American Rivers - Center for Biological Diversity
Center for Health, Environment & Justice - Clean Air Task Force
Clean Water Action – Earthjustice – Earthworks - Environment America
Environmental Defense Fund - Natural Resources Defense Council
Nature Abounds – OMB Watch - Sierra Club – The Wilderness Society

March 7, 2012

The Honorable Bob Abbey
Director
Bureau of Land Management
1840 C Street, N.W., Room 5650
Washington, D.C. 20240

The Honorable Jeffrey Zients
Acting Director
The Office of Management and Budget
725 17th Street, N.W.
Washington, D.C. 20503

Re: Upcoming Revisions to BLM Regulation of Oil and Gas Extraction on Public Lands

Dear Director Abbey and Acting Director Zients:

We were pleased to learn that the Bureau of Land Management (BLM) is planning to propose new rules for oil and gas wells that are governed by federal leases. It is our hope that the BLM proposal will break new ground toward requiring oil and gas producers to use the best available practices to protect America's clean air, clean water, wildlands, and human health. As the largest manager of oil and gas resources in the United States, the BLM can—and should—be a model for all oil and gas operations.

New rules are essential at this point in time. People across the country are seriously concerned about threats to the environment and public health and local community disruption presented by oil and gas development activities, including hydraulic fracturing and other well stimulation techniques, but also risks associated with site development, well integrity, water and waste management, and air emissions—especially air toxics, ozone-forming pollutants and methane, a highly potent greenhouse gas. Many communities are adjacent to federal minerals leased by the BLM, which may be beneath public lands, national forests, national wildlife refuges, or private property. As you know, the BLM is responsible for 700 million acres of onshore subsurface mineral estate in 40 states throughout the nation, from California to Virginia, North Dakota to Texas. This acreage is roughly the size of Argentina. Millions of people live, work, and go to school near or even above these resources and expect the federal government to protect their health and safety, as well as their public lands, from the impacts of this industrial process.

Of course, some areas should be completely off limits to oil and gas development – including the most sensitive lands, such as proposed wilderness areas, and areas that support critical water sources. Likewise, safe setbacks are needed from homes, schools, and sensitive environmental features.

Where drilling does occur, the BLM should have rigorous, fully protective standards in place. The technology used in oil and gas production has evolved rapidly but, unfortunately, regulation has not kept pace. The BLM's rules are insufficient to protect public health and the environment. Interior Secretary Ken Salazar has recognized this, stating, "BLM's current regulations specific to hydraulic fracturing—or stimulation operations—are in many ways outdated; they were written in 1982; and they reflect neither the significant technological advances in hydraulic fracturing nor the tremendous growth in its use that has occurred in the last 30 years."[1] Improved regulation can reduce the risks presented by oil and gas development to clean air, clean water, wildlife habitat, and communities. Some in industry have moved to increasingly use such practices as green completions, wastewater recycling, closed-loop waste management systems, and the like, and have found that many of these approaches are economical to adopt. However, rigorous standards to improve environmental performance need to be set down in law to guarantee all operators are employing best practices wherever oil and gas development activities occur.

The BLM has an opportunity to lead the country toward a future where the oil and gas production industry develops these resources more responsibly—in ways that reduce threats to public health and the environment and that respect the quality of life in local communities. Our organizations and our members eagerly await the formal proposal of the BLM's new rules and hope they will reveal a new path toward safer and cleaner oil and gas operations.

As the Shale Gas Subcommittee of the Secretary of Energy Advisory Board stated in its final report, if action is not taken to reduce the environmental impact accompanying the very considerable expansion of shale gas production expected across the country, there is a real risk of serious environmental consequences. Yet the Subcommittee found that, although most of its recommendations are ready for implementation, there has been less progress than it had hoped.[2] Given all the recent information about the risks of oil and gas development, the public expects urgent and meaningful action from your agency.

Based on an unofficial draft that has been widely circulated, it appears the BLM will focus on three primary topics: disclosure of chemicals used in well stimulation techniques such as hydraulic fracturing, management of flowback fluid, and mechanical integrity. These are the right topics for the agency to be addressing at this time, and we urge you to consider the specific recommendations endorsed by many of our organizations, as outlined below. We also support adoption of strong standards to substantially reduce emissions of methane from oil and gas operations. Additionally, many more topics need to be urgently addressed to effectively manage

---

[1] Statement of Ken Salazar, Secretary of the Interior, Before the Committee on Natural Resources, United States House of Representatives: The Future of U.S. Oil and Natural Gas Development on Federal Lands and Waters. November 16, 2011.

[2] Secretary of Energy Advisory Board, Shale Gas Production Subcommittee, Second Ninety Day Report, November 18, 2011, page 10.

the full suite of risks posed by oil and gas development activities. As the stewards of America's public lands and natural resources, we urge BLM to ensure these new rules properly manage the environmental and public health risks associated with oil and gas extraction. Thank you for your consideration of these comments.

Sincerely yours,

William Robert Irvin, President
American Rivers

Kieran Suckling, Executive Director
Center for Biological Diversity

Lois M. Gibbs, Executive Director
Center for Health, Environment & Justice

Armond Cohen, Executive Director
Clean Air Task Force

Bob Wendelgass, President
Clean Water Action

Trip Van Noppen, President
Earthjustice

Jennifer Krill, Executive Director
Earthworks

Margie Alt, Executive Director
Environment America

Fred Krupp, President
Environmental Defense Fund

Frances Beinecke, President
Natural Resources Defense Council

Melinda Hughes-Wert, President
Nature Abounds

Katherine McFate, President and CEO
OMB Watch

Michael Brune, Executive Director
Sierra Club

William H. Meadows, President
The Wilderness Society

<u>Regional Organizations</u>

Erik Molvar, Executive Director
Biodiversity Conservation Alliance

Maya K. van Rossum,
Delaware Riverkeeper
Delaware Riverkeeper Network

Ernie Reed, Council Chair
Heartwood

Bob Cross, President
Ozark Society

Brent Walls, Upper Potomac Manager
Potomac Riverkeeper Inc.

Josh Pollock, Executive Director
Rocky Mountain Wild

Dan Randolph, Executive Director
San Juan Citizens Alliance

Patrick Sweeney, Regional Director
Western Organization of Resource Councils

Greg Costello, Executive Director
Western Environmental Law Center

John Horning, Executive Director
WildEarth Guardians

Arkansas
Bill Kopsky, Executive Director
Arkansas Public Policy Panel
Arkansas Citizens First Congress

Gladys Tiffany, President
OMNI Center for Peace, Justice & Ecology

Vernon Bates, Chairman
Ouachita Watch League

Shawn Porter, Director
Ozark Water Protection Alliance

Terry Tremwel, Chair of the Board
Trem|Wel Energy, LLC

Shannon Hensley, Chairperson
URGE Coalition of Arkansas

California
Jeanette Vosburg, President
Ballona Network

Michael J. Painter, Coordinator
Californians for Western Wilderness

David Landecker, Executive Director
Environmental Defense Center

Patricia McPherson, President
Grassroots Coalition

Jeff Kuyper, Executive Director
Los Padres ForestWatch

Colorado
Elise Jones, Executive Director
Colorado Environmental Coalition

Bruce Gordon, President
EcoFlight

Jeanne Bassett, Program Director
Environment Colorado

Gretchen Nicholoff, President
Western Colorado Congress

Sloan Shoemaker, Executive Director
Wilderness Workshop

Montana
Walter Archer, Board Chair
Northern Plains Resource Council

New Jersey
Doug O'Malley, Field Director
Environment New Jersey

New Mexico
Sanders Moore, State Director
Environment New Mexico

Oscar Simpson, Chair
New Mexico Sportsmen

Laddie Mills, Coordinator
San Juan Quality Waters Coalition

New York
David Van Luven, Director
Environment New York

Paul Gallay, President
Hudson Riverkeeper

North Dakota
Don Morrison, Executive Director
Dakota Resource Council

Ohio
Cheryl Johncox, Executive Director
Buckeye Forest Council

Julian Boggs, Advocate
Environment Ohio

Pennsylvania
Myron Arnowitt, Director
Clean Water Action

Erika Staaf, Clean Water Advocate
PennEnvironment

Texas
Luke Metzger, Director
Environment Texas

Utah
Scott Groene, Executive Director
Southern Utah Wilderness Alliance

Virginia
Kate Wofford, Director
Shenandoah Valley Network

David Hannah, Conservation Director
Wild Virginia

West Virginia
Judith Rodd, Director
Friends of Blackwater

Wyoming
Christina Denney, Chair
Clark Resource Council

John Fenton, Chair
Pavillion Area Concerned Citizens

Wilma Tope, Chair
Powder River Basin Resource Council

Linda Baker, Executive Director
Upper Green River Alliance

Laurie Milford, Executive Director
Wyoming Outdoor Council

CHEMICAL DISCLOSURE

CURRENT REGULATIONS

Disclosure of chemicals used in oil and gas extraction on federal lands is not required under current BLM rules. Onshore Oil and Gas Order #1 requires:

IV(e) Completion Reports. Within 30 days after the well completion, the lessee or operator must submit to the BLM two copies of a completed Form 3160–4, Well Completion or Recompletion Report and Log. Well logs may be submitted to the BLM in an electronic format such as ‘‘.LAS’’ format. Surface and bottom-hole locations must be in latitude and longitude.

Form 3160-4 does not, however, require the disclosure of hydraulic fracturing chemicals.[3]

RECOMMENDED REGULATIONS

BLM SHOULD REQUIRE PRE- AND POST-FRACTURE DISCLOSURE OF ALL HYDRAULIC FRACTURING CHEMICALS

The following should be made publicly available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation to afford local residents the time and information needed to conduct baseline testing of their air and water. This information should be submitted either with the application for a permit to drill, if available at the time, or as a sundry notice. The reporting database must allow users to search and sort data by chemical name, CAS number, operator, date, and geographic area.

1. Baseline water quality analyses for all protected water within the area of review[4]
2. Operator name
3. Proposed date of the hydraulic fracturing treatment
4. County in which the well is located
5. API number for the well
6. Well name and number
7. Latitude and longitude of the wellhead
8. Depth of all proposed perforations, reported as both true vertical depth and measured depth

---

[3] See, e.g. http://www.blm.gov/pgdata/etc/medialib/blm/ak/aktest/energy/og_forms.Par.62294.File.dat/3160-4_WellCmpltnRpt.pdf

[4] The area of review should be the region around a well or group of wells that will be hydraulically fractured where protected water may be endangered. It should be delineated based on 3D geologic and reservoir modeling that accounts for the physical and chemical extent of hydraulically induced fractures, injected hydraulic fracturing fluids and proppant, and displaced formation fluids and must be based on the life of the project. The physical extent would be defined by the modeled length and height of the fractures, horizontal and vertical penetration of hydraulic fracturing fluids and proppant, and horizontal and vertical extent of the displaced formation fluids. The chemical extent would be defined by that volume of rock in which chemical reactions between the formation, hydrocarbons, formation fluids, or injected fluids may occur, and should take into account potential migration of fluids over time.

9. Geologic name, geologic description, and top and bottom depth of the formation that will be hydraulically fractured
10. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
11. Each proposed hydraulic fracturing additive[5] and the trade name, vendor, and a brief description of the intended use or function
12. Each proposed chemical that will be added to the base fluid, reported by the name and/or chemical compound and Chemical Abstracts Service (CAS) number
13. Proposed quantity of each chemical, reported as volume or weight percentage of the total fluid, as appropriate

The following must be made publicly available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation to ensure that local residents have the information they need should this information differ from the original plan. This database must allow users to search and sort data by chemical name, CAS number, operator, date, and geographic area.

1. Operator name
2. Actual date of the hydraulic fracturing treatment
3. County in which the well is located
4. API number for the well
5. Well name and number
6. Latitude and longitude of the wellhead
7. Depth of all perforations, reported as both true vertical depth and measured depth
8. Geologic name, geologic description, and top and bottom depth of the formation that was hydraulically fractured
9. Actual source, volume, geochemistry, and timing of withdrawal of all base fluids
10. Actual hydraulic fracturing additives used and the trade name, vendor, and a brief description of the intended use or function
11. Each chemical added to the base fluid, reported by the name and/or chemical compound and Chemical Abstracts Service (CAS) number
12. Actual quantity of each chemical used, reported as volume or weight percentage of the total fluid, as appropriate
13. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes. The purpose of this is to aid operators and regulators in determining whether recycling is feasible and, if not, the most appropriate disposal method.

BLM should retain the right to request from the owner/operator or service company the chemical formula of each hydraulic fracturing additive in case of, for example, a health emergency or an investigation of suspected water contamination.

The bar for claiming and awarding trade secret protection of any chemicals must be set very high. We recommend an approach similar to that of the Emergency Planning and Community Right to Know Act (EPCRA). The core elements of such an approach include:

[5] A "hydraulic fracturing additive" is a chemical or chemical compound that is added to the base fluid and typically referred to by a generic name (e.g. biocide, viscosifier, friction reducer, etc) or trade name.

- The entity claiming trade secret protection must submit the information on a confidential basis to the agency.
- If the entity is claiming trade secret protection for a chemical identity, it must report the chemical family name associated with the chemical on the public disclosure website.
- When asserting a trade secret claim, the entity must submit substantiating facts in the form of the information required under 40 CFR 350.7(a), and shall include a certification by an owner, operator or a senior corporate official that is substantially identical to the certification language provide in part 4 of the form at 40 CFR 350.27.
- Any person may challenge a trade secret claim by filing a petition with the agency. The agency shall uphold the claim of entitlement to trade secret protection only if it determines the claim satisfies sufficiency requirements in the form of those required under 40 CFR 350.13.
- A trade secret claimant or a person challenging a trade secret may appeal an agency determination on the sufficiency or insufficiency of a trade secret claim by seeking review in U.S. District Court.

BLM can create provisions under its own authority that mirror those references from EPCRA, above.

Disclosure of chemicals used in the hydraulic fracturing process is only one of several areas of regulation pertaining to hydraulic fracturing that BLM should update. Others include requirements for the planning, design, operation, monitoring, and reporting of hydraulic fracturing operations.[6]

BANNING DIESEL IN WELL STIMULATION

CURRENT REGULATIONS

There are no current federal rules regarding which chemicals may be used for hydraulic fracturing. There are federal regulations applicable to hydraulic fracturing, however, when diesel is used. Fracturing where diesel is used is "underground injection" for purposes of the SDWA. 42 U.S.C. § 300h(d)(1)(B)(ii). A permit for diesel use may only be issued where the applicant demonstrates that "the underground injection will not endanger drinking water sources." 42 U.S.C. § 300h(b)(1)(B).[7]

RECOMMENDED REGULATIONS

BLM SHOULD BAN DIESEL AND RELATED PRODUCTS

BLM should ban the use of diesel fuel and related products in well stimulation. Diesel can contain carcinogenic compounds such as benzene, toluene, ethylbenzene, and xylene ("BTEX"). The Department of Energy Secretary of Energy Advisory Board Shale Gas Subcommittee found that, in light of these risks and the available alternatives, "there is no technical or economic reason to use diesel as a stimulating fluid."[8]

---

[6] See, e.g. NRDC Comments to U.S. EPA on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels http://docs.nrdc.org/energy/files/ene_11120901a.pdf

[7] Id

[8] Natural Gas Subcommittee, First 90-day interim report, (August 18, 2011), http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf

BLM should similarly examine other common or particularly hazardous chemicals and determine whether they should be categorically prohibited. While there is currently not an available methodology for assessing the toxicity of each chemical proposed to be introduced into a well and for determining less hazardous alternatives that are equally effective, BLM should coordinate with relevant federal agencies and research institutions (e.g. EPA, NIOSH, OSHA, CDC, NIH, etc.) to develop protocols for performing such analyses.

FLOWBACK MANAGEMENT

CURRENT REGULATIONS

Flowback is the term used to describe hydraulic fracturing fluids that return to the surface after a hydraulic fracturing operation is complete. Produced water is water that is trapped underground in geologic formations and comes to the surface when oil and gas are produced. While flowback is not explicitly regulated under current BLM rules, in practice flowback is likely currently managed under the rules pertaining to produced water.

The full suite of regulations pertaining to management of produced water is listed in Onshore Oil and Gas Order #7 (OOGO#7) with other pertinent regulations at 43 CFR 3162 and in Onshore Oil and Gas Order #1 (OOGO#1). Relevant provisions to the recommendations made in the following section include:

43 CFR 3162.5-1(b) The operator shall exercise due care and diligence to assure that leasehold operations do not result in undue damage to surface or subsurface resources or surface improvements. All produced water must be disposed of by injection into the subsurface, by approved pits, or by other methods which have been approved by the authorized officer. Upon the conclusion of operations, the operator shall reclaim the disturbed surface in a manner approved or reasonably prescribed by the authorized officer.

OOGO#7-III(A) All produced water from Federal/Indian leases must be disposed of by (1) injection into the substance [sic]; (2) into pits; or (3) other acceptable methods approved by the authorized officer, including surface discharge under NPDES permit. Injection is generally the preferred method of disposal.

OOGO#7-III(A) Unless prohibited by the authorized officer, produced water from newly completed wells may be temporarily disposed of into pits for a period of up to 90 days, if the use of the pit was approved as a part of an application for permit to drill. Any extension of time beyond this period requires documented approval by the authorized officer.

OOGO#7-III(D)(1)(b) The daily quantity of water to be disposed of (maximum daily quantity shall be disposed of (maximum daily quality shall be cited if major fluctuations are anticipated) [sic] and a water analysis (unless waived by the authorized officer as unnecessary) that includes the concentrations of chlorides, sulfates, pH, Total Dissolved Solids (TDS), and toxic constituents that the authorized officer reasonably believes to be present.

OOGO#1-III(D)(4) The Surface Use Plan of Operations must: Describe the access road(s) and drill pad, the construction methods that the operator plans to use, and the proposed means for containment and disposal of all waste materials;

OOGO#1-III(D)(4)(e) Location and Types of Water Supply: Information concerning water supply, such as rivers, creeks, springs, lakes, ponds, and wells, may be shown by quarter-quarter section on a map or plat, or may be described in writing. The operator must identify the source, access route, and transportation method for all water anticipated for use in drilling the proposed well. The operator must describe any newly constructed or reconstructed access roads crossing Federal or Indian lands that are needed to haul the water as provided in item b. of this section. The operator must indicate if it plans to drill a water supply well on the lease and, if so, the operator must describe the location, construction details, and expected production requirements, including a description of how water will be transported and procedures for well abandonment.

OOGO#1-III(D)(4)(g) Methods for Handling Waste: The Surface Use Plan of Operations must contain a written description of the methods and locations proposed for safe containment and disposal of each type of waste material (e.g., cuttings, garbage, salts, chemicals, sewage, etc.) that results 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. The operator must describe plans for the construction and lining, if necessary, of the reserve pit.

RECOMMENDED REGULATIONS

BLM should update its produced water regulations to explicitly include flowback fluid. In addition, BLM regulations for the handling of these fluids are outdated and therefore the following improvements should be made to reduce the risk of adverse environmental impacts associated with waste fluids.

USE OF PITS TO STORE OR DISPOSE OF FLOWBACK FLUID SHOULD BE PROHIBITED

Flowback fluid can contain hydraulic fracturing chemicals, salts, heavy metals, volatile organic compounds, hydrocarbons, and naturally occurring radioactive material (NORM)[9]. The use of pits and/or centralized surface impoundments to capture or dispose of flowback water can result in greater surface disturbance and higher risk of leaks and spills, which can result in groundwater or surface water contamination. Pits can also be a significant source of hazardous and toxic air pollution.[10]

The use of pits and/or centralized surface impoundments to capture or dispose of flowback water from Federal/Indian leases should be prohibited. Closed-loop systems should be used to collect flowback for treatment and reuse or transportation to a disposal facility. Sufficient tanks must be utilized to capture the entire anticipated flowback volume and be located within secondary containment.

A geochemical analysis should be performed on all flowback, including for all contaminants for which EPA has set primary and secondary drinking water standards, hydrocarbons, standard inorganic ions, NORM, and hydraulic fracturing chemicals. The results of such analysis should be used as a guide to determine the most appropriate disposal method.

---

[9] See, e.g.,
Otton, J.K,, 2006, Environmental aspects of produced-water salt releases in onshore and estuarine petroleum-producing areas of the United States- a bibliography: U.S. Geological Survey Open-File report 2006-1154, 223p.
U.S. Geological Survey, 1999, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment—An Issue for the Energy Industry, USGS Fact Sheet FS–142–99, 4p.
Alley, B., Beebe, A., Rodgers, J., and Castle, J.W., 2011, Chemical and physical characterization of produced waters from conventional and unconventional fossil fuel resources: Chemosphere, v.85, no.1, pp: 74-82.

[10] National Risk Management Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, 2009, Measurement of Emissions from Produced Water Ponds: Upstream Oil and Gas Study #1, 195p.

OPERATORS SHOULD DEVELOP AND IMPLEMENT WATER USE AND WASTE WATER MANAGEMENT PLANS

Proper pre-drill planning can aid in successful water use and waste water management. The requirement in Onshore Oil and Gas Order #1 that operators must, "…identify the source, access route, and transportation method for all water anticipated for use in drilling the proposed well," should be expanded to include water used for hydraulic fracturing in the proposed well.

Operators should submit to BLM a plan for cumulative water use over the life of the project. The plan should take into account other activities that will draw water from the same sources, such as agricultural or industrial activities; designated best use; seasonal and longer timescale variations in water availability; and historical drought information. Elements of the plan should include but are not limited to:

1. The anticipated source, timing, and volume of withdrawals and intended use;
2. Anticipated transport distances and methods (e.g. pipeline, truck) and methods to minimize related impacts including but not limited to land disturbance, traffic, vehicle accidents, and air pollution.
3. Anticipated on-site storage methods;
4. A description of methods the operator will use to maximize the use of non-potable water sources including reuse and recycling of wastewater;
5. An evaluation of potential adverse impacts to aquatic species and habitat, surface water, groundwater, and wetlands, including the potential for the introduction of invasive species, and methods to minimize those impacts;
6. Anticipated chemical additives and chemical composition of produced water, with particular attention to those chemicals that would hinder the reuse or recycling of wastewater or pose a challenge to wastewater treatment.

As part of the Surface Use Plan of Operations requirement to describe, "…the proposed means for containment and disposal of all waste materials," and the required Methods for Handling Waste, operators should submit to the BLM a proposed plan specifically for handling wastewater, such as flowback and produced fluids. Elements of the plan should include but are not limited to:

1. Anticipated cumulative volumes of wastewater over the life of the project, including what volume will be reused/recycled vs. disposed;
2. Anticipated on-site temporary storage methods;
3. Anticipated transport distances and methods (e.g. pipeline, truck) and methods to minimize related impacts including but not limited to land disturbance, traffic, vehicle accidents, and air pollution;
4. An assessment of currently available and anticipated disposal methods, e.g. disposal wells, wastewater treatment facilities, etc. This assessment must enumerate the disposal options available and evaluate the ability of those options to handle projected wastewater volumes. In the case of wastewater treatment facilities, the assessment must also evaluate the ability of those facilities to successfully treat the wastewater such that it would not pose a threat to water supplies into which it is discharged.

MECHANICAL INTEGRITY

CURRENT REGULATIONS

43 CFR 3162.4-2(b) After the well has been completed, the operator shall conduct periodic well tests which will demonstrate the quantity and quality of oil and gas and water. The method and frequency of such well tests will be specified in appropriate notices and orders. When needed, the operator shall conduct reasonable tests which will demonstrate the mechanical integrity of the downhole equipment.

RECOMMENDED REGULATIONS

BLM SHOULD REQUIRE MECHANICAL INTEGRITY MONITORING AND CORRECTION PLANS

Achieving and maintaining mechanical integrity are crucial to the protection of drinking water. Loss of mechanical integrity is a known or suspected cause of water contamination in oil and gas fields around the country, including in Bainbridge Township, Ohio[11], and Mamm Creek Field, Garfield County, Colorado.[12] As shown above, current BLM regulations are minimal and allow operators and regulators broad discretion on when and where mechanical integrity should be verified. BLM should update its regulations to provide clear, enforceable standards for mechanical integrity testing and verification.

Operators should be required to maintain mechanical integrity of wells at all times. Mechanical integrity should be periodically tested by means of a pressure test with liquid or gas, a tracer survey such as oxygen activation logging or radioactive tracers, a temperature or noise log, and a casing inspection log. The frequency of such testing should be based on site and operation specific requirements and be delineated in a testing and monitoring plan prepared, submitted, and implemented by the operator.

Mechanical integrity and annular pressure should be monitored over the life of the well. Instances of sustained casing pressure can indicate potential mechanical integrity issues. The annulus between the production casing and tubing (if used) should be continually monitored. Continuous monitoring allows problems to be identified quickly so repairs may be made in a timely manner, reducing the risk that a wellbore problem will result in contamination of USDWs.

Operators should also develop, submit, and implement a corrosion and erosion monitoring and correction plan. Well components such as casing, tubing, and cement can degrade over time due to contact with formation fluids, hydrocarbons, acid gas, treatment chemicals, and fine particles. Well stimulation (e.g. hydraulic fracturing), workovers, maintenance, seismic activity, and age can also contribute to degradation of well components. Such degradation can potentially lead to loss of mechanical integrity and therefore a monitoring and correction plan should be required.

---

[11] Ohio Department of Natural Resources, Division of Mineral Resources Management, “Report on the Investigation of the Natural Gas Invasion of Aquifers in Bainbridge Township of Geauga County, Ohio” September 1, 2008

[12] McMahon, P.B., Thomas, J.C., and Hunt, A.G., 2011, Use of diverse geochemical data sets to determine sources and sinks of nitrate and methane in groundwater, Garfield County, Colorado, 2009: U.S. Geological Survey Scientific Investigations Report 2010–5215, 40 p.

BLM SHOULD REVISE AND UPDATE WELL CONSTRUCTION REQUIREMENTS TO REFLECT TECHNOLOGICAL ADVANCEMENTS

Proper well design and construction are crucial first step to ensuring long-term mechanical integrity. Operators must demonstrate that wells will be designed and constructed to ensure both internal and external mechanical integrity. Internal mechanical integrity refers to the absence of leakage pathways through the casing; external mechanical integrity refers to the absence of leakage pathways outside the casing, primarily through the cement.

Casing must be designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; corrosion; erosion; and hydraulic fracturing pressure. The casing design must include safety measures that ensure well control during drilling and completion and safe operations during the life of the well.

The components of a well that ensure the protection and isolation of USDWs are steel casing and cement. Multiple strings of casing are used in the construction of oil and gas wells, including: conductor casing, surface casing, production casing, and potentially intermediate casing. For all casing strings, the design and construction should be based on Good Engineering Practices (GEP), Best Available Technology (BAT), and local and regional engineering and geologic data. All well construction materials must be compatible with fluids with which they may come into contact and be resistant to corrosion, erosion, swelling, or degradation that may result from such contact.

CONDUCTOR CASING:

Current BLM regulations:

None.

Recommended Regulations:

Depending on local conditions, conductor casing can either be driven into the ground or a hole drilled and the casing lowered into the hole. In the case where a hole is excavated, conductor casing should be fully cemented to surface. A cement pad should also be constructed around the conductor casing to prevent the downward migration of fluids and contaminants.

SURFACE CASING:

Current BLM regulations:

OOGO#2 – III(B)(1)(c) The surface casing shall be cemented back to surface either during the primary cement job or by remedial cementing.

OOGO#2 – III(B)(1)(e) All indications of usable water shall be reported to the authorized officer prior to running the next string of casing or before plugging orders are requested, whichever occurs first.

OOGO#2 – III(B)(1)(f) Surface casing shall have centralizers on the bottom 3 joints of the casing (a minimum of 1 centralizer per joint, starting with the shoe joint).

Recommended Regulations:

Surface casing is used to: isolate and protect groundwater from drilling fluids, hydrocarbons, formation fluids, and other contaminants; provide a stable foundation for blowout prevention equipment; and provide a conduit for drilling fluids to drill the next section of the well.

Surface casing setting depth must be based on relevant engineering and geologic factors, but generally should be:

- Shallower than any pressurized hydrocarbon-bearing zones
- 100 feet below the deepest USDW

Surface casing must be fully cemented to surface by the pump and plug method. If cement returns are not observed at the surface, remedial cementing must be performed to cement the casing from the top of cement to the ground surface. If shallow hydrocarbon-bearing zones are encountered when drilling the surface casing portion of the hole, operators must notify regulators and take appropriate steps to ensure protection of USDWs.

INTERMEDIATE CASING:

Current BLM regulations:

None.

Recommended Regulations:

Depending on local geologic and engineering factors, one or more strings of intermediate casing may be required. This will depend on factors including but not limited to the depth of the well, the presence of hydrocarbon-or fluid-bearing formations, abnormally pressured zones, lost circulation zones, or other drilling hazards. When used, intermediate casing should be fully cemented from the shoe to the surface by the pump and plug method. Where this is not possible or practical, the cement must extend from the casing shoe to 600 feet above the top of the shallowest zone to be isolated (e.g. productive zone, abnormally pressured zone, etc). Where the distance between the casing shoe and shallowest zone to be isolated makes this technically infeasible, multi-stage cementing must be used to isolate any hydrocarbon- or fluid-bearing formations or abnormally pressured zones and prevent the movement of fluids.

PRODUCTION CASING:

Current BLM regulations:

None.

Recommended Regulations:

To be most protective, one long-string production casing (i.e. casing that extends from the total depth of the well to the surface) should be used. This is preferable to the use of a production liner – in which the casing does not extend to surface but is instead “hung” off an intermediate string of casing – as it provides an additional barrier to protect groundwater. The cementing requirements are the same as for intermediate casing.

PRODUCTION LINER:

Current BLM regulations:

OOGO#2-III(B)(1)(b) For liners, a minimum of 100 feet of overlap between a string of casing and the next larger casing is required.

Recommended Regulations:

If production liner is used instead of long-string casing, the top of the liner must be hung at least 200 feet above previous casing shoe. The cementing requirements for production liners should be the same as for intermediate and production casing.

GENERAL:

Current BLM regulations:

43 CFR 3162.5-2(d) Protection of fresh water and other minerals. The operator shall isolate freshwater-bearing and other usable water containing 5,000 ppm or less of dissolved solids and other mineral-bearing formations and protect them from contamination. Tests and surveys of the effectiveness of such measures shall be conducted by the operator using procedures and practices approved or prescribed by the authorized officer.

OOGO#2-III(B) Casing collars shall have a minimum clearance of 0.422 inches on all sides in the hole/casing annulus, with recognition that variances can be granted for justified exceptions.

OOGO#2-III(B) All waiting on cement times shall be adequate to achieve a minimum of 500 psi compressive strength at the casing shoe prior to drilling out.

OOGO#2-III(B)(1)(a) All casing, except the conductor casing, shall be new or reconditioned and tested casing. All casing shall meet or exceed API standards for new casing. The use of reconditioned and tested used casing shall be subject to approval by the authorized officer: approval will be contingent upon the wall thickness of any such casing being verified to be at least 87 1/2 percent of the nominal wall thickness of new casing.

OOGO#2-III(B)(1)(d) All of the above described tests shall be recorded in the drilling log.

OOGO#2 – III(B)(1)(f) Surface casing shall have centralizers on the bottom 3 joints of the casing (a minimum of 1 centralizer per joint, starting with the shoe joint).

OOGO#2 – III(B)(1)(g) Top plugs shall be used to reduce contamination of cement by displacement fluid. A bottom plug or other acceptable technique, such as a preflush fluid, inner string cement method, etc., shall be utilized to help isolate the cement from contamination by the mud fluid being displaced ahead of the cement slurry.

OOGO#2 – III(B)(1)(h) All casing strings below the conductor shall be pressure tested to 0.22 psi per foot of casing string length or 1500 psi, whichever is greater, but not to exceed 70 percent of the minimum internal yield. If pressure declines more than 10 percent in 30 minutes, corrective action shall be taken.

OOGO#2-III(B)(1)(i) On all exploratory wells, and on that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. Formation at the shoe shall be tested to a minimum of the mud weight equivalent anticipated to control the formation pressure to the next casing depth or at total depth of the well. This test shall be performed before drilling more than 20 feet of new hole.

Recommended Regulations:

For surface, intermediate, and production casing, a sufficient number of casing centralizers must be used to ensure that the casing is centered in the hole and in accordance with API Spec 10D (Specification for Bow-Spring Casing Centralizers) and API RP 10D-2 (Recommended Practice for Centralizer Placement and Stop Collar Testing). At a minimum, casing should be centralized at the top, shoe, above and below a stage collar or diverting tool (if used) and through all protected water zones. This is necessary to ensure that the cement is distributed evenly around the casing and is particularly important for directional and horizontal wells. In deviated wells, the casing will rest on the low side of the wellbore if not properly centralized, resulting in gaps in the cement sheath where the casing makes direct contact with the rock. Casing collars should have a minimum clearance of 1.25 inches on all sides to ensure a uniformly concentric cement sheath.

For any section of the well drilled through fresh water-bearing formations, drilling fluids must be limited to air, fresh water, or fresh water based mud and exclude the use of synthetic or oil-based mud or other chemicals. This typically applies to the surface casing and possibly conductor casing portions of the hole.

Current BLM requirements for casing pressure testing, at OOGO#2 – III(B)(1)(h) are best practice.

Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive.

Current BLM requirements for waiting on cement time at OOGO#2-III(B) are best practice. In addition, the cement mixture must have a 72-hour compressive strength of at least 1200 psi and the API free water separation must average no more than six milliliters per 250 milliliters of cement, tested in accordance with API RP 10B-2.

For cement mixtures without published compressive strength tests, the operator or service company must perform such tests in accordance with the current API RP 10B and provide the results of these tests to regulators prior to the cementing operation. The test temperature must be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of cement. A better quality of cement may be required where local conditions make it necessary to prevent pollution or provide safer operating conditions.

Prior to cementing, the hole must be prepared to ensure an adequate cement bond by circulating at least two hole volumes of drilling fluid and ensuring that the well is static and all gas flows are killed. Current BLM requirements for the use of plugs and/or spacer fluids at OOGO#2 – III(B)(1)(g) is best practice.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, casing shoe tests should be performed immediately after drilling out of the surface or intermediate casing. This should be required for all wells, not only those listed at OOGO#2-III(B)(1)(i). These tests may include Formation Integrity Tests (FIT), Leak-Off Tests (LOT or XLOT), and pressure fall-off or pump tests. Casing shoe tests are used to ensure casing and cement integrity, determine whether the formations below the casing shoe can withstand the pressure to which they will be subjected while drilling the next section of the well, and gather data on rock mechanical properties. If any of the casing shoe tests fail, remedial action must be taken to ensure that no migration pathways exist. Alternatively, the casing and cementing plan may need to be revised to include additional casing strings in order to properly manage pressure.

Cement integrity and location must be verified using cement evaluation tools that can detect channeling in 360 degrees. Verifying the integrity of the cement job is crucial to ensure no unintended migration of fluids. Traditional bond logs cannot detect the fine scale channeling which may allow fluids to slowly migrate over years or decades and therefore the use of more advanced cement evaluation logs is crucial.

When well construction is completed, the operator should certify, in writing, that the casing and cementing requirements were met for each casing string.

OPERATIONS AND MONITORING

CURRENT REGULATIONS

There are currently no rules for operation or monitoring of stimulation treatments.

RECOMMENDED REGULATIONS

Each hydraulic fracturing treatment must be modeled using a 3D geologic and reservoir model prior to operation. Operators should perform a pressure fall-off or pump test, injectivity tests, and/or a mini-frac. Data obtained from such tests can be used to refine the hydraulic fracture model, design, and implementation.

Prior to starting a hydraulic fracturing treatment, all cemented casing strings must be pressure tested to a pressure at least 500 psi greater than the maximum pressure to which they will be subjected during hydraulic fracturing. If the pressure declines more than 10% in a 30 minute interval or there are other indications of a lack of mechanical integrity, corrective action must be taken prior to the commencement of completion activities.

During hydraulic fracturing, operators must continuously monitor each casing annulus and report any instances where pressure exceeds 80% of the API rated minimum internal yield on any casing string in communication with the hydraulic fracturing treatment. The operator must also continuously monitor and record surface injection pressure, slurry rate, proppant concentration, fluid rate, sand or proppant rate, and annuli pressure.

If at any point during the hydraulic fracturing operation the monitored parameters indicate a loss or potential loss of mechanical integrity, if injection pressure exceeds the fracture pressure of the confining zone(s), or if there are any indications that injected fluids or displaced formation fluids have contacted a transmissive fault or fracture or improperly constructed or plugged well, the operation must immediately cease. If any of the preceding occurs, the operator must notify the regulator within 24 hours and must take all necessary steps to determine the presence or absence of a leak or migration pathways to USDWs. Prior to any further operations, mechanical integrity must be restored and demonstrated to the satisfaction of the regulator and the operator must demonstrate that the ability of the confining zone(s) to prevent the movement of fluids to USDWs has not been compromised. If a loss of mechanical integrity is discovered , if the integrity of the confining zone has been compromised, or if fluids have reached a transmissive fault or improperly constructed or plugged well operators must take all necessary steps to evaluate whether injected fluids or formation fluids may have contaminated or have the potential to contaminate any unauthorized zones. If such an assessment indicates that fluids may have been released into a USDW or any unauthorized zone, operators must notify the regulator within 24 hours, take all necessary steps to characterize the nature and extent of the release, and comply with and implement a remediation plan approved by the regulator. If such contamination occurs in a USDW that serves as a water supply, a notification must be placed in a newspaper available to the potentially affected population and on a publically accessible website and all known users of the water supply must be individually notified immediately by mail and by phone.

Techniques to measure actual fracture growth should be used, including downhole tiltmeters and microseismic monitoring. These techniques can provide both real-time data and, after data processing and interpretation, can be used in post-fracture analysis to inform fracture models and refine hydraulic fracture design.

Operators should develop, submit, and implement a long-term groundwater quality monitoring program. Dedicated water quality monitoring wells should be used to help detect the presence of contaminants prior to their reaching domestic water wells. Placement of such wells should be based on detailed hydrologic flow models and the distribution and number of hydrocarbon wells. Baseline monitoring should begin at least a full year prior to any activity, with monthly or quarterly sampling to characterize seasonal variations in water chemistry. Monitoring should continue for 5 years or more after plugging and abandonment, depending on site-specific factors including but not limited to hydraulic fracturing pressures and fluid volumes, vertical separation between hydraulically fractured formations and USDWs, hydraulic gradients, and contaminant travel time.

REPORTING

CURRENT REGULATIONS

BLM's current regulations lack specificity as to the types of and instances in which information specific to stimulation operations must be reported. Some of this information may be captured by the generic reporting requirements listed below, but BLM should institute reporting rules specific to stimulation operations.

43 CFR § 3162.4-1 (a) The operator shall keep accurate and complete records with respect to all lease operations including, but not limited to, production facilities and equipment, drilling, producing, redrilling, deepening, repairing, plugging back, and abandonment operations, and other matters pertaining to operations. With respect to production facilities and equipment, the record shall include schematic diagrams as required by applicable orders and notices.

43 CFR § 3162.4-2 (a) During the drilling and completion of a well, the operator shall, when required by the authorized officer, conduct tests, run logs, and make other surveys reasonably necessary to determine the presence, quantity, and quality of oil, gas, other minerals, or the presence or quality of water; to determine the amount and/or direction of deviation of any well from the verticial; and to determine the relevant characteristics of the oil and gas reservoirs penetrated.

43 CFR § 3162.4-3 Monthly report of operations (Form 3160–6). (e) The depth of each active or suspended well, and the name, character, and depth of each formation drilled during the month, the date each such depth was reached, the date and reason for every shut-down, the names and depths of important formation changes and contents of formations, the amount and size of any casing run since last report, the dates and results of any tests such as production, water shut-off, or gasoline content, and any other noteworthy information on operations not specifically provided for in the form.

OOGO#1-IV(d) The operator must maintain structures, facilities, improvements, and equipment in a safe condition in accordance with the approved APD. The operator must also take appropriate measures as specified in Orders and Notices to Lessees to protect the public from any hazardous conditions resulting from operations. In the event of an emergency, the operator may take immediate action without prior Surface Managing Agency approval to safeguard life or to prevent significant environmental degradation. The BLM or the FS must receive notification of the emergency situation and the remedial action taken by the operator as soon as possible, but not later than 24 hours after the emergency occurred. If the emergency only affected drilling operations and had no surface impacts, only the BLM must be notified. If the emergency involved surface resources on other Surface Managing Agency lands, the operator should also notify the Surface Managing Agency and private surface owner within 24 hours. Upon conclusion of the emergency, the BLM or the FS, where appropriate, will review the incident and take appropriate action.

OOGO#1-IV(e) Completion Reports. Within 30 days after the well completion, the lessee or operator must submit to the BLM two copies of a completed Form 3160–4, Well Completion or Recompletion Report and Log. Well logs may be submitted to the BLM in an electronic format such as ‘‘.LAS’’ format. Surface and bottom-hole locations must be in latitude and longitude.

RECOMMENDED REGULATIONS

At a minimum, operators must report:

- As soon as possible, but no later than 24 hours after the following occur:
  - All instances of hydraulic fracturing injection pressure exceeding operating parameters as specified in the permit
  - All instances of an indication of loss of mechanical integrity
  - Any failure to maintain mechanical integrity
  - The detection of the presence of contaminants pursuant to the groundwater quality monitoring program
  - Indications that injected fluids or displaced formation fluids may pose a danger to USDWs
  - All spills and leaks
  - Any non-compliance with a permit condition
- Within 30 days after the well completion:
  - The results of:
    - Continuous monitoring during hydraulic fracturing operations
    - Techniques used to measure actual fracture growth
    - Any mechanical integrity tests

INFORMATION TO SUBMIT WITH THE PERMIT APPLICATION/SUNDRY

Under current rules, operators are not required to submit information specific to stimulation operations. Such data is necessary for regulators to determine whether the proposed stimulation program is properly designed and will not put well integrity, worker safety, or the environment at risk. In addition to the requirements at 43 CFR § 3162.3-1 and in Onshore Oil and Gas Order #1, operators should also submit the following information:

1. Information on the geologic structure, stratigraphy, and hydrogeologic properties of the proposed producing formation(s) and confining zone(s), including:
   a. Maps and cross-sections of the area of review
   b. The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not provide migration pathways for injected fluids or displaced formation fluids to USDWs
   c. Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the producing and confining zone(s); including geology/facies changes based on field

data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions

   d. Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the producing and confining zone(s)
   e. Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not affect the integrity of the confining zone(s)
   f. Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area
   g. Hydrologic flow and transport data and modeling
2. A list of all wells within the area of review that penetrate the producing or confining zone and a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require.
3. Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known
4. Baseline geochemical analyses of USDWs as outlined in the disclosure provisions, above
5. Well construction procedures that meet the well construction provisions, above
6. Proposed operating data for the stimulation operation:
   a. Operating procedure
   b. Calculated fracture gradient of the producing and confining zone(s)
   c. Anticipated fracture length and height
   d. Maximum pressure, rate, and volume of injected fluids and proppant and demonstration that the proposed hydraulic fracturing operation will not initiate fractures in the confining zone or cause the movement of hydraulic fracturing or formation fluids that endangers a USDW
7. Proposed chemical additives as outlined in the disclosure provisions, above