August 23, 2013

Via Regulations.gov Web Form to Bureau of Land Management

Bureau of Land Management
20 M Street, SE, Room 2134 LM
Washington, DC 20003
Attention: Regulatory Affairs

Re: Comments on Bureau of Land Management Supplemental Notice of Proposed Rulemaking for proposed rule entitled Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands (Revised)

Dear Regulatory Affairs Staff:

Environmental Defense Fund (EDF) appreciates this opportunity to comment on the Bureau of Land Management (BLM)'s proposed regulations on well stimulation on Federal and Indian Lands.

The BLM has clearly given serious thought and effort to this proposal. Overall, while the proposal has made progress since the original May 2012 publication of the proposed rules in the *Federal Register*, work remains to bring BLM's oil and gas production rules up to modern standards. On well integrity in particular, the proposed BLM rules fall short of those in Texas and Ohio. The increasing prevalence of high volume hydraulic fracturing of horizontal boreholes raises considerable challenges, and regulations governing modern well development must be continuously improved as techniques, practices, and capacity evolve over time.

These comments focus on the well integrity management issues raised by this rulemaking, as well as chemical disclosure, wastewater management, and the definition of "usable water." We will address a broad range of well integrity issues that we feel fall into the scope of the rulemaking even if the proposal does not have specific new provisions on the subject.

There is one issue we will not thoroughly address in these comments that nevertheless deserves serious consideration by the BLM: how BLM's rules and regulations on oil and gas development interact with those of the states in which the development occurs, and how the federal government and the states should coordinate. Both the current BLM system – Memoranda of Understanding, variances, etc. – and the proposed BLM variance process are ad hoc, uneven and opaque. Working with the states, the BLM should develop more formal, transparent, environmentally protective, and rational procedures for determining which regulations should govern in the event of a conflict.

I. Well Integrity

a. Cement Evaluation

The BLM has proposed to require operators to conduct cement evaluation logging prior to hydraulic fracturing. While well-intentioned, the conditions under which these tests should be performed and the manner in which they should be conducted must be altered to bring them in line with today's leading practices. Cement evaluation tools are important – for example, EDF believes that radial cement evaluation tools should be mandatory for production casing and, when hydraulic fracturing is conducted through it, intermediate casing. But generally speaking, instead of merely requiring operators to use a cement evaluation tool, the BLM would more effectively regulate cement jobs by instead requiring operators to show isolation of zones that require protection, aiming at the end rather than the means. Rather than relying on cement evaluation tools as the primary evaluation technique, the key to properly evaluating the quality of cement jobs is to require pressure testing and formation integrity testing for each casing string before the next is drilled, to call for cement evaluation logging under particular circumstances, and to require reporting and remediation of cement integrity failure. Onshore Order 2 calls for pressure testing of each casing string and formation integrity testing (or "shoe testing") of each casing shoe for portions of any well approved for a 5M BOPE system or greater.[1] It is unclear whether this threshold was designed with evaluation of cement integrity in mind, but in any case it ought to be superseded in the present rulemaking to cover all stimulated wells. Our comments below will lay out when cement evaluation logging is appropriate, what pressure testing should be required and when, and how operators should report and remediate cement integrity failures.

The BLM proposes to require all operators to "run a cement evaluation log or logs on each casing that protects usable water and the operator must submit those logs to the authorized officer within 30 days after completion of the hydraulic fracturing operations except as provided under (e)(3) of this section."[2] That exception exempts operators from conducting cement evaluation logging for new wells in the same field where a "type well" under similar geologic conditions has been successfully completed.[3]

[1] Onshore Oil and Gas Order No. 2(III)(B)(1)(h), (i).
[2] Revised Proposed Rule, Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands, 78 Fed. Reg. 31,636, 31,675 (May 24, 2013) (to be codified at 43 C.F.R. § 3162.3-3(e)(2)).
[3] *Id.* at 31,676 (to be codified at 43 C.F.R. § 3162.3-3(e)(3)).

Cement integrity is of critical importance to isolating usable water, potential flow zones, corrosive zones, lost circulation zones, and mineral resources from intrusion and damage during completion and production. But evaluating cement integrity is not as simple as requiring a cement evaluation log. Cement evaluation tools are useful in many contexts but can be unreliable. This is especially true for traditional cement bond logs. Such CBLs can produce both false positives and false negatives, are difficult to interpret, and produce results with a considerable band of uncertainty.[4] Surface casing (the casing that most frequently protects usable water) tends to respond poorly to cement bond logs and similar tools (traditional cement bond logs yield the most reliable results when used in deeper sections of wells with higher stress contrasts and heavier cements).[5] By providing that "an operator may select the tool used to prepare the CEL, as long as it is at least as effective in verifying the integrity of annular cement bond logging as is a cement bond log,"[6] the BLM has unintentionally set a very low bar.

For that reason, instead of a general rule to use a cement evaluation log for surface casings, we recommend the use of a casing pressure test prior to drill-out followed by a formation integrity test. The formation integrity test allows the operator to evaluate surface casing cement integrity, demonstrating that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the drilling permit, that no flow path exists to formations above the casing shoe, and that the casing shoe is competent to handle an influx of formation fluid or gas without breaking down. This formulation would use a stress test to show actual performance and provides specific metrics for success or failure. However, if fluid

[4] See Flournoy, R.M., Feaster, J.H.: "Field Observations on the Use of the Cement Bond Log and Its Application to the Evaluation of Cementing Problems," SPE 632, Society of Petroleum Engineers, New Orleans, LA, October 3-6, 1963 (Reporting false signals, particularly in thinner cement sheaths and hydrocarbon contaminated cement (pockets); noting that in multiple well studies, the cement bond log often indicated poor bonding when well performance and zone pressures were clearly isolated by cement; describing field tests that showed many wells had effective isolation even though the percentage of acceptable bond ranged from 31% to 75%. See also Thornhill, J.T., Benefield, B.G.: "Injection Well Mechanical Integrity," Report 625/9-87/007, US EPA, Washington DC, 1987 ("No one test provides sufficient information to make a determination of the mechanical integrity of an injection well. Rather, this determination is made from a combination of tests, each providing pieces of information to be evaluated together in making an informed judgment regarding the mechanical integrity of an injection well.") See also Hayden, R., Schlumberger, et al.: "Case Studies in Evaluation of Cement with Wireline Logs in a Deep Water Environment," SPWLA 52nd Annual Logging Symposium, May 14-18, 2011 ("When the presidential commission recently asked for information about cementing and cement evaluations, they started by saying that oil company representatives they interviewed told them that cement bond logging was so ambiguous that they might get three different interpretations from three different industry experts even when using the same log data. Unfortunately they were right.")

[5] *Compare with* King, G.E.: "Cement Evaluation Methods to Prove Isolation of Barriers in Oil and Gas Wells: Should a Cement Bond Log (CBL) Br Run or Required in Every Well?," July 12, 2012, *available at* http://gekengineering.com/Downloads/Free_Downloads/Cement_Bond_Log_(CBL)_Overview-DRAFT-2.docx

[6] *Id.* at 31,675 (to be codified at 43 C.F.R. § 3162.3-3(e)(2)).

returns, lift pressure, displacement, and/or other operations indicate inadequate cement coverage, then BLM should indeed require that the operator shall: (i) run a radial cement evaluation tool, a temperature survey, or other test approved by the BLM to identify the top of cement, (ii) submit a plan of remediation to the BLM for approval, and (iii) implement such plan by performing additional operations to remedy such inadequate coverage prior to continuing drilling operations.

It is unclear why the proposed rule focuses solely on casing strings that protect usable water. It is important that *every* casing string have isolation where needed, whether it is protecting usable water or for other reasons described above. For intermediate strings, when operations (e.g., fluid returns, lift pressure, and displacement) indicate inadequate coverage of any zone requiring isolation, then we recommend the BLM require operators to run a BLM-approved cement evaluation log to identify the top of cement, submit a plan to remediate the cement job, and to implement that plan following the resumption of drilling. We also recommend casing pressure testing and formation integrity testing for all intermediate casings. However, when hydraulic fracturing is conducted through the intermediate casing, then we recommend that BLM require operators to run a radial cement evaluation tool to assess cement integrity and placement, in addition to evaluating cement records and the results of annular pressure monitoring. Should the log show deficiencies, the operator should be required to remediate prior to further drilling and plug and abandon the well should the deficiencies be irremediable.

For production strings, we recommend that, in addition to casing pressure testing and an evaluation of cementing records and annular pressure monitoring results, operators should in all cases run a radial cement evaluation tool to further assess cement integrity and placement, with remediation for insufficient isolation as above.

Assuming that BLM retains a presumptive requirement to use cement evaluation tools subject to an exception based on experience with "type wells," BLM's type well exception should be revised from a single type well to a showing of integrity for *five* wells meeting specified criteria. Allowing the exemption after the first well seems premature – how would one establish, with a single example, that "operations such as drilling, cementing, and hydraulic fracturing are likely to be successfully replicated using the same design"?[7] Instead, we recommend the following formulation:

> Operator may request an exemption from the requirement to run a cement evaluation tool if the operator has:

[7] *Id.* at 31,674 (to be codified at 43 C.F.R. § 3160.0-5) (definition of type well).

(i) successfully set and cemented the casing for which the exemption is requested in at least 5 wells drilled by the same operator in the same operating field;

(ii) obtained cement evaluation tool logs that support the findings of cementing records, annular pressure monitoring results and other tests demonstrating that successful cement placement was achieved to isolate known hydrocarbon bearing intervals, abnormal pressure zones or lost circulation zones;

(iii) shown that the well for which the exemption is requested will be constructed and cemented using the same or similar techniques, methods, and cement formulation used in the 5 wells that have had successful cement jobs; and

(iv) submitted an exemption request to BLM containing the information required under (i) – (iii) above.

This formulation is much more stringent than the BLM proposal while still allowing operators to save time and money on testing when it is environmentally acceptable to do so. However, we would only support such an approach to cement evaluation tool requirements if operators are also required to show cement integrity through other means, i.e. formation integrity testing, casing pressure testing, and a requirement to report and remediate signs of cement integrity failure. [8]

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[8] For an example of this multi-pronged approach to verifying well integrity in practice, see Ohio's Well Construction standards at 1501:9-1-08. Selected passages:

> (3) In order to verify casing integrity and proper cement displacement, the owner shall pressure test each cemented casing string greater than two hundred feet long in accordance with the test method of either paragraph (D)(3)(a) or (D)(3)(b) of this rule.
>
> > (a) Immediately upon landing the latch-down plug, the owner shall increase displacement pressure by at least five hundred pounds per square inch and hold pressure for five minutes. If pressure declines by ten per cent or more, casing integrity and cement placement shall be further evaluated and appropriate corrective action shall be taken to verify casing integrity and cement displacement. If the float apparatus does not hold, the owner shall pump the volume that flowed back, and shut in until the cement has sufficiently set.
> >
> > (b) Prior to drilling the cement plug, the owner shall test any permanently cemented casing strings, at a minimum pump pressure in pounds per square inch calculated by multiplying the length of the casing string by 0.2, but not less than three hundred pounds per square inch. The test pressure may not decline by more than ten per cent during the thirty-minute test period.

b. Mechanical Integrity Testing

(i) If, at the end of thirty minutes of such testing, the pressure shows a drop greater than ten per cent, the owner shall not resume further operations until the condition is corrected. A pressure test demonstrating a pressure drop equal to or less than ten per cent after thirty minutes is evidence that the condition has been corrected.

(ii) Casing integrity may be verified in conjunction with blowout preventer testing without a test plug using either the test pressure described in paragraph (D)(3)(b) of this rule, or the pressure required to test the blowout preventer, whichever is greater.

(E) Casing shoe tests. The chief may require the owner to conduct a casing shoe test after drilling below the surface casing and/or the intermediate casing seat if the pressure gradient of the permitted hydrocarbon reservoir exceeds 0.5 pounds per square inch per foot, or in areas where fracture gradients are unknown.

. . . .

(4) Surface casing.

. . . .

(c) If cement is not circulated to the ground surface or the bottom of the cellar and the top of cement cannot be measured from surface, the owner shall perform tests as approved by the inspector. The owner shall notify the inspector prior to performing the tests. After the nature of the well construction deficiency is determined, the owner shall contact the inspector and obtain approval for the procedures to be used to perform any required additional cementing operations. Surface casing shall not be perforated for the purpose of remedial cementing unless intermediate casing is set and cemented to surface, or otherwise authorized by the chief.

(d) If remedial options fail and the chief determines that USDWs are not adequately isolated or protected, the chief may issue an administrative order suspending further drilling operations. If the chief determines additional remedial measures will not isolate and protect the USDW, the chief shall issue an administrative order requiring the well to be plugged.

. . . .

(6) Intermediate casing.

. . . .

(e) If the cement placement indicators including fluid returns, lift pressure, or annular pressure indicate inadequate isolation of any flow zone, the owner shall obtain approval of the inspector for the proposed plan for determining top of cement and/or performing additional cementing operations.

. . . .

(7) Production casing and liners.

. . . .

(iv) If operations indicate inadequate cement coverage or isolation of the hydrocarbon bearing zones, the owner shall obtain approval of the inspector for procedures to determine the top of cement and/or perform corrective actions.

The proposal requires mechanical integrity testing of the vertical sections of the casing prior to hydraulic fracturing or refracturing.[9] We question why the BLM would limit this test to the vertical sections of the casing, when hydraulic fracturing is usually performed through the horizontal section. It is essential to establish integrity throughout the wellbore – a well is only as strong as its weakest component. In addition to casing pressure tests for each casing string and formation integrity tests following each drill-out, we recommend the following language for the full-well integrity test prior to hydraulic fracturing:

> Prior to commencing completion or refracturing operations, or commencing hydraulic fracturing operations on a well that has not previously undergone a hydraulic fracturing treatment, all cemented casing strings and all tubing strings to be used by an operator in conducting the hydraulic fracturing treatment shall be tested to a pressure at least 500 psi greater than the anticipated maximum surface pressure to be experienced during either the completion operations or the life of the completion. A successful mechanical integrity test is one where the pressure stabilizes within 10% of the required test pressure and remains stable for a full 30 minute test period. A failed test requires immediate wellwork to remedy the failure, and a repeat test until successful. Non-cemented production completions shall be tested to a minimum of (i) 70% of the lowest activating pressure for pressure actuated sleeve completions or (ii) 70% of formation integrity for open-hole completions, as determined by a formation integrity test.

This formulation also provides direction for response to failed tests.

c. Area of Review

As discussed below, regulators around the country are beginning to consider requirements for operators to evaluate subsurface integrity in the area surrounding their proposed wells and mitigate opportunities for hydraulic fracture communication with offset wells and natural fractures. This "area of review," adapted from a similar requirement in the Underground Injection Control context, delineates a volume of the subsurface where the operator identifies and documents active, orphaned and abandoned wells that penetrate the "impacted strata" (see definition below) for the well, along with natural faults and fractures that may provide communication of fluid from the well to protected waters, either directly or through artificial conduits. The operator would analyze these pathways and make a determination that no such pathway may be a conduit of fluids into a source of protected water. The operator would

[9] *Id.* at 31,676 (to be codified at 43 C.F.R. § 3162.3-3(f)).

adjust their drilling and hydraulic fracturing plans, work with producers of nearby active wells to mitigate risk of fluid communication, and plug improperly abandoned wells if necessary to achieve this.

Subsurface communication of hydraulic fracturing fluid through existing boreholes and natural fractures is a serious concern. While we are not aware of a comprehensive survey of fluid migration and blowouts that have resulted from this problem, there is no question that such communication is possible, and reports from Pennsylvania, Colorado, and Alberta, among other states,[10] have documented incidences of subsurface communication (sometimes called "frack hits").

Currently, there are regulatory proposals on this subject under development in Alaska[11] and Pennsylvania[12] (Alberta[13] has an extensive program on this issue that would be difficult to translate to the U.S. context). Pennsylvania's current proposal does not fully achieve the goals of a proper subsurface review—it lacks a requirement to investigate active wells or take action to mitigate the risk of fluid migration. Alaska's proposal is strong and succinctly captures the goal of an area of review, requiring the following in its permit applications:

> (12) the location, orientation, and a report on the mechanical condition of each well that may transect the confining zones and information sufficient to support a determination that such wells will not interfere with containment of the hydraulic fracturing fluid within the one-half mile radius of the proposed wellbore trajectory;
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> (13) the location, orientation, and geological data of known or suspected faults and fractures that may transect the confining zones, and information sufficient

[10] *See, e.g.*, Gayathri Valdyanathan, *Hydraulic Fracturing: Canada Steps Up Well Monitoring to Avoid 'Frack Hits'*, ENERGYWIRE (Aug. 8, 2013), http://www.eenews.net/stories/1059985756; Gayathri Valdyanathan, *Hydraulic Fracturing: When 2 Wells Meet, Spills Can Often Follow*, ENERGYWIRE (Aug. 5, 2013), http://www.eenews.net/stories/1059985587 (reporting alleged 'frack hits' in New Mexico, Oklahoma, Arkansas, Montana, and West Virginia); Scott Detrow, *Perilous Pathways: How Drilling Near An Abandoned Well Produced a Methane Geyser*, STATEIMPACT (Oct. 9, 2012, 8:30 AM), http://stateimpact.npr.org/pennsylvania/2012/10/09/perilous-pathways-how-drilling-near-an-abandoned-well-produced-a-methane-geyser/.

[11] The Alaska Oil and Gas Conservation Commission has proposed amendments to ALASKA ADMIN. CODE. tit. 20, ch. 25, *available at* http://doa.alaska.gov/ogc/frac/02_Hydraulic%20Fracturing%20Proposed%20Regulations.pdf.

[12] See proposed amendment to 25 PA. CODE § 78.52a, *available at* http://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/OilGasReports/2012/TAB%20MEETINGS/APR232013/2013-04-23_Ch_78_Subch_C_ANNEX_A_(2013-04-02).pdf.

[13] Directive 083: Hydraulic Fracturing—Subsurface Integrity (May 21, 2013), *available at* http://www.aer.ca/documents/directives/Directive083.pdf. *See also* Interim IRP 24—Fracture Stimulation: Interwellbore Communication (Mar. 27, 2013), *available at* http://www.enform.ca/safety_resources/publications/PublicationDetails.aspx?a=29&type=irp.

> to support a determination that any such faults and fractures will not interfere with the containment of the hydraulic fracturing fluid within one-half mile radius of the proposed wellbore trajectory.[14]

The BLM may also want to consider the following, more fully fleshed-out language when crafting "area of review" requirements:

- "Impacted strata" shall mean (i) the productive horizon that is to be stimulated with a hydraulic fracturing treatment and (ii) all strata that are immediately adjacent to such productive horizon and are within the estimated or calculated fracture height for such hydraulic fracturing treatment.

- "Intervening zone" shall refer to those geological formations (or part of a formation) located between the top boundary of the productive horizon that is being hydraulically fractured and the base of the deepest stratum or zone that contains protected water.

- "Limited intervening zone" shall mean an intervening zone that (i) is less than 1,000 vertical feet thick, or (ii) is more than 1,000 vertical feet thick, but which the BLM determines, based on the lithologic, geomechanical or other properties of the formations that comprise the intervening zone, may not contain an adequate confining layer or is in a structurally complex geologic setting with known faults that extend through the intervening zone and are likely to be transmissive. Notwithstanding the foregoing, an intervening zone less than 1,000 vertical feet thick may be excluded from classification as a "limited intervening zone" if the BLM determines that such intervening zone contains an adequate confining layer.[15]

- "Productive horizon" shall mean any hydrocarbon strata determined to contain commercial quantities of hydrocarbons.

- "Required distance" shall mean (i) 1,320 feet or (ii) such other greater or lesser distance as the BLM may specify in the event the BLM determines that regional or local conditions justify a larger or smaller area of investigation.

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[14] Proposed amendment to ALASKA ADMIN. CODE. tit. 20, § 25.283(a)(12)-(13).

[15] For technical justification of the selection of 1,000 vertical feet as the default demarcation point for close proximity wells, please see Kevin Fisher & Norman Warpinski, *Hydraulic Fracture-Height Growth: Real Data*, 27(1) SPE PRODUCTION & OPERATIONS 8-19 (2012)(SPE 145949), *and* Richard J. Davies et al., *Hydraulic fractures: How far can they go?*, 37(1) MARINE AND PETROLEUM GEOLOGY 1-6 (2012).

- “Area of investigation” shall mean (i) with respect to a vertical well or the vertical portion of a horizontal well, a circular area formed by projecting a radius the required distance from the center of the well and (ii) with respect to the horizontal portion of a horizontal well, the combination of (a) a rectangular area formed by projecting a line the required distance perpendicular to, and on both sides of, the entire perforated section of the horizontal borehole plus (b) two semi-circular areas, the first formed by projecting a radius the required distance from the beginning point of the perforated section of the horizontal borehole, and the second formed by projecting a radius the required distance from the ending point of the perforated section of the horizontal borehole.

- As part of permit application, a statement that, based on operator’s analysis of the intervening zone, including an evaluation of existing wells of record that penetrate the impacted strata within the area of investigation, the intervening zone contains an adequate confining layer and no such well may be a conduit for movement of fluids into a source of protected water.

- Prior to beginning a hydraulic fracturing treatment, operator shall identify and assess (i) the condition of existing production wells and abandoned wells that penetrate the impacted strata within the area of investigation, and (ii) known geologic faults and natural fracture zones that transect the impacted strata within the area of investigation. Operator shall verify that such wells, faults and natural fracture zones will not permit migration of the fracturing fluids, hydrocarbons, or other contaminants into a strata that contains protected water. Improperly constructed wells, improperly abandoned wells, or orphaned wells, must be remedied or properly plugged and abandoned if there is a risk that the hydraulic fracture treatment may communicate with these wells and result in protected water contamination or pose other environmental, health or safety risks.

- For wells with a limited intervening zone, the confining layer analysis must include information on the geologic structure, stratigraphy and hydrogeologic properties of the proposed producing formation(s) and intervening zone in the area of investigation, including (a) geologic name and description of all formations penetrated, including relevant logs, (b) structure maps, including any faults, and (c) any geomechanical analyses, including permeability, relative hardness (using Young’s Modulus) and relative elasticity (using Poisson’s Ratio). The confining layer analysis may be submitted on a well-by-well basis, or may be approved by the BLM for an area, and referenced as a pre-approved confining layer analysis in the well application for wells with a limited intervening zone drilled in such area.

We understand that Onshore Order 1 has a requirement that, as part of their permit application, operators must "include a map and may include a geospatial database that includes all known wells, regardless of the well status (producing, abandoned, etc.), within a one-mile radius of the proposed location."[16] This provision gets at some of the principles described above, but it is in some ways both overinclusive and underinclusive. The BLM considers the relevant area of investigation to surround the wellhead only, ignoring the area around the horizontal lateral, which may extend two miles or more from the wellhead – thus capturing large areas of unaffected land while missing large areas of impacted land. Further, the relevant wells are those that penetrate the "impacted strata;" shallow wells far above the horizontal lateral are extremely unlikely to communicate with fractures many thousands of feet below (except in the case of limited intervening zone wells and those fractured at very shallow depths). The point is that, to the extent the BLM wants operators to be cognizant of subsurface hazards and minimize their risk of fluid communication to protected water, it is critical to rationalize and modernize this provision as part of a comprehensive Area of Review regulation.

d. Annular Gap

Onshore Order 2(III)(B) provides that "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."[17] BLM's gap of 0.422" is measured from the collar, compared with Ohio's greater minimum gap of 0.5" from the collar.[18] (For smaller pipes, 0.5" from the collar is approximately equivalent to 0.75" from the pipe itself; with larger pipes, the collars have greater widths.)

While it is sensible enough to craft an annular gap rule around distance from collars as opposed to distance from the pipe, BLM's gap is nevertheless too narrow to allow for proper cement emplacement. It is also too narrow to enable accurate cement bond log evaluations – which is problematic and surprising given BLM's proposed reliance on cement bond logs![19] There is ample discussion in the technical literature of optimal annular gap and cement sheath thickness. Generally, these sources favor as much as a 1.5" gap when considering efficacy of mud removal, optimal cement emplacement, and other factors. The sources cited in the

[16] Onshore Oil and Gas Order No. 1(III)(D)(4)(d), 72 Fed. Reg. 10,328, 10,332 (Mar. 7, 2007).
[17] Onshore Oil and Gas Order No. 2(III)(B).
[18] OHIO ADMIN. CODE 1501-9:1-08(H)(1) (2012).
[19] API 10TR1

footnote below represent a broad range of expert opinion tested over time; some support 1.0" as a minimum while others allow a 0.75" minimum.[20] EDF is aware of no credible technical literature supporting an annular gap of less than 0.75" inches (measured from the body of the pipe) as a general rule.

The technical literature uses distance from pipes, but even adding the width of a collar, BLM's minimum annular gap is clearly narrower than recommended by experts, and less than almost all state provisions addressing this issue, including Ohio,[21] Pennsylvania,[22] Michigan,[23] and Texas (at least with regard to its surface casing rule).[24] We appreciate the BLM rule's allowance for variances when conditions require, but the minimum annular gap should be wider.

Based on the literature presented above, EDF recommends that the BLM require a minimum annular gap of either 0.75" or 1" for all casing strings, subject to properly justified variances.

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[20] API 10TR1 speaks to cement sheath thickness needed for adequate cement log evaluation, calling for at least 0.75"—but it is important to remember that adequate cement log evaluation is only one consideration in deciding what annular gap is adequate. These other considerations favor a gap of more than 0.75" (except where an exception is granted for good cause). API 65-2 speaks to the importance of wider annuli for mud clearance and static gel strength. *See, e.g.*, J.J. AZAR & G. ROBELLO SAMUEL, DRILLING ENGINEERING (2007), at 309 ("The necessary clearance between the outside of the casing and the drilled hole depends on the hole and the mud condition. In cases where mud conditioning is good or the mud is lightweight and the formations are competent, a clearance of 1 ½ in. total diameter difference is acceptable. Primary cementing operations may not be successful given this clearance, and cementing backpressures will be high. A better clearance for general-purpose well completions is 2-3 in. For higher mud weights, poorer mud conditioning, poor quality hole, and higher formation pressures, the clearance should be increased.").

[21] OHIO ADMIN. CODE 1501-9:1-08(H)(1) (0.5" from casing collar).

[22] 25 PA CODE § 78.83(b) (0.5" from casing collar or coupling). This regulates surface casing annular gap only.

[23] Michigan provides the following:

> (4) For the purpose of proper sealing of wells and the prevention of waste, the minimum hole size for a given casing shall be as shown in table 410:
>
> Table 410
>
> | Casing size outside diameter (O.D.) - inches | Minimum hole size outside diameter (O.D.) - inches |
> |---|---|
> | Up to 7 O.D. | Casing O.D. + 1 1/2 |
> | More than 7 O.D. | Casing O.D. + 2 |
> | More than 10 3/4 O.D. | Casing O.D. + 3 |
>
> An exception to the minimum hole size as shown in table 410 may be granted by the supervisor or authorized representative of the supervisor, upon a written request by the permittee or applicant, if it is determined that the proposal provides proper sealing of the well. The supervisor or authorized representative of the supervisor may require a larger hole size for the surface hole than the size shown in table 410 in order to prevent waste.

MICH. ADMIN. CODE r. 324.410 (2012).

[24] The BLM standard is weaker than Texas for surface casing, and little better than the Texas rule for deeper casing, which EDF believes to be inadequate. *See generally* 16 TEX. ADMIN. CODE § 3.13 (2013).

When evaluating exceptions, the BLM should consider whether the proposed annular gap is sufficiently large for the criteria described above. The ultimate consideration for this and all casing and cementing design considerations is whether the proposed well architecture will isolate appropriate zones and prevent annular migration of formation fluid to protected water.

e. Confining Layer/Limited Intervening Zones

While in most cases there are thousands of feet of essentially impermeable rock between the productive horizon where hydraulic fracturing takes place and protected water, in the cases where there is a "limited intervening zone" of short distance or uncertain geology, it is critical that operators show that there is nevertheless a "confining layer" such that the well will not create conduits for movement of fluid into a source of protected water. This concept is similar to "Area of Review," and in fact, shares some of the language. Below are suggested definitions, some of which are repeated from above:

- "Confining layer" shall mean that portion of an intervening zone that has sufficient areal extent and integrity to act as an effective impermeable barrier to the vertical migration of gases or other fluids into any strata or zones that contain protected water.

- "Intervening zone" shall refer to those geological formations (or part of a formation) located between the top boundary of the productive horizon that is being hydraulically fractured and the base of the deepest stratum or zone that contains protected water.

- "Limited intervening zone" shall mean an intervening zone that (i) is less than 1,000 vertical feet thick, or (ii) is more than 1,000 vertical feet thick, but which the BLM determines, based on the lithologic, geomechanical or other properties of the formations that comprise the intervening zone, may not contain an adequate confining layer or is in a structurally complex geologic setting with known faults that extend through the intervening zone and are likely to be transmissive. Notwithstanding the foregoing, an intervening zone less than 1,000 vertical feet thick may be excluded from classification as a "limited intervening zone" if the BLM determines that such intervening zone contains an adequate confining layer.[25]

[25] For technical justification of the selection of 1,000 vertical feet as the default demarcation point for close proximity wells, please see Kevin Fisher & Norman Warpinski, *Hydraulic Fracture-Height Growth: Real Data*, 27(1) SPE PRODUCTION & OPERATIONS 8-19 (2012)(SPE 145949), *and* Richard J. Davies et al., *Hydraulic fractures: How far can they go?*, 37(1) MARINE AND PETROLEUM GEOLOGY 1-6 (2012).

Operators should be required, as part of their application to drill, to submit a statement that, based on operator's analysis of the intervening zone, including an evaluation of existing wells of record that penetrate the impacted strata within the area of investigation, the intervening zone contains an adequate confining layer and no such well may be a conduit for movement of fluids into a source of protected water, and a statement whether or not the well will have a limited intervening zone. For wells with limited intervening zones and uncertain or thin confining layers, the BLM should impose special requirements for hydraulic fracturing. In its recent well integrity rulemaking, Texas recognized that limited intervening zone wells could pose water contamination problems without certain precautions and adopted language to that end.[26] The

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[26] Texas RRC 13 defines a minimum separation well as "a well in which hydraulic fracturing treatment will be conducted and for which (i) the vertical distance between the base of usable quality water and the top of the formation to be stimulated is less than 1,000 vertical feet; (ii) the director has determined contains inadequate separation between the base of usable quality water and the top of the formation in which hydraulic fracturing treatments will be conducted; or (iii) the director has determined is in a structurally complex geologic setting." 16 TEX. ADMIN. CODE § 3.13(a)(2)(L)(i)-(iii).

The rule goes on to provide the following additional regulations for such wells:

> (D) The following conditions also apply if the well is a minimum separation well, unless otherwise approved by the director:
>
> (i) Cementing of the production casing in a minimum separation well shall be by the pump and plug method. The production casing shall be cemented from the shoe up to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface).
>
> (ii) The operator shall pressure test the casing string on which the pressure will be exerted during stimulation to the maximum pressure that will be exerted during hydraulic fracturing treatment. The operator shall notify the district director within 24 hours of a failed test. No hydraulic fracturing treatment may be conducted until the district director has approved a remediation plan, and the operator has implemented the approved remediation plan and successfully re-tested the casing (or fracture tubing).
>
> (iii) The production casing for any minimum separation well shall not be disturbed for a minimum of eight hours after cement is in place and casing is hung-off, and in no case shall the casing be disturbed until the cement has reached a minimum compressive strength of 500 psi.
>
> (iv) In addition to conducting an evaluation of cementing records and annular pressure monitoring results, the operator of a minimum separation well shall run a cement evaluation tool to assess radial cement integrity and placement behind the production casing. If the cement evaluation indicates insufficient isolation, completion operations may not re-commence until the district director approves a remediation plan and the operator successfully implements the approved plan.
>
> (v) The operator of a minimum separation well may request from the appropriate district director approval of an exemption from the requirement to run a cement evaluation tool. Such request shall include information demonstrating that the operator has:

Texas provision is worthy of BLM consideration. In the alternative, we recommend the following language:

- General Rules for Wells with a Limited Intervening Zone.
  - Wells with a limited intervening zone may not utilize open hole, open hole packer or other non-cemented completions.
  - Cementing of the production casing for a well with a limited intervening zone shall be by the pump and plug method. Sufficient cement shall be used to fill the annular space outside the casing from the casing shoe to the ground surface or to the bottom of the cellar.
  - The production casing for any well with a limited intervening zone shall not be disturbed for a minimum of 8 hours after cement is in place, and in no case shall the casing be disturbed until the cement has reached a minimum compressive strength of 500 psi.
  - In addition to an evaluation of cementing records and annular pressure monitoring results, operator shall run a radial cement evaluation tool to further assess cement integrity and placement. If cement evaluation indicates insufficient isolation, operator shall submit a plan of remediation to the BLM for approval and implement such plan by performing remedial operations prior to commencing completion operations. If the deficiencies cannot be remedied, the well shall be plugged and abandoned.
  - Operator may request an exemption from the requirement to run a cement evaluation tool if the operator has:
    - successfully set and cemented the casing for which the exemption is requested in at least 5 wells with limited intervening zones drilled by the same operator in the same operating field;
    - has obtained cement evaluation tool logs that support the findings of cementing records, annular pressure monitoring results and other tests demonstrating that successful cement placement was achieved to isolate

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(I) successfully set, cemented, and tested the casing for which the exemption is requested in at least five minimum separation wells by the same operator in the same operating field;

(II) obtained cement evaluation tool logs that support the findings of cementing records, annular pressure monitoring results or other tests demonstrating that successful cement placement was achieved to isolate productive zones, potential flow zones, and/or zones with corrosive formation fluids; and

(III) shown that the well for which the exemption is requested will be constructed and cemented using the same or similar techniques, methods, and cement formulation used in the five wells that have had successful cement jobs.

Id. § 3.13(a)(7)(D)(i)-(v).

known hydrocarbon bearing intervals, abnormal pressure zones or lost circulation zones;
        - shown that the well for which the exemption is requested will be constructed and cemented using the same or similar techniques, methods, and cement formulation used in the 5 wells that have had successful cement jobs; and
        - submitted an exemption request to BLM containing the information required above.[27]

- Prior to beginning a hydraulic fracturing treatment on a well with a limited intervening zone:
    - Operator must submit a hydraulic fracturing design plan for BLM approval. This plan must:
        - Verify that the well proposed to be hydraulically fractured meets the well construction standards established in BLM regulations and Onshore Orders;
        - Include an analysis of the site specific hydrology (depth of protected water) and geophysical characteristics of the intervening zone and confining layer(s) contained within the intervening zone. The purpose of the analysis is to demonstrate that the confining layer(s) has sufficient areal extent, impermeability and absence of transmissive faults or fractures so that the proposed hydraulic fracturing treatment design will not result in the vertical migration of the fracturing fluids, hydrocarbons, or other contaminants into strata that contains protected water or result in a horizontal fracture that intersects with a nearby well that could result in the vertical migration of the fracturing fluids, hydrocarbons or other contaminants into strata that contains protected water. A confining layer is of sufficient areal extent and thickness if it is capable of preventing or arresting vertical fracture propagation;
        - The confining layer analysis must include information on the geologic structure, stratigraphy and hydrogeologic properties of the proposed producing formation(s) and intervening zone in the area of investigation, including (a) geologic name and description of all formations penetrated, including relevant logs, (b) structure maps, including any faults, and (c) any geomechanical analyses, including permeability, relative hardness (using Young's Modulus) and relative elasticity (using Poisson's Ratio). The confining layer analysis may be submitted on a well-by-well basis, or may be approved by BLM for an area, and referenced as a pre-approved

[27] See Type Well discussion in section I(a).

confining layer analysis in the well application for wells with a limited intervening zone drilled in such area;

    - Utilize a 3D model populated with the most current data available and approved by BLM that will estimate the maximum vertical and horizontal fracture propagation length, and which shows that the hydraulic fracturing treatment will not propagate fractures into strata containing protected water. The model input and output shall be submitted as part of the application, and the model shall be based on all relevant geologic and engineering data including but not limited to rock mechanical and geochemical properties of the producing zone and confining layer(s) and anticipated hydraulic fracturing pressures, rates, and volumes; and
    - Describe in detail the proposed hydraulic fracturing treatment design, including the volumes, pressures, pump rates, hydraulic fracture fluid type, proppants and additives proposed.
  - Operator shall run a radial cement evaluation log or such other cement evaluation tool capable of identifying a cement channel as may be approved by BLM to determine the quality of the cement outside of the production casing. If the quality of the cement outside of the production casing is not sufficient to isolate strata containing protected water, then operator must develop a plan of remediation and receive approval from BLM for the plan of remediation before operator may proceed.
- Reporting requirements for Limited Intervening Zones: in addition to the required by other reporting provisions, for wells with a limited intervening zone, the operator shall also submit:
  - The results of the confining layer analysis required above;
  - The results of the hydraulic fracture treatment design analysis required above;
  - A post hydraulic fracturing treatment analysis using the same realistic model as used above and actual data from the hydraulic fracturing treatment, including the calculated fracture length and fracture height for the hydraulic fracture treatment; and
  - The results of the cement evaluation log required above.

f. <u>Isolation of Flow Zones and Corrosive Zones</u>

Onshore Order 2 provides that "proposed casing and cementing programs shall be conducted as approved to protect and/or isolate all usable water zones, lost circulation zones, abnormally pressured zones, and any prospectively valuable deposits of minerals."[28] Operators should indeed be required to isolate these zones, but this list misses two important zones that, when not isolated, can cause integrity problems. The first are corrosive zones, and the second are flow zones.

Zones containing corrosive fluids, if not isolated, can quickly damage unprotected casing, leading to integrity failure. The BLM should adopt the Texas Railroad Commission's definition of, and procedures relating to, zones with corrosive formation fluids:

> Any zone designated by the director or identified by the operator using available data containing formation fluids that are capable of negatively impacting the integrity of casing and/or cement or have a demonstrated trend of failure for similar casing and cement design in the field. The Commission will maintain a list of known zones by district and county that are considered zones with corrosive formation fluids, and make this information available to all operators. The Commission will revise this list as necessary based on information provided, or otherwise made available, to the Commission.[29]

The BLM should further adopt the Texas Railroad Commission's general requirement that "Casing shall be cemented across and above all productive zones, potential flow zones, and/or zones with corrosive formation fluids,"[30] with specific requirements for each casing.

With respect to flow zones, operators should be required to isolate all zones capable of causing annular flow that could negatively impact the quality of the cement or result in annular overpressurization, in order to prevent vertical migration of fluids or gases behind the casing. EDF thinks this is a better formulation than the Onshore Order II phrase "abnormally pressured." The current BLM terminology is both overinclusive (because not all abnormally pressured zones are sufficient to cause annular flow that could negatively impact the quality of the cement or could result in annular overpressurization[31]) and potentially underinclusive

[28] Onshore Oil and Gas Order No. 2(III)(B).
[29] 16 TEX. ADMIN. CODE § 3.13(a)(2)(O).
[30] *Id.* § 3.13(a)(4)(D).
[31] By annular overpressurization we mean the following: the wellbore condition that occurs when (i) fluids in the annulus between the surface casing and the intermediate/production casing are pressurized to such an extent so as to potentially allow for the migration of confined fluids or gases at the surface casing shoe or (ii) fluids in the annulus between any intermediate casing (if intermediate casing is set) and the production casing are pressurized to such an extent so as to potentially allow for the migration of confined fluids or gases at the intermediate casing shoe. The BLM may want to consider incorporating this concept into its definition of potential flow zones.

(because “abnormally pressured” is not defined and might leave out phenomena that could damage the cement or casing).

Both Texas and Ohio have included flow zone isolation language in recent rulemakings, and both present a workable model for inclusion of this concept into BLM’s regulations. Texas defines potential flow zones as “[a] zone designated by the director or identified by the operator using available data that needs to be isolated to prevent sustained pressurization of the surface casing/intermediate casing or production casing annulus sufficient to cause damage to casing and/or cement in a well such that it presents a threat to subsurface water or oil, gas, or geothermal resources. The Commission will maintain a list of known zones by district and county that are considered potential flow zones and make this information available to all operators. The Commission will revise this list as necessary based on information provided, or otherwise made available, to the Commission.”[32] The rule provides generally that “[c]asing shall be cemented across and above all productive zones, potential flow zones, and/or zones with corrosive formation fluids”[33] (similar provisions exist for each casing string), and that “[w]here necessary, the cement slurry shall be designed to control annular gas migration consistent with, or equivalent to, the standards in API Standard 65-Part 2: Isolating Potential Flow Zones During Well Construction.”[34]

Highlighting the salience of this issue, Ohio’s well construction rules emphasize the importance of isolation of flow zones throughout. Key passages include: “Casing shall be centralized in each segment of the wellbore to provide sufficient casing standoff and foster effective circulation of cement to isolate critical zones including aquifers, flow zones, voids, lost circulation zones, and hydrocarbon production zones”;[35] “Intermediate casing may be set at the discretion of the owner to isolate flow zones, lost circulation zones, or other geologic hazards, unless otherwise required by this rule or the approved permit”;[36] “If the intermediate wellbore penetrates one or more flow zones, cement shall be placed at least five hundred feet above the uppermost flow zone. The cement used to control annular gas migration from flow zones shall be designed consistent with recommended methods in API ‘65-2 Isolating Potential Flow Zones during Construction.’ The cement shall reach a compressive strength of five hundred pounds per square inch before drill out. Annular pressure shall be measured prior to drill out to verify isolation of the flow zone.”[37] We recommend the BLM consult API Standard 65-Part 2: Isolating Potential Flow Zones During Well Construction.

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[32] 16 TEX. ADMIN. CODE § 3.13(a)(2)(N).
[33] *Id.* § 3.13(a)(4)(D).
[34] *Id.* § 3.13(a)(4)(E).
[35] OHIO ADMIN. CODE 1501-9:1-08(K)(3).
[36] *Id.* at 1501-9:1-08(M)(6)(a).
[37] *Id.* at 1501-9:1-08(M)(6)(d).

We propose superseding the Onshore Order 2 language in this rulemaking by providing that "proposed casing and cementing programs shall be conducted as approved to protect and/or isolate all usable water zones, lost circulation zones, abnormally pressured zones, *potential flow zones, zones with corrosive formation fluids,* and any prospectively valuable deposits of minerals." Further, the BLM should adopt the definitions for "potential flow zone" and "zones with corrosive formation fluids" used by the Texas Railroad Commission,[38] and maintain similar lists of potential flow zones and corrosive zones to be made available to all operators on BLM lands.

g. Cement Quality

It is critically important for proper well integrity that operators use the right type of cement for each application. BLM's current and proposed rules and orders do not adequately provide appropriate cement quality standards. While the BLM proposes to require operators to report information about cement used,[39] the rules do not ensure that operators use the right cement in the right way under given circumstances.

EDF recommends the following four regulatory additions:

1) A requirement that cement be manufacturing in conformance with standard methods (e.g. API Specification 10A)

We suggest the following language:

> Cement must conform to API Specification 10A (Specification for Cement and Material for Well Cementing). BLM may require specific cement additives, quantities or types in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution, prevent vertical migration of fluids in the wellbore, or provide safer conditions in the well or the area surrounding the well. Consideration should be given to including gas blockers or static gel strength accelerators if permeable gas-bearing intervals are being cemented, and to including additives resistant to CO_2 and H_2S

[38] 16 TEX. ADMIN. CODE § 3.13(a)(2)(N), (O).
[39] Revised Proposed Rule, Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands, 78 Fed. Reg. 31,636, 31,677 (May 24, 2013) (to be codified at 43 C.F.R. § 3162.3-3(i)(8)) ("The operator must submit well logs and records of adequate cement bonds including the cementing operations monitoring report, any cement evaluation log, and the result of the mechanical integrity test as required by paragraphs (e)(1),(e)(2), and (f) of this section.").

degradation if conditions dictate. Operator may request use of other cement types for approval BLM by providing detailed cement design and test criteria.[40]

2) A requirement for slurry to meet appropriate quality standards (e.g., free water separation and optimum density)

We suggest the following language:

> Cement slurry must be prepared to minimize, to the greatest extent practicable, its free water content. In no event shall the free water separation for the slurry average more than (i) two milliliters per 250 milliliters of cement tested for cement inside the zone of critical cement or (ii) three and one-half milliliters per 250 milliliters of cement tested for cement outside the zone of critical cement. Cement mix water chemistry must be proper for the cement slurry designs. At a minimum, the water chemistry of the mix water must be tested for pH prior to use, and the cement must be mixed to manufacturer's recommendations. An operator's representative must be on site verifying that the cement mixing, testing, and quality control procedures used for the entire duration of the cement mixing and placement are consistent with the approved engineered design and meet the cement manufacturer recommendations, API standards, and the requirements of these rules.[41]

For a definition of zone of critical cement, we recommend the following language:

> "Zone of critical cement" shall mean (i) for surface casing strings greater than 300 feet in length, the bottom 20% of the casing string, but in no event shall it be more than 1,000 feet or less than 300 feet, (ii) for surface casing strings of 300 feet or less in length, the zone of critical cement shall extend to the land surface, and (iii) for intermediate and production casings, the bottom 20% of the casing string or not less than 300 feet above the casing shoe or proposed productive horizon.

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[40] *See also* 16 TEX. ADMIN. CODE § 3.13(a)(4)(B), "The base cement shall meet the standards set forth in API Specification 10A: Specification for Cement and Material for Well Cementing or the American Society for Testing and Materials (ASTM) Specification C150/C150M, Standard Specification for Portland Cement (or a Commission-approved equivalent standard)" *and* § 3.13(b)(1)(D)(iv), "The Commission may require a better quality of cement mixture to be used in any well or any area if conditions indicate that a better quality of cement is necessary to prevent pollution, isolate productive zones, potential flow zones, or zones with corrosive formation fluids or prevent a safety issue in the well."

[41] *See also* 16 TEX. ADMIN. CODE § 3.13(b)(1)(D)(iii), "In addition to the minimum compressive strength of the cement, the free water content shall be minimized to the greatest extent practicable in the cement slurry to be used in the zone of critical cement. In no event shall the free water separation average more than two milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B-2: Recommended Practice for Testing Well Cements, inside the zone of critical cement, or more than six milliliters per 250 milliliters of cement tested outside the zone of critical cement."

3) Requirement to test cement slurry in accordance with standard methods prior to cementing if published data are unavailable

Recommended language for this requirement:

> Cement mixtures for which published performance data are not available must be tested by the operator or the company providing the cementing services. Tests must be made on representative samples of cement and additives using the equipment and procedures required by API RP 10B. Cement design and test data must be furnished to BLM prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure:
>
> (i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement; and
>
> (ii) For lead cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater.[42]

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[42] *See also* 16 TEX. ADMIN. CODE § 3.13(b)(1)(E),

> "Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures in, or equipment and procedures equivalent to those in, API RP 10B-2, Recommended Practice for Testing Well Cements. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished to the Commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure.
>
> (i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement.

BLM should have the authority to require specific cement blends to isolate problematic zones: see recommended language for 1) above.

h. Wellbore Conditioning

Current rules require the use of top plugs and either bottom plugs or other techniques to help isolate the cement from contamination by the mud fluid being displaced ahead of the cement slurry.[43] EDF believes this standard to be insufficiently specific as to the steps needed to properly condition the borehole prior to cement emplacement, or how to respond to irregularities.

EDF recommends the following three requirements concerning wellbore conditioning:

1) A requirement to establish circulation prior to commencement of cementing.
2) If circulation cannot be established, then standards addressing how cement seals will be emplaced to effectively isolate specified zones.
3) Operators should ensure that borehole is as static as feasible (i.e. non-gassing) prior to cement circulation.

To that end we recommend the following language from Ohio:[44]

1) Prior to cementing, the wellbore shall be conditioned to kill gas flow, foster adequate cement displacement, and ensure a high quality bond between cement and the wellbore. If circulation cannot be established or maintained, the inspector shall require testing to evaluate cement displacement. If tests indicate cement displacement or quality is inadequate to meet the standards, the owner shall not resume drilling activity until corrective action has achieved compliance with the standards.

2) If oil-based drilling mud is used, the wellbore shall be conditioned with a mud flush and the spacer volume should be designed for a minimum of ten minutes of contact time prior to cementing production casing in the horizontal segment of a wellbore.

(ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater."

[43] Onshore Oil and Gas Order No. 2 (III)(B)(1)(g).
[44] OHIO ADMIN. CODE 1501-9:1-08(I)(1)-(3).

3) Where underground mine voids, solution voids, or other geologic features render circulation infeasible, the owner shall install a cement basket or other approved device as close as possible above the top of the void or thief zone.

In the event that a circulation failure is not discovered until *after* cementing has occurred, EDF recommends the following provision from Texas[45]:

> If cement does not circulate to ground surface or the bottom of the cellar, the operator or the operator's representative shall obtain the approval of the district director for the procedures to be used to perform additional cementing operations, if needed, to cement surface casing from the top of the cement to the ground surface.

i. Surface Casing

Onshore Order 2 has a few well construction requirements pertaining specifically to the surface casing, including a requirement to cement to surface and a centralization requirement (which we will address later in these comments).[46] The BLM should address the following two subjects to supplement its existing surface casing-specific rules:

1) Minimum depth below the base of protected water that the casing shoe must extend; and
2) A requirement that the surface casing must be set before the borehole penetrates the hydrocarbon-bearing flow zone.

EDF recommends the following language:

> Operator shall set and cement sufficient surface casing to a minimum depth of at least 100 feet below the base of the deepest strata containing protected water, but above any hydrocarbon strata that are capable of annular flow that could negatively impact the quality of the cement or result in annular overpressurization. Surface casing must be set deep enough and into a competent formation to ensure the BOP can contain any formation pressure that many be encountered when drilling the next section of the hole below the surface casing shoe.

We must stress here that the BLM should be flexible about this distance from jurisdiction to jurisdiction. In some cases, 100 feet will be too far, and in others, not far enough, depending on

[45] 16 TEX. ADMIN. CODE § 3.13(b)(1)(C).
[46] Onshore Oil and Gas Order No. 2 (III)(B)(1)(c),(f).

subsurface geology. We suggest 100 feet as a general rule, but the BLM should be prepared to vary this number by field, region, or state. It is nevertheless important to establish a distance as a general rule to provide some predictability for operators.[47]

j. Intermediate and Production Casings

BLM's current and proposed rules say virtually nothing on construction standards for intermediate or production casing. BLM ought to provide standards for these strings, as Texas,[48] Ohio[49] and other states do. The following is proposed language for each of these

[47] For alternative formulations, see 16 TEX. ADMIN. CODE § 3.13(b)(1)(B)(i), "An operator shall set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Groundwater Advisory Unit of the Oil and Gas Division. Unless surface casing requirements are specified in field rules approved prior to the effective date of this rule, before drilling any well, an operator shall obtain a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth. In no case, however, is surface casing to be set deeper than 200 feet below the specified depth without prior approval from the district director. The district director may grant such approval on an area basis." *See also*, OHIO ADMIN. CODE 1501-9:1-08(M)(4)(a), "An owner shall set and cement sufficient surface casing at least fifty feet below the base of the deepest USDW, or at least fifty feet into competent bedrock, whichever is deeper, and as specified by the permit, unless otherwise approved by the chief."

[48] 16 TEX. ADMIN. CODE § 3.13(b)(2) provides the following language:

> (2) Intermediate casing requirements for land wells and bay wells.
>
> (A) Cementing method. Each intermediate string of casing shall be cemented from the shoe to a point at least 600 feet (measured depth) above the shoe. If any productive zone, potential flow zone, or zone with corrosive formation fluids is open to the wellbore above the casing shoe, the casing shall be cemented;
>
> (i) if the top of cement is determined through calculation, from the shoe up to a point at least 600 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids;
>
> (ii) if the top of cement is determined through performance of a temperature survey, from the shoe up to a point at least 250 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids;
>
> (iii) if the top of cement is determined through performance of a cement evaluation log, from the shoe up to a point at least 100 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluid; or
>
> (iv) to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface); or
>
> (v) as otherwise approved by the district director.

(B) Top of cement. The calculated or measured top of cement shall be indicated on the appropriate completion form required by §3.16 of this title (relating to Log and Completion or Plugging Report).

(C) Alternate method. In the event the distance from the casing shoe to the top of the shallowest productive zone, potential flow zone, and/or zone with corrosive formation fluids make cementing, as specified above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively isolate and seal the zones to prevent fluid migration to or from such strata within the wellbore.

[49] OHIO ADMIN. CODE 1501-9:1-08(M)(6) provides the following language:

(6) Intermediate casing.

(a) Intermediate casing may be set at the discretion of the owner to isolate flow zones, lost circulation zones, or other geologic hazards, unless otherwise required by this rule or the approved permit.

(b) The owner shall set and cement intermediate casing in a competent formation in the following situations:

(i) If groundwater containing total dissolved solids of less than ten thousand milligrams per liter is encountered below the base of cemented surface casing;

(ii) Through a gas storage reservoir when drilling to strata beneath a gas storage reservoir within the storage protective boundary;

(iii) When drilling to permitted hydrocarbon zones deeper than the silurian clinton sandstone east of the updip pinchout; such casing shall be set through the Mississippian berea sandstone, or one thousand feet, whichever is greater;

(iv) For wells drilled horizontally, in the Marcellus shale, or deeper, such casing shall be set through the Mississippian berea sandstone or one thousand feet, whichever is greater; or

(v) In other situations as determined by the chief.

(c) For each intermediate string of casing that is permanently set in the wellbore, tail cement shall extend from the seat to a point at least five hundred true vertical feet above the casing seat, or to a point at least two hundred feet above the seat of the next larger diameter casing string.

(d) If the intermediate wellbore penetrates one or more flow zones, cement shall be placed at least five hundred feet above the uppermost flow zone. The cement used to control annular gas migration from flow zones shall be designed consistent with recommended methods in API "65-2 Isolating Potential Flow Zones during Construction." The cement shall reach a strings – it includes provisions that have been and will be discussed at length in other sections of these comments, especially with respect to well integrity testing, zones to be isolated, and test wells.

Intermediate Casing:

(a) Intermediate casing must be installed when necessary to isolate protected water not isolated by surface casing and to seal off anomalous pressure zones, lost circulation zones and other drilling hazards.

(b) Intermediate casing must be set to protect groundwater if surface casing was set above the base of protected water, and/or if additional protected water was found below the surface casing shoe. When intermediate casing is installed to protect groundwater, the operator shall set a full string of new intermediate casing to a minimum depth of at least 100 feet below the base of the deepest strata containing protected water and cement to the surface. The location and depths of any hydrocarbon strata or protected water strata that is open to the wellbore above the casing shoe must be confirmed by coring, electric logs or testing and shall be reported as part of the post-treatment report.

(c) Abnormal pressure zones, lost circulation zones, and other drilling hazards encountered while drilling below the surface casing must be recorded and reported to BLM and made available to other operators in the area as part of the post-treatment report.

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compressive strength of five hundred pounds per square inch before drill out. Annular pressure shall be measured prior to drill out to verify isolation of the flow zone.

(e) If the cement placement indicators including fluid returns, lift pressure, or annular pressure indicate inadequate isolation of any flow zone, the owner shall obtain approval of the inspector for the proposed plan for determining top of cement and/or performing additional cementing operations.

(f) Liners may be set and cemented as intermediate casing provided that the cemented liner has a minimum of two hundred feet of cemented lap within the next larger casing, and the liner top is pressure tested to a level equal to or higher than the maximum anticipated pressure to be encountered in the interval to be drilled below the liner. The test pressure may not decline by more than ten per cent during the thirty minute test period. If at the end of a thirty minute pressure test, the pressure has dropped by more than ten per cent, the owner shall not resume operations until the condition is corrected and verified by a thirty minute pressure test.

(d) In the case that intermediate casing was set for a reason other than to protect strata that contains protected water, the intermediate casing string shall be cemented from the shoe to a point at least 600 true vertical feet above the shoe, or if any hydrocarbon strata that is capable of annular flow which could jeopardize control of the well, could negatively impact the quality of the cement or could result in annular overpressurization is open to the wellbore above the casing shoe, the casing shall be cemented from the shoe up to a point at least 600 true vertical feet above the top of the shallowest such hydrocarbon strata, or to a point at least 200 feet above the shoe of the next shallower casing string that was set and cemented in the well.[50] Liners may be set and cemented as intermediate casing provided that the cemented liner has a minimum of 200 true vertical depth feet of cemented lap within the next larger intermediate casing, and the liner top is pressure tested to a level equal to or higher than the maximum anticipated pressure to be encountered in the interval to be drilled below the liner. The location and depths of productive horizons, any hydrocarbon strata or any strata containing protected water that is open to the wellbore above the casing shoe must be confirmed by coring, electric logs or testing.

(e) Prior to drilling out below the intermediate casing shoe, the intermediate casing shall be pressure tested to a minimum of 1,500 psi and/or at a pressure that will determine if the casing integrity is adequate to meet the well design and construction objectives.

(f) Immediately after drilling out below the intermediate casing shoe, a formation pressure integrity test shall be performed to determine that formation integrity at the casing shoe is adequate to meet the maximum anticipated well bore pressure at total depth. The FIT test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the permit application; no flow path exists to formations above the casing shoe; and that the casing shoe is competent to handle an influx of formation fluid or gas without breaking down. In the event the FIT results fail to meet the criteria identified in the preceding sentence, operator shall contact BLM to receive instructions on any necessary remedial or other actions which must be taken in order for operator to proceed with its operations.

(g) In the event the distance from the casing shoe to the top of the shallowest productive horizon, hydrocarbon strata capable of annular flow or strata containing protected water, makes cementing, as specified above, impossible or impractical, multi-

[50] Cement height requirements are based on API Guidance Document HF1 and consideration of hydrostatic pressure conditions during cementing operations to prevent loss of returns. API, HF1: HYDRAULIC FRACTURING OPERATIONS—WELL CONSTRUCTION AND INTEGRITY GUIDELINES (1st ed., Oct. 2009), *available at* http://www.api.org/~/media/Files/Policy/Exploration/API_HF1.pdf.

stage cementing operations may be used to cement the casing in a manner that will effectively seal off all such possible horizons or strata and prevent fluid migration to or from such horizons or strata within the wellbore.

(h) If operations (e.g. fluid returns, lift pressure and displacement) indicate inadequate coverage of any productive horizon, any hydrocarbon strata capable of annular flow or any strata containing protected water, operator shall (i) run a radial cement evaluation tool, a temperature survey, or another test approved by BLM to identify the top of cement, (ii) submit a plan of remediation to BLM for approval, (iii) and implement such plan by performing additional cementing operations to remedy such inadequate coverage prior to continuing drilling operations.

(i) When a hydraulic fracturing treatment is conducted through intermediate casing, operator shall run a radial cement evaluation tool to assess cement integrity and placement, in addition to evaluating cementing records and the results of annular pressure monitoring. If the cement evaluation tool indicates insufficient isolation, operator shall submit to and comply with BLM site-specific guidance for remedying cementing deficiencies prior to drilling further into the hole. If such deficiencies cannot be remedied, the well must be plugged and abandoned.

(j) Operator may request an exemption from the requirement to run a cement evaluation tool if operator has:

> (i) successfully set and cemented the casing for which the exemption is requested in at least 5 wells drilled by the same operator in the same operating field;
>
> (ii) has obtained cement evaluation tool logs that support the findings of cementing records, annular pressure monitoring results and other tests demonstrating that successful cement placement was achieved to isolate known hydrocarbon bearing intervals, abnormal pressure zones or lost circulation zones;
>
> (iii) shown that the well for which the exemption is requested will be constructed and cemented using the same or similar techniques, methods, and cement formulation used in the 5 wells that have had successful cement jobs; and
>
> (iv) submitted an exemption request to BLM containing the information required under (i) – (iii) above.

Production Casing:[51]

[51] Alternative language:

From 16 Tex. Admin. Code § 3.13(b)(3): Production casing requirements for land wells and bay wells.

> (A) Centralizers. In deviated and horizontal holes, the operator shall provide centralization as necessary to ensure zonal isolation between the top of the interval to be completed and the shallower zones that require isolation.
>
> (B) Cementing method. The production string of casing shall be cemented by the pump and plug method, or another method approved by the Commission, with sufficient cement to fill the annular space back of the casing to the surface or to a point at least 600 feet above the shoe. If any productive zone, potential flow zone and/or zone with corrosive formation fluids is open to the wellbore above the casing shoe, the casing shall be cemented in a manner that effectively seals off all such zones by one of the methods specified for intermediate casing in paragraph (2) of this subsection. A float collar or other means to stop the cement plug shall be inserted in the casing string above the shoe. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating casing pressure tests. In the event that the distance from the casing shoe to the top of the shallowest productive zone, potential flow zone and/or zone with corrosive formation fluids make cementing, as required above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively seal off all such zones, and prevent fluid migration to or from such zones within the wellbore. Uncemented casing is allowable within a producing reservoir provided the production casing is cemented in such a manner to effectively isolate and seal off that zone from all other productive zones in the wellbore as required by §3.7 of this title (relating to Strata To Be Sealed Off).
>
> (C) Reporting of top of cement. Calculated or measured top of cement shall be indicated on the appropriate completion form required by §3.16 of this title.
>
> (D) Isolation of gas/oil contact zones. The position of the gas-oil contact shall be determined by coring, electric log, or testing. The producing string shall be landed and cemented below the gas-oil contact, or set completely through and perforated in the oil-saturated portion of the reservoir below the gas-oil contact.

From Ohio Admin. Code 1501-9:1-08(M)(7):

> (7) Production casing and liners.
>
> (a) Cemented completions.
>
> (i) The production casing shall be cemented with sufficient cement to fill the annular space to a point at least five hundred true vertical feet above the seat in an open-hole vertical completion or the uppermost perforation in a cemented vertical completion, or one thousand feet above the kickoff point of a horizontal well. If any flow zone is present, including strata that may contain hydrocarbons in commercial quantities or a hydrogen sulfide-bearing flow zone, the casing shall be cemented in a manner that effectively isolates such strata with at least five hundred feet of cement above the zone. The cement slurry shall be designed to control annular gas migration consistent

(a) Production casing shall be cemented by the pump and plug method, or another method approved by BLM with sufficient cement to fill the annular space back of the casing to the surface, or to a measured depth at least 600 feet above (i) the production casing shoe or the uppermost perforation in a vertical well (whichever is higher), or (ii) the point where a horizontal well first penetrates the zone to be hydraulically

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with recommended methods in API "65-2 Isolating Potential Flow Zones during Construction."

(ii) When cementing the production string of a well that will be stimulated by hydraulic fracturing, and the uppermost perforation is less than five hundred feet below the base of the deepest USDW, sufficient cement shall be used to fill the annular space outside the casing from the seat to the ground surface or to the bottom of the cellar. If cement is not circulated to the ground surface or the bottom of the cellar, the owner shall notify the inspector and perform tests approved by the inspector. After the top of cement outside the casing is determined, the owner or his authorized representative shall contact the inspector and obtain approval for the procedures to be used to perform any required additional cementing operations.

(iii) Liners may be set and cemented as production casing, provided that the cemented liner has a minimum of two hundred true vertical depth feet of cemented lap within the next larger casing, and the liner top is pressure tested to a level that is at least five hundred pounds per square inch higher than the maximum anticipated pressure to be encountered by the wellbore during completion and production operations. The test pressure may not decline by more than ten per cent during the thirty minute test period. If at the end of a thirty minute pressure test, the pressure has dropped by more than ten per cent, the owner shall not resume operations until the condition is corrected and verified by a thirty minute pressure test. Liners may only be set and cemented as production casing in horizontal shale gas wells if approved by the chief.

(iv) If operations indicate inadequate cement coverage or isolation of the hydrocarbon bearing zones, the owner shall obtain approval of the inspector for procedures to determine the top of cement and/or perform corrective actions.

(b) Packer completions. Packer or other non-cemented completions may be used in place of cemented completions. If intermediate casing is run with this type of completion, cementing shall meet the requirements of paragraph (M)(7) of this rule. If intermediate casing is not run, a multi-stage cementing tool shall be run above the top external packer and cemented to fill the annular space outside the casing to the surface or to a point at least five hundred feet above the packer or casing seat. The chief may approve alternative completion proposals. Any approved alternative shall meet the well construction standards of section 1509.17 of the Revised Code and these rules.

fractured.[52] If any productive horizon or hydrocarbon strata capable of annular flow that could negatively impact the quality of cement or result in annular overpressurization are open to the wellbore above the production casing shoe, the production casing shall be cemented in a manner that effectively seals off all such horizons or strata by one of the methods specified for intermediate casing above.

A full string of production casing must be installed and cemented if both surface casing and intermediate casing are used as water protection casing. A production liner may be hung from the base of the intermediate casing and used as production casing as long as the surface casing is used as the water protecting casing and intermediate casing is set for a reason other than isolation of protected water. The production liner must be cemented with a minimum measured depth of 200 feet of cemented lap within the next larger casing. The liner top must be pressure tested to a level that is at least 500 psi higher than the maximum anticipated pressure to be encountered by the wellbore during completion and production operations. The production casing string or production liner must be centralized in a manner that will provide for proper zonal isolation by the cement. All centralizers must meet API Spec 10D (Recommended Practice for Casing Centralizers – for bow string centralizers) or API Spec 10 TR4 (rigid and solid centralizers) and 10D-2 (Petroleum and Natural Gas Industries, Equipment for Well Cementing, Part 2, Centralizer Placement and Stop Collar Testing).

(b) The identification of the productive horizon(s) shall be determined by coring, electric log, mud-logging, or testing. For cemented well completions, the production casing shall be landed and cemented into or below the productive horizon(s). For open-hole well completions, the production casing shall be landed and cemented into or above the productive horizon(s).

(c) In addition to an evaluation of cementing records and annular pressure monitoring results, operator shall run a radial cement evaluation tool to further assess cement integrity and placement. If cement evaluation indicates insufficient isolation, operator shall submit a plan of remediation to BLM for approval and implement such plan by performing remedial operations prior to commencing completion operations. If the deficiencies cannot be remedied, the well shall be plugged and abandoned.

(d) Operator may request an exemption from the requirement to run a cement evaluation tool if the operator has:

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[52] Cement height requirements are based on API HF1 guidance document and consideration of hydrostatic pressure conditions during cementing operations to prevent loss of returns. API, HF1: HYDRAULIC FRACTURING OPERATIONS—WELL CONSTRUCTION AND INTEGRITY GUIDELINES (1st ed., Oct. 2009), *available at* http://www.api.org/~/media/Files/Policy/Exploration/API_HF1.pdf.

(i) successfully set and cemented the casing for which the exemption is requested in at least 5 wells drilled by the same operator in the same operating field;

(ii) has obtained cement evaluation tool logs that support the findings of cementing records, annular pressure monitoring results and other tests demonstrating that successful cement placement was achieved to isolate known hydrocarbon bearing intervals, abnormal pressure zones or lost circulation zones;

(iii) shown that the well for which the exemption is requested will be constructed and cemented using the same or similar techniques, methods, and cement formulation used in the 5 wells that have had successful cement jobs; and

(iv) submitted an exemption request to BLM containing the information required under (i) – (iii) above.

(e) Open hole, open hole packer or other non-cemented completions may be used in the place of cemented completions. If intermediate casing is run with this type of completion, the cementing of the intermediate casing must meet the cementing guidelines set forth in Section 4.5 hereof. If intermediate casing is not run, a multi-stage cementing tool must be run above the top external packer and cemented to fill the annular space outside the casing to the surface or to a point at least 600 feet above the packer or casing shoe. Alternatively, when no zones containing protected water exist in the open hole, two additional open hole packers may be installed in the casing string above the production zone.

k. Centralizers

BLM's current rules provide for surface casing centralization on the bottom three joints of the casing, with a minimum of one centralizer per joint, starting at the joint shoe.[53] However, there are no rules for centralization of casings other than the surface casing, and no standards for the centralizing equipment. This is insufficient to ensure proper centralization throughout the well.

EDF recommends the following language for centralization:

At a minimum, casing shall be centralized within one joint of casing from the top, at the shoe, above and below a stage collar or diverting tool, if run, and through all protected water zones. In nondeviated holes, a centralizer shall be placed every fourth joint from

[53] Onshore Oil and Gas Order No. 2(III)(B)(1)(f).

the cement shoe to the ground surface or to within one joint of casing from the bottom of the cellar, or casing shall be centralized by implementing an alternative centralization plan approved by the BLM. In deviated holes, BLM may require the operator to provide additional centralization. All centralizers must meet API Spec 10D (Recommended Practice for Casing Centralizers – for bow string centralizers) or API Spec 10 TR4 (rigid and solid centralizers) and 10D-2 (Petroleum and Natural Gas Industries, Equipment for Well Cementing, Part 2, Centralizer Placement and Stop Collar Testing).[54]

l. <u>Monitoring of Injection Parameters During Hydraulic Fracturing</u>

EDF applauds the BLM for its proposal to require operators to monitor and record wellbore annuli pressures during the hydraulic fracturing operation.[55] However, there are a number of other parameters that it would be helpful for operators to monitor while conducting hydraulic fracturing in order to maintain quality standards and troubleshoot in case of irregularities. In

[54] OHIO ADMIN. CODE 1501-9:1-08(K) provides the following language on centralizer standards:

(K) Centralizer standards.

(1) All bowspring centralizers shall meet the standards of API "10 D, Specification for Bow-Spring Casing Centralizers."

(2) All rigid centralizers shall meet the standards of API "10 TR 4 Considerations Regarding Selection of Centralizers for Primary Cementing Operations."

(3) Casing shall be centralized in each segment of the wellbore to provide sufficient casing standoff and foster effective circulation of cement to isolate critical zones including aquifers, flow zones, voids, lost circulation zones, and hydrocarbon production zones.

Alternatively, see Texas language:

(G) Centralizers. Surface casing shall be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, pipe centralization as follows is required: a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers shall meet specifications in, or equivalent to, API spec 10D Specifications for Bow-Spring Casing Centralizers; API Spec 10 TR4, Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations; and API RP 10D-2, Recommended Practice for Centralizer Placement and Stop Collar Testing. 16 TEX. ADMIN. CODE § 3.13(b)(1)(G).

For production casing:

(A) Centralizers. In deviated and horizontal holes, the operator shall provide centralization as necessary to ensure zonal isolation between the top of the interval to be completed and the shallower zones that require isolation. 16 TEX. ADMIN. CODE § 3.13(b)(3)(A).

[55] Revised Proposed Rule, Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands, 78 Fed. Reg. 31,636, 31,654 (May 24, 2013) (to be codified at 43 C.F.R. § 3162.3-3(g)(1)).

addition to annuli pressures, operators should be required to monitor the following four factors:

(i) surface injection pressure (psi);

(ii) slurry rate (bpm);

(iii) proppant concentration (ppa); and

(iv) fluid rate (bpm).

m. <u>Hydraulic Fracture Service Company Certification</u>

Hydraulic fracturing is a complex, technical, and potentially dangerous operation. It is essential that service companies that undertake hydraulic fracturing do so responsibly, in accordance with relevant regulations, and with the utmost attention to safety. Texas recently amended its oil and gas regulations to require operators to file an "organization report" and financial security in order to conduct oil and gas activities in the state as a way to maintain quality control in the state's oilfield services industry.[56] The BLM should adopt a similar model for hydraulic fracturing service companies. The following language creates a certification program:

> Approved Hydraulic Fracturing, Perforation and/or Logging Contractors.
>
> (a) In order to comply with these rules, when utilizing an HF service company or other contractors to perform hydraulic fracturing, perforation and/or logging services in connection with the completion of a well, operators shall utilize only those contractors approved by BLM. HF service companies or contractors who seek to perform hydraulic fracturing, perforation and/or logging services, or operators may apply with BLM for designation as approved contractors. Such approval will be granted by BLM upon a showing by the applicant of its ability to perform hydraulic fracturing, perforating and/or logging services (as the case may be) in accordance with the standards required by BLM in compliance with this rule. The list of approved contractors will be reviewed by BLM on a regular basis, but in no event less frequently than once per year, to ensure said contractors remain capable of competently performing the required work involved with completion operations.
>
> (b) An HF service company, contractor or operator seeking designation as an approved contractor by BLM shall file a request of such designation with BLM in accordance with all applicable procedures governing such requests. The request shall

[56] 16 TEX. ADMIN. CODE § 3.1 (2013).

contain such information as BLM shall reasonably require to assess the applicant's ability to competently perform such hydraulic fracturing, perforating and/or logging services in compliance with this rule.

The BLM shall either approve or deny the application to be designated as an approved contractor. If the BLM does not recommend approval, or denies the application, the applicant may request a hearing on its application.

n. Wellbore Integrity Monitoring During Production

BLM's rules provide little oversight and guidance once a well has been completed and production has begun. Current rules provide for "periodic well tests which will demonstrate the quantity and quality of oil and gas and water,"[57] and a monthly report of operations.[58] Both of these are geared toward financial considerations, and not toward safety and the environment. We recommend the following suite of post-completion monitoring provisions:

(a) Operator shall monitor and measure the performance of each producing well and submit production reports on a monthly and annual basis, or at such other regular intervals as the BLM may establish. For the first thirty days of operation, operator shall monitor each producing well on a daily basis. All other wells must be monitored at least weekly. Production and well monitoring reports shall include the amount of gas, oil and water produced and pressure monitoring data and shall be submitted to the BLM Operator shall keep these records for a minimum period of five (5) years after they are created and for any longer time period and in such form (e.g., electronic) as specified by the BLM.

(b) Operator shall conduct regular periodic tests of each producing well. Such tests shall record the amount of gas, oil, water produced per day or such other interval as the BLM may establish, and flowing and shut-in tubing pressure and all annular casing pressures.

(c) The wellhead, tree and related surface control equipment shall be maintained and tested to ensure pressure control is maintained throughout the life of the well. Casing pressure shall be monitored and operator shall record and report annular casing pressures to the BLM on an annual basis. Upon observation, operator shall report to the BLM, as soon as reasonably possible, (i) any annular pressures in excess of 70% of the API rated minimum internal yield or collapse strength of the casing, and (ii) any surface

[57] 43 C.F.R. § 3162.4-2.
[58] *Id.* § 3162.4-3.

casing pressures that exceed known hydrostatic pressure at the casing shoe or a pressure equal to: .70 times 0.433 times the true vertical depth of the surface casing shoe (expressed in feet), and shall take immediate action to remedy annular overpressurization.

(d) All annular valves shall be accessible from the surface or shall be left open and be plumbed to the surface with working pressure gauges. The BLM shall require installation of a properly functioning pressure relief device on any casing annulus, unless the BLM approves otherwise. The maximum set pressure of a surface casing pressure relief device shall be determined in accordance with BLM rules. Operator shall report all pressure releases from required pressure relief devices to the BLM within 24 hours of detection.

(e) Operator shall monitor its producing wells at least weekly for any corrosion, equipment deterioration, hydrocarbon release or changes in well characteristics that could potentially indicate a deficiency in the wellhead, tree and related surface control equipment, production casing, intermediate casing, surface casing, tubing, cement, packers or any other aspect of well integrity necessary to ensure isolation of any underground sources of protected water and prevent any other health, safety or environmental issue. If operator has cause to suspect such a deficiency, operator must notify the BLM and immediately take action to remedy the deficiency, which may require operator to perform diagnostic testing on the well to determine whether a deficiency does exist and the best method of repair. If diagnostic testing is required, such testing shall be done as soon as is reasonably practical after operator has cause to suspect a deficiency, and if the testing reveals that a deficiency has occurred then operator shall (i) promptly take all appropriate measures to prevent contamination of protected water and otherwise protect the environment, and (ii) promptly commence remedial operations that are designed to repair the deficiency. If operator is not able to effectively repair the deficiency and/or implement a pressure maintenance plan to ensure the protection of all underground sources of protected water and the environment, operator shall be required to immediately plug and abandon the well in accordance with the requirements of Onshore Order 2(II)(G).

II. Chemical Disclosure

EDF appreciates the BLM's recognition that disclosure of chemicals used in hydraulic fracturing enhances public safety, promotes transparency, and will ultimately lead to the use of less deleterious chemicals. While the current proposal represents an improvement over the May 2012 version, there remain five areas where improvement is warranted.

a. Concentration of chemicals by additive

The proposal would require disclosure of "maximum ingredient concentration in additive (% by mass), and maximum ingredient concentration in hydraulic fracturing fluid (% by mass)."[59] We agree that reporting of concentration is important to give regulators a general idea of how much of a chemical will be present on a well site. Requiring that chemical concentration be reported by *additive*, in addition to the concentration in hydraulic fracturing fluid as a whole, is an overreach that may have unintended consequences. To the extent that the additives are proprietary and thus subject to the BLM's trade secret exemption, the concentration of particular chemicals in an additive will often itself be a trade secret. Thus the rule would have the effect of creating more trade secret exemptions, which are an administrative burden and run counter to the spirit of the rule. Further, from an environmental standpoint, the concentration of a chemical in a particular additive does not matter nearly as much as the concentration overall. The BLM should reform the rule by eliminating the "maximum ingredient concentration in additive (% by mass)" requirement.

b. Trade secret policy

i. No path for challenging trade secrecy status

While the proposal requires operators to submit an affidavit that what is claimed as trade secret in fact qualifies for trade secret status,[60] the proposal fails to provide a mechanism for citizens to challenge that status. The BLM does not make an active determination of the veracity of trade secret claims, and without a channel for citizen intervention, there is a risk of false claims overwhelming the BLM's auditing apparatus. The BLM should establish a procedure for citizens to challenge trade secret claims, perhaps through a modified hearing process, and a claim of trade secret protection should only be upheld if the claim satisfies the requirements of 43 C.F.R. § 3162.3-3(j)(1).

ii. Access to trade secret information for health professionals and emergency responders

[59] Revised Proposed Rule, Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands, 78 Fed. Reg. 31,636, 31,656, 31,672, 31,676 (May 24, 2013) (to be codified at 43 C.F.R. § 3162.3-3(i)(1)).
[60] 78 Fed. Reg. at 31,637, 31,659-60 (to be codified at 43 C.F.R. § 3162.3-3(j)).

The proposal has a provision to allow the BLM to acquire trade secret information,[61] but we are concerned that the information pathway to health professionals and emergency responders could be too slow or burdensome to adequately serve the needs of the public. To that end we recommend the following language be added to BLM's trade secret exemption provision:

> Operator, HF service companies and suppliers shall provide the identity and concentration of any chemical contained in an additive utilized by or supplied to operator, including any such chemical claimed to be a trade secret, to any health professional who requests such information. With respect to any chemical claimed to be a trade secret, the health professional shall provide a written statement of need for the information and shall execute a confidentiality agreement if requested by operator, HF service company or supplier, as applicable. The confidentiality agreement shall be in a form prescribed by the BLM. The written statement of need shall include a statement that the health professional has a reasonable basis to believe that (A) the information is needed for purposes of diagnosis or treatment of an individual, (B) the individual being diagnosed or treated may have been exposed to the chemical concerned, and (C) knowledge of the information will assist in such diagnosis or treatment. Where a health professional determines that a medical emergency exists and the identity and concentration of chemical claimed to be a trade secret may be necessary for diagnosis or treatment, the HF service company, supplier or operator, as applicable, shall immediately disclose the information to that health professional upon a verbal acknowledgement by the health professional that the information shall be maintained as confidential, except as provided by this section. If the health professional cannot reach the HF service company, supplier or operator, or if the HF service company, supplier or operator refuses to provide information in its possession to the health professional, then, if a medical emergency exists, the BLM shall provide the information directly to the health professional. The HF service company, supplier or operator, as applicable, may request a written statement of need and a confidentiality agreement from all health professionals to whom information regarding the specific identity and concentration of any chemical claimed to be a trade secret was disclosed as soon as circumstances permit. Nothing in this section shall be construed to prohibit a health professional from disclosing information received under this section to any person the health professional determines necessary in order to assist in the diagnosis or treatment of an individual, including, but not limited to, another health professional, a patient or a public health official. Nothing in this section shall be construed to prohibit a medical professional from making any report required by law or by professional ethical standards. This rule does not authorize a person to withhold information, including

[61] 78 Fed. Reg. at 31, 659-60, 31,677 (to be codified at 43 C.F.R. § 3162.3-3(j)(2)).

> information that may qualify for trade secret protection elsewhere in this section, that state or federal law requires to be provided to any health professional.

Other states, notably Colorado, have adopted similar provisions.[62]

c. Use of FracFocus

i. FracFocus as the Chemical Disclosure Registry of Choice

EDF supports the BLM using FracFocus as the primary Chemical Disclosure Registry for wells drilled on BLM lands. FracFocus is the only national clearinghouse for disclosure information around the country, and it is of significant and obvious benefit to the public. While FracFocus has certainly had its problems and growing pains, it is a work in progress that is steadily improving – and we expect it to continuously improve over time. Data quality is one area that needs improvement. This in part depends on implementing procedures to check for obvious mistakes in submitted information, but it largely depends on improved enforcement by regulatory agencies to make sure that operators are complying with the disclosure laws of particular jurisdictions. Effective enforcement, in turn, depends on integrating FracFocus with the Risk Based Data Management System used by most state agencies. The Ground Water Protection Council is currently integrating the two systems. Another area that needs improvement is enabling the public to search and aggregate disclosure records in a more robust way. FracFocus recently transitioned to an XML-based database, which sets the stage for

[62] *See, e.g.,* Colorado Oil and Gas Conservation Commission Rule 205a(b)(5):

> "Disclosure to health professionals. Vendors, service companies, and operators shall identify the specific identity and amount of any chemicals claimed to be a trade secret to any health professional who requests such information in writing if the health professional provides a written statement of need for the information and executes a confidentiality agreement, Form 35. The written statement of need shall be a statement that the health professional has a reasonable basis to believe that (1) the information is needed for purposes of diagnosis or treatment of an individual, (2) the individual being diagnosed or treated may have been exposed to the chemical concerned, and (3) knowledge of the information will assist in such diagnosis or treatment. The confidentiality agreement, Form 35, shall state that the health professional shall not use the information for purposes other than the health needs asserted in the statement of need, and that the health professional shall otherwise maintain the information as confidential. Where a health professional determines that a medical emergency exists and the specific identity and amount of any chemicals claimed to be a trade secret are necessary for emergency treatment, the vendor, service provider, or operator, as applicable, shall immediately disclose the information to that health professional upon a verbal acknowledgement by the health professional that such information shall not be used for purposes other than the health needs asserted and that the health professional shall otherwise maintain the information as confidential. The vendor, service provider, or operator, as applicable, may request a written statement of need, and a confidentiality agreement, Form 35, from all health professionals to whom information regarding the specific identity and amount of any chemicals claimed to be a trade secret was disclosed, as soon as circumstances permit. Information so disclosed to a health professional shall in no way be construed as publicly available."

enhanced searchability. In order to ensure that FracFocus maintains its momentum in improving critical functionalities like searchability, we call for the BLM to work with the Ground Water Protection Council to ensure that FracFocus meets BLM's needs, and for BLM to select a date after which, if FracFocus is not on track to meet BLM's needs, BLM will pursue an alternative public disclosure vehicle.

ii. Alternative disclosure pathways

Under the BLM proposal, operators may submit disclosure information to "FracFocus, another BLM-designated database, or in a Subsequent Report Sundry Notice."[63] To the extent that the information required to be disclosed is within the scope of FracFocus, the BLM should either require the use of FracFocus or the agency should itself upload the information received on Subsequent Report Sundry Notices (functionality that would enable the BLM do to so is being streamlined in updates to the FracFocus interface). One of the main features of FracFocus is that it is a national database designed to host the disclosure information for all wells drilled in the United States. Allowing the disclosure information from BLM wells to be fragmented between FracFocus and a separate, yet-undeveloped BLM archive would frustrate that purpose.

d. Hydraulic Fracturing versus Well Stimulation

Earlier versions of this rulemaking required disclosure of fluids used in "well stimulation," but this has since been narrowed to hydraulic fracturing. This narrowing is unnecessary and would exempt disclosure of stimulations using, for example, acid fracturing. The BLM should restore the original, broader, language. In the event such information cannot be reported to FracFocus, it is appropriate for the BLM itself to take custody of these data.

e. Master Lists

Numerous stakeholders have called for disclosure of stimulation fluid chemicals prior to stimulation activities, noting that such information can be used by landowners who may wish to conduct baseline water quality sampling prior to well development, and that such information is needed by regulators in order to assess and mitigate risk. We agree that chemical information should be provided prior to well development in order to address these needs and believe the most efficient and effective method for doing so would be to require operators and service companies to supply the BLM with master lists of chemicals proposed to be used in the coming year. This information should be broken down by geographic region, by both state and target formation. The rule should require that if a chemical is used that was not identified on an annual prospective master list, the master list should be immediately updated. Finally, operators should be required to provide a master list of chemicals *actually* used in the

[63] 78 Fed. Reg. at 31,676 (to be codified at 43 C.F.R. § 3162.3-3(i)).

preceding year – again, specified by state and target formation – and should include total volumes used for each chemical. Master lists should be made available on a publicly accessible website that allows user to search and sort information.

One way to collect this information is to tie it into hydraulic fracturing service company certification, described above in Section 1(m). We recommend appending the following language to the certification language in order to implement a Master List program:

> (c) In addition to the other requirements of this section if an HF service company or operator seeking designation as an approved contractor by the BLM seeks to perform hydraulic fracturing treatments on BLM lands, the HF service company or operator (as the case may be) shall submit to the BLM, along with its request for approved contractor designation, the following additional information:
>
> > (i) A list of all base fluids that the HF service company or operator, as the case may be, expects to use in any hydraulic fracturing treatment performed on BLM lands;
> >
> > (ii) A list of all additives that the HF service company or operator, as the case may be, expects to use in any hydraulic fracturing treatment performed on BLM lands;
> >
> > (iii) A list of all chemicals, and their associated CAS numbers, the HF service company or operator, as the case may be, expects to use in any hydraulic fracturing treatment performed in the state; provided, however, in those limited situations where the identity of any such chemical, and its associated CAS number, is entitled to be withheld as a trade secret under BLM rules, then (i) the requesting party shall supply both the identity of such chemical and the chemical family associated with such chemical to the BLM, (ii) the BLM shall protect and hold confidential the identity of such chemical and its associated CAS number and (iii) the BLM shall identify where chemical information is withheld and disclose the chemical family associated with such chemical on any report or list that the BLM makes available to the public; and
> >
> > (iv) Contact information for the authorized agent of the HF service company or operator, as the case may be, that can provide health professionals with the chemical information required to be disclosed by BLM rules.

> The HF service company or operator, as the case may be, shall provide updated information to the BLM within thirty (30) days of the date any of the information described above becomes inaccurate or incomplete.
>
> (d) The BLM shall post all information provided under this section to a publicly accessible website along with instructions for health professionals on how to obtain the chemical information required to be disclosed by BLM rules, including any such chemical information that qualifies for trade secret protection.

III. Wastewater

Much work remains to be done in future rulemakings to improve agency rules governing waste management and disposition – particularly as relates to waste characterization, waste tracking, construction and maintenance of storage facilities, spill prevention and containment, leak detection, and other issues. Currently, many of those practices are unregulated or are governed by Onshore Orders and Instruction Memoranda that are decades old and in need of overhaul. These comments will address the two modest changes made in the proposed rule related to the storage, handling, and disposition of wastewater.

First, the proposed rule requires storage of all recovered fluids (flowback and produced water) in lined pits or tanks.[64] This is a positive change – moving the agency away from a long outdated policy of allowing the use of unlined pits for storage. We understand the definition of lined pits to be incorporated by reference from Onshore Oil and Gas Order No. 7, Disposal of Produced Water: "... an excavated and/or bermed area that is required to be lined with natural or manmade material that will prevent seepage. Such pit shall also include a leak detection system."[65] We would include the following clause to the language in 2(h): after "Storage of all recovered fluids must be in either tanks or lined pits," add "Procedures shall be in place to routinely monitor the integrity of the liner of the pit." This requirement would be in line with Texas RRC 3.8:[66]

> (I) Procedures shall be in place to routinely monitor the integrity of the liner of pit. If liner failure is discovered at any time, the pit shall be emptied and the liner repaired prior to placing the pit back in service. Acceptable monitoring procedures include an annual visual inspection of the pit liner or the installation of a double liner and leak detection system. Alternative monitoring procedures may be approved by the director if

[64] 78 Fed. Reg. at 31,676 (to be codified at 43 C.F.R. § 3162.3-3(h)).
[65] Onshore Oil and Gas Order No. 7(II)(G); 58 Fed. Reg. 58,506 (Nov. 2, 1993).
[66] 16 TEX. ADMIN. CODE § 3.8.

the operator demonstrates that the alternative is at least equivalent in the protection of surface and subsurface water as the provisions of this section.

> (II) The liner of a pit with a single liner shall be inspected annually to ensure that the liner has not failed. This inspection shall be completed by emptying the pit and visually inspecting the liner.
>
> (III) If the operator does not propose to empty the pit and inspect the pit liner on at least an annual basis, the operator shall install a double liner and leak detection system. A leak detection system shall be installed between a primary and secondary liner. The leak detection system must be monitored on a monthly basis to determine if the primary liner has failed. The primary liner has failed if the volume of water passing through the primary liner exceeds the action leakage rate, as calculated using accepted procedures, or 1,000 gallons per acre per day, whichever is larger.
>
> (IV) The operator of the pit shall keep records to demonstrate compliance with the pit liner integrity requirements and shall make the records available to commission personnel upon request.

Second, the rule requires operators to report the total volume of flowback and produced water recovered, the methods used for wastewater handling, and the methods used for wastewater disposal. These basic reporting requirements are a step in the right direction – however, significant deficiencies remain in BLM's wastewater disposal program.

Of particular concern, this rulemaking does nothing to modernize an antiquated provision in Onshore Order Number No. 7, Disposal of Produced Water, Section III. B. that permits "disposal" of oilfield fluids through pit evaporation.[67] Properly designed and maintained pits

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[67] Onshore Oil and Gas Order No. 7(III)(B):

> (1)(b) On-lease disposal: Disposal of water in pits. When approval is requested for disposal of produced water in a lined or unlined pit, the operator shall submit a Sundry Notice, Form 3160-5. The operator shall comply with all the applicable Bureau of Land requirements and standards for pits established in this Order. On National Forest lands, where the proposed pit location creates new surface disturbance, the authorized officer shall not approve the proposal without the prior approval of the Forest Service.
>
> . . . .
>
> (2)(a)(ii) Off-lease disposal: On leased or unleased Federal/Indian lands. Disposal of water in pits. When approval is requested for removing water that is produced from wells on leased Federal or Indian lands and is to be disposed of into a lined or unlined pit located on another lease or unleased Federal lands, the operator shall submit to the authorized officer a Sundry Notice, Form 3160-5.
>
> . . . .

can be appropriate options for flowback and produced water *storage* but are not appropriate disposal options. The Texas Railroad Commission adopted a statewide order prohibiting operators from using pits for evaporative disposal of oil field wastes in 1967[68] – that such an allowance would remain on BLM's books in 2013 is highly troubling. These provisions should be eliminated.

Finally, the BLM should clarify language regarding handling of recovered fluid. In proposed 3162.3-3 Subsequent well operations; Hydraulic fracturing, section (i)(5)(iii) appears to reference the "hauling by truck, or transporting by pipeline" as a disposal method.[69] Clarification is needed to identify potential disposal method(s) as opposed to methods of transportation.

IV. Definition of Usable Quality Water

EDF applauds the BLM's desire to protect not just "fresh water" but usable quality water generally, and we appreciate that the agency has attempted to correct problems with a prior definition of the term "usable water." In regard to the currently proposed definition, we generally endorse comments being filed by the Clean Air Task Force, Clean Water Action, Natural Resources Defense Council, and Sierra Club.

V. Air Quality and Methane Emissions

> (2)(b)(ii) Disposal of water on State and privately- owned lands: Disposal of water in pits. When approval is requested for removing water that is produced from wells on leased Federal and/or Indian lands and is to be disposed of into a pit located on State or privately- owned lands, the operator shall submit to the authorized officer, in addition to a Sundry Notice, Form 3160-5, a copy of the permit issued for the pit by the State or any other regulatory agency, if required, for disposal in such pit. Submittal of the permit will be accepted by the authorized officer and approval will be granted for removal of the produced water unless the authorized officer states in writing that such approval will have adverse effects on the Federal/Indian lands or public health and safety. If such a permit is not issued by the State or other regulatory agency, the requested removal of the produced water from leased Federal or Indian lands will be denied.

[68] *A Chronological Listing of Key Events in the History of the Railroad Commission of Texas (1960-1979)*, RAILROAD COMM'N OF TEXAS, http://www.rrc.state.tx.us/about/history/chronological/chronhistory03.php (discussing adoption of Statewide Rule 8).

[69] 78 Fed. Reg. at 31,676 (to be codified at 43 C.F.R. § 3162.3-3(i)(5)(iii)).

While outside the scope of this particular rulemaking, BLM has the authority and the obligation to more stringently regulate emissions of air toxics and methane from oil and gas production on BLM land. We reiterate here (and attach as an appendix) our comments on air quality and methane emissions submitted with respect to BLM's original oil and gas production rulemaking in September 2012. We look forward to working with BLM on a timely subsequent rulemaking dealing with these important issues.

Respectfully submitted,

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September 10, 2012

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.

Re: Oil and Gas; Well Stimulation; Including Hydraulic Fracturing, on Federal and Indian Lands, 77 Fed. Reg. 27,691 (May 11, 2012).

EDF appreciates the opportunity to submit these comments on the Bureau of Land Management's ("BLM's") proposed rule, Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands, 77 Fed. Reg. 27,691 (May 11, 2012) ("Proposed Rule"). Environmental Defense Fund (EDF) is a non-profit, non-partisan, non-governmental environmental organization that combines law, policy, science, and economics to find solutions to today's most pressing environmental problems.

EDF supports the BLM's efforts to mitigate the health and environmental impacts of oil and natural gas development on federal lands, and we have addressed many specifics in the proposed rules in separately-filed comments. We provide these brief, supplementary comments to stress the importance that the final rule address air quality impacts associated with oil and natural gas development on federal lands, including significant emissions of methane, which is a potent climate forcer. We also respectfully recommend a self-certification program to help ensure compliance with these important air quality measures.

I. BLM's Statutory Authority to Address Air Quality on Federal Lands

The federal laws governing the Department of Interior's ("DOI's") authority to manage and lease the public lands it administers require that the Department protect human health and the environment from harmful air pollution associated with oil and gas development and to minimize waste and degradation of the resources it manages. The Federal Land Policy and Management Act of 1976 ("FLPMA") requires DOI manage the public lands in a manner that "that will protect the quality of . . . air and atmospheric . . . values,"[1] and further requires the

[1] 43 U.S.C. § 1701(a)(8).

Department to "prevent permanent impairment of the quality of the environment."[2] FLPMA also includes a mandate to "by regulation or otherwise, take any action necessary to prevent unnecessary or undue degradation of the lands."[3]

DOI has delegated management of oil and gas leases to BLM,[4] which has implemented the statutory provisions through regulations. The standard lease form that governs the contract between BLM and all lessees seeking to develop an oil and gas lease requires that oil and gas operators "conduct operations in a manner that *minimizes adverse impacts to the land, air,* and water, to cultural, biological, visual, and other resources, and to other land uses or users."[5] (emphasis added). In carrying out activities on federal lands, lessees must comply with environmental obligations imposed by BLM, including conducting operations in a manner which protects environmental quality and controls pollution.[6]

These statutory provisions and implementing regulations provide manifest authority for BLM to issue air quality regulations, and the agency must do so to fulfill its statutory mandate to manage public lands in a manner that "that will protect the quality of . . . air and atmospheric . . . values."

II. Importance of Reducing Air Emissions from Oil and Natural Gas Operations on Federal Lands

Oil and natural gas operations on federal lands emit significant amounts of deleterious air pollution, including smog-forming Volatile Organic Compounds ("VOCs"); hazardous air pollutants like benzene, a known carcinogen; and methane, which is a contributor to tropospheric ozone and a potent climate forcer.

Methane has a warming potential seventy-two times that of carbon dioxide over the short term (twenty years) and twenty-five times that of carbon dioxide over a longer time-frame (one-hundred years).[7] In addition to its climate impacts, methane contributes to higher global

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[2] *Id.* at §§1702(c).

[3] *Id.* § 1732(b); *see also* Proposed Rule 76 Fed. Reg. at 27,694.

[4] *See* BLM oil and gas leasing and operations regulations at 43 C.F.R. pts. 3100 and 3160.

[5] BLM Offer to Lease and Lease for Oil and Gas, Form 3100-11, at 4 (October 2008).

[6] *See* BLM leasing regulations at *Id*. pt. 3160 et seq.

[7] The values of 25 and 72 are methane's global warming potential (GWP); GWP is a commonly used concept to compare the radiative forcing of GHGs relative to that of CO2. The Intergovernmental Panel on Climate Change (IPCC) typically uses a 100-year time horizon for the calculation of GWP; but a 20-year horizon is sometimes used.

background concentrations of ozone pollution.[8] According to EPA's most recent greenhouse gas inventory, natural gas and petroleum systems represent 37% of U.S. methane emissions, making them the largest domestic source of methane.[9] Moreover, a recent paper from the National Oceanic and Atmospheric Administration measured methane concentrations in the Denver-Julesburg Basin in Colorado and concluded that "the methane source from natural gas systems in Colorado [estimated using EPA's State Inventory Tool] is most likely underestimated by at least a factor of two."[10]

Reducing methane and other air pollution from oil and natural gas operations on federal lands satisfies two of BLM's statutory charges. Reducing this climate altering pollution helps to "protect the quality of . . . air and atmospheric . . . values." At the same time, because methane is the primary constituent of natural gas, reducing methane emissions often involves plugging leaks across the system, capturing natural gas that would otherwise be lost to the atmosphere. In reducing air pollution, then, BLM is also helping to satisfy its mandate to develop resources on federal lands in a way that avoids unnecessary or undue degradation. Hence, BLM's statutory charge makes the agency uniquely situated to adopt protective clean air measures that reduce pollution and conserve valuable resources.

In satisfying this mandate, EDF respectfully urges that BLM issue air quality regulations that comprehensively cover all wells that are pollution sources in the oil and natural gas sector. Indeed, the Proposed Rule provides non-air quality requirements for hydraulically fractured wells, and it is essential that air quality regulations similarly address any well that discharges a significant amount of pollution. This is particularly critical given rapidly shifting market fundamentals which are driving development of co-producing wells in liquids-rich plays. These wells can produce significant amounts of both oil and natural gas, and evidence indicates that companies are pouring extensive capital resources into developing these liquids-rich plays.[11] It is critical, therefore, that BLM's air quality regulations address the significant pollution from these sources.

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[8] J. Jason West et al., *Global Health Benefits of Mitigating Ozone Pollution with Methane Emission Controls*, 103 PROC. NAT'L ACAD. SCI. 3988, 3989 (2006).

[9] EPA, METHANE EMISSIONS, HTTP://WWW.EPA.GOV/CLIMATECHANGE/GHGEMISSIONS/GASES/CH4.HTML.

[10] PÉTRON , *supra* note **Error! Bookmark not defined.** at 18.

[11] For instance, Chesapeake Energy plans to allocate 85% of its drilling capital expenditures to liquids-rich plays and operate only 24 dry-gas rigs in 2012, a decline of 50 dry-gas rigs from its 2011 average. Chesapeake Energy, "Chesapeake Energy Corporation Updates Its 2012 Operating Plan in Response to Low Natural Gas Prices," January 23, 2012, http://www.chk.com/news/articles/pages/1651252.aspx. Shell is likewise planning a $1 billion investment to target liquids-rich plays like the Eagle Ford. NGI's Shale Daily, **"**Shell to Focus on Liquids-Rich Assets, Leverage Gas", February 6, 2012

Any comprehensive program to mitigate methane and other air pollution must include, among other things, requirements that address the following emissions:

- Well-Completions: Require green completions at all significant pollution sources.
- Pneumatic Controllers. Require existing pneumatic controllers to be low or no-bleed.[12]
- Well-site Fugitive Emissions. Require LDAR (or DI&M)[13] to detect and repair leaking pumps, flanges, seals, connectors, etc. located at well sites.
- Glycol Dehydrators. Require area source dehydrators to control emissions by 95% or 98%.[14]
- Crude Oil / Condensate / Produced Water Tanks. Require existing condensate (including those that emit less than 6 tons per year VOCs) to control emissions by 98 percent.[15]
- Pneumatic Pumps. Require 98% VOC control.[16]
- Workovers. Require Reduced Emission Completions.
- Reciprocating Internal Combustion Engines. Require post-combustion controls such as selective catalytic reduction for lean burn engines and non-selective catalytic reduction with air fuel controller for rich burn engines.[17]

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[12] CO. Department of Public Health and Environment Reg. 7, XVIII; Colorado Oil and Gas Conservation Commission Rule 805(b)(2)(E).

[13] LDAR (Leak Detection and Repair) requires operators check for fugitive leaks at specified thresholds and at regular intervals, and then repair leaks above thresholds within a certain time. (DI&M) Directed Inspection and Maintenance requires operators conduct a baseline survey to identify leaky equipment, and then only repair those that are cost-effective to fix. Subsequent leak detection surveys are designed based on data from prior surveys, allowing operators to concentrate repairs on those components most likely to leak and profitable to repair.

[14] Colorado currently requires Single or co-located glycol dehydrators at adjacent or contiguous E&P sites, natural gas compressor stations, drip stations, or gas processing plants with total VOC emissions ≥15 Tpy must reduce emissions from still vents and vents from gas-condensate-glycol separators by 90%. CO. Department of Public Health and Environment Reg. 7, XVII.D and XII.H.

[15] Colorado currently requires existing and new tanks with 2 Tpy VOCs or more, under common ownership or operation in NA, NA/M, with cumulative emissions ≥30 Tpy must reduce overall emissions by 90% between May-Oct. and by 70% during the remainder of the year using a device capable of achieving 95% control efficiency (System-wide control strategy). [15] CO. Department of Public Health and Environment Regulation 7 at XII.D.2.(a)(x).

[16] Wyoming Department of Environmental Quality, Air Quality Division, Oil and Gas Production Facilities Chapter

[17] All rich burn RICE in the Colorado ozone nonattainment area have NSCR controls due to requirements for such engines in Colorado's AQCC Regulation 7 and The Colorado Dept. of Health and Environment is considering additional post-combustion controls for other engines in the state. See RAQC Planning Tool.

III. Self Certification Compliance Framework

Finally, EDF respectfully suggests that BLM extend its reliance on self-certification measures in the Proposed Rule to air quality requirements designed to reduce methane and other harmful pollutants. The Proposed Rule already contains several self-certification provisions,[18] and such provisions can enhance accountability and serve as an important piece of an overall framework to ensure compliance with these important air quality measures.

Robust compliance and enforcement mechanisms are necessary in order to ensure that the public reaps the clean air benefits of any air quality standards. Publicly-available data documenting compliance and enforcement with required emission standards, as well as periods of non-compliance, is essential to ensuring compliance and transparency. In particular, citizens living near oil and gas activities should be able to rest easy that the air outside their homes is safe to breathe. Penalties for non-compliance with the standards must be met with stringent penalties including criminal liability. Repeated failure to comply with the proposed standards should result in temporary or permanent restrictions on production operations.

A rigorous program should have the following attributes:

1) Certification of truth, accuracy and completeness;
2) Certification by a senior company official;
3) Documentation of periods of non-compliance;
4) Publicly-available compliance reports; and
5) Stiff penalties for non-compliance.

A well-designed self-certification requirement is an essential element of a rigorous compliance and enforcement program but is not sufficient standing alone and may not supplant vital government compliance and enforcement responsibilities.

IV. Conclusion

Thank you for this opportunity to comment on the Proposed Rule. EDF supports rigorous pollution control requirements governing oil and natural gas development on federal lands, and we respectfully urge that the Bureau incorporate air quality requirements – including methane mitigation measures – into its final rulemaking package.

[18] *E.g.*, 43 C.F.R. § 3162.3–3(g)(9) (operator self-certification with respect to well bore integrity).

Sincerely,

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