operators to obtain the proper permits and rights to use surface and groundwater. No revisions to rule were made as a result of these comments.

Some commenters expressed concern about the lack of groundwater use regulation in the rule. Commenters recommended that the rule include an assessment of water availability, provisions for reducing water use during droughts, and require that

[9] American Petroleum Institute (API) guidance, ''Hydraulic Fracturing Operations-Well Construction and Integrity Guidelines, First Edition, October 2009.''

companies monitor the level of the water table. Other comments suggested that the rule provide for protection of over-appropriation of water and disclosure of water take that should occur prior to the start of hydraulic fracturing operations. All of these items are beyond the scope of this rule. States and tribes have regulatory authority over water usage. However, as a matter of course, the BLM requires the submission of information on water sources to assist the BLM in assessing the environmental effects of individual drilling operations. The NEPA process requires that Federal agencies assess the environmental impacts of their proposed actions to inform their decision-making and this includes effects on water resources. The information on water sources will be part of an environmental analysis of hydraulic fracturing operations. No revisions to the rule were made as a result of this comment.

One commenter recommended operators should pay for monitoring wells when there is suspected contamination. Other commenters recommended that the rule be strengthened by requiring the operator to physically replace any water supply that is contaminated. These recommendations are beyond the scope of this rule. The goal of the rule is to ensure proper wellbore construction and handling of produced fluids to prevent any contamination. If a situation arises where contamination from hydraulic fracturing operations is suspected, the BLM will work closely with states and tribes to determine the proper course of action. The proper course of action for any given situation will depend on the unique circumstances of that situation. No revisions to the rule were made as a result of this comment.

Mandatory Recycling

Some commenters asked that the rule include a requirement that some quantity of the water used in hydraulic fracturing operations must be recycled water. The commenters did not offer specific quantities. The BLM encourages operators to treat and recycle the water returned after performing hydraulic fracturing along with the water produced from the formation. Many operators are currently looking at options for using produced water and/or recycled water for their hydraulic fracturing operations. However, mandating the recycling of water is outside of the scope of this rule. No revisions to the rule were made as a result of these comments.

Breach of Contract

Some commenters asserted that the rules would make oil and gas operations uneconomic, and that would result in Federal liability for a breach of the lease. Federal oil and gas leases clearly provide that the lease rights are subject to all current and future regulations. The rule is an operational regulation and does not change any financial term of any Federal or Indian lease. The BLM does not expect the rule to dissuade operators from drilling in geologically promising areas. Lessees and operators routinely decide not to drill on leases found to be geologically unpromising or uneconomic, but the BLM is not required to waive drilling and completion regulations to improve profitability.

Tribal Issues

Some commenters asserted that the rule would be a breach of trust on Indian lands. The BLM disagrees. As all the other provisions of 43 CFR part 3160, the rule protects trust resources to the same extent that it protects resources in or on Federal lands. The commenters did not identify any provision of the Constitution, or a treaty, statute, or regulation that the rule violates. One tribe in its comments proposed 10 specific conditions of approval that it wanted to apply to hydraulic fracturing operations on its tribal lands. The BLM imposes conditions of approval on a case-by-case basis based on unique on-the-ground geologic, environmental, and operational circumstances. Specific conditions of approval are beyond the scope of this rulemaking and are inappropriate in a rule of general applicability. If hydraulic fracturing is proposed for specific tribal lands and the tribe proposes specific conditions for the BLM to apply, the BLM will consider the tribe's proposal for that development.

Some commenters said that the BLM has no authority under the FLPMA to promulgate regulations on Indian lands. The BLM agrees. The BLM's authority to regulate oil and gas operations on Indian lands does not come from the FLPMA. The Act of March 3, 1909 (25 U.S.C. 396), the Indian Mineral Leasing Act (IMLA) (25 U.S.C. 396d), and the Indian Mineral Development Act (25 U.S.C. 2107) assign regulatory authority to the Secretary over Indian oil and gas leases on trust lands (except those excluded from the IMLA, *i.e.,* the Crow Reservation in Montana, the ceded lands of the Shoshone Reservation in Wyoming, the Osage Reservation in Oklahoma, and the coal and asphalt lands of the Choctaw and Chickasaw Tribes in Oklahoma). The Secretary delegated to the BLM the authority to oversee oil and gas operations on Indian mineral leases through the Departmental Manual (235 DM 1.K.). The Bureau of Indian Affairs' regulations provide that BLM's operating regulations at 43 CFR part 3160 apply to oil and gas leases on trust and restricted Indian lands, both tribal and individually owned. See 25 CFR 211.4, 212.4, and 225.4.

Some commenters said that the FLPMA prohibits the BLM from exercising any part of the Secretary's trustee responsibilities over Indian lands. On the contrary, the FLPMA expressly provides that the Director of the BLM ''shall perform such duties as the Secretary may prescribe with respect to the management of lands and resources under [her] jurisdiction according to the applicable provisions of [the FLPMA] and any other applicable law.'' 43 U.S.C. 1731(a). Indian trust and restricted lands and minerals are resources under the Secretary's jurisdiction under applicable law. Therefore the delegation of operational oversight to the BLM of oil and gas development on Indian lands as exercised in this final rule is proper.

Several commenters said that the BLM's consultation process was not adequate. In light of statutory responsibilities and executive policies, including the Department's Tribal Consultation Policy (Secretarial Order 3317) and Executive Order 13175, the BLM attaches great importance to tribal consultation. During the proposed rule stage, the BLM initiated government-to-government consultation with tribes on the proposed rule and offered to hold follow-up consultation meetings with any tribe that desired to have an individual meeting. In January 2012, the BLM held four regional tribal consultation meetings, to which over 175 tribal entities were invited. Individual follow-up consultation meetings involved the local BLM authorized officers and management, including State Directors. After the publication of the initial proposed rule, tribal governments and tribal members were also invited to comment directly on the proposed rule.

In June 2012, the BLM held additional regional consultation meetings in Salt Lake City, Utah; Farmington, New Mexico; Tulsa, Oklahoma; and Billings, Montana. Eighty-one tribal members representing 27 tribes attended the meetings. In those sessions, the BLM and tribal representatives engaged in substantive discussions of the proposed hydraulic fracturing rule. A variety of issues were discussed, including, but

not limited to, the applicability of tribal laws, validating water sources, inspection and enforcement, wellbore integrity, and water management. Additional individual consultations with tribal representatives took place. Consultation meetings were also held at the National Congress of American Indian Conference in Lincoln, Nebraska, on June 18, 2012, and at New Town, North Dakota on July 13, 2012.

After publication of the supplemental proposed rule, the BLM again held regional meetings with tribes in Farmington, New Mexico, and Dickinson, North Dakota, in June 2013. Representatives from six tribes attended. The discussions included a variety of tribal-specific and general issues. One change resulting from those discussions is the re-drafting of paragraph 3162.3–3(k) to clarify that tribal and state variances are separate from variances for a specific operator. The BLM again offered to follow up with one-on-one consultations, and several such meetings were held with individual tribes. Several tribes, tribal members, and associations of tribes provided comments on the revised proposed rule.

In March 2014, the BLM invited tribes to participate in another meeting in Denver, Colorado. Twelve tribal representatives attended the meeting. There was significant discussion of issues raised in the comments on the revised proposed rule. The BLM believes its tribal consultation efforts were thorough.

Nonetheless, some commenters assert that the BLM failed to follow the stages of consultation set out in the Departmental consultation policy and Executive Order 13175. The BLM believes that it has complied with that Executive Order and with Secretarial Order 3317. The BLM understands the importance of tribal sovereignty and self-determination, and seeks to continuously improve its communications and government-to-government relations with tribes.

Some commenters said that the rule continued to apply the same requirements to operations on Indian lands as on Federal lands. They said that the BLM should promulgate different rules for Indian lands, citing as examples the authority of the BIA over cancellation of Indian leases, and ONRR's royalty valuation criteria for operations on Indian lands. The BLM does not assert that implementing its operational regulations on oil and gas operations on Indian lands is the only possible way to carry out the Secretary's trust responsibilities under the Indian mineral statutes cited earlier. Nonetheless, it is the means chosen by the Secretary and the BIA, and is more economic than creating a parallel set of regulations and regulatory personnel in the BIA. The BLM believes it is fulfilling its part of the Secretary's trust responsibilities by requiring operations on Indian lands to meet the same standards as those on Federal lands.

Some commenters urged the BLM to allow tribes to opt out of the final rule. A commenter also cited to BIA's regulations that provide for a tribal constitution or charter issued under the Indian Reorganization Act of 1934, or resolution authorized by such constitution to supersede the regulations in 25 CFR part 211 (which includes 25 CFR 211.4). See 25 CFR 211.29. That section, however, also includes a proviso that tribal law may not supersede the requirements of Federal statutes applicable to Indian mineral leases, and that the regulations in that part apply to tribal leases and permits that require the Secretary's approval. The commenters have not explained why, among all the other requirements of 43 CFR part 3160, an opt-out should be provided for this rule. Some commenters said that the final rule should be ''inoperative'' on tribal lands once the tribe has demonstrated that its regulatory program is ''sufficient'' to govern hydraulic fracturing operations. The Indian mineral leasing statutes previously cited do not authorize tribes to opt-out of the Secretary's regulations, and, unlike some environmental statutes, do not authorize tribal ''primacy.'' Furthermore, the BLM has no way of terminating the Secretary's trust responsibilities for hydraulic fracturing operations if a tribe were to opt out of having the BLM's regulations apply on that tribe's lands, or if the BLM failed to implement the final rule because a tribe was implementing its own program.

Several commenters addressed the variance provision approvingly. Some urged the BLM to recognize tribal regulations. The BLM recognizes that some tribes have been proactive in regulating hydraulic fracturing on their lands. It is not the BLM's intent to preempt tribal regulations. Commenters did not bring to the BLM's attention any tribal regulation or lease provision that the final rule would preempt. In the absence of preemption, tribal law would apply to leases of tribal and individually owned Indian land in addition to the final rule.

The variance provision of the rule allows the BLM, in cooperation with a tribe, to issue a variance that would apply to all wells within that tribe's lands, or to specific fields or basins within those lands, if the State Director determines that the proposal meets or exceeds the objectives of the provision for which a variance is requested. A variance would not necessarily adopt tribal regulations as the Federal rule. However, a variance would, for example, be a way of doing such common-sense things as aligning reporting requirements of the two sovereigns, addressing unique geological conditions, or facilitating technological innovation, while maintaining the performance standards and adequate margins of protection provided in the final rule.

Some commenters said that the variance provision does not comply with policies promoting tribal sovereignty, self-determination, and the Federal government's trust responsibility. The BLM believes that the rule is consistent with the Federal government's trust responsibility because it assures that Indian lands receive the same substantive protection as Federal lands, and that it promotes tribal sovereignty by facilitating coordination to achieve the goals of both sovereigns. By recognizing tribal regulations, it accords with tribal self-determination to the extent that could be expected from a rule governing hydraulic fracturing operations.

A commenter stated that tribal variances should not be subject to public comment. The rule does not provide for public notice and comment on tribal variances and the rule is not revised as a result of this comment.

Some commenters asked that the BLM provide more information about how to obtain contracts and funding under Public Law 93–638, the Indian Self-Determination and Education Assistance Act of 1975, 25 U.S.C. 450 *et seq.,* as amended. Implementation of Public Law 93–638 and its amending statutes is beyond the scope of this rulemaking, and is governed by regulations in Title 25 of the CFR. If a tribe wishes to apply for a contract to perform any of BLM's functions under 43 CFR part 3160, it should contact the BLM.

Some commenters opposed the rule, or said that it should not apply on Indian lands, stating that it would increase operators' costs, and thereby make Indian lands less attractive to the oil and gas industry, potentially resulting in reductions of revenue to the tribes. The rule would not render Indian lands more or less attractive than Federal lands. In reviewing the comments and preparing the final rule, the BLM has looked for ways to reduce costs and burdens for operators, and to focus on requirements that promote the

goals of assuring isolation and protection of usable water. As shown in the economic analysis, the costs of complying with the final rule on Federal or Indian lands will be a small percentage of an operator's costs of drilling and completing a well. Those additional costs would be easily outweighed by revenues that operators might anticipate from a geologically attractive area. Tribes and their members will also benefit from the substantial increase in assurance that their usable water will be isolated and protected.

Cost Recovery

Some commenters supported the rule and suggested that the rule include a cost recovery fee for hydraulic fracturing approval and inspection. The BLM did not propose a separate cost recovery fee for hydraulic fracturing approval and inspection in the initial and supplemental proposed rules. Section 365 of the Energy Policy Act of 2005 prohibits the Secretary from implementing a rulemaking that would enable an increase in fees to recover additional costs related to processing drilling-related permit applications and use authorizations until the end of fiscal year 2015. The BLM fully expects to process requests for hydraulic fracturing concurrently with the processing of drilling applications. The final rule does not include such fees, however, the BLM may address that in any future cost recovery adjustments.

BLM's Jurisdiction

Some commenters asserted that the rule is beyond the Secretary's jurisdiction because protection of surface waters and groundwaters are under the EPA's jurisdiction, not the BLM's jurisdiction. The BLM agrees that regulation of the quality of surface waters under the Clean Water Act, and the regulation of groundwater under the SDWA, are the duties of EPA and states and tribes. The requirements of this rule do not interfere with those programs. The rule does not address discharges to surface waters at all. The rule clarifies the existing definition of usable water to defer to state or tribal designations of aquifers as underground sources of drinking water or as exempted aquifers under the SDWA, so long as these designations are not inconsistent with the SDWA.

Some commenters challenged the Secretary's authority to regulate well construction and operation. Some claimed that the Secretary has no authority to disapprove or to require revisions to a hydraulic fracturing proposal. Some claim that the Secretary has no authority other than to lease lands and collect royalties. The BLM disagrees. The Secretary has authority to promulgate this rule, as the Secretary had for the other sections in 43 CFR part 3160 and the onshore oil and gas orders. That authority includes the FLPMA, the MLA, the Mineral Leasing Act for Acquired Lands, and the various Indian mineral statutes. Each lease is expressly subject to existing and future regulations. The BLM has authority to condition or to deny APDs, and this rule extends that authority to proposals for hydraulic fracturing operations.

Some commenters objected to the rule on the grounds that protection of water is a states' rights issue. The BLM agrees to a certain extent, and has revised the rule, as discussed elsewhere, to reduce potential conflicts with states' water allocation and water quality regulations. Other commenters said that the BLM lacks statutory authority to control water quality and usage because that authority is vested with the EPA and the states.

The BLM is not controlling water quality or usage under this rule. Operators are responsible for complying with state or tribal requirements for obtaining water for use in hydraulic fracturing operations and for discharges into surface or groundwater. The BLM will not be issuing or vetoing rights to use water or discharge permits. However, the BLM will need to know an operator's proposed source of water and planned disposal method in order to consider the potential environmental impacts and compliance with NEPA, but the BLM will not be adjudicating water rights.

Federalism Assessment

Some commenters believed that the rule requires a Federalism assessment under Executive Order (EO) 13132. The BLM believes that there will be no financial impacts to the states as a result of this rule. Operators will have some increases in costs, but the BLM does not believe that production from Federal lands will be reduced as a result of this rule. Therefore, a Federalism assessment is not required.

Compliance With E.O. 12866 and E.O. 13175

Many commenters suggested that the annual costs of the rule would exceed $100 million per year and that the BLM failed to comply with E.O.12866 and E.O.13175. One commenter suggested that the costs would be $345 million per year, broken out as follows: $310 million for enhanced casing costs; $5.6 million for initial delay costs; $1.7 million for administrative costs; $2.6 million for cement logs; $5.9 million for log delays; and $19.6 million if the BLM were to require tanks to manage flowback. Other commenters referenced these cost figures. Another commenter suggested the costs of the rule could be as low as $30 million per year or as high as $2.7 billion per year. The range was due to uncertainty about the rule's effect on field operations. The areas of uncertainty in the comments are related to drilling delays and completion schedules, the number of impacted wells, additional requirements resulting from the usable water definition, and costs to conduct CELs on surface and intermediate casing. Another commenter suggested a range of possible costs of $0–$750 million per year.

The BLM has complied with E.O.12866 and E.O.13175. After reviewing and analyzing the submitted data, the BLM found that many of the assertions that the commenters made are based on flawed assumptions or confusion about the requirements in the rule. Commenters have also provided constructive feedback about rule provisions that would pose costs to operators that the BLM had not anticipated. Through the course of this rulemaking, the BLM adjusted requirements to better reflect the best management practices of operators conducting hydraulic fracturing operations and to resolve the unintended consequences that the proposed rules would have caused. The following discussion details comments by topic area.

Commenters suggested that usable water is not fully defined, that there are costs associated with identifying usable water zones, and that the costs are variable and uncertain. Various commenters suggested per-well costs of $4,000–$5,000, $8,000–$10,000, $60,000, and $400,000. Activities associated with identifying usable water include drill logs, water sampling, geologic characterization ($3,000–$8,000 or up to $408,000 per field development), and drill stem testing ($200,000 per test).

As explained in the discussion of section 3162.3–3(d), the final rule removes the requirement that an operator must identify the usable water zones with a drill log. Existing Onshore Order 1 already requires that an operator's drilling plan include the estimated depth and thickness of zones potentially containing usable water. In the final rule, the BLM expects operators to use all available information to identify usable water zones, consistent with Onshore Order 1. As such, and since this information will likely already be readily available to

operators, and is already required for the drilling plan, the BLM does not anticipate any incremental costs associated with identifying usable water zones.

Commenters suggested that the BLM's definition of usable water would pose additional costs, since the 10,000 ppm TDS standard in the proposed rule is higher than the 5,000 ppm TDS standard in the previous 43 CFR 3162.5–2(d). Our detailed response to these comments appears in the discussion of the definition of usable water and in section 3162.3–3(d) of this preamble. In short, the current requirements regarding usable water exist in Onshore Order 2, which was published after the requirements in the previous section 3162.5–2(d). Onshore Order 2 specifies a 10,000 ppm TDS standard that is consistent with our definition in the proposed and final rules. While the previous section 3162.5–2(d) specified a lower standard, it was superseded by Onshore Order 2 in 1988. This final rule clarifies any confusion between the regulations in the CFR and Onshore Order 2 standards. Since the 10,000 ppm TDS standard is not new, it does not result in additional costs.

Several commenters suggested that the rule would require operators to perform additional cementing that would pose costs to operators. A commenter's analysis suggests that the rule would require operators to run deeper surface casing, two-stage cementing on the production casing, or the addition of an intermediate string of casing, for a total cost of $310M (calculated as 2,350 feet per well of additional casing at $37 per foot for 3,566 wells). Another commenter suggested that, by requiring operators to run a CEL on all strings that protect usable water, operators would need to run cement for the entire lengths of these casings.

As explained in the discussion of the definitions section and section 3162.3–3(d) of this preamble, because the definition of usable water has not substantially changed in this rule, and because existing Onshore Order 2 already requires casing and cementing to protect and isolate all usable water zones, there will be no significant changes in costs of running casing and cement.

Commenters generally believe that the economic analysis underestimates the costs of running CELs, particularly for CELs on the surface casing. One commenter's analysis accepted the BLM's cost estimates for the CEL requirement. Another commenter suggested the CEL costs would be $24,000–$109,000 per well ($3,500–$5,700 for a CBL log, or $5,000–$6,500 for a CBL on the surface casing, $20,000 for a CBL on the intermediate casing, and rig delay costs up to $100,000). One commenter suggested the BLM neglected to include $50,000 per day in rig time from the analysis. One commenter suggested using delay costs of $1,833.33/hour ($1,000 for rig costs and $833.33 for ancillary costs). Commenters referenced EPA guidance that cement should harden for 72 hours for each casing.

As explained in the section 3162.3–3(c) discussion in this preamble, in the final rule the requirements for a CEL on the surface casing of a type well when cement returns to the surface with no indication of inadequate cementing are removed. The final rule instead requires well logging in a manner that is consistent with industry standards. The economic analysis is revised to account for this change.

A commenter identified a formatting error in calculating the costs of a CEL on the intermediate casing. The commenter was correct, and the formatting error is corrected.

Commenters suggested that MIT costs should be considered at a cost of $10,000 per test. The BLM disagrees that the costs of an MIT are attributable to the final rule. The requirements of the rule are consistent with industry guidance on hydraulic fracturing and with state regulations. Industry guidance states that the operator should pressure test the casing string through which the hydraulic fracturing will occur prior to commencing the hydraulic fracturing operation. API Guidance Document HF1 titled ''Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines'' (First Edition, October 2009) states that ''prior to perforating and hydraulic fracturing operations, the production 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'' (p. 12). In addition, ''prior to beginning the hydraulic fracture treatment, all equipment should be tested to make sure it is in good operating condition. All high-pressure lines leading from the pump trucks to the wellhead should be pressure tested to the maximum treating pressure'' (p. 16). The BLM also reviewed state regulations in California, Colorado, Montana, New Mexico, North Dakota, Oklahoma, Texas, Utah, and Wyoming. From FY 2010 to FY 2013, the number of well completions on Federal and Indian lands in those states accounted for 99.3 percent of the total well completions on Federal and Indian lands nationwide. The state regulations in those states either require pressure tests on all casing strings or on the casing strings through which the completion operation will occur. Therefore, we believe that the MIT requirement will not pose an incremental cost to most responsible operators.

Several commenters suggested that in order to provide the actual length and height of the fractures (see section 3162.3–3(d)), an operator would have to conduct a ''frack model'' and that the associated costs are not accounted for in the analysis. They suggested that costs may range from $4,500–$200,000 per well depending on the sophistication of the modeling required. The BLM does not intend to require that operators undertake modeling. The BLM revised the requirement in section 3162.3–3(d) of the final rule to allow for greater operational flexibility, for example, by allowing operators to report the estimated length and height. Operators would not undertake the expense of hydraulically fracturing a well without an estimation or calculation of the propagation of the fissures. The final rule does not require additional modeling.

In the supplemental proposed rule, the BLM solicited comments concerning the incremental costs of a requirement to manage flowback with tanks instead of lined pits. One commenter suggested lined impoundments or semi-rigid atmospheric tanks are more cost effective than steel tanks. It estimated the 5-year net present value costs at: Impoundments $2.3 million, semi-rigid tanks $2.42 million, steel tanks $23 million). A commenter's analysis suggested a tank requirement would cost $19.6 million per year (or $11,500 per well). Another commenter suggested that an open pit costs $447,000 and a closed-loop system costs $267,000 (an $180,000 cost advantage). Section 3162.3–3(h) of the final rule requires that operators manage recovered fluids in enclosed above-ground tanks until approval of a produced water plan pursuant to Onshore Order 7. The economic analysis has been revised to address the costs associated with this revision.

One commenter suggested that hydraulic fracturing operations have additional ancillary costs that are borne by the public, including wider roads and more road maintenance. The economic analysis measures the incremental costs of implementing the rule, not all costs associated with

hydraulic fracturing. The BLM did not revise the rule or the analysis as a result of this comment.

Several commenters suggested that the analysis should consider the cost of remedial cement squeezes. The practice of squeeze cementing is an operation in a well whereby a cement slurry is forced (squeezed) under pressure into a formation, or a channel behind the casing, or through holes purposely placed in the casing. One commenter suggested that costs for remedial cement squeezes may range between $0–$120,000, or $142,000 per well. Another commenter suggested that typical costs for cement remediation could include: Perforating casing—$12,000; squeeze cementing—$30,000; and post-squeeze CBLs—$6,000–$20,000. Further, the commenter believes that one cement squeeze would require 4 days and two squeezes would require 9 days to complete. The commenter estimated the minimum total cost to be $128,000 for a single cement squeeze and $284,000 for two squeezes, considering rig delay time and direct remediation costs only. Further, the commenter suggests that there is uncertainty in how many cement remediation jobs would be required after the hydraulic fracturing operation occurs.

The concerns about remedial cement squeezes were predicated on two arguments—that CELs are interpretive and that in implementing the rule, the BLM would require operators to perform remedial cement squeezes whenever the CEL detected a cement void. Final section 3162.3–3(e) does not require operators to run a CEL on the surface casing in every case. When there are indications of inadequate cement, the final rule specifies actions that an operator must take that are in line with current remedial procedures. Operators typically run CELs on the cement behind intermediate casings that protect usable water when they do not witness cement returns to surface. Therefore, the BLM believes that the CEL requirements in the final rule would not compel operators to take remedial action that they normally would not have taken otherwise. Thus, the revised requirements do not pose any incremental costs to operators.

Commenters suggested that the type well concept is unclear and undefined. Commenters presented a range of estimates for type well applicability. A commenter suggested 3 percent to over 50 percent per field depending on the maturity. A 5 percent increase in type well applicability is associated with a $34 million increase in industry costs. Another commenter suggests 14.29 percent of all wells because 6–8 wells can be drilled from the same platform. Another commenter suggested it could mean one type well per section (10 type wells per 640-acre section).

The final rule does not carry forward the type well concept or the CEL requirement for the surface casing. Thus, neither the costs of CELs for all surface casings, nor the cost savings from the type well are relevant for the final rule.

Commenters suggested that the economic analysis should consider legal challenges and delays to APDs. The BLM did not revise the final rule or alter the analysis to consider potential legal challenges or APD delays, because any potential delays that might arise as a result of legal challenges are speculative and not the result of the rule itself.

One commenter suggested that the analysis should account for the cost of labor required to implement the rule. In the economic analysis for both the initial proposed and the supplemental proposed rules, the BLM considered the additional BLM workload and cost required as a distributional cost. The BLM agrees with the comment and has revised the final analysis to include the labor costs as part of the total costs of the rule.

Some commenters agreed with the BLM's administrative cost estimate, while others thought that the estimate should be reevaluated. The administrative workload was based on the estimated agency review time. In the final rule's analysis, the BLM reevaluated the administrative costs given the changes to the rule. The results of the BLM reevaluation are discussed later in the Paperwork Reduction Act section of this rule.

Commenters suggested that the BLM failed to consider the effects on tribal governments, and that the rule will have a disproportionate effect on tribes. Commenters suggested that the compliance costs of the rule will discourage operators from developing resources on Federal and Indian lands, reduce royalties, and harm local economies. Some commenters suggest that there could be negative spillover effects on state and private lands as well.

The analysis for the proposed and supplemental proposed rules included impacts on tribal lands. The BLM revised the final rule's analysis to addresses these impacts. The BLM believes that the rule will not have a disproportionate effect on tribes, given the requirements are consistent with current industry best practices.

Many commenters suggested that the economic analysis failed to quantify or describe the benefits of the rule and that the benefits must support the BLM's proposed action. Commenters disagreed with the characterization of risk and of the incidence of problems. Commenters also acknowledged that the risk of hydraulic fracturing is largely unknown. One commenter suggests estimating the environmental risk or determining society's willingness to pay for risk reduction.

The BLM does not quantify the benefits of the rule, because it is unable to monetize the incremental reduction in risk that the rule confers. It further believes that determining society's willingness to pay for risk reduction would need to rely on a firm understanding of the incremental risk reduction. However, this does not mean that the rule is without benefits. The final rule includes requirements, many of which are already consistent with industry guidance, to ensure that operators conduct hydraulic fracturing in a manner that minimizes environmental and health risks associated with these activities. These requirements are also generally consistent with several state regulations governing hydraulic fracturing.

One commenter suggested that Federal Remediation Technologies Roundtable case studies referenced in the proposed rule's economic analyses are inappropriate because none of the studies are studies of hydraulic fracturing operations. One commenter referenced testimony that the remediation of groundwater contaminated by oil and gas wastes can range from $100,000 to $1 million. The BLM included these figures in the analysis to provide context about the cost of potential problems, but it does not use the figures to quantify a benefit.

Commenters suggested that the rule lacks economic justification and is unnecessary, that there have been no events of groundwater contamination, and the benefits must outweigh the costs. Elsewhere in this preamble we have discussed the need and purpose for the rule and it is prudent for the BLM to be proactive in the protection of resources on Federal and Indian lands. Throughout the rulemaking process, the BLM has been mindful of the potential compliance costs to the operator. The requirements in the final rule are consistent with industry best practices and the burden should be minimal. In addition to that, the rule is necessary given the overall scale of development and emergence of increasingly complex hydraulic fracturing operations that apply increased pressures and volumes of fluid within the subsurface. The BLM agrees that efforts to trace contaminants in groundwater to specific hydraulic

fracturing operations have been controversial, in light of the technical difficulties and scientific uncertainties. But no law requires the BLM to wait for a significant pollution event before promulgating common-sense preventative regulations. Also, the numerous official reports of frack hits (unplanned surges of pressurized fluid from hydraulic fracturing operations into other wells) show that the industry is in need of regulation to protect other wells and to prevent contamination of surface and possibly sub-surface resources caused by frack hits.

Commenters suggested that some of the requirements in the rule are duplicative of state rules, that the rule is duplicative and unnecessary, and that the analysis should reflect that. The economic analysis accounts for areas in which the rule's requirements are consistent with existing requirements (whether in current BLM onshore orders or in state regulations) or consistent with current industry best practice. For activities required by the rule that are already performed by operators, the economic analysis does not attribute the costs of those activities to the final rule.

Commenters suggested that wells that have been constructed prior to this rule should be grandfathered. Otherwise, operators would have to workover wells to comply with cement repair provisions. If not, those costs should be considered. As described in the discussion of final section 3162.3–3(a), the final rule clarifies which paragraphs of the final rule will apply to wells constructed prior to the effective date of the rule, and the economic analysis reflects the terms of the final rule.

Operators planning to conduct hydraulic fracturing on existing wells will need to submit documentation that demonstrates that adequate cementing was achieved for all casing strings designed to isolate and protect usable water. Monitoring reports of cement jobs are common in the industry and the operator should be able to provide such documentation to the BLM without any burden even for wells drilled prior to this rule. For older completed wells, to the extent that these reports are not available, the operator may provide any other information or perform any other measures deemed necessary by the authorized officer to assure that the cementing will isolate and protect usable water zones. Operators planning to conduct hydraulic fracturing on existing wells will also need to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone. Operators will be able to run a CEL on the production casing, as is consistent with prudent operating practice, without an additional cost burden.

Environmental Impacts

Certain commenters expressed concern stating that the environmental assessment (EA) did not consider a reasonable range of alternatives to the proposed action. Commenters claimed that, other than the No Action alternative, all alternatives looked too similar to be considered different alternatives. Commenters further suggested that the BLM consider alternatives that: (1) Do not impose cement evaluation log (CEL) requirements; (2) Defer to states with hydraulic fracturing rules regardless of whether they meet or exceed the requirements of the BLM's rule; (3) Ban hydraulic fracturing entirely or in sensitive areas; (4) Regulate air emissions from hydraulic fracturing operations; (5) Ban the use of diesel in hydraulic fracturing fluid; or (6) Ban the use of harmful chemicals in hydraulic fracturing fluid.

To help inform the development of the hydraulic fracturing rule, the Secretary and the BLM hosted forums in Washington, DC and various parts of the country to receive input from the public regarding their concerns about hydraulic fracturing activities on onshore Federal and Indian lands. A majority of the concerns raised during the sessions relate to the risks hydraulic fracturing activities pose to surface and subsurface sources of water, the constituents of the fluids injected into the ground as part of the hydraulic fracturing process, and concerns over the management of the fluids used during and recovered after a well is fractured.

The information gathered from these sessions, coupled with the BLM's authority to regulate all oil and gas operations on Federal and Indian lands, helped guide the development of the BLM's *Purpose and Need* statement in the environmental assessment (EA).

The *Purpose and Need* section of the EA states that ''The BLM's existing limited regulations pertaining to hydraulic fracturing operations need strengthening to provide adequate protection of water resources.'' The *Purpose and Need* section of the EA further states that, ''Pursuant to the FLPMA, the Indian mineral leasing acts, and other statutes, the BLM administers oil and gas operations in a manner that protects Federal and Indian lands, while providing for opportunities to develop oil and gas resources on those lands.''

The BLM's obligation under NEPA is to analyze a reasonable range of alternatives (not every conceivable alternative) that would meet the bureau's purpose and need for Federal action and allow for a reasoned choice among alternatives to be made. The Council on Environmental Quality (CEQ) has determined that ''Reasonable alternatives include those that are practical or feasible from the technical and economic standpoint and using common sense, rather than simply desirable from the standpoint of the applicant.'' [10]

The BLM analyzed six alternatives that respond to the BLM's purpose and need for Federal action. These alternatives consider a broad range of prescriptions for how hydraulic fracturing operations should be regulated, including the option of not promulgating a rule—the No Action alternative. Regarding the action alternatives, Alternative B seeks to regulate all forms of well stimulation, including hydraulic fracturing, and prescribes a particular way to confirm wellbore integrity and zonal isolation of usable water-bearing zones, *i.e.,* through the use of cement bond logs for all wells that are to be stimulated. In contrast, Alternative E seeks to regulate hydraulic fracturing operations specifically, and broadens the set of cement evaluation tools that may be used (not just a cement bond log) to confirm wellbore integrity and zonal isolation of usable water-bearing zones. Alternative E also evaluates the concept of a type well, which would serve as a model well for hydraulic fracturing in a field where geologic characteristics are similar. A cement evaluation log would not be required for all wells that would replicate the successful type well in the same field. The BLM also looked at alternatives that were less and more restrictive in the way recovered fluids should be handled. The following table outlines the alternatives that the BLM considered as part of its NEPA analysis.

[10] CEQ, Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations, 46 FR 18026, 18027 (1981) (Q 2a–).

Name of alternative	Description of alternative
Alternative A—No Action	Under this alternative, the BLM would neither promulgate a rule to amend existing regulations nor add any new regulation.
Alternative B—Initial Proposed Well Stimulation Rule	Under this alternative, the BLM would promulgate the well stimulation rule entitled Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands, which was published in the **Federal Register** on May 11, 2012 (77 FR 27691)
Alternative C—Unlined Pits	This alternative is identical to Alternative A except oil and gas operators would not be required to line the pits that store the fluids flowed back from a well after well stimulation operations are complete.
Alternative D—Storage Tank Requirement	This alternative is identical to Alternative B except that it requires oil and gas operators to use storage tanks to manage flowback.
Alternative E—Proposed Action—Supplemental Proposed Hydraulic Fracturing Rule.	Under this alternative, the BLM would promulgate the supplemental proposed hydraulic fracturing rule entitled *Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands,* which was published in the **Federal Register** on May 24, 2013 (78 FR 31636). This alternative is similar to Alternative B, the Initial Proposed Rule, except it contains sufficient changes that publication of a revised proposed rule was necessary.
Alternative F—BLM Preferred Alternative, Final Hydraulic Fracturing Rule.	Under this alternative, the BLM would promulgate the final rule entitled: *Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands.* This alternative is similar to Alternative E, but with certain modifications based on comments received during the public comment period for the Supplemental Proposed Rule on *Oil and Gas; Hydraulic Fracturing, on Federal and Indian Lands.*

Alternative C evaluated the option of not requiring operators to line their pits to temporarily store recovered fluids. Alternative D evaluated the option of requiring operators to use only storage tanks to store recovered fluids. Under Alternative F, the BLM requires the use of rigid enclosed, covered, or netted and screened above-ground tanks with a 500 bbl capacity, but will consider the use of a lined pit so long as the risk of adversely affecting sensitive water resources, such as surface water and shallow groundwater, was low and use of storage tanks was infeasible for environmental, public health, or safety reasons. However, Alternative F does not include a requirement to perform a cement evaluation log on all casing strings. Rather, it requires operators to circulate cement to the surface for the surface casing and either circulate cement to the surface or run a CEL on the intermediate and production casing, in addition to performing specific well integrity tests, to confirm wellbore integrity and zonal isolation. These alternatives meet the BLM's purpose and need for Federal action and comply with CEQ's requirement to also consider the No Action alternative, which is Alternative A.

In addition to the six alternatives analyzed in the environmental assessment, the BLM also considered additional alternatives that were eliminated from detailed analysis. The BLM considered an alternative to defer to the states' and tribes' hydraulic fracturing rules regardless of whether those rules meet or exceed the agency's hydraulic fracturing requirement. However, those governments are regulating hydraulic fracturing operations in varying ways. For example, the state regulations range from not regulating the activity at all in some states to fairly comprehensive regulation in other states. The BLM administers oil and gas operations in many states and on various Indian reservations, and the agency needs a baseline set of standards that would apply to Federal and Indian oil and gas leases in all states. These standards must meet the agency's unique responsibilities under the FLPMA, the Indian mineral leasing acts, and other statutes to administer oil and gas operations in a manner that protects Federal and Indian lands. The BLM's regulations are necessary because the BLM is unable to delegate its responsibilities to the states and tribes. An alternative that would defer to state and tribal hydraulic fracturing rules, even in circumstances where those rules do not meet or exceed the requirements of the BLM's rule, would not meet the purpose and need for the BLM's action. Moreover, an alternative deferring only to more stringent regulations would be unnecessary. None of the alternatives considered by the BLM for this rulemaking would preempt a more stringent state or tribal law. Unless a specific variance is granted by the BLM, operators on Federal leases must comply both with this rule and any applicable state requirements, just as they already must comply with both BLM rules and state rules on a variety of drilling and completion issues. This alternative was therefore not carried forward for further analysis.

The BLM considered an alternative that would ban hydraulic fracturing activities in all areas. However, such an alternative may render most oil and gas development projects on Federal and Indian land infeasible, as indicated by the fact that the BLM estimates that 90 percent of the wells drilled on Federal and Indian land are hydraulically fractured. The BLM has a responsibility under the FLPMA to act as a steward for the development, conservation, and protection of Federal lands, by implementing multiple use principles and recognizing, among other values, the Nation's need for domestic sources of minerals from the public lands. The Secretary of the Interior has responsibilities under the Indian mineral leasing acts to assist tribes and individual Indians in obtaining the benefits of mineral development while protecting other resources. A ban or moratorium would not satisfy the BLM's development responsibility under the FLPMA, or the Secretary's responsibilities under other statutes, when regulations can adequately reduce the risks associated with hydraulic fracturing operations. In addition, a part of the BLM's purpose and need for this action is to administer oil and gas operations in a manner that protects Federal and Indian lands while providing for opportunities to develop oil and gas resources on those lands. An alternative that would ban or place a moratorium on hydraulic fracturing operations would not meet the purpose

and need for the BLM's action, and was not carried forward for further analysis.

Similarly, the BLM considered an alternative that would ban hydraulic fracturing activities in sensitive areas. However, the BLM has other tools and processes in place to ensure protection of sensitive areas. For example, the BLM has rules at 43 CFR 3100.0–3(a)(2)(iii) that prohibit the leasing of Federal minerals beneath incorporated cities, towns, and villages. Also, during development of a Resource Management Plan (RMP), the BLM identifies areas needing protection as areas closed to leasing or areas open to leasing, but with stipulations that limit or prohibit surface occupancy. Further, specific setbacks from sensitive areas are more effective when they are determined at a level where the information associated with a given sensitive area is available. That information is gathered and maintained at the field office level where specific drilling and hydraulic fracturing operations are permitted. At the permitting stage, the BLM conducts additional analysis as required by NEPA, when drilling/hydraulic fracturing proposals are received. The analysis includes onsite inspections, which identify any additional sensitive areas. Using that information, the BLM then develops proper mitigation to protect these areas. Mitigation could include moving the well location or including site-specific conditions of approval (COAs). In addition, if unnecessary or undue degradation impacts are identified on public land, or unacceptable impacts are identified on Indian land, which cannot be mitigated, the BLM may deny the proposal. Through existing regulations, the RMP process, and the subsequent site-specific analyses, the BLM has or can specify measures to ensure protection of sensitive areas. Furthermore, state set-back requirements would normally apply on Federal lands, and tribal set-back requirements would apply on tribal lands (see also existing section 3162.3–1(b)). Since setback requirements are already addressed in existing regulations, land use planning, and internal processes and policy, minimum setback distances are not necessary in this rule. For these reasons, an alternative that entails setbacks from sensitive areas would not be a reasonable alternative, and was not carried forward for further analysis.

The BLM considered an alternative that would regulate emissions associated with the hydraulic fracturing process. However, this alternative is not within the scope of this rulemaking. The purpose and need for the BLM's action is, among other things, to improve its regulatory framework to account for hydraulic fracturing activities and establish procedures that would provide adequate protection of water resources on Federal and Indian lands. Please note that the EPA issued final rules to reduce air pollution from the oil and natural gas industry. The final rules were issued in 2012 and include air standards for natural gas wells that are hydraulically fractured. For these reasons, the alternative was not carried forward for analysis.

The BLM considered an alternative that would ban the use of harmful chemicals in the fluids used to hydraulically fracture a well. Chemicals used during the hydraulic fracturing process are tailored to the downhole conditions of a given well. In this rule, to be conservative, the BLM treats all chemicals used in hydraulic fracturing as if they were hazardous. Thus, the rule is written to ensure that all hydraulic fracturing fluids are confined to the intended zone and do not contaminate usable water zones, and that recovered fluids do not contaminate surface or groundwater. For these reasons, an alternative to ban hazardous chemicals was not carried forward for analysis.

Similarly, the BLM considered an alternative that bans the use of diesel fuel in hydraulic fracturing fluids. Diesel fuel is used as a base fluid instead of water where the hydrocarbon-bearing formation would swell when coming into contact with water, limiting or preventing the flow of oil and gas into the wellbore. The regulation of diesel fuel in hydraulic fracturing fluids is committed to EPA under the SDWA and the Energy Policy Act of 2005. The action alternatives would prevent hydraulic fracturing fluids, recovered fluids, and hydrocarbons from contaminating usable water sources. Banning the use of diesel fuel on Federal and Indian lands could prevent some oil and gas resources from being developed, even though such operations would be allowed by the EPA's regulations and guidance. That would not serve the purpose and need for the regulation. Accordingly, an alternative to ban the use of diesel fuel was not carried forward for analysis.

Certain commenters recommended that the BLM not only analyze the impacts from the proposed rule, but rather all impacts associated with hydraulic fracturing operations in order to determine the effectiveness of the rule. Those commenters wanted an analysis of impacts to landscapes, air, wildlife, etc., as well as increased greenhouse gas emissions released as a result of increased production from unconventional sources made available only because of hydraulic fracturing technologies.

An expanded description of hydraulic fracturing operations is provided in the Environmental Impacts section of the EA, and in the discussion of the No Action Alternative. Analyzing impacts associated with actual site-specific hydraulic fracturing activities is outside the scope of the EA for this rule. The BLM's Preferred Alternative is not to consider the approval of a specific hydraulic fracturing operation, but rather to consider how its existing rules should be revised to respond to changes in technologies for hydraulic fracturing and the public's concern regarding the practice. Approvals to develop Federal and Indian oil and gas resources (including proposals to hydraulically fracture wells) are made at different levels of the agency's organization and during various decision-making processes—land use planning, oil and gas leasing, and permitting. It is at those decision points where the BLM would analyze, through the NEPA process, impacts to landscapes, air, wildlife, etc., as well as greenhouse gas emissions released from oil and gas development.

The BLM has analyzed the action alternatives in comparison to the No Action Alternative. The CEQ requires that a No Action Alternative be considered. The No Action Alternative would not amend the BLM's oil and gas regulations. Instead oil and gas activities on Federal and Indian lands would continue under existing regulations. The No Action Alternative provides a useful basis for comparison, enabling decision-makers to compare the magnitude of environmental effects of the action alternatives against the No Action Alternative. The No Action alternative also demonstrates the consequences of not meeting the need for the action.

The BLM has evaluated the effectiveness of the rule when evaluating the effects of the No Action Alternative in Chapter IV of the EA. The BLM determined that if none of the action alternatives were to be implemented, operators or their contractors would still perform hydraulic fracturing operations on Federal and Indian lands, usually without the BLM's prior approval, and without performance standards specific for wells to be fractured. The BLM and the public would not have an adequate assurance that hydraulic fracturing operations performed on Federal and Indian lands are conducted in a safe and environmentally sound manner, particularly because there would not be a regulation that provides: (1) For the disclosure of chemicals used in the stimulation process; (2) A means to

confirm that all hydraulically fractured wells would be able to withstand the pressures of an anticipated hydraulic fracturing event and that all chemicals injected would be contained within the well and targeted producing formations; or (3) An assurance that the fluids recovered from the hydraulic fracturing process are handled and disposed of properly.

Some commenters believe that the scope of the rule requires the preparation of an EIS. The comments in favor of an EIS make one or more of three different positions. First, some commenters believe that an EIS is required because of the trade secrets provision within the rule. Although the rule contains requirements for disclosure, there are provisions that allow operators to withhold trade secrets. Those commenters said that the BLM cannot claim that the rule's chemical disclosure requirement will help the agency and other agencies make an accurate determination of whether hydraulically fractured fluids could be the source of any future reports of groundwater contamination. Without the information about trade secrets, the commenters said, future approvals of hydraulic fracturing operations could not accurately predict environmental impacts, and thus the BLM should prepare an EIS for the final rule.

Second, some commenters believe that an EIS is required because multiple significance factors are present under the regulations which would govern widespread hydraulic fracturing on public lands throughout the country. The alleged significance factors include adverse environmental effects, significant impacts to public health and safety, unique characteristics of the geographic area, controversial effects, uncertain risks, cumulatively significant impacts, adverse effects to threatened and endangered species, and potential violations of environmental laws. Commenters said that the significant impacts of widespread hydraulic fracturing on public lands that would take place under the regulations contradict BLM's ultimate conclusion in the EA that the proposed regulations would have no significant impacts on the environment.

Third, some commenters have expressed concern with the EA's analysis of socioeconomic impacts. Commenters said a nationwide rule that has economic and employment impacts is a major Federal action requiring the preparation of an EIS, therefore, the NEPA analysis performed for the proposed rule is inadequate. The commenter said that the BLM is in error in determining that an EA is sufficient to analyze the impacts associated with the rule. The commenter said that a nationwide rule of this magnitude and its coinciding economic and employment impacts certainly rise to the level of ''Major Federal Action,'' and therefore questioned the BLM's determination that an EA is sufficient.

The BLM has not prepared an EIS in response to those comments. First, the comments based on the trade secrets provisions miss the point that BLM's evaluation of the impacts associated with promulgation of the rule, and with the BLM's later evaluation of site specific impacts, does not require operators to disclose trade secrets. The BLM will make its decisions on proposals to conduct hydraulic fracturing operations on the assumption that the operations will use hazardous chemicals. The BLM will not approve proposals unless the operator demonstrates that the well was cased, cemented, and tested to show that it will isolate and protect usable water, and that recovered fluids will be isolated from surface and groundwater. The precise chemical constituents are not necessary for the BLM to assure that the operation will protect surface and groundwater. Exemptions from public disclosure for trade secrets or confidential business information will not prevent the BLM from assessing the environmental impacts of future hydraulic fracturing operations, and thus do not require an EIS for this rule.

Second, the comments that advocate an EIS because of multiple significance factors which would govern widespread hydraulic fracturing on public lands throughout the country misunderstand the effect and impact of this rule. Federal agencies are required to prepare an EIS when they will take a major Federal action that will potentially have a significant effect (direct, indirect, or cumulatively) on the human environment. The BLM's action is to update its existing regulations that pertain to hydraulic fracturing operations on Federal and Indian leases. Analyzing impacts associated with actual site-specific hydraulic fracturing activities is outside the scope of the EA for this rule. The BLM's proposed action is not to consider the approval of a specific hydraulic fracturing operation, but rather to consider how its existing rules should be revised to respond to changes in technologies for hydraulic fracturing and the public's concern regarding the practice. Approvals to develop Federal and Indian oil and gas resources (including proposals to hydraulically fracture wells) are made at different levels of the agency's organization and during various decision-making processes—land use planning, oil and gas leasing, and permitting. It is at those decision points where the BLM would conduct further analysis under NEPA to evaluate impacts to landscapes, air, wildlife, etc., as well as increased greenhouse gas emissions released from oil and gas development.

In the EA prepared for this rule, the BLM evaluated a range of reasonable alternatives, including the final rule, to determine whether its promulgation of the final rule would result in a significant effect on the human environment. In making its Finding of No Significant Impact (FONSI), the BLM considered the significance factors set out in 40 CFR 1508.27, which include the significance factors identified by commenters. For the reasons discussed in more detail in the EA and FONSI, the BLM concluded that the final rule would not have a significant impact on the environment and that no EIS was required.

Furthermore, the rule is not connected to other actions that may require an EIS because it does not automatically trigger land use planning decisions, oil and gas leasing, or hydraulic fracturing operations. The rule will be in effect regardless of any previous leasing or development. The rule is not an interdependent part of a larger action and it does not depend on any larger action for its justification.

The rule will govern future hydraulic fracturing operations, as will stipulations in oil and gas leases, and COAs in permits to drill. The lease stipulations and COAs can address local conditions and resources. Thus, the rule does not foreclose reasonable mitigation for site-specific direct, indirect, or cumulative impacts.

Under the CEQ's regulations, an EIS is required only if the issuance of a rule or regulation may significantly affect the quality of the human environment. 40 CFR 1508.18. The human environment includes the natural and physical environment and the relationship of people with that environment, but economic or social effects do not by themselves require preparation of an EIS. 40 CFR 1508.14. The EA refers to and analyzes the socioeconomic impacts of the rule that are provided in the separate economic analysis. The economic analysis shows that the rule will increase compliance costs of operators, but also discloses that those increased costs would be only a small percentage of the costs of drilling and hydraulically fracturing an oil and gas well. Thus, only marginally prospective lands could even theoretically become less attractive to the oil industry, and

the employment and revenue impacts of the rule, if any, will be impossible to separate from the greater influences of geologic conditions, technological innovations, and market forces. The BLM's EA thus appropriately determined that there would be no significant impacts to the quality of the human environment, and it is not necessary for the BLM to prepare an EIS.

Certain commenters stated that the BLM did not inform the public that it was preparing a NEPA analysis, nor did it circulate a draft EA. Other commenters expressed similar concern saying the BLM did not provide a public comment period and therefore, the public was not able to provide meaningful input at a time when the environmental analysis could have been altered and improved.

Unlike the procedures for issuing an EIS, which includes specific formal notification requirements through the **Federal Register** and minimum requirements for inviting public comments, the CEQ's and the DOI's NEPA implementing regulations require Federal agencies to involve the public when preparing an EA, but gives discretion to each agency to determine whether it is appropriate to make the EA available for public comment and review.

On May 11, 2012, the BLM issued the notice of proposed rulemaking and then issued a supplemental notice of proposed rulemaking on May 24, 2013. The 2012 proposal was available for public comment for 120 days and the 2013 notice was available for 90 days. Both rules put the public on notice that the EA was available for review and comment along with the other documents in the administrative record. The BLM, in fact, received several comments concerning the substance of the EA, and those comments have been considered. Thus, comments suggesting that the EA was unavailable, or not properly made available for comment, are incorrect.

III. Procedural Matters

Federal and Indian Oil and Gas Leasing Activity

To understand the context of the costs and benefits of this rule, the BLM includes background information concerning the BLM's leasing of Federal oil and gas, and management of Federal and Indian leases. This analysis explains the basis for the conclusions related to the procedural matters sections that follow. The BLM Oil and Gas Management program is one of the largest mineral leasing programs in the Federal Government. At the end of fiscal year (FY) 2013, there were 47,427 Federal oil and gas leases covering 36,092,482 acres, 93,598 producible and service drill holes, and 99,975 producible and service completions on Federal leases. Table 1 shows the sales volume, sales value, and royalty generated from Federal and Indian oil and gas production in 2013. For FY 2013, onshore Federal oil and gas leases produced about 133 million bbl of oil, 2.67 trillion cubic feet (Tcf) of natural gas, and 2.5 billion gallons (Gal) of natural gas liquids, with a sales value of almost $24 billion and generating royalties of almost $2.7 billion. Oil and gas production from Indian leases was almost 46 million bbl of oil, 238 billion cubic feet (Bcf) of natural gas, and 155 million gallons of natural gas liquids, with a sales value of over $5 billion and generating royalties of $860 million for the Indian mineral owners.

TABLE 1—FEDERAL AND INDIAN OIL AND GAS PRODUCTION AND ROYALTIES, FISCAL YEAR 2013

Jurisdiction	Commodity	Sales volume	Sales value	Revenue
Federal Leases	Oil (bbl)	133,364,128	$11,927,069,991	$1,444,886,822
	Gas (Mcf)	2,662,577,254	9,905,897,816	1,051,198,875
	NGL (Gal)	2,477,721,602	2,076,639,138	195,789,932
Subtotal			23,909,606,945	2,691,875,629
Indian Leases	Oil (bbl)	45,966,597	4,137,453,205	721,089,106
	Gas (Mcf)	238,717,918	813,440,706	124,217,560
	NGL (Gal)	155,399,916	135,369,266	15,192,781
Subtotal			5,086,263,176	860,499,447

Source: Office of Natural Resources Revenue (ONRR), Federal Onshore Reported Royalty Revenue, FY 2013 and American Indian Reported Royalty Revenue, FY 2013.

Need for Policy Action

To summarize the need for policy action, the National Academy of Science has identified three potential pathways for hydraulic fracturing fluids or oil and gas from hydraulic fracturing operations to contaminate usable water resources. The BLM agrees that the most likely pathway would be a leak in the wellbore casing, and that assurances of the strength of the casing are appropriate. The BLM also believes that it is important to consider known faults or natural fissures that could serve as pathways between the fractured zone and usable water before approving a hydraulic fracturing operation. A related issue is prevention of ''frack hits,'' which are unplanned surges of pressurized fluids from one wellbore into another wellbore. Frack hits have resulted in surface spills on Federal and non-federal lands and have caused the loss of recoverable oil and gas, but they have not yet been shown to be a source of contamination of usable water. Furthermore, proper management of recovered fluids on the surface is necessary to prevent leaks and spills that could contaminate surface waters and shallow aquifers; the BLM needs to fill the existing regulatory gap between completion of a hydraulic fracturing operation and the implementation of an approved plan for permanent disposal of produced water. Finally, the BLM, the public, and tribes should have access to information about the chemicals injected into Federal or Indian lands, consistent with statutory protections for proprietary information. The following discusses those needs for policy action in more detail.

Much of the debate about hydraulic fracturing has centered on fluid or gas migration; that is, the potential that hydraulic fracturing fluids pumped into deep geologic formations, or oil or gas liberated by hydraulic fracturing will migrate into shallower drinking water sources with potential contamination made more likely if the wellbore integrity is compromised. Most reports suggesting that hydraulic fracturing operations contributed to contamination of water supplies involve instances of abnormally high concentrations of methane in water wells or monitoring wells in or near areas with active oil and gas drilling.

For example, the National Academy of Sciences issued reports in 2011 [11] and in 2012 [12] finding that there are at least three possible mechanisms for fluid migration into shallow drinking-water aquifers that could help explain the increased methane concentrations observed in water wells that existed around shale gas wells in Pennsylvania:

1. The movement of gas-rich solutions within the shale formations up into shallow drinking-water aquifers;
2. The movement of gas through inadequately constructed, or leaky gas-well casings; and
3. The creation of new or enlarging of existing fractures above the shale formation as a result of hydraulic fracturing, which increases the connectivity of the entire fracture system, thus allowing the gas to absolve out of solution and migrate through the fracture systems and into shallow aquifers.

These reports have indicated that the movement of gas-rich solutions within the shale formations up into shallow drinking-water aquifers is the least likely possibility. This is due primarily to the extensive distance between the shale formations and the shallow aquifers as well as high underground pressures exerted against the deep shale formations. The most likely possibility for gas contamination would be from leaky gas-well casings. These leaks could occur at hundreds of feet underground, with methane passing laterally through the well casing and vertically through fracture systems. There is also a possibility for gases to migrate through fractures above the shale formation that is created or enlarged as a result of hydraulic fracturing and thus expanding the overall underground fracture system. These new fractures could potentially relieve the pressures exerted against these gas-rich solutions, which would allow the gas to come out of solution and migrate through the fracture system and potentially into shallow aquifers or improperly plugged wells. However, these researchers have stated that the possibility of such occurrence is unlikely, but still unknown.

The focus on fluid or gas migration is only one aspect of potential damage. According to the EPA, there are other potential impacts, including stress on surface water and groundwater 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.[13]

The BLM is aware that a small number of hydraulic fracturing operations on Federal lands have communicated with other wells in their vicinity. Those hydraulic fracturing operations created fractures that connected with existing fissures or fractures in the shale, allowing pressurized fluids to flow into nearby wellbores. During these instances of downhole inter-well communication, known as ''frack hits,'' the pumped-in hydraulic fracturing fluid may flow into and up through a nearby well, causing a blow out and spill.

The Secretary of Energy's Advisory Board

At the President's direction, the Secretary of Energy's Advisory Board convened a Natural Gas Subcommittee to evaluate hydraulic fracturing issues. The subcommittee met with industry, service providers, state and Federal regulators, academics, environmental groups, and many other 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 final report, issued on November 18, 2011, recommended, among other things, that operators and regulating agencies ''adopt best practices in well development and construction, especially casing, cementing, and pressure management. Pressure testing of cemented casing and state-of-the-art cement bond logs should be used to confirm formation isolation. Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing jobs. The regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing.'' [14]

Public Concern

The public and various groups have expressed strong concerns about the prevalence of hydraulic fracturing and the chemical content of the fluids used in the process. Some of the comments frequently heard during the public forums previously discussed 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.

Improving Governmental Processes

The BLM has existing regulations for hydraulic fracturing, found in 43 CFR 3162.3–2. Under that regulatory provision, an operator must seek approval from the BLM before performing ''non-routine'' fracturing operations. Conversely, an operator performing ''routine'' fracturing operations does not currently need the BLM's approval. The regulation makes a distinction between ''routine'' and ''non-routine'' fracturing operations, but it does not define them. This omission makes the distinction functionally difficult to apply and confusing for both the agency and the regulated public.

Also, hydraulic fracturing operations conducted now are vastly different than the operations conducted decades ago. For decades, hydraulic fracturing was a completion or re-completion technology that used relatively small quantities of fluid to improve the flow of hydrocarbons around the bottom of conventional wells. Due to advances in horizontal drilling, hydraulic fracturing operations are now conducted on wells with longer lateral legs (often 1 to 2 miles) and require far larger volumes of water. The chemical content of the hydraulic fracturing fluids is also a growing concern to the public, such that many state regulatory authorities now require the chemical disclosure of fracturing fluids. The information that the BLM currently requires before and after fracturing operations is inadequate and does not reflect the complex nature of the operations.

From a resource management perspective, the current regulation results in incomplete information being provided to the BLM. That lack of

[11] Osborn, S., *et al.* (2011). *Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing.* Proceedings of the National Academy of Sciences.

[12] Warner, N., *et al.* (2012). *Geochemical evidence for possible natural migration of Marcellus Formation brine to shallow aquifers in Pennsylvania.* Proceedings of the National Academy of Sciences, Vol. 109, July 24, 2012.

[13] U.S. Environmental Protection Agency (May 20, 2014). *Natural Gas Extraction—Hydraulic Fracturing: Providing Regulatory Clarity and Protections against Known Risks.* Retrieved from *http://www2.epa.gov/hydraulicfracturing# providing.*

[14] Secretary of Energy Advisory Board (2011). *Shale Gas Production Subcommittee Second Ninety Day Report.* November 18, 2011. Retrieved from *http://www.shalegas.energy.gov/resources/111811_final_report.pdf.*

information restricts the BLM's ability as the resource manager to make informed resource decisions about hydraulic fracturing operations or to respond effectively to incidents that may occur. Knowledge of the hydraulic fracturing operations will help the BLM better manage and protect public and tribal resources.

Potential for Externalities

Generally, there is greater potential for undesirable events or incidents to occur when operations are conducted in wells that are constructed improperly, where the plans are inadequate, or when the fluids are not properly managed. This potential extends to hydraulic fracturing operations, where the well may extend laterally and for longer distances, greater pressures are placed on the well, and larger volumes of fluids are used and recovered. As with all drilling and production activities, there is a potential that they may pose a negative externality to society, considering limitations in understanding the extent of potential damage or determining a causal relationship between the operation and the damage.

Relative to wells constructed with sufficient and demonstrated integrity, wells that are inadequately constructed may not sufficiently isolate formation gas or fluids from water resources or may be more likely to fail during fracturing operations. Although wellbore integrity provisions exist in current BLM regulations, this rule would enhance those provisions to account for advances in technology and hydraulic fracturing operations. In addition, the recovered fluid from hydraulic fracturing operations may pose additional risk to the surface and subsurface environments if not managed and disposed of properly.

Estimating Benefits and Costs

After reviewing the requirements of the final rule, we have determined that it 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. Additionally, we have determined that it would not have a significant economic impact on a substantial number of small entities.

Many of the requirements are currently met by operators as a matter of standard industry practice or in compliance with existing state regulations or other BLM regulations (including Onshore Oil and Gas Orders No. 1 and No. 2). We measure the incremental burden to operators against that baseline. While some requirements do not pose an additional burden, other requirements will pose an additional burden.

We estimate that the rule will impact about 2,800 hydraulic fracturing operations per year, but that it could impact up to 3,800 operations per year based on previous levels of activity on Federal lands and growing activity on Indian lands. We estimate that the compliance cost could reach about $11,400 per operation or $32 million per year. The estimated per-operation compliance costs represent about 0.13 to 0.21 percent of the cost of drilling a well. Given the potential to impact 3,800 operations per year, the compliance costs might reach $45 million per year.

The BLM estimated or described the potential costs and benefits that would occur as a result of the rule. As such, it analyzes the impacts in relation to the current operating environment (or the baseline). In analyzing costs and benefits, it is important to differentiate between the activities that an operator conducts (either voluntarily or in compliance with state or Federal requirements) and those new activities that the rule would compel.

Office of Management and Budget (OMB) Circular A–4 recognizes that not all benefits and costs can be described in monetary or even in quantitative terms. In those cases, it directs agencies to present any relevant quantitative information along with a description of the unquantified effects.

We use a bottom-up approach to measure the incremental impacts rather than a top-down approach. In doing so, the BLM estimates the number of hydraulic fracturing operations per year for future years, determines the applicability of the requirements on the operations, determines the unit cost of compliance per requirement, and then calculates the total costs across all requirements and operations. Due to the uncertainty of the hydraulic fracturing activity in future years, the BLM presents a range of costs based on the range of potential activity. We chose to use a bottom-up approach because a requirement may not pose an incremental compliance cost, depending on the operators' voluntary compliance (generally determined as whether the requirement is consistent with industry guidance or best practice) or the regulatory requirements in the jurisdiction within which the operation will occur.

The BLM's approach to estimating the number of hydraulic fracturing operations is described in the Economic Analysis for this rule, which is available from the BLM at the address listed in the **ADDRESSES** section of this rule. The BLM took the number of well completions on Federal and Indian lands for FY 2010 to FY 2013, and assumed that 90 percent of wells were completed using hydraulic fracturing and that 3 percent of those wells would be recompleted. The BLM then used the results from that 4-year period to forecast 3 future years of implementation over a 3-year period in the future, resulting in an estimate of about 2,815 hydraulic fracturing operations on Federal and Indian lands per year.

For the annual estimate of completions using hydraulic fracturing, the BLM uses the 3-year average of the implementation years within each state and reservation. Recognizing the dip in well completions on Federal lands in FY 2013, and recognizing that previous levels of activity were higher, the BLM also calculated costs using the FY 2012 level of activity on Federal lands, prior to the FY 2013 decrease, and presents that estimate as an upper bound of potential costs.

The BLM expects that operators are already in compliance with many of the rule's requirements as a matter of company practice or standard industry practice (described in the Economic Analysis), or to meet state regulations (described in the Economic Analysis) or Federal regulations (described in the Economic Analysis). Where the rule's requirements are consistent with industry guidance, state regulations, or Federal regulations, the BLM considered the applicability of the requirement to be 0 percent and the incremental impact to be zero. We consider partial applicability in areas and in situations where the operator is expected to comply voluntarily, for example, when a requirement costs less than the alternative.

Measuring the Incremental Costs

Application Requirement: The operator must submit an application to conduct a hydraulic fracturing operation with the APD or an NOI when it plans to hydraulically fracture a well for which it has:

- Not yet submitted an APD as of the effective date of this rule;
- Submitted an APD, but the APD has yet to be approved as of the effective date of this rule;
- An approved APD or APD extension on the effective date of this rule, drilling did not begin until after the effective date, and does not conduct

hydraulic fracturing within 90 days after the effective date;

- Started (but does not complete) drilling before the effective date and does not conduct hydraulic fracturing within 90 days after the effective date;
- Completed drilling 180 days prior to the effective date, and does not conduct hydraulic fracturing within 90 days after the effective date; or
- Completed drilling 180 or more days prior to the effective date.

The operator may also submit an application for a group of wells as part of an MHFP, thus reducing the number of potential applications.

This is a new requirement and poses an incremental burden to the operator and the BLM. The information required in the application should be readily available or known to the operator. The information should not require any additional information gathering. An MHFP will allow for efficiencies in submission and review.

The BLM expects there to be fewer applications than there are hydraulic fracturing operations, because of the option to make one submission for a group of wells, a process which is designed to achieve additional efficiencies.

The BLM estimates the applicability of this requirement based on the number of well completions using hydraulic fracturing that we expect to occur. Since the BLM assumes that every hydraulic fracturing operation will require an application, our estimate is inclusive of all instances described in the first paragraph of this section (and particularly in bullets 3 through 6) where an operator would be required to submit an application to conduct hydraulic fracturing.

The data are as follows:

(a) Applicability of requirement = 100 percent of operations. Although the BLM allows for the operator to submit a single NOI covering a group of wells, it is uncertain whether the operator will prefer that method over submitting an application with the APD. For the purpose of this analysis, the BLM assumes that the operator will submit an application for a single well, especially in the near-term future.

(b) Cost per application = $643. The cost per application includes the operator burden and the BLM burden. For both burdens, the BLM estimates the compliance or review hours and the respective wage. The compliance cost for the operator is estimated to be about $496 per application (calculated as 8 hours at about $61.99 per hour). The review cost for the BLM is estimated to be about $147 per application (calculated as 4 hours at about $36.66 per hour).[15] Some commenters stated that the additional informational requirements would cause additional delays in the processing of APDs and thus constitute an opportunity cost on the operator. This argument is not supported. The supporting statement for the Paperwork Reduction Act estimates only 4 hours of additional review time for the BLM to review this information. This does not present a measureable delay in processing time, and no revisions were made to the cost estimate on that basis.

Usable Water Requirement: The operator must isolate all usable water and other mineral-bearing formations and protect them from contamination. Usable water means generally those waters containing up to 10,000 ppm of TDS. Usable water includes, but is not limited to: (i) Underground water that meets the definition of ''underground source of drinking water'' as defined at 40 CFR 144.3; (ii) Underground sources of drinking water under the law of the state (for Federal lands) or tribe (for Indian lands); and (iii) Water in zones designated by the state (for Federal lands) or tribe (for Indian lands) as requiring isolation or protection from hydraulic fracturing operations.

The following geologic zones are deemed not to contain usable water:

(i) Zones from which an operator is authorized to produce hydrocarbons provided that the operator has obtained all other authorizations required by the EPA, the State (for Federal lands), or the tribe (for Indian lands) to conduct hydraulic fracturing operations in the specific zone;

(ii) Zones designated as exempted aquifers under 40 CFR 144.7; and

(iii) Zones that do not meet the definition of underground source of drinking water at 40 CFR 144.3 which the state (for Federal lands) or the tribe (for Indian lands) has designated as exempt from any requirement to be isolated or protected from hydraulic fracturing operations.

This requirement does not pose an incremental cost. The term usable water is defined in a manner consistent with existing BLM requirements in Onshore Oil and Gas Order No. 2, Drilling Operations on Federal and Indian Oil and gas leases (53 FR 46798) (Onshore Order 2). Onshore Order 2 section III.B. requires casing and cement to ''protect and/or isolate all usable water zones.'' Onshore Order 2 defines ''isolate'' as ''using cement to protect, separate, or segregate usable water and mineral resources'' (section II.I.) and ''usable water'' as ''generally those waters containing up to 10,000 ppm of total dissolved solids'' (section II.Y.). Onshore Order 2 has been in effect since 1988; therefore, the requirement to protect and/or isolate usable water generally containing up to 10,000 ppm of TDS has been in effect since that time. This rule corrects the inconsistency between the definition in Onshore Order 2 (the definition in effect) and the definition in the existing 43 CFR 3162.5–2(d). The definition in the CFR, of a 5,000 ppm standard, was superseded by the Onshore Order 2 definition in 1998.

(a) Applicability of requirement = 0 percent of operations

(b) Incremental cost per requirement = $0

Cement Monitoring Requirement: During cementing operations on any casing used to isolate usable water zones, the operator must monitor and record the flow rate, density, and pump pressure and submit a cement operation monitoring report, including this information, to the authorized officer prior to commencing hydraulic fracturing operations. For wells drilled prior to the effective date of the rule, the operator is required to provide documentation that demonstrates that the well is adequately cemented.

This requirement does not pose an incremental cost. API Guidance Document HF1 stresses the importance of using data from reports, logs, and tests to evaluate the quality of a cement job, including drilling reports, drilling fluid reports, cement design and related laboratory reports, etc. Based on this information and our observations of field operations, the BLM believes that operators monitor cementing operations as a matter of practice and can easily provide this information to the authorized officer prior to conducting hydraulic fracturing. The administrative burden of providing this information to the BLM is contained in the application requirement.

(a) Applicability of requirement = 0 percent of operations

(b) Incremental cost per requirement = $0

Surface Casing Requirements: The operator must observe cement returns to the surface and document any indications of inadequate cement (such as, but not limited to, lost returns, cement channeling, gas cut mud, failure of equipment, or fallback from the surface exceeding 10 percent of surface casing setting depth, or 200 feet, whichever is less). If there are indications of inadequate cement, then

[15] The cost formulation for administrative requirements is detailed in the supporting statement for the Paperwork Reduction Act.

the operator must determine the top of the cement with a CEL, temperature log, or other method or device approved by the authorized officer.

This requirement does not pose an incremental cost. Onshore Order 2 requires the operator to return cement to the surface (section II.B.1.c.). Documenting indications of adequate cement and taking corrective action are necessary responses when such issues arise.

(a) Applicability of requirement = 0 percent of operations

(b) Incremental cost per requirement = $0

CEL on Intermediate Casing that Protects Usable Water: If the operator does not cement the intermediate casing string to surface and the intermediate casing is used to isolate usable water, then the operator must run a CEL to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone.

This requirement might pose an additional burden to the operator. API Guidance Document HF1 stresses the importance of using data from reports, logs, and tests to evaluate the quality of a cement job. According to the guidance, 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.'' [16] A cement bond log ''measures the presence of cement and the quality of the cement bond or seal between the casing and the formation.'' [17] Logs are important in ''determining that the well drilling construction is adequate and achieves the desired design objectives.'' [18] It is industry practice to run logs on the production casing of wells. For the intermediate casing, if cement is not circulated to the surface, operators may run a CEL or other diagnostic tools to determine the adequacy of the cement integrity and that the cement reached the desired height (above any exposed USDW or any hydrocarbon bearing zone). State requirements of conditions of the drilling permit may also necessitate the running of logs on the intermediate casing.

Generally, the BLM expects that the operator would log the intermediate casing to ensure that the well was constructed according to design. Logging the casing may also be warranted if the operator plans to hang a production liner off of the intermediate casing, if the proposed fracturing is through the intermediate casing, for hole stability, for isolation through salt zones, or for isolation through disposal zones.

Some states require logging of the intermediate casing through regulation in a manner that is consistent with this rule. North Dakota requires a CBL on the intermediate casing; Colorado requires a CBL if the operator uses a production liner; and Texas specifies that the operator must identify the top of cement (with a CBL or temperature log) if it does not cement to the surface. California and Wyoming may require it in certain circumstances. Additionally, the BLM and states may require operators to log the intermediate casing as a condition of approval if, for example, any of the conditions in the previous paragraph apply. Industry guidance states that operators may run a CBL and/or other diagnostic tools to determine the adequacy of the cement integrity and that the cement reached the desired height.

The rule requires that the operator demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone. When the operator does not circulate cement to the surface, it will most often comply with this requirement by running a CEL on the production casing (when the operator is conducting hydraulic fracturing through the production string). That process is described later. However, if the operator plans to conduct the fracturing operation through a production liner that is hung from the intermediate casing, then it must either circulate the cement behind the intermediate string to surface or run a CEL on the intermediate casing string. Although we believe that this requirement is consistent with prudent operations, the intent of the industry guidance, other state regulations, and conditions of approval that the BLM generally places on APDs where the operator uses a production liner hung from the intermediate casing, we recognize that, in some cases, the rule would compel the operator to run a CEL when it would not have done so otherwise.

The BLM does not have credible data on the prevalence of voluntary compliance or the prevalence of CEL requirements as conditions of approval. The BLM assumes that the rule will compel new action for all operations in states without existing regulations requiring a CEL of the intermediate casing. The BLM also recognizes that, as a result of this assumption, the cost estimates will be overstated.

(a) Applicability of requirement = 0 percent of operations in ND and CO; 2.5 percent in TX ; and 5 percent in other states. Based on field experience, the BLM anticipates that only about 5 percent of wells have intermediate casing to protect usable water.

(b) Incremental cost per requirement = $111,200. After the operator cements the intermediate casing, it must wait a number of hours for the cement to harden before commencing drilling operations. After that time, the operator will pressure test the casing, drill out, and perform a leak-off test. The BLM received some comments indicating that a CEL test necessitates that the cement harden for 72 hours. These comments do not take into consideration the time that the operator must wait to perform other well tests. The BLM also notes that operators generally use additives to speed up the hardening of cement behind intermediate casing. For the purpose of our analysis, the BLM considers only the additional wait time required for the CEL, accounting for 48 hours of additional time at a cost of $1,900 per hour. The cost for a CEL on the intermediate casing includes the test ($20,000) and the cost of maintaining idle drilling equipment on-site ($91,200). The BLM believes that 48 hours is the upper bound of the potential cost. In addition, the operator could potentially avoid delays in part or entirely by running the CEL at some point while drilling the production casing.

CEL on Production Casing that Protects Usable Water: If the operator does not cement the production casing string to the surface, then the operator must run a cement evaluation log to demonstrate that there is at least 200 feet of adequately-bonded cement between the zone to be hydraulically fractured and the deepest usable water zone.

This requirement does not pose an incremental cost. API Guidance Document HF1 indicates that operators run a log to evaluate the quality of the cement bond on the production casing as a matter of industry practice. This is consistent with observations of field operations. Colorado and North Dakota require a CBL in their regulations. Texas specifies that the operator must identify the top of cement (with a CBL or temperature log) if it does not cement to the surface. California and Wyoming may require it under certain circumstances. In states that do not specify a requirement in their regulations, the BLM still expects that

[16] Ibid, p. 8.

[17] Ibid, p. 9.

[18] Ibid, p. 10.

the operator to run a CEL as a matter of practice.

(a) Applicability of requirement = 0 percent of operations

(b) Incremental cost per requirement = $0

Corrective Action Requirement: On all casing strings where the operator cements to the surface, the operator must document any indications of inadequate cement (such as, but not limited to, lost returns, cement channeling, gas cut mud, failure of equipment, or fallback from the surface exceeding 10 percent of surface casing setting depth or 200 feet, whichever is less). If there are indications of inadequate cement, then the operator must:

- Notify the authorized officer within 24 hours of discovering the inadequate cement;
- Submit an NOI to the authorized officer requesting approval of a plan to perform remedial action to achieve adequate cement. In emergencies or in situations of an immediate nature that may result in unnecessary delays, the operator may request oral approval from the authorized officer for actions to be undertaken to remediate the cement and follow-up with a written notice afterwards;
- Verify that the remedial action was successful with a CEL or other method approved in advance by the authorized officer; and
- Submit a subsequent report for the remedial action including a signed certification that the operator corrected the inadequate cement job in accordance with the approved plan with the results from the CEL or other approved test.

This requirement poses an administrative burden, but not an operational burden. The BLM and many state regulations and requirements have established protocol for remedial actions in the event of inadequate cementing, which require operators to remediate and/or take action as directed by the regulatory authority. For example, Onshore Order 2 requires that operators perform remedial cementing if cement is not circulated back to the surface for the surface casing (section III.B.1.c.). Onshore Order 2 also requires an additional pressure test and/or remedial action as specified by the authorized officer if a pressure test indicates that casing strings do not meet minimum standards (section III.B.1.h.). The BLM believes that this requirement will impose an administrative burden on the operator who observes indications of inadequate cementing, but not an operational burden. In the supplemental proposed rule, the BLM had specified that the operator would have to run a CEL to demonstrate that the remedial action was successful, but the final rule's requirement is that the operator may use a CEL or other approved test, presumably a temperature log, that would not result in delays.

(a) Applicability of requirement = 3 percent of operations. The number of wells where there is an indication that the initial cement jobs require repairs is generally believed to be between 1 percent and 5 percent.[19] The BLM uses the midpoint of the range, or 3 percent, and applies it to the number of newly drilled wells for the activity data.

(b) Cost per response = $643. Burden includes the operator burden and the BLM burden. The compliance cost for the operator is estimated to be about $496 per application (calculated as 8 hours at about $61.99 per hour). The review cost for the BLM is estimated to be about $147 per application (calculated as 4 hours at about $36.66 per hour).

Mechanical Integrity Test Requirement: If hydraulic fracturing through the casing is proposed, the operator must test the casing to not less than the maximum anticipated surface pressure that will be applied during the hydraulic fracturing process. If hydraulic fracturing through a fracturing string is proposed, then the operator must test the fracturing string to not less than the maximum anticipated surface pressure minus the annulus pressure applied between the fracturing string and the production or intermediate casing.

This requirement does not pose an incremental cost. Industry guidance and state regulations are consistent with this requirement. Industry guidance on hydraulic fracturing states that the production casing of a well should be pressure tested prior to completion. The BLM also reviewed state regulations in California, Colorado, Montana, New Mexico, North Dakota, Oklahoma, Texas, Utah, and Wyoming. From FY 2010 to FY 2013, the number of well completions on Federal and Indian lands in those states accounted for 99.3 percent of the total well completions on Federal and Indian lands nationwide. The state regulations in those states either require pressure tests on all casing strings or on the casing strings through which the completion operation will occur.

(a) Applicability of requirement = 0 percent of operations

(b) Incremental cost per requirement = $0

Monitor Annulus Pressures and Reporting Requirement: During the operation, the operator must continuously monitor and record the annulus pressures at the bradenhead and between any intermediate casings and the production casing. The operator must submit a continuous record of all annuli pressure during the fracturing operation in the subsequent report. If during any hydraulic fracturing operation any annulus pressure increases by more than 500 psi as compared to the pressure immediately preceding the stimulation, the operator must take immediate corrective action and orally notify the authorized officer as soon as practical, but no later than 24 hours following the incident. Within 30 days after the hydraulic fracturing operations are completed, the operator must submit a report containing all details pertaining to the incident, including corrective actions taken, as part of a subsequent report.

This requirement does not pose an incremental cost. API Guidance Document HF1 says that if the annular space is not cemented to the surface, then operators should monitor pressures in the annulus between the production casing and the intermediate casing. ''Pressure is normally measured at the pump and in the pipe that connects the pump to the wellhead. If the annulus between the production casing and the intermediate casing has not been cemented to the surface, the pressure in the annular space should be monitored and controlled. Pressure behavior throughout the hydraulic fracture treatment should be monitored so that any unexplained deviation from the pretreatment design can be immediately detected and analyzed before operations continue . . . Unexpected or unusual pressure behavior during the hydraulic fracturing process could indicate some type of problem.'' [20] Based on this information and our observations of field operations, we believe that operators monitor annulus pressures during hydraulic fracturing operations as a matter of practice and can easily provide this information to the authorized officer after conducting hydraulic fracturing. The administrative burden of providing this information to

[19] Percent range cited by George King, a petroleum engineer for Apache Corporation (Behr, P. (October 1, 2012). *Safety of shale gas wells is up to the states—and the 'cement job'. EnergyWire*). That range is consistent with a survey of enforcement actions conducted by the Energy Institute (Groat, C. & Grimshaw, T. (February 2012). *Fact-based regulation for environmental protection in shale gas development.* The Energy Institute, p. 16).

[20] API Guidance Document HF1, p. 21.

the BLM is contained in the post-fracturing reporting requirements.

(a) Applicability of requirement = 0 percent of operations

(b) Incremental cost per requirement = $0

Storage Tank Requirement: The operator must manage recovered fluid in ''rigid enclosed, covered or netted and screened above-ground tanks.'' The tanks may be vented, unless Federal law, or state regulations (on Federal lands) or tribal regulations (on Indian lands) require vapor recovery or closed-loop systems. The tanks are also limited in size to 500 bbl of capacity or less. Under certain limited circumstances, the operator may seek approval to use a lined pit with a leak detection system.

This is a new requirement and could pose an incremental burden to the operator depending on the size and specifics of the operation, and whether the management of recovered fluids in tanks is already required by the state or tribe. Although API Guidance Document HF2 does not specify the use of rigid above-ground tanks to manage recovered fluids from hydraulic fracturing operations, our observations of field operations indicate that the use of rigid above-ground tanks for receiving recovered fluids is very common, regardless of the state's requirements. These tanks are commonly referred to as ''frac tanks,'' constructed of steel, and have a holding capacity of up to 21,000 gallons, or 500 bbl, of fluid. The tanks are generally limited to that capacity or size due to their transportability on surface roads to and from a well site. Enclosed tanks are generally provided with anti-burst air vents to vent pressurized gas to prevent safety hazards or they may be connected to a system that collects the pressurized gas for sale or combustion. Some tanks of the same size specifications, steel construction, and rigidity, may have open tops that allow the operator to more easily inspect the flowback visually, pump out fluids, and vacuum out the proppants.

The rule prohibits the use of other larger-volume above-ground semi-rigid tanks (with a capacity of up to 40,000 bbl) for managing recovered fluids. These tanks are ''semi-rigid,'' because they are constructed of steel sections and assembled on-site. These tanks are rarely used for managing flowback directly and are more often used for holding fresh water before the hydraulic fracturing operation and sometimes for holding water after it has been separated and treated after hydraulic fracturing operations.

The use of rigid steel tanks to manage recovered fluids tends to vary by operator and the regions in which they operate. These tanks are particularly prevalent in the Eastern U.S. and are being incorporated into model standards for shale development.[21] Among Western states, where development on Federal and Indian lands is most prevalent, New Mexico and Texas generally require storage tanks, but allow operators to apply for permits to use pits. Colorado requires storage tanks in Surface Water Supply Areas.[22]

Our observations of field operations in the Western states lend evidence to the widespread use of steel rigid tanks to manage recovered fluids from hydraulic fracturing operations in those states. Further, by examining the expected volume of recovered fluids, and the relative costs of using storage tanks versus a pit for these volumes, the BLM believes that the use of storage tanks often will cost less than pits for operations on Federal and Indian lands as discussed in more detail below.

In the supplemental proposed rule, the BLM solicited comment concerning the incremental costs of a requirement to manage recovered fluids with tanks instead of lined pits.

One commenter supported the broad use of steel tanks, but recommended that the BLM not require closed-loop systems, citing concerns about costs, the pressurization of gas, and ability to make visual inspections of the fluid, the advantage of maintaining flexibility depending on the operations or conditions, and the EPA's regulations covering emissions from storage tanks. It also supported the option of potentially using larger volume atmospheric tanks and lined impoundments (or pits), both with secondary containment and leak detection systems, for large volume hydraulic fracturing operations.[23]

The commenter estimated the costs of steel tanks, semi-rigid tanks, and pits over a 5-year period (using a present discounted value approach and a 10 percent discount rate) for multiple operations, with a cumulative total capacity of about 250,000 bbl. It estimated the costs of an engineered impoundment to be $2.3 million, semi-rigid tanks to be $2.42 million, and steel tanks to be $23 million, all over a 5-year period (see Table 5).

TABLE 5—COMMENTER COST ESTIMATES FOR MANAGING RECOVERED FLUIDS

	Engineered impoundment	Semi-rigid steel tanks	Steel tanks
Number of impoundments or tanks	1	6	500
Impoundment or tank capacity (bbl)	250,000	40,000	500
Total capacity (bbl)	250,000	240,000	250,000
Initial construction or set up-take down cost	$2,970,000	$51,000 × 6 = $306,000	n/a
Annual operating or Rental Cost	$20,000	$132,000 × 6 = $792,000 (assumes $11,000 monthly rental fee).	$16,425 × 500 = $8,212,500 (assumes $45 daily rental fee)
5-Year net present value (NPV) (at 10%)	$2,300,000	$2,420,000	$23,000,000

In reviewing these data, it would be inappropriate to conclude simply that using steel tanks would cost 10 times more than a pit. The commenter did not specify the number of hydraulic fracturing operations that a pit, or deployment of semi-rigid tanks or rigid steel tanks, might service over the 5-year period. The BLM expects that while each method could service the same number of hydraulic fracturing operations at the same general location, pits are limited to a single geographic location, but tanks are portable and can be deployed at different geographic locations over the 5-year period, thereby servicing a larger number of operations

[21] Center for Sustainable Shale Development Web site. Accessed on March 29, 2013, *http://037186e.netsolhost.com/site/performance-standards/.*

[22] A map of designated Surface Water Supply Areas, accessed on May 27, 2014, is available at *http://cogcc.state.co.us/rulemaking/FinalDraftRules/CDPHE317B_Map.pdf.*

[23] The comment letter from ConocoPhillips, dated August 22, 2013, is available in the rulemaking docket at *www.regulations.gov.*

and reducing the per-operation cost of using tanks over that time period.

We also note that the transportability and severability of 500 steel tanks allow an operator to service multiple operations in different locations at the same time. For example, 500 steel tanks could service 5 large operations (of 100 steel tanks each) concurrently in different geographic locations.

The BLM received other comments about the incremental costs of requiring storage tanks. A commenter's analysis suggested a tank requirement would pose an incremental cost of $5,500 per operation or $19.6 million for the industry per year. Another commenter suggested that an open pit costs $447,000 and a closed-loop system costs $267,000 (an $180,000 cost advantage).

The BLM did not receive comments on the prevalence of voluntary compliance among operations or across operations, though the first commenter supported the broad use of storage tanks and the potential option to use larger tanks or pits. The BLM would generally expect that an operator would choose to use steel tanks voluntarily (when otherwise not compelled to do so by regulation, condition of approval, environmental consideration, or company practice) in situations where tanks would cost the same as or less than pits, and this may be largely dependent on the volume of recovered fluids expected.

The amount of water used to hydraulically fracture a well and the amount of fluid recovered from the operations vary depending on the formation and the operation itself. The BLM examined data extracted from FracFocus [24] for wells completed in 2013, shown in Figure 3. The data show that the average volume of water used for the hydraulic fracturing operations was 60,279 bbl (or more than 2.5 million gallons). The BLM used the number of well completions on Federal and Indian lands from FY 2010–FY 2013 to develop a weighted average for hydraulic fracturing operations on Federal and Indian lands. Shown in Figure 3, the BLM would expect the average volume of water used for hydraulic fracturing operations on Federal and Indian lands to be 24,385 bbl (or more than 1 million gallons).

FIGURE 3—AVERAGE WATER USED IN HYDRAULIC FRACTURING OPERATIONS, 2013, AND ESTIMATED RECOVERED FLUIDS

State	Average volume of water used (bbl) (data extracted from FracFocus)	Range of recovered fluids (bbl)	
		Low (15%)	High (40%)
Alaska	2,343	351	937
Arkansas	203,648	30,547	81,459
California	2,375	356	950
Colorado	52,013	7,802	20,805
Kansas	35,373	5,306	14,149
Louisiana	89,333	13,400	35,733
Mississippi	111,500	16,725	44,600
Montana	50,058	7,509	20,023
New Mexico	19,110	2,866	7,644
North Dakota	56,535	8,480	22,614
Ohio	107,855	16,178	43,142
Oklahoma	78,600	11,790	31,440
Pennsylvania	128,122	19,218	51,249
South Dakota	61,227	9,184	24,491
Texas	61,412	9,212	24,565
Utah	8,885	1,333	3,554
Virginia	706	106	282
Washington	23,264	3,490	9,306
West Virginia	143,873	21,581	57,549
Wyoming	17,397	2,610	6,959
Weighted Average (based on the operations in the dataset)	60,278	9,042	24,111
Weighted Average (based on average volume of the operations by state and the distribution of operations on Federal and Indian lands)	24,385	3,658	9,754

Note: There were no data in the FracFocus extraction for Alabama and Nevada, which had a total of only seven well completions from FY 2010–FY 2013.

The data extracted from FracFocus do not show the amount of fluid recovered from the operations. The EPA indicates that this amount may range widely from 15 percent to 80 percent of the original amount injected, depending on the site.[25] Halliburton lists ranges for fluid recovery for popular producing areas that are more modest, as follows: [26]

- Bakken: 15–40 percent
- Eagle Ford: < 15 percent
- Permian Basin: 20–40 percent
- Marcellus: 10–40 percent
- Denver-Julesburg: 15–30 percent

Figure 3 also provides the range of volumes expected to be recovered from hydraulic fracturing operations, which is estimated to range from 3,658 bbl (10 percent) to 9,754 bbl (40 percent) on average based on the data.

The BLM contacted service providers of tanks used for the management of fluids from hydraulic fracturing operations to better examine the per-operation incremental costs of using rigid steel tanks instead of a pit. We estimated the baseline cost of

[24] Skytruth.org, ''2013 Reports Data,'' accessed on November 20, 2014.

[25] EPA Web site, ''Hydraulic Fracturing Research Study,'' accessed on November 20, 2014 at *http://www.epa.gov/ogwdw000/uic/pdfs/hfresearchstudyfs.pdf.*

[26] Halliburton, ''Produced and Flowback Water Recycling and Reuse: Economics, Limitations, and Technology,'' accessed on November 25, 2014 at *http://www.halliburton.com/public/multichem/contents/Papers_and_Articles/web/Feb-2014-Oil-Gas-Facilities-Article.pdf.*

constructing and operating a pit based on the first commenter's data. We estimated the 5-year NPV (using a discounted rate of 7 percent) of a pit to be about $2,460,000, generating an annualized cost of about $92,000 and, finally, a per-operation cost of about $98,400, assuming a pit could service 5 operations per year and 25 operations over a 5-year period.[27] Using the BLM's Automated Fluid Minerals Support System (AFMSS) well-completion data from January 2008 to December 2012, we found that operators completed an average of 5.067 wells in a case.

In Table 2, we provide the general engineering costs for rigid steel tanks provided by service companies and then we calculate per-operation job costs based on the capacity number of potential job capacities. In addition, for each job capacity, we estimate the cost of the tank deployment for that operation and the incremental cost per operation when employed instead of a pit. Other assumptions include that the transportation to and from the site for steel tanks will take 4 hours, and that the rental period is either 14 or 21 days.

TABLE 2—GENERAL ENGINEERING COSTS FOR STEEL RIGID TANKS PER OPERATION AND INCREMENTAL COSTS, BY JOB CAPACITY

Engineering Costs		
Job duration (days)	14	21
Tank capacity (bbl)		500
Transportation to site ($/hr/tank)		$120
Rental ($/day/tank)		$40
Transportation from site ($/hr/tank)		$120
Job Capacity (10,000 bbl)		
Tanks required	20	20
Costs per operation	$30,400	$36,000
Incremental cost instead of a pit	−$68,000	−$62,400
Job Capacity (30,000 bbl)		
Tanks required	60	60
Costs per operation	$91,200	$108,000
Incremental cost instead of a pit	−$7,200	$9,600
Job Capacity (50,000 bbl)		
Tanks required	100	100
Costs per operation	$152,000	$180,000
Incremental cost instead of a pit	$53,600	$81,600

According to the available information, rigid steel tanks are less costly than pits on smaller and medium volume jobs lasting 14 days (*e.g.,* $68,000 and $7,200 advantage for jobs with capacities of 10,000 and 30,000 bbl, respectively) and likely to be more costly than pits for higher-volume jobs (*e.g.,* $53,600 disadvantage for jobs with a capacity of 50,000 bbl). For jobs lasting 21 days, rigid steel tanks are likely to be less costly than pits on jobs up to the job capacity threshold described above.

Given the assumptions, and for a job lasting 14 days, the point at which the cost of using tanks and the cost of using a pit are roughly equal is when the job capacity is 32,368 bbl. This means that steel tanks would cost less for jobs where the volume of recovered fluids is less than 32,368 bbl and pits would cost less for jobs where the volume of recovered fluids is greater than 32,368 bbl. For a job lasting 21 days, the point at which the cost of using tanks and the cost of using a pit are roughly equal is when the job capacity is 27,333 bbl.

The BLM derived these thresholds using the following progression:

(1) Per-operation cost of pit = Cost of steel tanks for an operation

(2) Per-operation cost of pit = [Cost of tank transport to and from site + Cost of tank rental]

(3) Per-operation cost of pit =
2 * [(Cost of tank transport $/hr/tank) * (hours) * (Job capacity/tank capacity)]
+ [(Cost of rental $/day/tank) * (days) * (Job capacity/tank capacity)]

(4) [Per-operation cost of pit/3.04] = Job capacity bbl; when the job duration is 14 days; or
[Per-operation cost of pit/3.60] = Job capacity bbl; when the job duration is 21 days

(5) Job capacity bbl = 32,368; when the job duration is 14 days; or
Job capacity bbl = 27,333; when the job duration is 21 days

To estimate voluntary compliance, we looked at the percent of operations (in the data extracted from FracFocus) where the job capacity (measured as the 40 percent of the water used) was less than the thresholds of 32,368 bbl and 27,333 bbl.

Where the job capacity exceeded the threshold, the BLM assumed that the operators would not have voluntarily used storage tanks. We then calculated the average job capacity for operations above this threshold based on the distribution of operations on Federal and Indian lands. We estimate that the average job capacity for operations exceeding the threshold*s* is either 47,575 or 55,631 bbl. See Table 5C. We note again that operators may choose to use steel tanks irrespective of costs, for example in adherence to condition of approvals, environmental considerations, company practice, etc.

Based on that average job capacity, we then calculated an average incremental cost of using tanks instead of a pit for only those operations where we do not estimate that the operator will

[27] We attempted to replicate the commenter's derivation of the 5-Year NPV (at 10%) for the engineered impoundment in order to estimate an annualized value for a pit with a 7% discount rate. We roughly generated the commenter's value by assigning one-third of the capital costs to initial construction (year 0) and two-thirds of the capital costs to the take down costs (year 5).

voluntarily comply. Assuming job durations lasting 14 days, we estimate the average incremental cost to be $71,840 per operation that exceeds the threshold of 32,368 bbl. Assuming job durations last 21 days, we estimate the average incremental cost to be $74,400 per operation that exceeds the threshold of 27,333 bbl. Due to the variability of job durations across the U.S., we use the average incremental cost to be $74,400 per operation as a basis for the cost estimates, recognizing that this is likely to both overestimate and constrain the potential costs.

TABLE 5C—ESTIMATED VOLUNTARY COMPLIANCE OF A STEEL TANK REQUIREMENT AND THE AVERAGE VOLUME OF RECOVERED FLUIDS FOR OPERATIONS WHERE THE OPERATOR IS NOT EXPECTED TO VOLUNTARILY COMPLY

State	Job duration of 14 days		Job duration of 21 days	
	Estimated voluntary compliance (%)	Average volume of recovered fluids for operations exceeding the threshold (40% recovery rate)	Estimated voluntary compliance (%)	Average volume of recovered fluids for operations exceeding the threshold (40% recovery rate)
Alaska	100.0	0	100.0	0
Arkansas	2.9	83,926	2.9	83,926
California	100.0	0	100.0	0
Colorado	84.7	58,980	71.7	45,616
Kansas	100.0	0	95.6	27,597
Louisiana	49.3	53,781	30.4	47,650
Mississippi	66.7	130,775	66.7	130,775
Montana	91.8	37,257	79.6	32,260
New Mexico	96.7	79,352	96.1	72,616
North Dakota	86.8	50,455	75.1	40,842
Ohio	0.0	43,142	0.0	43,142
Oklahoma	68.5	63,084	61.9	57,248
Pennsylvania	12.4	55,208	7.1	53,780
South Dakota	100.0	0	100.0	0
Texas	68.2	57,699	64.3	54,663
Utah	100.0	0	100.0	0
Virginia	100.0	0	100.0	0
Washington	100.0	0	100.0	0
West Virginia	3.3	58,566	0.0	57,549
Wyoming	93.3	39,880	92.3	38,629
Weighted Average (based on distribution of operations in FracFocus)	70.3	57,283	65.4	53,398
Weighted Average (based on distribution of operations on Federal and Indian lands)	93.5	55,631	90.6	47,757

With respect to the applicability of the requirement, we estimate that the rule will have no impact in states with existing requirements for use of tanks. We also assume that the rule will have no impact where operators are expected to voluntarily comply with the use of tanks regardless of the rule (the rates of assumed voluntary compliance are in Table 5C). We assume that for all other states, the rule will compel action on 100 percent of the operations, even though we expect that operators are already in compliance with the rule as a matter of voluntary practice.

(a) Applicability of requirement = 0 percent of operations in NM and TX based on state regulations; 0 percent in AK, CA, SD, UT, based on estimated voluntary compliance; 97.1 percent in AR, 28.3 percent in CO, 4.4 percent in KS, 69.6 percent in LA, 33.3 percent in MS, 20.4 percent in MT, 24.9 percent in ND, 100 percent in OH, 38.1 percent in OK, 92.9 percent in PA, and 7.7 percent in WY, based on estimated voluntary compliance; 100 percent in AL and NV, based on lack of validating data. We attribute the appropriate percentages to each tribe based on geographic location.

(b) Incremental cost per operation = $74,400. This incremental cost is only for those operations where the use of storage tanks is not required by state regulations and where the operator is not expected to use storage tanks voluntarily. Operations that are most likely to incur this cost are in states where 0.8% of all oil and gas activity on public lands occurs. Incremental average costs across all operations on public and Indian lands are $5,544 (see Table 6A). Under the rule, the operator may request approval to use a lined pit that is equipped with a leak detection system. While Onshore Order 7 requires leak detection systems for produced water disposal pits, which may be used on a long-term basis, there has been no requirement for leak detection systems on temporary pits until now. According to BLM engineers citing analogous EPA data, the cost of equipping a pit with a leak detection system might range from $2 to $9 per square foot, depending on the sophistication of the system (EPA 2012, Field Demonstration of Innovative Condition Assessment Technologies for Water Mains: Leak Detection and Location). Assuming 2,000 feet of piping and that a centralized pit might service 5 operations, the per-operation cost of equipping a centralized pit with a leak detection system might be between $800 and $3,600. Additional cost information for leak detection systems is available in the EPA Notice of Proposed Rulemaking for Liners and Leak Detection for Hazardous Waste and Land Disposal Units. The notice suggests that costs of a leak detection system would be about $6,100 for a half-acre pit and $6,520 for an acre pit. Again, that cost could be spread across multiple hydraulic fracturing operations and, assuming a pit services 5 completions, the per-operation cost might be $1,200 to $1,300. However, according to the

specifications listed in Onshore Order 7, the BLM engineers also believe that the costs of including a leak detection system could be higher and generally comparable to using storage tanks.

The BLM examined an alternative approach to the final rule. That alternative would have required the operator to manage recovered fluids in a lined pit, at a minimum. The requirement to manage recovered fluids in lined pits or storage tanks is consistent with almost all existing state regulations in states where new oil and gas activity is occurring on BLM-managed lands. The BLM examined regulations in nine states where new drilling activity is most prevalent on Federal lands and found that those states either have existing minimum requirements for lined pits or storage tanks or that operators use lined pits or tanks to ensure the protection of groundwater. One exception, California, does not appear to have a statewide minimum requirement for lined pits, but such requirements may be contained within rules specific to particular fields within the state. Further, according to Resources for the Future (RFF), Alabama, Arkansas, Kansas, Louisiana, Mississippi, Pennsylvania, and South Dakota also have existing pit liner requirements.[28] Considering the low level of oil and gas development on Federal lands in these states where lined pits are permitted, the impact of this provision is likely to be very small. The BLM does not have data on the pit-liner requirements on Indian lands or the voluntary use of lined pits in general, as is recommended as a minimum standard by industry guidance.[29] The BLM estimated the unit cost of lining a pit to be $6,000, using prices quoted by suppliers of about $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.

(a) Applicability of requirement (alternative) = 0 percent of operations in AL, AR, CO, KS, LA, MS, MT, ND, NM, OK, PA, SD, TX, UT, WY; 20 percent in CA; 50 percent in AK, NV, OH, and Indian lands.

(b) Incremental cost per operation (alternative) = $6,000.

Post-Fracturing Reporting Requirement: The operator must submit information to the BLM after the hydraulic fracturing operation in a subsequent report. The operator must disclose the chemicals used to the BLM, and may use FracFocus for that disclosure. The operator may withhold formulations that are deemed to be a trade secret.

This is a new requirement and poses an incremental burden to the operator and the BLM to review. The information required in the application should be all readily available or known to the operator. The information should not require any additional information gathering. Unlike the application, which may be an MHFP for a group of wells, the operator will submit a unique subsequent report for each operation. The disclosure requirement is included in the post-fracture report. The operator may post to FracFocus or submit the chemical information directly to the BLM, and it may withhold trade secret information by submitting an affidavit. The disclosure requirement only poses an incremental burden to the operator in states that do not already require disclosure to FracFocus. The BLM notes that Colorado, Montana, North Dakota, Oklahoma, Texas, and Utah, require disclosure to FracFocus already and so the Federal requirement would not pose an incremental burden to those operations.

(a) Applicability of requirement = 100 percent of operations.

(b) Cost per requirement = $723. Burden includes the operator burden ($558 per Subsequent Report (SR) Sundry) and the BLM burden ($165 per SR Sundry). We estimate that the operator will require 9 hours at about $61.99 per hour to comply with the SR Sundry and that the BLM will require 4.5 hours at about $36.66 per hour to review the SR Sundry. The bases for these estimates are explained in the supporting statement for the Paperwork Reduction Act.

Variance Requests: The operator may submit a variance for BLM approval.

Operators taking advantage of this provision will incur an incremental cost. Previously, the BLM estimated that it might receive variance requests on 10 percent of the applications, primarily because of previously proposed requirement to run a CEL on the surface casing and the type well provision. Since the final rule does not contain those provisions, the BLM believes that it might receive fewer variance requests. However, there is still the potential that operators will request a variance (or approval) for the storage tank requirement or for a CEL on the intermediate casing (*e.g.,* the operator may request to use a temperature log or other test).

(a) Applicability of requirement = 10 percent of operations.

(b) Cost per request = $643. Burden includes the operator burden and the BLM burden. The compliance cost for the operator is estimated to be about $496 per application (calculated as 8 hours at about $61.99 per hour). The review cost for the BLM is estimated to be about $147 per application (calculated as 4 hours at about $36.66 per hour).

Benefits Framework

The potential benefits of the rule are significant, but are more challenging to monetize than the costs; however, the rule will significantly reduce the risks associated with hydraulic fracturing operations on Federal and Indian lands, particularly risks to surface waters and usable groundwater. The operational requirements of the final rule generally conform to industry guidance on hydraulic fracturing and state regulations. The operational requirements should ensure that hydraulic fracturing is conducted in a manner than minimizes any environmental and health risks.

The use of storage tanks in lieu of pits reduces the potential risk to surface and groundwater resources. The BLM expects that through this rule, since it incorporates many of the best practices currently used by companies to manage recovered fluid, will provide environmental benefit and provide the best possible avoidance of surface and groundwater spills and contamination. Pits require careful design, construction (including fencing and netting), monitoring and reclamation. Rigid steel tanks used for recovered fluids are typically mounted on truck trailers or are transportable by truck. They require space on a well pad. However, any leaks are readily detectable without special equipment. As compared with pits, tanks better isolate recovered fluids from contamination by surface sediments that might increase the costs of recycling the fluids.

The tank requirement also specifies that where an operator uses an ''enclosed'' tank, the tank may be vented unless another Federal, state, or tribal law or requirement requires a closed-loop system or vapor recovery. Tanks that are not enclosed will need to be covered, netted or screened to exclude wildlife. That is not a new requirement. BLM has issued an instructional memorandum for authorized officers to assure that pits, tanks, and similar structures are fully enclosed in netting or screens to exclude wildlife. This requirement helps prevent accidental

[28] The RFF findings cited are available on its Web site under flowback/wastewater storage and disposal, accessed on May 27, 2014: *http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx.*

[29] API, HF2.

deaths of species protected under the Migratory Bird Treaty Act or other laws.

The primary challenge in monetizing benefits lies in the quantification of a baseline risk associated with specific operating practices and in the measurement of the change in that risk that the BLM can attribute to the rule's requirements. For example, the risk of spills associated with the use of pits versus the risk of spills associated with the use of storage tanks is unknown, though it is generally recognized that tanks carry less risk onsite. In an initial analysis for the proposed rule, we attempted to value the reduction in risk, but we do not believe that the available information represented modern hydraulic fracturing operations nor were we able to distinguish between the risks posed by wells that were hydraulically fractured and wells with conventional completion techniques.

Operators are required to notify the BLM when undesirable events occur, but there are limitations in using the BLM data on undesirable events for this analysis. Undesirable events may include accidents, or accidental spills or releases of hydrocarbon fluids, produced water, hydraulic fracturing flowback fluids, or other substances. Undesirable events also include ''frack hits,'' which are unplanned surges of pressurized fluids into other wells. These events have the potential to adversely affect public lands, Indian lands, and other important resources.

There are several limitations in using these data. First, the data do not specify whether the undesirable events occur in conjunction with or as a result of hydraulic fracturing operations. In addition, the available data cannot be readily matched with particular provisions in the rule. The data provide figures for the incidence of spills, accidents, injuries, and other impacts on a well, but the pit liner information is generally not specified in the incident reports for spills or leaks. As such, there is difficulty in quantifying the level of risk reduction that would be attributed to the regulations, even though the regulations would most certainly reduce risk.

Although operators are required to remediate damage when it occurs, there may be uncertainty about the true value or extent of any potential damage or limitations in connecting an incident to an operation. Even if the damage is internalized, and as long as the compliance costs are less than the damage costs, the net benefit to society would be less than if the incident was avoided, since resources would have been unnecessarily dedicated to the remediation.

Damage, in general, is unknown, particularly when attempting to generalize damage costs which may vary by expected magnitude and reversibility of effects. Also, the valuation of the damage may also take many and highly variable forms. For example, an undesirable incident occurring during hydraulic fracturing might require the remediation of surface or subsurface areas. The incident might also require that the operator shut-in temporarily or plug the well before it may produce all of the mineral resources. In this case, the operator would lose revenue and society would not benefit from the produced resources. Such would be the same for spills.

The following is an example of an event that occurred in 2012 when a hydraulic fracturing operation on one Federal well affected another Federal well. The incident occurred on November 20, 2012, in Lea County, New Mexico.[30] The fracture path of the first well intercepted the fracture path of the second well, pushing produced fluids through the second well and its associated equipment such as the separator and an open top fiberglass tank. The open-top fiberglass tank overflowed into an unlined firewall. The firewall was over-topped and fluids ran into a pasture. The fluids also entered a second facility via flow lines and over-topped an open fiberglass tank to overflow into an unlined containment berm. The majority of fluids, 1,220 bbl consisting primarily of fracturing fluids, were contained within unlined firewalls and inside two 210-barrel open-topped fiberglass tanks. About 60 bbl of oil ran into a pasture near the second well.

In order to control the event, the fracturing job had to be shut in. The active wells in the area were also shut in. The surface damage included less than 0.1 acre of pasture land, and the removal and disposal of the material inside the two firewalls. Vacuum trucks picked up all of the standing fluids. The impacted surface material was removed for sampling, site delineation, and remediation.

This ''frack hit'' incident illustrates the difficulty in estimating benefits. The environmental damage included potential surface contamination and subsequent remediation efforts, and most of the environmental damage appears to have been remediated by the operator. Aside from the environmental damage, there were several economic impacts, including the shutting-in of the impacted wells for a period of time, wellbore damage to the second wells, potentially lost fracturing stages, and unrecovered resources.

Since relative risk is unknown, the BLM provides a qualitative discussion of benefits. Field experience tells us that the remediation of a minor incident, such as the surface remediation after a minor spill, might cost about $15,000 and range upwards. Remediation efforts of larger spills are much more complicated and can reach the hundreds of thousands of dollars. The remediation of a major incident will likely be more complex. As with the example incident, there were surface, possible subsurface impacts to multiple wells, and potentially stranded resources (from lost fracturing stages of permanent plugging of wells). The Federal Remediation Technologies Roundtable makes a number of case studies available on its Web site (though none are hydraulic fracturing incidents) concerning contamination to aquifers where the remediation costs may be $1 million.

Discounted Present Value

There is a time dimension to estimates of potential costs and benefits. While the incremental costs of the rule are likely to occur within a comparatively short period of time, the incremental benefits may continue into the future. The further in the future that the benefits and costs are expected to occur, the smaller the present value associated with the stream of costs and benefits.

For this analysis, we expect that the potential incremental costs posed to an operation will occur within a short timeframe, starting generally with the APD submission and ending with the subsequent report. As such, we generally use undiscounted costs for the requirements. However, in order to determine the incremental cost of the storage tank requirement, we adjusted the 5-year data provided by a commenter to annualize the costs of constructing and operating a pit based on the net present value of costs using a 7 percent discount rate.

Uncertainty

The costs and benefits provided in this analysis are estimates and come with uncertainty. Generally, the primary sources of uncertainty are:

- Number of hydraulic fracturing operations on Federal and Indian lands occurring in the future. The economic analysis describes the method the BLM used to estimate operations that will occur in the future. The BLM also considers an upper bound estimate which should constrain the costs.

[30] The Carlsbad Field Office submitted an Initial Report for the major undesirable event, occurring on lease NMNM0631.

• Delays and costs associated with the CEL on the intermediate casing. Sources of uncertainty are: (1) The prevalence by which the operator will run a log on the intermediate casing as a matter of practice; and (2) The ways in which operators may run logs on the intermediate casing while avoiding delays.

• Storage tank costs. The BLM estimated voluntary compliance based on the average volume of recovered fluids and a number of cost assumptions, including the per-operation cost of a pit. In some areas, field observations indicate that the use of storage tanks is higher than the estimated voluntary compliance. As such, we believe the compliance costs of this requirement are still likely to be overestimated.

• Benefits of specific provisions. The BLM is unable to estimate the incremental benefits of the rule because the BLM is unable to ascribe incremental benefits to the particular provisions of the rule. Nonetheless, the rule's provisions are generally consistent with best management practices of the industry at large and of several firms within the industry.

Results: Total Costs of the Rule

The BLM estimates that the rule will impact 2,814 hydraulic fracturing operations per year in the near-term on Federal and Indian lands. The BLM estimates that the incremental cost of the rule on Federal and Indian lands will be about $26 million per year. These estimates are based on expectations about the future well completions on Federal and Indian lands. In order to meet a $100 million per year threshold, we estimate that the number of hydraulic fracturing operations on Federal and Indian lands would have to be about 3.83 times higher than we anticipate, or over 10,775 operations per year.

The estimated per-operation compliance costs of about $11,400 represent about 0.13 to 0.21 percent of the cost of drilling a well. The compliance costs, shown in Table 6A, were developed by dividing the total costs of the rule by the number of hydraulic fracturing operations expected to occur, per year. Because we believe that operators would have undertaken some of the rule's requirements voluntarily or as a result of state requirements, we expect that some of the compliance costs will be borne by a relatively small number of operations. This is particularly the case with respect to the requirement to use rigid above-ground tanks, which we estimate to be less costly than lined pits for operations with recovered fluids below a certain volume. In those cases where fluid volumes exceed a certain threshold, we estimate that the compliance with the storage tank requirement could cost an operator $74,400 (representing approximately 0.8 to 1.4 percent of the cost of drilling a well) Through our analysis we estimate that this is only a small subset of total operations. These operations are those where the volumes of recovered fluids are expected to be very high and typically occur in states (Arkansas, Louisiana, Mississippi, Ohio, Oklahoma, and Pennsylvania) which represent only about 0.8% of estimated hydraulic fracturing activities on Federal and Indian land (from FY 2010 to FY 2013).

The costs of drilling a well may vary by reservoir or formation, depth, and length, site-specific characteristics, as well as operator efficiencies. The Energy Information Administration suggests costs of about $5.4 million which we believe may be a lower bound estimate of the costs for drilling a well to be completed with hydraulic fracturing. The EIA figures were last updated in 2007, were not specific to horizontal wells or hydraulically fractured wells, and included costs of drilling exploratory or development wells. We adjusted the EIA figures to 2015 dollars. Meanwhile, horizontal wells drilled in the Bakken formation have been reported to cost $5.6 million (cited by Investopedia from Continental Resources in 2010) and, most recently, between $7–9 million per well (cited from various companies in industry trade journal Oil Patch Hotline 2015).

Small Number of Operations

As discussed in the Economic Analysis, well completions decreased on Federal lands from FY 2012 to FY 2013, but increased steadily on Indian lands on an annual basis since FY 2010. If the FY 2012 level of activity on Federal lands is used as a basis for the estimate, the rule could potentially impact up to 3,775 hydraulic fracturing operations per year on Federal and Indian lands at an incremental cost of about $45 million per year.

Many of the rule's requirements are consistent with industry guidance and some are required by existing BLM regulations and state regulations. Accordingly, to the extent that industry is already in voluntary compliance, the cost of several provisions may be overestimated. Where the rule's requirements are consistent with industry practice or state regulations, there will not be an incremental cost. There are two requirements in particular that are likely to pose the bulk of the estimated costs.

First, the rule requires the operator to run a CEL on the intermediate casing if that casing string protects usable water and if the operator chooses not to cement the casing to the surface. Industry guidance suggests that an operator may run a cement bond log on the intermediate casing to show that the casing was cemented to the design. The BLM believes that operators will generally run logs on the intermediate casing, particularly if they plan to conduct hydraulic fracturing through a production liner that is hung from the intermediate casing, and that states or the BLM may specify this as a condition of approval, even if it is not in regulation. Since the BLM does not have validating data, the analysis assumes that the rule would compel CELs in all areas, except those states that require them in regulation. As such, the costs associated with this requirement are likely overstated.

Second, the rule requires the operator to manage recovered fluids in storage tanks. Industry guidance suggests that operators may use storage tanks or pits to manage recovered fluids. Some states require the use of tanks by regulation and some states have adopted the practice as a policy through guidance or as a standard condition of approval for drilling operations. Our observations of field operations indicate that operators almost always use storage tanks, which indicates that they may be doing so voluntarily. The BLM estimated the voluntary use of storage tanks in states that do not have regulations requiring their use. Still, in some areas, our field observations indicate that the use of storage tanks is higher than the estimated voluntary compliance. As such, the costs associated with this requirement are also likely overstated.

Cost Breakout According to Federal and Tribal Lands

On Federal lands only, the BLM estimates that the final rule would impact 2,144 hydraulic fracturing operations per year in the near-term future and that the rule poses an incremental cost of about $22 million per year. The rule could potentially impact up to 3,105 operations per year on Federal lands at an incremental cost of about $35 million per year.

Tables 3A and 3B depict the annual incremental costs associated with the rule's requirements, attributed to operations on Federal lands within a state. It accounts for consistencies between a state's requirements and the rule's requirements.

On Indian lands, the BLM estimates that the final rule would impact 670 hydraulic fracturing operations per year in the near-term future and that the rule poses an incremental cost of about $10 million per year. The estimate accounts for the steady increase in activity on Indian lands over the past few years.

Table 4 depicts the annual incremental costs associated with the rule's requirements, attributed to operations on Indian lands within a reservation. The highest total costs are associated with operations in the Fort Berthold, Uintah and Ouray, and Jicarilla Apache reservations, due to the volume of activity within those reservations.

TABLE 3A—ESTIMATED ANNUAL INCREMENTAL COSTS ASSOCIATED WITH ACTIVITY ON FEDERAL LANDS

Federal lands, by state	Number of operations per year	Application (sundry)	Remedial action reporting (sundry)	CEL on intermediate casing	Storage tank	Post-fracture reporting (sundry)	Variance requests (sundry)	Total costs
ALASKA	9	$5,787	$174	$50,040	$0	$6,507	$579	$63,086
ALABAMA	1	643	19	5,560	74,400	723	64	81,410
ARKANSAS	3	1,929	58	16,680	216,727	2,169	193	237,756
CALIFORNIA	188	120,884	3,627	1,045,280	0	135,924	12,088	1,317,803
COLORADO	59	37,937	1,138	0	1,242,257	42,657	3,794	1,327,783
KANSAS	0	0	0	0	0	0	0	0
LOUISIANA	2	1,286	39	11,120	103,565	1,446	129	117,584
MISSISSIPPI	6	3,858	116	33,360	148,651	4,338	386	190,709
MONTANA	1	643	19	5,560	15,178	723	64	22,187
NORTH DAKOTA	173	111,239	3,337	0	3,204,929	125,079	11,124	3,455,708
NEW MEXICO	732	470,676	14,120	4,069,920	0	529,236	47,068	5,131,020
NEVADA	0	0	0	0	0	0	0	0
OHIO	2	1,286	39	11,120	148,800	1,446	129	162,819
OKLAHOMA	15	9,645	289	83,400	425,196	10,845	965	530,340
PENNSYLVANIA	12	7,716	231	66,720	829,411	8,676	772	913,526
SOUTH DAKOTA	4	2,572	77	22,240	0	2,892	257	28,038
TEXAS	23	14,789	444	63,940	0	16,629	1,479	97,281
UTAH	579	372,297	11,169	3,219,240	0	418,617	37,230	4,058,553
WYOMING	335	215,405	6,462	1,862,600	1,919,148	242,205	21,541	4,267,361
TOTAL	2,144	1,378,592	41,358	10,566,780	8,328,262	1,550,112	137,859	22,002,963

TABLE 3B—POTENTIAL UPPER BOUND ESTIMATE (USING FY 2012 LEVEL OF ACTIVITY)—ESTIMATED ANNUAL INCREMENTAL COSTS ASSOCIATED WITH ACTIVITY ON FEDERAL LANDS

Federal lands, by state	Number of operations per year	Application (sundry)	Remedial action reporting (sundry)	CEL on intermediate casing	Storage tank	Post-fracture reporting (sundry)	Variance requests (sundry)	Total costs
ALASKA	1	$643	$19	$5,560	$0	$723	$64	$7,010
ALABAMA	1	643	19	5,560	74,400	723	64	81,410
ARKANSAS	7	4,501	135	38,920	505,697	5,061	450	554,764
CALIFORNIA	222	142,746	4,282	1,234,320	0	160,506	14,275	1,556,129
COLORADO	365	234,695	7,041	0	7,685,148	263,895	23,470	8,214,248
KANSAS	1	643	19	5,560	3,274	723	64	10,283
LOUISIANA	4	2,572	77	22,240	207,130	2,892	257	235,168
MISSISSIPPI	0	0	0	0	0	0	0	0
MONTANA	15	9,645	289	83,400	227,664	10,845	965	332,808
NORTH DAKOTA	127	81,661	2,450	0	2,352,751	91,821	8,166	2,536,849
NEW MEXICO	956	614,708	18,441	5,315,360	0	691,188	61,471	6,701,168
NEVADA	0	0	0	0	0	0	0	0
OHIO	3	1,929	58	16,680	223,200	2,169	193	244,229
OKLAHOMA	15	9,645	289	83,400	425,196	10,845	965	530,340
PENNSYLVANIA	0	0	0	0	0	0	0	0
SOUTH DAKOTA	5	3,215	96	27,800	0	3,615	322	35,048
TEXAS	39	25,077	752	108,420	0	28,197	2,508	164,954
UTAH	517	332,431	9,973	2,874,520	0	373,791	33,243	3,623,958
WYOMING	827	531,761	15,953	4,598,120	4,737,718	597,921	53,176	10,534,649
TOTAL	3,105	1,996,515	59,895	14,419,860	16,442,177	2,244,915	199,652	35,363,014

TABLE 4—ESTIMATED ANNUAL INCREMENTAL COSTS ASSOCIATED WITH ACTIVITY ON TRIBAL LANDS

Reservation or BIA agency	Number of operations per year	Application (sundry)	Remedial action reporting (sundry)	CEL on intermediate casing	Storage tank	Post-fracture reporting (sundry)	Variance requests (sundry)	Total costs
ANADARKO	6	$3,858	$116	$33,360	$170,078	$4,338	$386	$212,136
ARDMORE	0	0	0	0	0	0	0	0
BLACKFEET	4	2,572	77	22,240	60,710	2,892	257	88,749

TABLE 4—ESTIMATED ANNUAL INCREMENTAL COSTS ASSOCIATED WITH ACTIVITY ON TRIBAL LANDS—Continued

Reservation or BIA agency	Number of operations per year	Application (sundry)	Remedial action reporting (sundry)	CEL on intermediate casing	Storage tank	Post-fracture reporting (sundry)	Variance requests (sundry)	Total costs
CHEYENNE & ARAPAHO	1	643	19	5,560	28,346	723	64	35,356
CONCHO	14	9,002	270	77,840	396,850	10,122	900	494,984
CROW	0	0	0	0	0	0	0	0
EASTERN NAVAJO	19	12,217	367	105,640	0	13,737	1,222	133,182
FIVE CIVILIZED TRIBES	0	0	0	0	0	0	0	0
FORT BELKNAP	0	0	0	0	0	0	0	0
FORT BERTHOLD	334	214,762	6,443	0	6,187,550	241,482	21,476	6,671,713
FORT PECK	0	0	0	0	0	0	0	0
JICARILLA APACHE	93	59,799	1,794	517,080	0	67,239	5,980	651,892
MUSKUGEE	0	0	0	0	0	0	0	0
OKMULGEE	2	1,286	39	11,120	56,693	1,446	129	70,712
PAWNEE	9	5,787	174	50,040	255,118	6,507	579	318,204
SHAWNEE	0	0	0	0	0	0	0	0
SHIPROCK	4	2,572	77	22,240	0	2,892	257	28,038
SOUTHERN UTE, BIA	0	0	0	0	0	0	0	0
TAHLAQUAH	1	643	19	5,560	28,346	723	64	35,356
TALIHINA	1	643	19	5,560	28,346	723	64	35,356
TURTLE MOUNTAIN	2	1,286	39	0	37,051	1,446	129	39,950
UINTAH AND QURAY	176	113,168	3,395	978,560	0	127,248	11,317	1,233,688
UTE MOUNTAIN UTE	0	0	0	0	0	0	0	0
WIND RIVER	4	2,572	77	22,240	22,915	2,892	257	50,954
TOTAL	670	430,810	12,924	1,857,040	7,272,005	484,410	43,081	10,100,270

Cost Breakout by Activity

Tables 5A and 5B show the incremental costs by requirement for operations on Federal and Indian lands. The BLM estimates that the largest incremental costs are associated with the operational requirements for a CEL on certain intermediate casing and storage tanks to manage recovered fluids. As mentioned previously, the BLM does not have specific data about the prevalence of voluntary compliance with these requirements irrespective of the rule. Accordingly, these estimates are may be overstated. The BLM estimates that the CEL requirement will impact a fraction of the operations, but could cost operators $12.4 million annually (and potentially up to $16.3 million). The BLM also estimates that the incremental annual cost of requiring storage tanks (instead of allowing pits) could cost operators about $15.6 million (and potentially up to $23.7 million).

Compliance Costs Per-Operation

The rule would result in compliance costs of about $11,400 per hydraulic fracturing operation. Average compliance costs to meet the requirements for a CEL on certain intermediate casing and for storage tanks represent the bulk of the per-operation compliance costs. The results are in Tables 6A and 6B.

Of the estimated per-operation compliance costs, the administrative burden represents about $1,450. The BLM estimates that the operator will assume about $1,118 and the BLM will assume $331 of that amount. The administrative burden figures are in Tables 7A and 7B.

The review of information associated with the application, subsequent report, remedial action report (when applicable), and variance request (when applicable) will pose an additional workload to the BLM of about 25,400 hours per year. That additional burden represents about 12.20 full-time equivalent (FTE) of workload or, as a practical matter, about 13.80 staffed positions (takes into account leave and holidays).

TABLE 5A—ESTIMATED ANNUAL INCREMENTAL COSTS, BY REQUIREMENT

Jurisdiction	Number of operations per year	Application (sundry)	Remedial action reporting (sundry)	CEL on intermediate casing	Storage tank	Post-fracture reporting (sundry)	Variance requests (sundry)	Total costs
Federal lands	2,144	$1,378,592	$41,358	$10,566,780	$8,328,262	$1,550,112	$137,859	$22,002,963
Indian lands	670	430,810	12,924	1,857,040	7,272,005	484,410	43,081	10,100,270
Total	2,814	1,809,402	54,282	12,423,820	15,600,266	2,034,522	180,940	32,103,233

TABLE 5B—POTENTIAL UPPER BOUND ESTIMATE (USING FY 2012 LEVEL OF ACTIVITY)—ESTIMATED ANNUAL INCREMENTAL COSTS, BY REQUIREMENT

Jurisdiction	Number of operations per year	Application (sundry)	Remedial action reporting (sundry)	CEL on intermediate casing	Storage tank	Post-fracture reporting (sundry)	Variance requests (sundry)	Total costs
Federal lands	3,105	$1,996,515	$59,895	$14,419,860	$16,442,177	$2,244,915	$199,652	$35,363,014
Indian lands	670	430,810	12,924	1,857,040	7,272,005	484,410	43,081	10,100,270
Total	3,775	2,427,325	72,820	16,276,900	23,714,182	2,729,325	242,733	45,463,284

TABLE 6A—AVERAGE PER-OPERATION COMPLIANCE COSTS, BY REQUIREMENT

Jurisdiction	Number of operations per year	Application (sundry)	Remedial action reporting (sundry)	CEL on intermediate casing	Storage tank	Post-fracture reporting (sundry)	Variance requests (sundry)	Total costs
Federal lands	2,144	$643	$19	$4,929	$3,884	$723	$64	$10,263
Indian lands	670	643	19	2,772	10,854	723	64	15,075
Total	2,814	643	19	4,415	5,544	723	64	11,408

TABLE 7A—ANNUAL ADMINISTRATIVE BURDEN, BY REQUIREMENT

Party assuming burden	Application (sundry)	Remedial action reporting (sundry)	Post-fracture reporting (sundry)	Variance requests (sundry)	Total costs
Operators	$1,395,744	$41,872	$1,570,212	$139,574	$3,147,403
BLM	413,658	12,410	464,310	41,366	931,744
Total	1,809,402	54,282	2,034,522	180,940	4,079,146

TABLE 7B—AVERAGE PER-OPERATION ADMINISTRATIVE BURDEN, BY REQUIREMENT

Party assuming burden	Application (sundry)	Remedial action reporting (sundry)	Post-fracture reporting (sundry)	Variance requests (sundry)	Total costs
Operators	$496	$15	$558	$50	$1,118
BLM	147	4	165	15	331
Total	643	19	723	64	1,450

Economic Impact Analysis and Distributional Assessments

Energy System Impact Analysis

Executive Order 13211 requires 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.

A key consideration is the extent to which the costs of the requirements might impact investment, production, employment, and a number of other factors. That is, to what extent, if any, would an operator choose to invest in other areas, non-Federal and non-Indian lands, when faced with the cost requirements of the rule. Since the bulk of the costs of this rule would apply to hydraulic fracturing operations on wells that are yet to be drilled (and not on existing wells and to refracturing operations), operators will be able to account for any cost increases up front when making investment decisions.

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

For the average hydraulic fracturing operation, the compliance costs represent about 0.13 to 0.21 percent of the cost of drilling a well. Since the estimated compliance costs are not substantial when compared with the total costs of drilling a well, the BLM believes that the rule is 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.

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 final rule requires operators, who have not already done so, to conduct one-time tests on a well or make a one-time installation of a mitigation feature. In addition, operators are required to perform administrative tasks related to a one-time event.

Compliance with a few of the operational requirements is expected to pose an additional cost to the operator and is likely to shift resources from firms in the crude oil and natural gas extraction industries (NAICS codes: 211111—Crude Petroleum and Natural Gas Extraction, 211112—Natural Gas Liquid Extraction) to firms providing support services for drilling oil and gas wells (NAICS code: 213111—Drilling Oil and Gas Wells).

Of principal 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. The BLM believes that the rule would result in an additional cost per well hydraulic fracturing operation that is small and will not alter the investment or employment decisions of firms.

Small Business Impact 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 if a rule would have a significant economic impact, either detrimental or beneficial, on a substantial number of small entities. See 5 U.S.C. 601–612. Congress enacted the RFA to ensure that Government regulations do not unnecessarily or disproportionately burden small entities. 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 percent of the entities operating in the relevant sectors [31] are small businesses in that they employ fewer than 500 employees. Also, within these relevant sectors, small firms account for 74 percent of the total value of shipments and receipts for services, 86 percent of the total cost of supplies, 78 percent of the total capital expenditures (excluding land and mineral rights), and 67 percent of the paid employees (see the Economic Analysis).

Small entities represent the overwhelming majority of entities operating in the onshore crude oil and natural gas extraction industry. As such, the 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 firms most likely to be affected by the rule are those conducting hydraulic fracturing activities on Federal and Indian lands. More specifically, the firms most impacted are expected to be those drilling new wells for hydraulic fracture completions. The BLM compiled a list of firms that completed wells according to AFMSS. The BLM expects that these firms are most likely to be impacted by the rule. From that list, the BLM researched for company annual report filings with the Securities and Exchange Commission (SEC) to determine annual company net incomes and employment figures. From the original list, the BLM found 55 company filings. Of those, 33 were small businesses. For the purposes of this analysis, the BLM assumes that all entities (all lessees and operators) that may be affected by this rule are small entities, even though that is not actually the case.

Using the net income data for the small businesses that filed SEC Form 10–K, the BLM used the estimated compliance costs per hydraulic fracturing operation to calculate the percent of compliance costs as a portion of annual company net incomes for 2011. The BLM used the absolute values of the percentages in the average, so that the negative net incomes would not negate the positive net incomes, and vice versa. Averaging results for the small businesses that the BLM examined, the average costs of the rule are expected to represent about 0.15 percent of the company net incomes. The results of those findings are in Table 8.

TABLE 8—SMALL BUSINESS' COMPANY NET INCOME AND COMPLIANCE COSTS AS A SHARE OF NET INCOME

Descriptive statistic	Company net income	Hydraulic fracturing operation on federal lands (%)	Hydraulic fracturing operation on Indian lands (%)	Hydraulic fracturing operation (without distinction) (%)
Average of absolute values	67,288,696	0.132	0.195	0.147
Average	27,566,704	0.005	0.008	0.006
Minimum value	−228,063,000	−0.858	−1.260	−0.954
Maximum value	392,678,000	0.731	1.074	0.813

The rule deals with hydraulic fracturing on all Federal and Indian lands (except those excluded by statute). Please see the discussion earlier in this preamble for the discussion of the need for, and objectives of the rule and a discussion of the impacts of the rule. The BLM received many comments on the economic impacts of the supplemental proposed rule, as discussed elsewhere in this preamble.

There would be some increased costs associated with the enhanced recordkeeping requirements and some new operational requirements. Specifically, there will be increased costs for operators to manage recovered

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

fluids in above-ground tanks until they have approved plans for disposal of produced water pursuant to Onshore Order No. 7. Operators that do not routinely run a CEL to ensure that the producing zone is isolated from usable water or that do not routinely run an MIT prior to hydraulic fracturing operations will face increased costs. Submission of hydraulic fracturing plans for prior approval, and submission of detailed reports after hydraulic fracturing operations will be new costs, as will the costs of submitting chemical information or of submitting an affidavit. Maintaining access to information on chemicals that was withheld from submission may also pose a cost. The application, reporting and data retention requirements are not overly burdensome because they are for information readily available to the operator or its service contractors. The reasons for those requirements and responses to comments on each requirement are discussed previously in this preamble. As shown on Tables 5A, 5B, 6A, 6B, 7A, 7B, and 8, the BLM expects that the costs of compliance with this rule would be minor in comparison to overall operations costs.

The BLM has taken steps to reduce costs on small entities by not promulgating a general requirement to run a CEL on surface casings, by allowing submission of chemical data through FracFocus, by providing for submission of a request for approval for hydraulic fracturing in a master hydraulic fracturing plan, by clarifying that isolating and protecting usable water means 200 feet of competent cement between the fractured zone and the usable water zone, by clarifying that modeling of fissure propagation is not required, and by allowing for both operation-specific and state or tribal variances. Therefore, the BLM has determined that the rule would not have a significant economic impact on a substantial number of small entities.

Also, based on the available information, the BLM estimates the annual effect on the economy of the regulatory changes will be less than $100 million. This rule will not create a major increase in costs or prices for consumers, individual industries, Federal, state, or local government agencies, or geographic regions. In addition, this regulation will not have any significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States-based enterprises to compete with foreign-based enterprises in domestic and export markets.

Executive Order 12866, Regulatory Planning and Review

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 requirement that operators provide to the BLM information regarding hydraulic fracturing operations that they are not currently providing to the BLM.

This rule would not create inconsistencies or otherwise interfere with an action taken or planned by another agency. This rule would not change the relationships of oil and gas operations with other agencies. These relationships are included in agreements and memoranda of understanding that would not change with this rule. In addition, this rule would not materially affect the budgetary impact of entitlements, grants, loan programs, or the rights and obligations of their recipients. Please see the discussion of the impacts of the rule described earlier in this section of the preamble.

Unfunded Mandates Reform Act

Under the Unfunded Mandates Act, agencies must prepare a written statement about benefits and costs prior to issuing a proposed or final rule that may result in aggregate expenditure by state, local, and tribal governments, or by the private sector, of $100 million or more in any one year.

This 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 rule is also not subject to the requirements of Sections 202 or 205 of the Unfunded Mandates Reform Act (UMRA).

This 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; it contains no requirements that apply to such governments nor does it impose obligations upon them.

Executive Order 12630, Governmental Actions and Interference With Constitutionally Protected Property Rights (Takings)

Under Executive Order 12630, the rule will not have significant takings implications. A takings implication assessment is not required. This rule establishes recordkeeping requirements for hydraulic fracturing operations and some additional operational requirements on Federal and Indian lands. All such operations are subject to lease terms which expressly require that subsequent lease activities be conducted in compliance with subsequently adopted Federal laws and regulations. The rule conforms to the terms of those Federal leases and applicable statutes and as such the rule is not a governmental action capable of interfering with constitutionally protected property rights. Therefore, the rule will not cause a taking of private property or require further discussion of takings implications under this Executive Order.

Executive Order 13352, Facilitation of Cooperative Conservation

Under Executive Order 13352, the BLM has determined that this rule will not impede facilitating cooperative conservation and takes appropriate account of and consider the interests of persons with ownership or other legally recognized interests in land or other natural resources. The rulemaking process involved Federal, state, local, and tribal governments, private for-profit and nonprofit institutions, other nongovernmental entities and individuals in the decision-making. The process provides that the programs, projects, and activities are consistent with protecting public health and safety.

Executive Order 13132, Federalism

Under Executive Order 13132, this rule will not have significant Federalism effects. A Federalism assessment is not required because the rule will 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 rule will not have any effect on any of the items listed. The rule affects the relationship between operators, lessees, and the BLM, but it does not impact states. Therefore, under Executive Order 13132, the BLM has determined that this rule will not have sufficient Federalism implications to warrant preparation of a Federalism Assessment.

Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

Under Executive Order 13175, the President's memorandum of April 29, 1994, ''Government-to-Government Relations with Native American Tribal Governments'' (59 FR 22951), The Department of the Interior Policy on Consultation with Indian Tribes (Dec. 1, 2011), and 512 Departmental Manual 2, the BLM evaluated possible effects of the 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 rule has the potential to affect Indian tribes. In conformance with the Department'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 four cities in January 2012.

The purpose of those meetings was to solicit initial feedback and preliminary comments from the tribes. 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 groundwater; and the operator having to provide documentation that the water used for the fracturing operation was legally acquired. The BLM considered these concerns during the drafting of the final rule.

After publication of the proposed rule, the BLM held another series of meetings to obtain comments and recommendations from tribes and tribal organizations. Those meetings were held in June 2012 in Utah, New Mexico, Oklahoma, and Montana. The BLM also engaged in one-on-one consultations as requested by several tribes. Some tribal representatives were concerned about risks to the quality of their vital water supplies. Others, though, were more concerned with the risk that increased compliance costs would drive the industry off of Indian lands, and deprive the tribes of much-needed revenues and economic development.

After publication of the supplemental proposed rule, the BLM again held regional meetings with tribes in Farmington, New Mexico, and Dickinson, North Dakota, in June 2013. Representatives from six tribes attended. The discussions included a variety of tribal-specific and general issues. The BLM again offered to follow up with one-on-one consultations, and several such meetings were held with individual tribes. Several tribes, tribal members, and associations of tribes provided comments on the supplemental proposed rule.

In March 2014, the BLM invited tribes to participate in another meeting in Denver, Colorado. Representatives from seven tribes attended. There was significant discussion of issues raised in the comments on the supplemental proposed rule. The BLM subsequently held several consultations with individual tribes.

The BLM understands the importance of tribal sovereignty and self-determination, and seeks to continuously improve its communications and government-to-government relations with tribes.

The BLM has considered and responded to the concerns expressed by the tribal representatives both orally and in written comments, as described previously. In particular, it has made changes that will reduce economic burdens of compliance for many operators.

Several tribes provided written and oral comments critical of the proposed rule. Other tribes said that the rules violated tribal sovereignty. The final rule, however, is not unique. Regulations promulgated by the Bureau of Indian Affairs render the BLM's operating regulations in 43 CFR part 3160 applicable to oil and gas leases of trust and restricted Indian lands, both tribal and individually owned. See 25 CFR 211.4, 212.4, and 225.4.

Some tribes insist that those BIA regulations are in violation of the FLPMA, which they said restricts the BLM's authority to Federal lands. Section 301 of the FLPMA, however, charges the Director of the BLM to carry out functions and duties as the Secretary may prescribe with respect to the lands and the resources under the Secretary's jurisdiction according to the applicable provisions of the FLPMA and any other applicable law. 43 U.S.C. 1731(a). See also 43 U.S.C. 1731(b). The Act of March 3,1909 (1909 Act) (at 25 U.S.C. 396), the Indian Minerals Leasing Act (IMLA) (at 25 U.S.C. 396d) and the Indian Mineral Development Act (IMDA) (at 25 U.S.C. 2107) provide the Secretary of the Interior with authority to promulgate regulations governing oil and gas operations and mineral agreements on certain Indian lands. As previously cited, the Secretary, through delegations in the Departmental Manual as reflected in the regulations promulgated by the BIA, has assigned to the BLM part of the Secretary's trust responsibilities to regulate oil and gas operations on those Indian lands. This rule concerning Indian lands is promulgated pursuant to the 1909 Act, the IMLA, and the IMDA, and will be implemented by the BLM under those authorities, consistent with Section 301 of the FLPMA.

Some tribes have asked that the final rule exempt Indian lands from its scope. Such an exemption would require the Secretary of the Interior to conclude, among other things, that usable waters in Indian lands, and the persons who use such waters, are less deserving of protection than waters and water users on Federal land. The Department of the Interior declines to reach that conclusion.

Some tribes have advocated that the rule should allow Indian tribes to decide individually whether the hydraulic fracturing regulations would apply on their lands. The BIA's regulations, however, apply to all of the BLM's oil and gas operating regulations on Indian lands, and do not allow the tribes to pick and select which of the BLM's regulations apply on their lands.

The tribes, however, report that industry representatives have threatened not to bid on Indian leases if the proposed rules were promulgated. The tribes are concerned that a major source of revenue and of economic development might leave Indian lands because of the costs of compliance with the rule. The BLM has carefully considered the tribes' comments, along with those of the oil and gas industry and of concerned citizens and governments. The final rule includes several changes from the initial proposed rules to reduce the costs and other burdens of compliance. Examples include not requiring a CEL on surface casings absent an indication of a cementing problem, allowing operators to use any one of a class of CELs to verify the adequacy of cement casings and not requiring the CEL to be approved before fracturing operations if there is no indication of problems with the cementing. The final rule also explicitly states that the BLM will require isolation of zones that the tribes designate for protection from oil and gas operations, and will not require isolation of zones that tribes have exempted from protection. (Note, though, that the final rule would not exempt an operator from the provisions of the SDWA.) Furthermore, the BLM could approve a variance from certain provisions of the rule applicable to all or parts of Indian lands, provided the relevant tribal rule meets or exceeds the effectiveness of BLM's rule. Such a variance could allow an operator's compliance with a tribe's standard or procedure to be accepted as compliance with the revised proposed rule, thus

reducing the compliance burdens for operators. Such changes should significantly reduce compliance costs for operators while still assuring protection of usable water resources.

The BLM is aware that the final rule could nonetheless result in some higher costs for operators on Federal and Indian lands, compared with compliance costs for hydraulic fracturing on non-Federal, non-Indian lands in some states with no regulations or less protective regulations. Regulatory compliance costs, however, are only one category in a long list of costs that operators compare to anticipated revenues when deciding whether and how much to bid on a Federal or Indian lease. The costs of this rule are estimated to be only 0.13 to 0.21 percent of the cost of drilling a well. It has not been the BLM's experience that regulatory compliance costs have caused the industry to avoid valuable oil and gas resources on Federal and Indian lands.

Executive Order 12988, Civil Justice Reform

Under Executive Order 12988, the Office of the Solicitor has determined that this rule will not unduly burden the judicial system and meets the requirements of Sections 3(a) and 3(b)(2) of the Order. The Office of the Solicitor has reviewed the rule to eliminate drafting errors and ambiguity. It has been written to minimize litigation, to provide clear legal standards for affected conduct rather than general standards, and to promote simplification and avoid unnecessary burdens.

Paperwork Reduction Act

The Paperwork Reduction Act (44 U.S.C. 3501–3521) provides that an agency may not conduct or sponsor, and a person is not required to respond to, a ''collection of information,'' unless it displays a currently valid OMB control number. Collections of information include requests and requirements that an individual, partnership, or corporation obtain information, and report it to a Federal agency (44 U.S.C. 3502(3); 5 CFR 1320.3(c) and (k).

The BLM included a request for approval of a collection of information in both the proposed rule and the supplemental proposed rule. OMB approved the collection for the final rule under control number 1004–0203.

Compliance with this collection of information will be required to obtain or retain a benefit for the operators of Federal and Indian (except on the Osage Reservation, the Crow Reservation, and certain other areas) onshore oil and gas leases, units, or communitization agreements that include Federal leases. After the effective date of the final rule, the BLM plans to request that OMB merge control number 1004–0203 with control number 1004–0137, ''Onshore Oil and Gas Operations,'' (expiration date: January 31, 2018).

The following activities comprise the information collection for the final rule.

Request for Prior Approval

• The final rule removes the distinction in existing 43 CFR 3162.3–2 between ''routine'' and ''non-routine'' fracturing jobs, and requires in section 3162.3–3(a) that operators propose and seek prior BLM approval for all hydraulic fracturing jobs except for three instances in which a well is drilled shortly before or after the effective date of the rule, and is hydraulically fractured within 90 days after the effective date of the rule. However, all other applicable provisions of the rule must be adhered to, including 3162.3–3(e), relating to monitoring and verification of cementing operations prior to hydraulic fracturing.

Section 3162.3–3(c) provides that a request to commence hydraulic fracturing may be submitted either on Form 3160–5 as a ''Notice of Intent (NOI) Sundry'' or as part of Form 3160–3, Application for Permit to Drill (APD), both of which are authorized by control number 1004–0137. The BLM will use the following-described information to determine whether or not to grant prior approval for hydraulic fracturing jobs.

Section 3162.3–3(d)(6) lists two requirements that apply only if an operator requests prior approval for hydraulic fracturing in an NOI after drilling and completing a well. The first requirement (at paragraph (d)(6)(i)) is a surface use plan of operations if the hydraulic fracturing operation would include surface disturbance. The second requirement (at paragraph (d)(6)(ii)) is documentation that adequate cementing was achieved for all casing strings designed to isolate usable water zones. These requirements are included in the collection activity labeled ''Request for Prior Approval of Hydraulic Fracturing Job Using a Notice of Intent Sundry Plus a Surface Use Plan of Operations Plus Documentation of Adequate Cementing.''

While the well completion report (Form 3160–4) that is approved under control number 1004–0137 requires some information about cementing, the second requirement in paragraph (d)(6)(ii) is not duplicative. The well-completion report requires the operator to disclose the number of sacks and type of cement, the slurry volume, the cement trop, and any cement squeeze information. The information we are requiring in paragraph (d)(6)(ii) is actual monitoring information from when the cementing operations took place, for example, pump pressures, cement density, and observations during the cement job. We anticipate that typically, an operator will comply with paragraph (d)(6)(ii) by providing us with information recorded on a service company's ''job ticket.''

Section 3162.3–3(e)(1) lists two requirements that apply only if an operator requests prior approval for hydraulic fracturing in an Application for Permit to Drill before drilling and completing a well. This provision requires operators to submit a cement operation monitoring report to the BLM before commencing hydraulic fracturing operations. The required elements of a cement operation monitoring report are (1) The flow rate, density, and pump pressure during pre-fracturing cementing operations on any casing used to isolate usable water zones; and (2) A determination of adequate cement for all casing strings that are used to isolate usable water zones. These requirements are included in the collection activity labeled, ''Request for Prior Approval of Hydraulic Fracturing Job Using an Application for Permit to Drill Plus a Cement Operation Monitoring Report.''

Unlike the supplemental proposed rule, the final rule does not require the operator to identify a ''type well'' as part of a request for prior approval for a group of wells. Instead, section 3162.3–3(c)(3) of the final rule provides for the submission of an MHFP. The differences between the ''type well'' requirement and the requirement for an MHFP are described in the preamble discussion of 43 CFR 3160.0–5 (''Definitions''). This discussion clarifies that the MHFP for a group of wells is only for initial planning purposes and that operators must submit all required information for each well and get approval for each well before drilling.

Remedial Action Plan

Section 3162.3–3(e)(3) requires an operator to notify the BLM within 24 hours of discovering inadequate cement on any casing used to isolate usable water and submit an NOI to the BLM requesting approval of a plan to perform remedial action. The BLM will use this collection activity to determine the adequacy of the proposed remedial action. At least 72 hours before starting hydraulic fracturing operations, operators must submit a subsequent report for the remedial action, which would include a signed certification that

the operator corrected the inadequate cement job along with the results from the CEL or other method showing that there is adequate cement.

Subsequent Report

Section 3162.3–3(i) lists information that must be provided to the BLM within 30 days after the completion of the last stage of hydraulic fracturing operations. We have revised the information that is required. The information is required for each well, even if the authorized officer approved fracturing of a group of wells.

The final rule lists the following requirements for a subsequent report:

(1) The true vertical depth of the well, total water volume used, and a description of the base fluid and each additive in the hydraulic fracturing fluid, including the trade name, supplier, purpose, ingredients, Chemical Abstract Service Number (CAS), maximum ingredient concentration in additive (percent by mass), and maximum ingredient concentration in hydraulic fracturing fluid (percent by mass). This information must be submitted to the authorized officer through FracFocus, another BLM-designated database, or in a subsequent report. If information is submitted through FracFocus or another BLM-designated database, the operator must specify that the information is for a Federal or an Indian well, certify that the information is correct, and certify compliance with applicable law;

(2) The actual source(s) and location(s) of the water used in the hydraulic fracturing fluid;

(3) The maximum surface pressure and rate at the end of each stage of the hydraulic fracturing operation and the actual flush volume;

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

(5) The actual measured depth of perforations or the open-hole interval;

(6) The total volume of fluid recovered between the completion of the last stage of hydraulic fracturing operations and when the operator starts to report water produced from the well to ONRR. If the operator has not begun to report produced water to ONRR when the subsequent report is submitted, the operator must submit a supplemental subsequent report to the authorized officer documenting the total volume of recovered fluid;

(7) The following information concerning the handling of fluids recovered covering the period between the commencement of hydraulic fracturing and the implementation of the approved plan for the disposal of produced water under BLM regulations (currently in Onshore Order 7):

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

(ii) The disposal method of the recovered fluids, including, but not limited to, the percent injected, the percent stored at an off-lease disposal facility, and the percent recycled;

(8) A certification signed by the operator that:

(i) The operator complied with the requirements in 43 CFR 3162.3–3(b), (e), (f), (g), and (h);

(ii) For Federal lands, the hydraulic fracturing fluid constituents, once they arrived on the lease, complied with all applicable permitting and notice requirements as well as all applicable Federal, state, and local laws, rules, and regulations; and

(iii) For Indian lands, the hydraulic fracturing fluid constituents, once they arrived on the lease, complied with all applicable permitting and notice requirements as well as all applicable Federal and tribal laws, rules, and regulations;

(9) The operator must submit the result of the mechanical integrity test as required by 43 CFR 3162.3–3(f); and

(10) The BLM may require the operator to provide documentation substantiating any of the information listed previously.

The information required in paragraphs (2) though (10), previously, must be submitted to the authorized officer in a subsequent report. This information will enable the BLM to have a complete record of the hydraulic fracturing job.

Affidavit in Support of Claim of Confidentiality

Section 3162.3–3(j) describes how an operator, or the operator and the owner of the information, may support a claim to be exempt from public disclosure of information otherwise required in the subsequent report. If required information is withheld, the regulation requires submission with the subsequent report of an affidavit that:

- Identifies the owner of the withheld information and provides the name, address and contact information for an authorized representative of the owner;
- Identifies the Federal statute or regulation that would prohibit the BLM from publicly disclosing the information if it were in the BLM's possession;
- Affirms that the operator has been provided the withheld information from the owner of the information and is maintaining records of the withheld information, or that the operator has access and will maintain access to the information held by the owner of the information;
- Affirms that the information is not publicly available;
- Affirms that the information is not required to be publicly disclosed under any applicable local, state, or Federal law (on Federal lands), or tribal or Federal law (on Indian lands);
- Affirms that the owner of the information is in actual competition and identifies competitors or others that could use the withheld information to cause the owner substantial competitive harm;
- Affirms that the release of the information would likely cause substantial competitive harm to the owner and provides the factual basis for that affirmation; and
- Affirms that the information is not readily apparent through reverse engineering with publicly available information.

In addition, if the operator relies upon information from third parties, such as the owner of the withheld information, to make the previous affirmations, the operator must provide a written affidavit from the third party that sets forth the relied-upon information. The BLM will use the information to determine whether to grant an exemption from public disclosure of information that otherwise would be required in a subsequent report.

Section 3162.3–3(j)(5) requires the operator to maintain records of any withheld information until the later of the BLM's approval of a final abandonment notice, or 6 years from the completion of hydraulic fracturing operations on Indian lands, or 7 years from the completion of hydraulic fracturing operations on Federal lands, consistent with applicable law. Any subsequent operator will be responsible for maintaining access to records of any withheld information during its operation of the well. The operator will be deemed to be maintaining the records if it can promptly provide the complete and accurate information to the BLM, even if the information is in the custody of its owner. This provision enables the BLM to have access to records of injected chemicals during the life of the well, while protecting trade secrets.

Section 3162.3–3(j)(6) provides that if any of the chemical identity information is withheld, the operator must provide the generic chemical name in the subsequent report.

Variance Request

Section 3162.3–3(k) provides that a decision on a variance request is not

subject to administrative appeal either to the State Director or under 43 CFR part 4.

Necessity/Avoidance of Unnecessary Duplication

The Paperwork Reduction Act requires each Federal agency to certify that its collections of information are necessary for the proper performance of agency functions, and are not unnecessarily duplicative of information otherwise reasonably accessible to the agency. 43 U.S.C. 3506(c)(3)(A) and (B). We received many comments on the proposed rule with respect to this standard, and we responded to them in the supplemental proposed rule. In addition, we received the following comments on the supplemental proposed rule with respect to this standard.

Comments: Numerous commenters said that in states where there is already a regulatory process for hydraulic fracturing, an operator should be allowed to submit the same information to the BLM as it does to the state.

Response: We made no changes as a result of these comments because the rule already addresses the expressed concerns. Section 3162.3–3(d) allows information submitted in accordance with state or tribal law to be submitted to the BLM if the information meets the standards of this rule. Section 3162.3–3(k)) allows the BLM to issue a statewide or regional variance to use state or tribal regulations and processes for permitting hydraulic fracturing operations if they meet or exceed the objectives of this rule.

Comment: One commenter requested that the BLM clarify the following statement in section 3162.3–3(d): If information submitted in accordance with states (on Federal lands) or tribal (on Indian lands) laws or regulations meets the standards prescribed by the BLM, such information may be submitted to the BLM as part of the Sundry Notice.

Response: We did not revise the rule in response to this comment. The statement in section 3162.3–3(d) provides clearly that if the information submitted to states or tribes meets the standards in this section, the operator does not need to generate any information. Operators may submit the information that was generated to meet the state or tribal requirements to the BLM.

Comments: Some commenters on the supplemental proposed rule questioned the necessity of collecting information in a subsequent report within 30 days after the completion of the last stage of hydraulic fracturing operations under section 3162.3–3(i). They stated that much of the information is required either in the NOI or in the well completion report (Form 3160–4) that is required by 43 CFR 3162.4–1(b).

Response: We disagree with comments claiming duplication between the NOI and the subsequent report. The information in the NOI allows the BLM to analyze the proposed operations to ensure that there will not be any unnecessary or undue degradation of public lands or breach of trust on Indian lands. The information also enables the BLM to develop any necessary mitigation to protect resources. In contrast, the information in the subsequent report allows the BLM to determine whether or not operations were conducted as designed and authorized. Some information, such as the results of the MIT and the cement operations monitoring report, are not included in the NOI, and can only be submitted after the operations are complete.

We did revise section 3162.3–3(i)(9) (paragraph (i)(8) of the supplemental proposed rule) in response to comments saying that the proposed requirement to submit well logs and records of adequate cement duplicates a requirement in the well completion report. However, we made no changes to section 3162.3–3(i) in response to other comments saying that the information required in the subsequent report duplicates information that is required in the well completion report. Examples of data that are required in the subsequent report, but not in the well completion report, include the cement operations monitoring report, the results of the MIT, and the operator certification that it complied with the paragraphs in the rule that assure wellbore integrity was maintained prior to and throughout the hydraulic fracturing operation.

Comment: A commenter recommended that all cementing requirements be eliminated from the rule because cementing operations are part of drilling operations and information is already submitted to state regulatory agencies for such operations. The commenter also asserted that cementing operations have little to do with hydraulic fracturing.

Response: We did not revise any provision in response to this comment. While cementing information is already submitted to state regulatory agencies and the BLM, this rule expands on the requirements by including cement monitoring, cement remediation, and cement evaluation. Moreover, the cementing information that is required is related to protection of usable water from hydraulic fracturing operations.

Comments: Some commenters stated that information regarding the water source that is required in section 3162.3–3(d)(3) would have already been provided as part of an APD.

Response: We did not revise the rule in response to this comment. While section III.D.4.e of Onshore Order 1 requires the operator to identify the location and type of water supply to be used during the drilling operations in the APD, this may or may not be the same as the water supply for hydraulic fracturing operations. Since the water supply may be different, this information must be included in the application for hydraulic fracturing.

Practical Utility

The Paperwork Reduction Act requires that each Federal agency certify that each collection of information has practical utility. The term ''practical utility'' means the ability of an agency to use information, particularly the capability to process such information in a timely and useful fashion. 44 U.S.C 3502(11) and 3506(c)(3)(A).

Comments: Commenters expressed various concerns with the requirement in section 3162.3–3(d)(3) to provide information concerning the water source and location of water supply. Some stated that they were unsure how we would use the information. Others stated that the water source could change and filing a Sundry Notice for the BLM to approve the change is burdensome.

Response: We did not revise the final rule in response to these comments. We require information about the proposed source of the water in order to conduct and document an environmental effects analysis that takes a hard look at the impacts of its Federal action and meets the requirements of NEPA. The BLM has always required operators to file a Sundry Notice for changes to the approved permit—whether it is an APD or an NOI for hydraulic fracturing.

Clarity

The Paperwork Reduction Act requires each Federal agency to certify that each collection of information is written using plain, coherent, and unambiguous terminology and is understandable to those who are to respond. 44 U.S.C. 3506(c)(3)(D).

Comments: Some commenters recommended restructuring of sections 3162.3–3(d)(3) and 3162.3–3(d)(4) of the supplemental proposed rule (pertaining to the NOI). They stated that restructuring these provisions would add clarity to the requirements.

Response: We revised sections 3162.3–3(d)(3) and 3162.3–3(d)(4) as suggested in these comments. Section 3162.3–3(d)(3) now requires information concerning the source and location of the water supply. The requirement for the measured depth of the proposed perforated or open-hole interval is moved to section 3162.3–3(d)(4)(v). The information regarding the proposed perforated interval is now a distinct requirement, and this information relates more closely with the other information required by section 3162.3–3(d)(4).

Consistency With Existing Reporting and Recordkeeping Practices

The Paperwork Reduction Act requires each Federal agency to certify that its collections of information are to be implemented in ways consistent and compatible, to the maximum extent practicable, with the existing reporting and recordkeeping practices of those who are to respond. 44 U.S.C. 3506(c)(3)(E). We received comments on the proposal to allow some of the information in a subsequent report to be submitted through FracFocus or another BLM-designated database.

Comments: Some commenters supported the provision (section 3162.3–3(i)) that allows some of the information in a subsequent report to be submitted through FracFocus or another BLM-designated database. They stated that provision would reduce duplication of efforts for the operators. They also supported the provision that allows operators in states that require disclosure on FracFocus to meet both the state and the BLM requirements through a single submission to FracFocus.

Some commenters suggested that additional information, such as the APD, status, compliance, volume of fluid recovered, and complaint process, should be reported through the FracFocus submission.

Other commenters were critical of FracFocus as not being user-friendly and for not allowing re-publication or linking with other databases. Some commenters were critical of FracFocus because of the unknown future condition and long-term reliability of this organization in hosting and retaining the data. A few commenters expressed concern about future funding, access, and data backup issues of FracFocus. Other commenters suggested that the disclosure registry should be searchable across forms and allow for meaningful cross-tabulation of search results. One of the commenters specified that each of the disclosure submissions should have a date stamp showing the actual date of submission to the database and validate/reject the correct/incorrect CAS Registry Numbers of the disclosed chemicals/ingredients when submitted. Another commenter suggested that the BLM should develop a public disclosure platform tailored to the agency's needs.

Some commenters expressed concern that the ownership of the data on FracFocus and the applicability of public disclosure laws, such as FOIA are unknown. A commenter suggested that the BLM adopt a procedure used in Texas that requires operators to submit to the state commission a copy of the information that they upload to FracFocus.

Some commenters argued that using FracFocus would violate an executive order requiring government information to be available to the public in open, machine-readable formats, and the implementing guidance from the Office of Management and Budget. See Executive Order 13642, 78 FR 93 (2013), and Memorandum for the Heads of Executive Departments and Agencies, M–13–13 (OMB 2013). That order provides, in pertinent part that the policy of the Executive Branch is that modernized Government information resources must be open and machine readable. The order is subject to several conditions, including available appropriations.

A commenter was concerned that using FracFocus could cause a conflict of interest because the GWPC is a trade association for oil and gas.

A commenter argued that using FracFocus would fail to meet minimum standards for managing government records.

A commenter raised an issue of implementation and enforcement—that because FracFocus does not show the date that information is uploaded, it will be difficult for the BLM to know if the information was submitted within the time required by the rule.

Response: The BLM did not make any changes to the rule in response to these comments. The responses that are summarized here are discussed in detail earlier in the preamble discussion of section 3162.3–3(i).

Under this final rule, submission of the required information through FracFocus is optional; an operator may instead submit it directly to BLM. The BLM's intent, however, is to reduce the paperwork burden on operators by allowing them to submit information through FracFocus, if they so choose. Thus, in states that require submission on FracFocus, there would be no additional burden of complying with this requirement of the rule. If an operator submits the information directly to the BLM, the BLM will upload the information to FracFocus, and retain a copy in its files.

The BLM did not adopt suggestions to allow additional information to be reported through the FracFocus submission because FracFocus is limited to chemical disclosures.

The GWPC has upgraded the FracFocus database to enhance its functionality for the public, state regulatory agencies and industry users. As mentioned earlier under New Requirements, GWPC and IOGCC, joint venture partners in the FracFocus initiative, announced the release of several improvements to FracFocus' system functionality. The new features are designed to reduce the number of human errors in disclosures, expand the public's ability to search records, provide public extraction of data in a ''machine readable'' format, update educational information on chemical use, environmental impacts from oil and gas production, and potential environmental impacts. The new self-checking features in the system will help companies detect and correct possible errors before disclosures are submitted. This feature will detect errors verifying that CAS numbers meet the proper format. GWPC recently met with the BLM and confirmed the following updates to FracFocus:

(a) Validation of the CAS number;

(b) Reduction of errors by taking measures, such as a water volume alert if the operators input exceedingly high numbers (>15 million gallons) in error, multiple disclosures with the same API numbers, etc.;

(c) Validation checks of the maximum ingredient concentration, using two checks/alerts when the sum exceeds 3% and 10%;

(d) Improved public search capabilities with faster response times when filtering search results;

(e) Updated record retention and amendment aspects to keep a backup copy of every disclosure submitted to FracFocus;

(f) Adopted established record management standards to meet proper data quality objectives;

(g) Notify the BLM through a group email box when an operator uploads the chemical disclosure data for a well;

(h) Include a link to a downloadable file containing the data in a machine-readable format; and

(i) Provide a date stamp when chemical disclosure data is uploaded from the BLM operations.

These updates are addressed in the most recent iteration of FracFocus.

The agreement would also require GWPC to include the BLM as a member of the Full and Technical Committees to engage in updates and developments to FracFocus.

The BLM expects that these requirements will yield further progress and improvement of the FracFocus site to meet the requirements of the rule by providing an effective chemical disclosure registry for the hydraulic fracture fluids.

The Federal FOIA does not apply to FracFocus, because it is operated by the GWPC, which is not an agency of the Federal Government. However, information on FracFocus concerning Federal or tribal wells is public information because FracFocus is a public Web site and there would be no need for the costs of delays associated with awaiting a response to a FOIA request. The public can access that information for themselves.

Executive Order 13642 does not prohibit the BLM from allowing operators to submit information through FracFocus. We believe that FracFocus is the quickest, most cost-effective way to make the information public. Working with FracFocus to meet the policy goals of the Executive Order, including machine-readable formats, will be more prompt and will use taxpayer dollars more efficiently than would the BLM creating and managing its own database solely for chemical disclosures.

The use of FracFocus does not constitute a conflict of interest. The members of GWPC are the states agencies (*www.gwpc.org/state-agencies*) that protect and regulate groundwater resources. They do not have a conflict of interest in operating FracFocus to serve as a way for operators to submit data to the BLM, or in making that information available to the public.

The use of FracFocus does not conflict with requirements for records management. FracFocus will not be the official repository of the chemical information required by the rule. Whether an operator submits information to the BLM directly or through FracFocus, the BLM will maintain access to all the relevant information. The information will also be available on FracFocus for the benefit of the public and state and tribal agencies.

The BLM will closely monitor FracFocus to ensure that operators submit information in a timely manner consistent with these regulations. Operators also have an incentive to assure that the BLM has received the required information within the deadlines. The BLM will be working with the GWPC to improve the ability of FracFocus to meet the BLM's needs and of operators on Federal or tribal lands.

Estimates of Burdens

The following table shows the estimated annual paperwork burdens associated with this rule.

ESTIMATES OF HOUR BURDENS

A. Total hours	B. Type of response	C. Number of responses	D. (column B × column C) Hours per response
Request for Prior Approval of Hydraulic Fracturing Job Using an Application for Permit to Drill Plus a Cement Operation Monitoring Report 43 CFR 3162.3–3(c)(1), (d), (e)(1), and (e)(2) Form 3160–3	2,614	8	20,912
Request for Prior Approval of Hydraulic Fracturing Job Using a Notice of Intent Sundry Plus a Surface Use Plan of Operations Plus Documentation of Adequate Cementing 43 CFR 3162.3–3(c)(2), (c)(3), (d), and (e). Form 3160–5	200	8	1,600
Sundry Notices and Reports on Wells/Hydraulic Fracturing/Request for Approval of Remedial Plan 43 CFR 3162.3–3(e)(3) Form 3160–5	84	8	672
Sundry Notices and Reports on Wells/Hydraulic Fracturing/Subsequent Report Sundry Notice 43 CFR 3162.3–3(g) and (i) Form 3160–5	2,814	8	22,512
Affidavit in Support of Claim of Confidentiality 43 CFR 3162.3–3(j)	2,814	1	2,814
Sundry Notices and Reports on Wells/Hydraulic Fracturing/Variance Request 43 CFR 3162.3–3 Form 3160–5	281	8	2,248
Totals	8,807	.....	50,758

No capital and start-up costs are involved with this information collection—respondents are not required to purchase additional computer hardware or software to comply with these information collection requirements. The Fiscal Year 2015 appropriations law (Pub. L. 113–203) directs the BLM to charge a $6,500 processing fee for Form 3160–3, Application for Permit to Drill or Re-Enter. We estimate that 5,000 of these applications are filed annually under control number 1004–0137, and another 2,614 will be filed under control number 1004–0203. The estimated non-hour cost burden is $32,500,000 under control number 1004–0137, and $16,991,000 under 1004–0203. The total estimated non-hour cost burden is $49,491,000.

National Environmental Policy Act

The BLM has prepared an environmental assessment (EA) that concludes that this rule will not constitute a major Federal action that may result in a significant effect on the human environment under section 102(2)(C) of the National Environmental Policy Act (NEPA), 42 U.S.C. 4332(2)(C). The EA, the Finding of No Significant Impact, and the Decision Record are available for review and on file in the BLM Administrative Record at the address specified in the **ADDRESSES** section.

Data Quality Act

In developing this rule, the BLM did not conduct or use a study, experiment, or survey requiring peer review under the Data Quality Act (Pub. L. 106–554).

Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Under Executive Order 13211, agencies are required to prepare and submit to OMB a Statement of Energy Effects for significant energy actions. This Statement is to include a detailed

statement of ''any adverse effects of energy supply, distribution, or use (including a shortfall in supply, price increases, and increase use of foreign supplies)'' for the action and reasonable alternatives and their effects.

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 believes that the additional cost per hydraulic fracturing operation is insignificant when compared with the drilling costs in recent years, the production gains from hydraulically fractured well operations, and the net incomes of entities within the oil and natural gas industries. For the average hydraulic fracturing operation, the compliance costs represent about 0.13 to 0.21 percent of the cost of drilling a well.

Since the estimated compliance costs are not substantial when compared with the total costs of drilling a well, the BLM believes that the rule is 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. As such, the rule is not a ''significant energy action'' as defined in Executive Order 13211.

Authors

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List of Subjects 43 CFR Part 3160

Administrative practice and procedure, Government contracts, Indians-lands, Mineral royalties, Oil and gas exploration, Penalties, Public lands-mineral resources, Reporting and recordkeeping requirements.

For the reasons stated in the preamble, and under the authorities stated below, the Bureau of Land Management amends 43 CFR part 3160 as follows:

PART 3160—ONSHORE OIL AND GAS OPERATIONS

■ 1. The authority citation for part 3160 is revised to read as follows:

Authority: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733, and 1740.

Subpart 3160—Onshore Oil and Gas Operations: General

§ 3160.0–3 [Amended]

■ 2. In § 3160.0–3 add ''the Federal Land Policy and Management Act (43 U.S.C. 1701 *et seq.*),'' after ''the Mineral Leasing Act for Acquired lands, as amended (30 U.S.C. 351–359),''.

■ 3. Amend § 3160.0–5 by adding definitions of ''annulus,'' ''bradenhead,'' ''Cement Evaluation Log (CEL),'' ''confining zone,'' ''hydraulic fracturing,'' ''hydraulic fracturing fluid,'' ''isolating or to isolate,'' ''master hydraulic fracturing plan,'' ''proppant,'' and ''usable water,'' in alphabetical order and by removing the definition of ''fresh water'' to read as follows:

§ 3160.0–5 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 casing; sometimes also called annular space.

* * * * *

Bradenhead means a heavy, flanged steel fitting connected to the first string of casing that allows the suspension of intermediate and production strings of casing and supplies the means for the annulus to be sealed.

Cement Evaluation Log (CEL) means any one of a class of tools that verify the integrity of annular cement bonding, such as, but not limited to, a cement bond log (CBL), ultrasonic imaging log, variable density logs, CBLs with directional receiver array, ultrasonic pulse echo log, or isolation scanner.

Confining zone means a geological formation, group of formations, or part of a formation that is capable of preventing fluid movement from any formation that will be hydraulically fractured into a usable water zone.

* * * * *

Hydraulic fracturing means those operations conducted in an individual wellbore designed to increase the flow of hydrocarbons from the rock formation to the wellbore through modifying the permeability of reservoir rock by applying fluids under pressure to fracture it. Hydraulic fracturing does not include enhanced secondary recovery such as water flooding, tertiary recovery, recovery through steam injection, or other types of well stimulation operations such as acidizing.

Hydraulic fracturing fluid means the liquid or gas, and any associated solids, used in hydraulic fracturing, including constituents such as water, chemicals, and proppants.

Isolating or to isolate means using cement to protect, separate, or segregate usable water and mineral resources.

* * * * *

Master hydraulic fracturing plan means a plan containing the information required in section 3162.3–3(d) of this part for a group of wells where the geologic characteristics for each well are substantially similar.

* * * * *

Proppant means a granular substance (most commonly sand, sintered bauxite, or ceramic) that is carried in suspension by the fracturing fluid that serves to keep the cracks in the geologic formation open when fracturing fluid is withdrawn after a hydraulic fracture operation.

* * * * *

Usable water means

(1) Generally those waters containing up to 10,000 parts per million (ppm) of total dissolved solids. Usable water includes, but is not limited to:

(i) Underground water that meets the definition of ''underground source of drinking water'' as defined at 40 CFR 144.3;

(ii) Underground sources of drinking water under the law of the State (for Federal lands) or tribe (for Indian lands); and

(iii) Water in zones designated by the State (for Federal lands) or tribe (for Indian lands) as requiring isolation or protection from hydraulic fracturing operations.

(2) The following geologic zones are deemed not to contain usable water:

(i) Zones from which the BLM has authorized an operator to produce oil and gas, provided that the operator has obtained all other authorizations required by the Environmental Protection Agency, the State (for Federal lands), or the tribe (for Indian lands) to conduct hydraulic fracturing operations in the specific zone;

(ii) Zones designated as exempted aquifers pursuant to 40 CFR 144.7; and

(iii) Zones that do not meet the definition of underground source of drinking water at 40 CFR 144.3 which the State (for Federal lands) or the tribe (for Indian lands) has designated as exempt from any requirement to be isolated or protected from hydraulic fracturing operations.

* * * * *

Subpart 3162—Requirements for Operating Rights Owners and Operators

■ 4. Amend § 3162.3–2 by revising the first sentence of paragraph (a) and revising paragraph (b) to read as follows:

§ 3162.3–2 Subsequent well operations.

(a) A proposal for further well operations must be submitted by the operator on a Sundry Notice and Report on Wells (Form 3160–5) as a Notice of Intent for approval by the authorized officer prior to commencing operations to redrill, deepen, perform casing repairs, plug-back, alter casing, recomplete in a different interval, perform water shut off, combine production between zones, and/or convert to injection. * * *

(b) Unless additional surface disturbance is involved and if the operations conform to the standard of prudent operating practice, prior approval is not required for acidizing jobs or recompletion in the same interval; however, a subsequent report on these operations must be filed using a Sundry Notice and Report on Wells (Form 3160–5).

* * * * *

■ 5. Revise § 3162.3–3 to read as follows:

§ 3162.3–3 Subsequent well operations; Hydraulic fracturing.

(a) *Activities to which this section applies.* This section, or portions of this section, apply to hydraulic fracturing as shown in the following table:

If . . .	Then
(1) No APD was submitted as of June 24, 2015	The operator must comply with all paragraphs of this section.
(2) An APD was submitted but not approved as of June 24, 2015. (3) An APD or APD extension was approved before June 24, 2015, but the authorized drilling operations did not begin until after June 24, 2015.	To conduct hydraulic fracturing within 90 days after the effective date of this rule, the operator must comply with all paragraphs of this section, except (c) and (d).
(4) Authorized drilling operations began, but were not completed before June 24, 2015 (5) Authorized drilling operations were completed after September 22, 2015. (6) Authorized drilling activities were completed before September 22, 2015	The operator must comply with all paragraphs of this section.

(b) *Isolation of usable water to prevent contamination.* All hydraulic fracturing operations must meet the performance standard in section 3162.5–2(d) of this title.

(c) *How an operator must submit a request for approval of hydraulic fracturing.* A request for approval of hydraulic fracturing must be submitted by the operator and approved by the authorized officer before commencement of operations. The operator may submit the request in one of the following ways:

(1) With an application for permit to drill; or

(2) With a Sundry Notice and Report on Wells (Form 3160–5) as a notice of intent (NOI).

(3) For approval of a group of wells submitted under either paragraph (c)(1) or (2) of this section, the operator may submit a master hydraulic fracturing plan. Submission of a master hydraulic fracturing plan does not obviate the need to obtain an approved APD from the BLM for each individual well.

(4) If an operator has received approval from the authorized officer for hydraulic fracturing operations, and the operator has significant new information about the geology of the area, the stimulation operation or technology to be used, or the anticipated impacts of the hydraulic fracturing operation to any resource, then the operator must submit a new NOI (Form 3160–5). Significant new information includes, but is not limited to, information that changes the proposed drilling or completion of the well, the hydraulic fracturing operation, or indicates increased risk of contamination of zones containing usable water or other minerals.

(d) *What a request for approval of hydraulic fracturing must include.* The request for approval of hydraulic fracturing must include the information in this paragraph. If the information required by this paragraph has been assembled to comply with State law (on Federal lands) or tribal law (on Indian lands), such information may be submitted to the BLM authorized officer as provided to the State or tribal officials as part of the APD or NOI (Form 3160–5).

(1) The following information regarding wellbore geology:

(i) The geologic names, a geologic description, and the estimated depths (measured and true vertical) to the top and bottom of the formation into which hydraulic fracturing fluids are to be injected;

(ii) The estimated depths (measured and true vertical) to the top and bottom of the confining zone(s); and

(iii) The estimated depths (measured and true vertical) to the top and bottom of all occurrences of usable water based on the best available information.

(2) A map showing the location, orientation, and extent of any known or suspected faults or fractures within one-half mile (horizontal distance) of the wellbore trajectory that may transect the confining zone(s). The map must be of a scale no smaller than 1:24,000.

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

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

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

(ii) The maximum anticipated surface pressure that will be applied during the hydraulic fracturing process;

(iii) A map at a scale no smaller than 1:24,000 showing:

(A) The trajectory of the wellbore into which hydraulic fracturing fluids are to be injected;

(B) The estimated direction and length of the fractures that will be propagated and a notation indicating the true vertical depth of the top and bottom of the fractures; and

(C) All existing wellbore trajectories, regardless of type, within one-half mile (horizontal distance) of any portion of the wellbore into which hydraulic fracturing fluids are to be injected. The true vertical depth of each wellbore identified on the map must be indicated.

(iv) The estimated minimum vertical distance between the top of the fracture zone and the nearest usable water zone; and

(v) The measured depth of the proposed perforated or open-hole interval.

(5) The following information concerning the handling of fluids recovered between the commencement of hydraulic fracturing operations and the approval of a plan for the disposal of produced fluid under BLM requirements:

(i) The estimated volume of fluid to be recovered;

(ii) The proposed methods of handling the recovered fluids as required under paragraph (h) of this section; and

(iii) The proposed disposal method of the recovered fluids, including, but not limited to, injection, storage, and recycling.

(6) If the operator submits a request for approval of hydraulic fracturing with an NOI (Form 3160–5), the following information must also be submitted:

(i) A surface use plan of operations, if the hydraulic fracturing operation would cause additional surface disturbance; and

(ii) Documentation required in paragraph (e) or other documentation demonstrating to the authorized officer that the casing and cement have isolated usable water zones, if the proposal is to hydraulically fracture a well that was completed without hydraulic fracturing.

(7) The authorized officer may request additional information prior to the approval of the NOI (Form 3160–5) or APD.

(e) *Monitoring and verification of cementing operations prior to hydraulic fracturing.* (1)(i) During cementing operations on any casing used to isolate and protect usable water zones, the operator must monitor and record the flow rate, density, and pump pressure, and submit a cement operation monitoring report for each casing string used to isolate and protect usable water to the authorized officer prior to commencing hydraulic fracturing operations. The cement operation monitoring report must be provided at least 48 hours prior to commencing hydraulic fracturing operations unless the authorized officer approves a shorter time.

(ii) For any well completed pursuant to an APD that did not authorize hydraulic fracturing operations, the operator must submit documentation to demonstrate that adequate cementing was achieved for all casing strings designed to isolate and protect usable water. The operator must submit the documentation with its request for approval of hydraulic fracturing operations, or no less than 48 hours prior to conducting hydraulic fracturing operations if no prior approval is required, pursuant to paragraph (a) of this section. The authorized officer may approve the hydraulic fracturing of the well only if the documentation provides assurance that the cementing was sufficient to isolate and to protect usable water, and may require such additional tests, verifications, cementing or other protection or isolation operations, as the authorized officer deems necessary.

(2) Prior to starting hydraulic fracturing operations, the operator must determine and document that there is adequate cement for all casing strings used to isolate and protect usable water zones as follows:

(i) *Surface casing.* The operator must observe cement returns to surface and document any indications of inadequate cement (such as, but not limited to, lost returns, cement channeling, gas cut mud, failure of equipment, or fallback from the surface exceeding 10 percent of surface casing setting depth or 200 feet, whichever is less). If there are indications of inadequate cement, then the operator must determine the top of cement with a CEL, temperature log, or other method or device approved in advance by the authorized officer.

(ii) *Intermediate and production casing.* (A) If the casing is not cemented to surface, then the operator must run a CEL to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone.

(B) If the casing is cemented to surface, then the operator must follow the requirements of paragraph (e)(2)(i) of this section.

(3) For any well, if there is an indication of inadequate cement on any casing used to isolate usable water, then the operator must:

(i) Notify the authorized officer within 24 hours of discovering the inadequate cement;

(ii) Submit an NOI (Form 3160–5) to the authorized officer requesting approval of a plan to perform remedial action to achieve adequate cement. The plan must include the supporting documentation and logs required under paragraph (e)(2) of this section. In emergency situations, an operator may request oral approval from the authorized officer for actions to be undertaken to remediate the cement. However, such requests must be followed by a written notice filed not later than the fifth business day following oral approval;

(iii) Verify that the remedial action was successful with a CEL or other method approved in advance by the authorized officer;

(iv) Submit a Sundry Notice and Report on Wells (Form 3160–5) as a subsequent report for the remedial action including:

(A) A signed certification that the operator corrected the inadequate cement job in accordance with the approved plan; and

(B) The results from the CEL or other method approved by the authorized officer showing that there is adequate cement.

(v) The operator must submit the results from the CEL or other method approved by the authorized officer (see paragraph (e)(3)(iv)(B) of this section) at least 72 hours before starting hydraulic fracturing operations.

(f) *Mechanical integrity testing prior to hydraulic fracturing.* Prior to hydraulic fracturing, the operator must perform a successful mechanical integrity test, as follows:

(1) If hydraulic fracturing through the casing is proposed, the casing must be tested to not less than the maximum anticipated surface pressure that will be applied during the hydraulic fracturing process.

(2) If hydraulic fracturing through a fracturing string is proposed, the fracturing string must be inserted into a liner or run on a packer-set not less than 100 feet below the cement top of the production or intermediate casing. The fracturing string must be tested to not less than the maximum anticipated surface pressure minus the annulus pressure applied between the fracturing string and the production or intermediate casing.

(3) The mechanical integrity test will be considered successful if the pressure applied holds for 30 minutes with no more than a 10 percent pressure loss.

(g) *Monitoring and recording during hydraulic fracturing.*

(1) During any hydraulic fracturing operation, the operator must continuously monitor and record the annulus pressure at the bradenhead. The pressure in the annulus between any intermediate casings and the production casing must also be continuously monitored and recorded. A continuous record of all annuli pressure during the fracturing operation must be submitted with the required Subsequent Report Sundry Notice (Form 3160–5) identified in paragraph (i) of this section.

(2) If during any hydraulic fracturing operation any annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation, the operator must stop the hydraulic fracturing operation, take immediate corrective action to control the situation, orally notify the authorized officer as soon as practicable, but no later than 24 hours following the incident, and determine the reasons for the pressure increase. Prior to recommencing hydraulic fracturing operations, the operator must perform any remedial action required by the authorized officer, and successfully perform a mechanical integrity test under paragraph (f) of this section. Within 30 days after the hydraulic fracturing operations are completed, the operator must submit a report containing all details pertaining to the incident, including corrective actions taken, as part of a Subsequent Report Sundry Notice (Form 3160–5).

(h) *Management of Recovered Fluids.* Except as provided in paragraphs (h)(1) and ((2) of this section, all fluids recovered between the commencement of hydraulic fracturing operations and the authorized officer's approval of a produced water disposal plan under BLM requirements must be stored in rigid enclosed, covered, or netted and screened above-ground tanks. The tanks may be vented, unless Federal law, or State regulations (on Federal lands) or tribal regulations (on Indian lands) require vapor recovery or closed-loop systems. The tanks must not exceed a 500 barrel (bbl) capacity unless approved in advance by the authorized officer.

(1) The authorized officer may approve an application to use lined pits only if the applicant demonstrates that use of a tank as described in this paragraph (h) is infeasible for environmental, public health or safety reasons and only if, at a minimum, all of the following conditions apply:

(i) The distance from the pit to intermittent or ephemeral streams or water sources would be at least 300 feet;

(ii) The distance from the pit to perennial streams, springs, fresh water sources, or wetlands would be at least 500 feet;

(iii) There is no usable groundwater within 50 feet of the surface in the area where the pit would be located;

(iv) The distance from the pit to any occupied residence, school, park, school bus stop, place of business, or other areas where the public could reasonably be expected to frequent would be greater than 300 feet;

(v) The pit would not be constructed in fill or unstable areas;

(vi) The construction of the pit would not adversely impact the hydrologic functions of a 100-year floodplain; and

(vii) Pit use and location complies with applicable local, State (on Federal lands), tribal (on Indian lands) and other Federal statutes and regulations including those that are more stringent than these regulations.

(2) Pits approved by the authorized officer must be:

(i) Lined with a durable, leak-proof synthetic material and equipped with a leak detection system; and

(ii) Routinely inspected and maintained, as required by the authorized officer, to ensure that there is no fluid leakage into the environment. The operator must document all inspections.

(i) *Information that must be provided to the authorized officer after hydraulic fracturing is completed.* The information required in paragraphs (i)(1) through (10) of this section must be submitted to the authorized officer within 30 days after the completion of the last stage of hydraulic fracturing operations for each well. The information is required for each well, even if the authorized officer approved fracturing of a group of wells (see § 3162.3–3(c)). The information required in paragraph (i)(1) of this section must be submitted to the authorized officer through FracFocus or another BLM-designated database, or in a Subsequent Report Sundry Notice (Form 3160–5). If information is submitted through FracFocus or another BLM-designated database, the operator must specify that the information is for a Federal or an Indian well, certify that the information is both timely filed and correct, and certify compliance with applicable law as required by paragraph (i)(8)(ii) or (iii) of this section using FracFocus or another BLM-designated database. The information required in paragraphs (i)(2) though (10) of this section must be submitted to the authorized officer in a Subsequent Report Sundry Notice (Form 3160–5). The operator is responsible for the information submitted by a contractor or agent, and the information will be considered to have been submitted directly from the operator to the BLM. The operator must submit the following information:

(1) The true vertical depth of the well, total water volume used, and a description of the base fluid and each additive in the hydraulic fracturing fluid, including the trade name, supplier, purpose, ingredients, Chemical Abstract Service Number (CAS), maximum ingredient concentration in additive (percent by mass), and maximum ingredient concentration in hydraulic fracturing fluid (percent by mass).

(2) The actual source(s) and location(s) of the water used in the hydraulic fracturing fluid;

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

(4) The actual, estimated, or calculated fracture length, height and direction.

(5) The actual measured depth of perforations or the open-hole interval.

(6) The total volume of fluid recovered between the completion of the last stage of hydraulic fracturing operations and when the operator starts to report water produced from the well to the Office of Natural Resources Revenue. If the operator has not begun to report produced water to the Office of Natural Resources Revenue when the Subsequent Report Sundry Notice is submitted, the operator must submit a supplemental Subsequent Report Sundry Notice (Form 3160–5) to the authorized officer documenting the total volume of recovered fluid.

(7) The following information concerning the handling of fluids recovered, covering the period between the commencement of hydraulic fracturing and the implementation of the approved plan for the disposal of produced water under BLM requirements:

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

(ii) The disposal method of the recovered fluids, including, but not limited to, the percent injected, the percent stored at an off-lease disposal facility, and the percent recycled.

(8) A certification signed by the operator that:

(i) The operator complied with the requirements in paragraphs (b), (e), (f), (g), and (h) of this section;

(ii) For Federal lands, the hydraulic fracturing fluid constituents, once they

arrived on the lease, complied with all applicable permitting and notice requirements as well as all applicable Federal, State, and local laws, rules, and regulations; and

(iii) For Indian lands, the hydraulic fracturing fluid constituents, once they arrived on the lease, complied with all applicable permitting and notice requirements as well as all applicable Federal and tribal laws, rules, and regulations.

(9) The operator must submit the result of the mechanical integrity test as required by paragraph (f) of this section.

(10) The authorized officer may require the operator to provide documentation substantiating any information submitted under paragraph (i) of this section.

(j) *Identifying information claimed to be exempt from public disclosure.*

(1) For the information required in paragraph (i) of this section, the operator and the owner of the information will be deemed to have waived any right to protect from public disclosure information submitted with a Subsequent Report Sundry Notice (Form 3160–5) or through FracFocus or another BLM-designated database. For information required in paragraph (i) of this section that the owner of the information claims to be exempt from public disclosure and is withheld from the BLM, a corporate officer, managing partner, or sole proprietor of the operator must sign and the operator must submit to the authorized officer with the Subsequent Report Sundry Notice (Form 3160–5) required in paragraph (i) of this section an affidavit that:

(i) Identifies the owner of the withheld information and provides the name, address and contact information for a corporate officer, managing partner, or sole proprietor of the owner of the information;

(ii) Identifies the Federal statute or regulation that would prohibit the BLM from publicly disclosing the information if it were in the BLM's possession;

(iii) Affirms that the operator has been provided the withheld information from the owner of the information and is maintaining records of the withheld information, or that the operator has access and will maintain access to the withheld information held by the owner of the information;

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

(v) Affirms that the information is not required to be publicly disclosed under any applicable local, State or Federal law (on Federal lands), or tribal or Federal law (on Indian lands);

(vi) Affirms that the owner of the information is in actual competition and identifies competitors or others that could use the withheld information to cause the owner of the information substantial competitive harm;

(vii) Affirms that the release of the information would likely cause substantial competitive harm to the owner of the information and provides the factual basis for that affirmation; and

(viii) Affirms that the information is not readily apparent through reverse engineering with publicly available information.

(2) If the operator relies upon information from third parties, such as the owner of the withheld information, to make the affirmations in paragraphs (j)(1)(vi) through (viii) of this section, the operator must provide a written affidavit from the third party that sets forth the relied-upon information.

(3) The BLM may require any operator to submit to the BLM any withheld information, and any information relevant to a claim that withheld information is exempt from public disclosure.

(4) If the BLM determines that the information submitted under paragraph (j)(3) of this section is not exempt from disclosure, the BLM will make the information available to the public after providing the operator and owner of the information with no fewer than 10 business days' notice of the BLM's determination.

(5) The operator must maintain records of the withheld information until the later of the BLM's approval of a final abandonment notice, or 6 years after completion of hydraulic fracturing operations on Indian lands, or 7 years after completion of hydraulic fracturing operations on Federal lands. Any subsequent operator will be responsible for maintaining access to records required by this paragraph during its operation of the well. The operator will be deemed to be maintaining the records if it can promptly provide the complete and accurate information to BLM, even if the information is in the custody of its owner.

(6) If any of the chemical identity information required in paragraph (i)(1) of this section is withheld, the operator must provide the generic chemical name in the submission required by paragraph (i)(1) of this section. The generic chemical name must be only as nonspecific as is necessary to protect the confidential chemical identity, and should be the same as or no less descriptive than the generic chemical name provided to the Environmental Protection Agency.

(k) *Requesting a variance from the requirements of this section.*

(1) Individual variance: The operator may make a written request to the authorized officer for a variance from the requirements under this section. A request for an individual variance must specifically identify the regulatory provision of this section for which the variance is being requested, explain the reason the variance is needed, and demonstrate how the operator will satisfy the objectives of the regulation for which the variance is being requested.

(2) State or tribal variance: In cooperation with a State (for Federal lands) or a tribe (for Indian lands), the appropriate BLM State Director may issue a variance that would apply to all wells within a State or within Indian lands, or to specific fields or basins within the State or the Indian lands, if the BLM finds that the variance meets the criteria in paragraph (k)(3) of this section. A State or tribal variance request or decision must specifically identify the regulatory provision(s) of this section for which the variance is being requested, explain the reason the variance is needed, and demonstrate how the operator will satisfy the objectives of the regulation for which the variance is being requested. A State or tribal variance may be initiated by the State, tribe, or the BLM.

(3) The authorized officer (for an individual variance), or the State Director (for a State or tribal variance), after considering all relevant factors, may approve the variance, or approve it with one or more conditions of approval, only if the BLM determines that the proposed alternative meets or exceeds the objectives of the regulation for which the variance is being requested. The decision whether to grant or deny the variance request must be in writing and is entirely within the BLM's discretion. The decision on a variance request is not subject to administrative appeals either to the State Director (for an individual variance) or under 43 CFR part 4.

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

(5) Due to changes in Federal law, technology, regulation, BLM policy, field operations, noncompliance, or other reasons, the BLM reserves the right to rescind a variance or modify any conditions of approval. The authorized officer must provide a written justification before a variance is rescinded or a condition of approval is modified.

■ 6. Amend § 3162.5–2 by revising the first sentence of paragraph (d) to read as follows:

§ 3162.5–2 Control of wells.

* * * * *

(d) *Protection of usable water and other minerals.* The operator must isolate all usable water and other mineral-bearing formations and protect them from contamination. * * *

Janice M. Schneider,

Assistant Secretary, Land and Minerals Management.

[FR Doc. 2015–06658 Filed 3–20–15; 4:15 pm]

BILLING CODE 4310–84–P