September 25, 2017

Via e-filing on www.regulations.gov

Ms. Katharine S. MacGregor, Deputy Assistant Secretary
United States Department of the Interior

Mr. Michael D. Nedd, Acting Director
Bureau of Land Management

Attn: 1004-AE52
Mail Stop 2134LM
1849 C Street NW
Washington, DC 20240

Re: RIN 1004-AE52. *Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands; Rescission of a 2015 Rule* (82 Fed. Reg. 34,464).

Dear Ms. MacGregor and Mr. Nedd:

On July 25, 2017, the Bureau of Land Management ("BLM") published a proposed rule that would rescind a final rule BLM issued in March 2015. The "2015 Rule" was designed to regulate hydraulic fracturing on federal and Indian lands.[1] This submission constitutes comments on the July 2017 proposal from the Independent Petroleum Association of America ("IPAA") and the Western Energy Alliance (the "Alliance") (collectively, the "Associations"). The Associations collectively represent thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts. It is the members of these groups that the proposed rescission will most significantly affect.[2] Independent

---

[1] 80 Fed. Reg. 16,128 (Mar. 26, 2015).

[2] The typical independent oil and natural gas producer is a small business which employs twelve full-time and three part time employees. *See* Independent Petroleum Ass'n of Am., *Profile of Independent Producers* at 2 (2012-2013) (describing the median size of independent oil and natural gas producing firms based on a survey of IPAA members), available at:
http://www.ipaa.org/wp-content/uploads/downloads/2014/07/2012-2013ProfileOfIndependentProducers.pdf.

producers drill about ninety-five percent of American oil and natural gas wells, produce about fifty-four percent of American oil, and more than eighty-five percent of American natural gas.

From the beginning, the Associations have actively engaged to assist BLM's rulemaking efforts related to hydraulic fracturing. The Associations offered significant substantive comments responsive to each of the proposals BLM published before finalizing the 2015 Rule and the Associations' members have conducted dozens of formal and informal meetings with BLM officials to provide technical insight into how hydraulic fracturing is conducted on federal lands and to explain the likely environmental and economic consequences of BLM's regulatory efforts. The Associations are grateful that BLM now realizes that the one-size-fits-all solution the agency issued in 2015 was not an appropriate mechanism to address unsubstantiated public concern about hydraulic fracturing.

On March 20, 2015, four-and-a-half years after initiating the rulemaking process, BLM issued the 2015 Rule.[3] On the same day, IPAA and the Alliance jointly filed a lawsuit challenging the 2015 Rule. IPAA and the Alliance contend, among other arguments, that aspects of the 2015 Rule: (i) violate federal law; (ii) lack justification; (iii) do not account for meaningful technical comments submitted during the rulemaking process; (iv) do not represent a logical outgrowth from the regulations proposed during the rulemaking process; and/or (v) exceed BLM's statutory authority.

On September 30, 2015, the United States District Court for the District of Wyoming entered a preliminary injunction, precluding BLM from implementing the 2015 Rule during the pendency of litigation over the rule.[4] The district court determined that the 2015 Rule was likely to be found invalid under the Administrative Procedure Act because: (i) BLM has not identified any legally supportable justifications for adopting the 2015 Rule and imposing the costs associated with the rule; (ii) components of the 2015 Rule do not represent a logical outgrowth of BLM's regulatory proposals; (iii) the 2015 Rule's failure to protect confidential commercial information is contrary to federal law; (iv) certain provisions of the 2015 Rule represent an unexplained departure from existing policies; (v) components of the 2015 Rule are irrationally structured making compliance impossible; (vi) the 2015 Rule's cost assessments rely on unsupported assumptions; and (vii) BLM lacks statutory authority to implement the 2015 Rule.

On June 21, 2016, the federal district court entered its final ruling on the merits.[5] Consistent with its conclusions at the preliminary injunction stage, the district court ruled that BLM lacked statutory authority to promulgate the 2015 Rule. Because the district court's ruling on the question of statutory authority resolved all claims the rule's challengers presented, the

---

[3] Although announced on March 20, 2015, the final rule was published in the *Federal Register* on March 26, 2015.
[4] *Wyoming v. Jewell*, No. 2:15-CV-043-SWS (D. Wyo.), Order on Mots. for Prelim. Inj., filed Sept. 30, 2015 (ECF No. 119).
[5] *Wyoming v. Jewell*, No. 2:15-CV-043-SWS (D. Wyo.), Order on Pets. for Review of Final Agency Action, filed June 21, 2016 (ECF No. 219).

district court did not revisit the additional flaws in BLM's rulemaking identified during the preliminary injunction phase of the case.

On September 21, 2017, the United States Court of Appeals for the Tenth Circuit dismissed all remaining proceedings related to the lawsuit without addressing the merits of the case. The Tenth Circuit concluded that, given BLM's initiation of this rulemaking and the unequivocal executive orders that President Trump and Secretary Zinke have issued directing BLM to rescind the 2015 Rule,[6] it would be a waste of judicial resources to continue litigation over the 2015 Rule.[7] Among other factors influential to its decision, the Tenth Circuit noted expressly that the continuation of oil and gas development under the status quo would not pose any hardship to BLM or the environment.[8]

Equally important, irrespective of the final outcome, the lawsuit's procedural history is conclusive evidence that, at the least, numerous aspects of the rule are less than ideal and many cannot withstand legal scrutiny. Given that background, rescinding the rule and reconsidering the policies that led to the 2015 Rule's enactment is a worthy exercise. The Associations also note that, in engaging in that exercise, BLM need not over-complicate its current task; the agency instead has the benefit of the administrative record that was compiled in association with the preparation of the 2015 Rule. As described in these technical comments, that record has certain holes, but it also provides a wide platform to support and expedite BLM's efforts in the current rulemaking.[9]

The Associations appreciate BLM's willingness to reconsider the 2015 Rule at this time. The Associations ask that BLM carefully consider the concerns and technical evidence discussed in these comments and rescind the 2015 hydraulic fracturing rule.

---

[6] *See* discussion *infra* Part VI.

[7] *See Wyoming v. Zinke*, __ F.3d __, Nos. 10-8068 & 10-8069, 2017 WL 4173619 (10th Cir. Sept. 21, 2017). Because the Tenth Circuit concluded that the appeal of the district court's decision was prudentially unripe, it did not address the merits of that decision. *See id.* at 2017 WL 4173619, at *6. Though the district court's ruling has been vacated as a procedural matter, the Tenth Circuit has never reversed, or even criticized, that decision.

[8] *Id.*, 2017 WL 4173619, at *6.

[9] To facilitate BLM's use of the 2015 administrative record, citations in these technical comments to material included in the 2015 administrative record include the reference to the Bates ranges of the material in the administrative record that BLM lodged with the federal district court on January 19, 2016. Those citations are designated "A.R." throughout these technical comments.

Thank you for your consideration of these comments.

Barry Russell
President & CEO
Independent Petroleum Association of America

Kathleen Sgamma
President
Western Energy Alliance

TABLE OF CONTENTS

Page

I. <u>THE 2015 RULE DISREGARDED CONGRESSIONAL PURPOSE</u>.

When crafting regulations, BLM must consider the statutory mandates that define the agency's mission and guide its policy. The Mineral Leasing Act authorizes the Secretary of the Interior "to prescribe necessary and proper rules and regulations and to do any and all things necessary to carry out and accomplish the purposes of this [Act]."[10] The *very first sentence* of the Mineral Leasing Act explains that Congress' purpose in enacting the Act was "[t]o promote the mining of coal, phosphate, oil, oil shale, and sodium on the public domain."[11] Congress has determined that it is "in the national interest to foster and encourage private enterprise in," among other endeavors, "the orderly and economic development of domestic mineral resources, reserves, and reclamation of metals and minerals to help assure satisfaction of industrial, security and environmental needs."[12] And Congress has instructed that "[i]t shall be the responsibility of the Secretary of the Interior to carry out this policy when exercising his authority under such programs as may be authorized by law."[13]

As BLM recognized in the regulatory preamble to the 2015 Rule,[14] the Federal Land Policy & Management Act ("FLPMA") also obligates BLM to "manage the public lands under principles of multiple use and sustained yield."[15] To meet this obligation, BLM must consider "a combination of balanced and diverse resource uses that takes into account the long-term needs of future generations for renewable and nonrenewable resources."[16] Congress has directed that access to federal lands for energy development must be efficient. BLM is required "[t]o ensure timely action on oil and gas leases and applications for permits to drill" and to effect policy that: (i) "ensures[s] expeditious compliance" with the National Environmental Policy Act and any other applicable environmental and cultural resources laws; (ii) "improve[s] consultation and coordination with the States and the public"; and (iii) "improve[s] the collection, storage, and retrieval of information relating to the oil and gas leasing activities."[17] The result of this statutory scheme is that, while BLM has a responsibility to "prevent unnecessary or undue degradation of the [public] lands,"[18] accounting for the productivity of the federal mineral estate is a statutory imperative.

The 2015 Rule is divorced from each of the relevant considerations Congress prescribed in these statutes. Rather than promote Congress' express objective – environmentally responsible and cost-effective development of natural resources on federal lands – the 2015 Rule would have

---

[10] 30 U.S.C. § 189.
[11] Act of Feb. 25, 1920, ch. 85, § 32, 41 Stat. 437.
[12] Mining & Minerals Policy Act of 1970, 30 U.S.C. § 21a.
[13] *Id.*
[14] *See* 80 Fed. Reg. at 16,137.
[15] 43 U.S.C. § 1732(a).
[16] 43 U.S.C. § 1702(c).
[17] Energy Policy Act of 2005, 42 U.S.C. § 15921(a)(1)(A)-(C).
[18] 43 U.S.C. § 1732(b).

imposed a regulatory framework that increased the costs of development, added additional layers of permitting and delay, exposed confidential commercial data to public disclosure in violation of federal law, disregarded principles of comity between federal and state regulators, and failed to deliver any meaningful environmental benefit.[19] As BLM now recognizes, the 2015 Rule was "unnecessarily duplicative of state and some tribal regulations" and would have "impose[d] burdensome reporting requirements and other unjustified costs" on American oil and gas producers.[20] Because the 2015 Rule was regulation for regulation's sake, the Associations support rescission of the rule.

A. THE 2015 RULE WAS NEVER JUSTIFED.

The chief justification BLM identified for the 2015 Rule was "public concern about whether [hydraulic] fracturing can lead to or cause the contamination of underground water sources."[21] BLM's regulatory preamble for the 2015 Rule, however, did not contain any technical discussion related to the likelihood of hydraulic fracturing operations impacting underground water sources. To the contrary, the Lead Petroleum Engineer of BLM's Fluid Mineral Division, Subijoy Dutta — one of the principal authors of the 2015 Rule[22] — had previously declared the assertion that "[f]racking fluids from all hydraulic fracturing operations are getting into groundwater" as a "Myth."[23]

Mr. Dutta's position is consistent with the understanding of the federal government's most senior officials charged with implementing environmental policy during the rulemaking period for the 2015 Rule, including: two former Environmental Protection Agency ("EPA") Administrators; two former Secretaries of the Interior; two former BLM Directors; and the former Secretary of Energy.[24] Numerous commenters pointed out during the public comment

---

[19] "Energy dominance" this is not. As explained throughout these technical comments, regulatory provisions that complicate federal energy development or discourage production of federal minerals are inconsistent with both BLM's statutory obligations and executive guidance that the President and Secretary have issued.
[20] 82 Fed. Reg. at 34,464.
[21] 80 Fed. Reg. at 16,128.
[22] *Id*. at 16,217.
[23] A.R. at DOIAR0051928, *Hydraulic Fracturing - Myths & Realities* (July 12, 2012) ("Myths & Realities").
[24] *See* A.R. at DOIAR0056627-28, Pub. Cmt., Am. Petroleum Inst. ("API") (Aug. 23, 2013) (collecting comments of senior government officials acknowledging a lack of confirmed cases of groundwater contamination resulting from hydraulic fracturing). These officials include: (i) former EPA Administrator Lisa Jackson ("There is no proven case where the fracking process itself has affected water."); (ii) former BLM Director Robert Abbey ("BLM has never seen any evidence of impacts to groundwater from the use of fracking technology on wells that have been approved by [BLM]... We believe based upon the track record so far that it is safe."); (iii) former Secretary of the Interior Ken Salazar ("With respect to hydraulic [fracturing] because it occurs so far underground we don't know any examples of [impacts] on public lands."); (iv) EPA Administrator Gina McCarthy "I am not aware of any definitive determinations that would contradict those statements [by Lisa Jackson, referenced above.]."); (v) BLM Director Neil Kornze ("I don't think we are aware of any clear approving cases."); (vi) Secretary of the Interior Sally Jewell ("I'm not aware of documented cases."); (vii) EPA Senior Advisor Ken Kopocis ("No, I am not [aware

continued on next page…

process preceding the issuance of the 2015 Rule that both experts and government regulators have repeatedly acknowledged a lack of any evidence linking the hydraulic fracturing process to groundwater contamination.[25] Yet the regulatory preamble for the 2015 Rule failed to reference a single confirmed case of hydraulic fracturing contaminating groundwater. This omission was particularly noteworthy given the extensive evidence in the administrative record documenting the lack of such incidents, particularly in light of the widespread use of hydraulic fracturing.[26]

Public concern was a perfectly legitimate reason for BLM to initiate a rulemaking, to investigate aspects of how hydraulic fracturing is used on federal lands, and to gather data about the impacts of hydraulic fracturing; but public concern alone was not sufficient legal justification for the final rule. "[U]nsubstantiated assumptions are insufficient justification and rational[e] to support [an agency's] promulgation of [] regulation."[27] Having never offered a technical basis or reason for promulgating the rule, it is reasonable for BLM to withdraw the 2015 Rule now.

B. THE 2015 RULE WAS ALWAYS DUPLICATIVE.

As BLM now recognizes, the 2015 Rule failed to account for states' long history of successfully regulating oil and gas development, including hydraulic fracturing. BLM acknowledged during the rulemaking for the 2015 Rule that "[s]ome states, including Alaska, Arkansas, Colorado, Illinois, Michigan, New Mexico, Ohio, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming have regulations in place addressing hydraulic fracturing operations."[28] BLM did not, however, explain how it identified these specific states or why it failed to include

---

…continued from previous page

of documented cases]."); and (viii) Secretary of Energy Ernest Moniz ("To my knowledge I still have not seen any evidence of fracking, per se, contaminating groundwater.").

[25] *See id.*; A.R. at DOIAR0056216-56222, Pub. Cmt., IPAA & W. Energy Alliance ("IPAA") (Aug. 22, 2013) (collecting studies and commentary from both experts and government regulators repeatedly acknowledging a lack of any evidence linking the hydraulic fracturing process to groundwater contamination).

[26] *See e.g.*, A.R. at DOIAR0065277, King & King, *Envtl. Risk Arising from Well Constr. Failure: Difference Between Barrier & Well Failure, & Estimates of Failure Frequency Across Common Well Types, Locations & Well Age*, Soc'y of Petroleum Eng'rs 166142 (2013) (observing that a study of 16,000 horizontal shale wells drilled in Texas failed to identify "a single groundwater contamination incident resulting from site preparation, drilling, well construction, completion, hydraulic fracturing stimulation, or production operations at any of these horizontal shale gas wells"); *id.* at DOIAR0051928, *Myths & Realities*, *supra* n. 23 (Dutta observing that "[h]ydraulic fracturing has been deployed more than 57,000 times in Kansas since 1947 with no documented cases of groundwater contamination"); *id.* at DOIAR0052533, Testimony of Cathy P. Foerster, Alaska Oil & Gas Conservation Comm'n Chair and Eng'g Comm'r (July 24, 2013) ("Moreover in its history of oil and gas operations Alaska has yet to suffer a single documented instance of subsurface damage to an underground source of drinking water."); *id.* at DOIAR0053101, "Four Corners Tribal Summit" (Aug. 2013) (emphasizing that although "Hydraulic fracturing has been going on in the San Juan since the 40s . . . [t]here has never been an incident of water contamination in the San Juan.").

[27] *Serv. Emps. Int'l Union, AFL-CIO, v. Gen. Servs. Admin.*, 830 F. Supp. 5, 10 (D.D.C. 1993) (emphasizing that an agency must rely on evidence, and not conclusory statements, to justify a rulemaking).

[28] 80 Fed. Reg. at 16,130.

numerous other states that had regulations addressing hydraulic fracturing at the time. BLM's list of states with hydraulic fracturing regulations notably omitted three states with significant activity on federal lands — California, Montana, and North Dakota — all of which had rules addressing hydraulic fracturing at the time the 2015 Rule was issued.[29] BLM also failed to recognize numerous other states identified in the administrative record that had regulations addressing hydraulic fracturing.[30]

The most significant omission, however, was not states that *did* have regulations governing hydraulic fracturing, but BLM's failure to identify any states that *did not* have regulations adequate to achieve the objectives of the 2015 Rule. BLM did not identify a single jurisdiction in which it contended hydraulic fracturing occurs on federal lands without sufficient regulatory protections. BLM presented no evidence that the 2015 Rule would be more effective in practice than existing state regulations protecting water and other environmental values.[31] Because BLM did not "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made," the 2015 Rule lacked justification as a matter of administrative law.[32]

The failure to conduct a meaningful review of existing state and tribal law undermined the legitimacy of the 2015 Rule. For BLM to properly assess the incremental impact the 2015 Rule would have had on oil and gas operations, it was essential for the agency to understand what operators were doing under then-existing law. It was impossible for BLM to quantify (or even qualify) the environmental benefits the 2015 Rule might have provided without knowing how the rule's requirements differed from those already in force; and BLM could not have accurately calculated the costs the 2015 Rule would have imposed without a comprehensive understanding of state law.[33]

---

[29] *See* CAL. CODE REGS. tit. 14, §§ 1751-89 (2015); MONT. ADMIN. R. 36.22.601-608 & 36.22.1001-1016; N.D. ADMIN. CODE 43-02-03-27.1.

[30] *See* A.R. at DOIAR0056214-216, Pub. Cmt., IPAA (citing regulations in additional states including Alabama, Arizona, Louisiana, Mississippi, Nevada, and South Dakota).

[31] In fact, senior officials within the agency warned that "[d]iverting [BLM's] resources from those important duties [related to public safety] to duplicate state functions that to date have proven to be 100% successful in preventing harm to the environment does not seem to be an effective or efficient use of limited taxpayer funds." A.R. at DOIAR0009170, Mem. from Jerry Stranahan, Branch Chief, Fluid Minerals, Colo. State Office to Steven Wells (Dec. 22, 2011). *See also* A.R. at DOIAR0026852, Mem. from Robin L. Hansen, Senior Petroleum Eng'r, Vernal Field Office to Dep't of Interior (Aug. 16, 2012) ("Will the implementation of the new regulations add any additional protection to the useable water zones than the regulations and field office requirements that are currently imposed on oil and gas operators under the Vernal Field Office at present? The answer is no.").

[32] *Sorenson Comm'cns, Inc. v. Fed. Comm'cns Comm'n*, 567 F.3d 1215, 1220-21 (10th Cir. 2009) (holding restrictions on lobbying expenses promulgated without justification were arbitrary and capricious).

[33] Indeed, the cost estimates that were prepared during the rulemaking process for the 2015 Rule made significant errors based on incorrect technical assumptions regarding existing requirements under state law. A more detailed discussion of these errors is contained in Part VIII of these technical comments.

Had BLM undertaken a comprehensive review of state regulations at the time it promulgated the 2015 Rule, the agency would have understood that states and tribes were adequately protecting public lands and that no additional layer of regulation was necessarily for BLM to satisfy its custodial obligations on federal lands. Not only was state regulation sufficient, it is preferable because it accounts for localized geology, operational conditions, socio-economic factors, and policy preferences.

C. FRACK HITS WERE NOT A PART OF THE PREVIOUS RULEMAKING.

Lacking substantial evidence of groundwater contamination, BLM attempted to justify the final rule based as an effort to prevent "frack hits."[34] "Frack hits," defined as an "unplanned surge of pressurized fluid into another well,"[35] involve the transmission of fluids from one wellbore in a producing formation to another wellbore in that same formation. "Frack hits" were an alleged problem BLM identified after the close of the comment period for the 2015 Rule — the term "frack hits" does not appear in the August 2013 supplemental proposed rule.[36]

Measures to protect against "frack hits" were not presented during the rulemaking preceding the issuance of the 2015 Rule. A review of the administrative record BLM compiled in association with the 2015 Rule demonstrates a failure to consider essential technical, legal, and policy questions. Those questions include, among others: (i) whether BLM has statutory authority to issue regulations to address "frack hits"; (ii) whether the provisions of the 2015 Rule meant to protect against "frack hits" would be effective from a technical perspective; (iii) who is financially responsible when repairs need to be made to offset wells to address concerns about "frack hits"; (iv) what are the legal and economic implications of compelling offset well owners to shut in, even temporarily; (v) what authority BLM has over offset well owners operating on private lands and developing private minerals; and (vi) what consequences might an order to shut in have on the correlative rights of offset well owners. These are all difficult and complicated technical, legal, and economic questions — the type of questions that notice and comment rulemaking are designed to help resolve.

Despite these questions remaining unanswered, the 2015 Rule would have nevertheless imposed a requirement that an operator wishing to conduct hydraulic fracturing submit a subsurface map of the zone to be fractured. Neither the 2015 Rule itself nor the regulatory preamble accompanying the rule provided any explanation regarding how BLM intended to use the information operators would have been required to submit or of how that information would

---

[34] *See* 82 Fed. Reg. at 34,465; 80 Fed. Reg. at 16,193.
[35] 80 Fed. Reg. at 16,148.
[36] *See* 78 Fed. Reg. 31,636 (May 24, 2013); *see also* 80 Fed. Reg. at 16,149 (conceding that the requirements in the final rule "that will allow the BLM to determine during the permit review process the potential for 'frack hits'" were not included in the supplemental proposed rule); A.R. at DOIAR0070125, *Policy Calls for the Hydraulic Fracturing Rule* (Dec. 20, 2013) ("The proposed rule does not address 'frack hits.'").

assist BLM "determine . . . the potential for frack hits."[37] BLM did not explain, if it was able to determine the potential for a "frack hit," how the agency intended to address that potential. The 2015 Rule does not acknowledge that BLM's regulatory authority could be limited when a well BLM determined might be affected is located on private land. It seems only that BLM intended to defer approval of hydraulic fracturing operations while BLM, case by case, attempted to interpret the required map and figure out what to do in response. The failure to properly analyze and consider these key aspects of the alleged "frack hits" problem is reason enough to rescind the 2015 Rule.

While there is much to say about the technical deficiencies in the 2015 Rule's treatment of "frack hits,"[38] the Associations believe that, as a matter of administrative law, any technical discussion must be deferred unless and until BLM submits a specific proposal for public consideration. That will allow the public to address the specific technical, legal, and economic questions that any specific proposal might invokes, rather than offer comments that lack both the context and precision necessary to assist BLM refine its policy choices. Whether "frack hits" represent a concern that BLM can and should address in a rulemaking is a policy question for another day. But because the issue of "frack hits" was not part of discussions between stakeholders and the agency during the rulemaking process for the 2015 Rule, it is reasonable that BLM would withdraw the 2015 Rule and defer issuance of any rule related to "frack hits" until the appropriate regulatory procedures are invoked.[39]

II. <u>THE 2015 RULE CANNOT BE JUSTIFIED NOW</u>.

As referenced above, the 2015 Rule lacked justification when it was issued. But the passage of time since BLM conducted the original rulemaking has further undermined each of

---

[37] 80 Fed. Reg. at 16,149.

[38] The 2015 Rule presumes, for example, that "frack hits" are an adverse incident that should avoided. A review of the literature, however, cast significant doubt on that premise. In the most thorough study to date, engineers from Schlumberger investigated 3,100 fracture interferences in 5 major basins – the Eagle Ford, Bakken, Haynesville, Niobrara, and Woodford – "to determine which basins are more prone to positive or negative fracture interferences from new infill wells." G. Miller et al., *Parent Well Refracturing: Economic Safety Nets in an Uneconomic Market* at 1, SPE-180200-MS (2016). The study found that "frack hits" could result in a range of outcomes, including improvements in production in offset wells. *See id.*, Table 1, at 7.

[39] The Chief of the BLM's Fluid Mineral Division, Steven Wells, conceded that measures to protect against "frack hits" in the 2015 Rule were not a logical outgrowth from the proposed rule and therefore cannot be implemented without a new notice allowing the public an opportunity to consider and comment on any specific proposal for provisions that relate to "frack hits." *See Wyoming v. Zinke*, 2:15-CV-00043-SWS (D. Wyo.), Tr. of Prelim. Injunction Proceedings at 90:5-91:7 (Naatz) (June 23, 2015). Wells was present in the courtroom when Dan Naatz, IPAA's Vice-President of Government Relations, testified regarding Wells' statements during a hearing in federal court. Neither Wells nor the Department of Justice made any effort to contradict Naatz' testimony during the hearing. As a matter of administrative law, the district court correctly observed that, "while frack hits may very well be a concern the BLM should address, they do not appear to be a valid justification for the Fracking Rule, particularly where they were not even raised as an issue in the supplemental rule." Prelim. Inj. Order, *supra* n.4, at 1535.

the sparse reasons BLM did offer in support of the 2015 Rule. Changes in law, technology, and public understanding of the hydraulic fracturing process all confirm that there is even less reason for the 2015 Rule now than there was at the time the rule was issued.

A. HYDRAULIC FRACTURING IS NOT NOVEL OR UNKNOWN.

BLM advises that it first began working on the 2015 Rule "in November 2010, when it held its first public forum amid growing public concern about the rapid expansion of complex hydraulic fracturing."[40] The contention that the alleged public concern resulted from "increased complexity" in hydraulic fracturing operations or "larger-scale operations,"[41] was always meritless. That argument did not account for detailed evidence in the record documenting the history of large-scale hydraulic fracturing operations, publicly available academic discussions of complex hydraulic fracturing operations dating back decades, and federal officials' acknowledgment that hydraulic fracturing is a "[w]ell stimulation technique that has been employed by the oil and gas industry since 1947."[42] The Associations note that the regulatory preamble to the 2015 Rule did not discuss which features of alleged "larger-scale operations" the 2015 Rule was meant to address nor did it describe how the 2015 Rule would account for the alleged "increased complexity" of contemporary oil and gas operations. To the contrary, BLM officials acknowledged that the oil and gas industry has been using hydraulic fracturing "since the late 1940s" and described hydraulic fracturing as "a proven process with minimal technical problems."[43]

But regardless whether hydraulic fracturing could be considered novel in 2010, the technique is certainly not unknown, un-researched, or otherwise mysterious in 2017. In April 2013, the Department of Energy estimated that at least two million oil and gas wells in the United States had been completed with hydraulic fracturing and noted that ninety-five percent of

---

[40] 80 Fed. Reg. at 16,128.
[41] *Id.*
[42] A.R. at DOIAR0027608, BLM, *Hydraulic Fracturing 101* (Aug. 29, 2012). *See also* A.R. at DOIAR0050813, Letter from Lee O. Fuller (IPAA) to Hon. Ron Wyden & Hon. Lisa Murkowski (May 30, 2013) (quoting Hr'g on the Sec'y of Energy Advisory Bd.'s Shale Gas Prod. Subcommittee's 90-day Report Before the S. Comm. on Energy & Natural Resources 4, 112th Cong. (Oct. 4, 2011) (written testimony of Stephen A. Holditch) ("I have been working in hydraulic fracturing for 40+ years and there is absolutely no evidence hydraulic fractures can grow from miles below the surface to the fresh water aquifers); *id.* at DOIAR0001188, Boyer et al., *Producing Gas from its Source*, OILFIELD REVIEW (Autumn 2006) (describing the application of "massive hydraulic fracturing treatments" in the Barnett Shale beginning in the mid-1980s); *id.* at DOIAR0025662, Adam Wilson, *Economic and Technology Drive Development of Unconventional Oil & Gas Reservoirs*, J. PETROLEUM ENG'G (July 2012) ("The increase in oil and gas process during the 1970s led to both an increase of rig count and the development of new technologies, such as massive hydraulic fracturing."); Sally Jewell, Sec'y, Dep't of the Interior, Nat'l Press Club Luncheon Series at 51:00-:10 (Oct. 31, 2013) ("Fracking has been an important tool in the toolbox for oil and gas for over fifty years."), available at: https://www.youtube.com/watch?v=oBXK4n80sBs.
[43] A.R. at DOIAR002408, Mem. from Michael D. Nedd, Assistant Dir., Minerals & Realty Mgmt. to Robert V. Abbey, Dir., BLM (Apr. 7, 2010).

new wells drilled today are hydraulically fractured.[44] In the three fiscal years after the Department of Energy issued that estimate, at least 4,480 oil and gas wells have been completed on federal lands alone.[45] Applying BLM's own estimates, it is likely that virtually all of these wells have been completed using hydraulic fracturing.[46] Yet notwithstanding the prolific amount of hydraulic fracturing activity, BLM acknowledges the "rarity of adverse environmental impacts" associated with hydraulic fracturing, both before the issuance of the 2015 Rule, and after the rule's promulgation during the time the rule was not in effect.[47]

BLM's observation that adverse environmental impacts are rare finds support in the administrative record the agency compiled during the rulemaking for the 2015 Rule. The regulatory preamble for the 2015 Rule cites only two reports, both involving wells in northern Pennsylvania not subject to BLM's existing regulations, for the proposition that hydraulic fracturing might threaten groundwater and other resources.[48] These reports are notable not only because the same group of researches authored each reports, but also because the conclusions reached in the studies are entirely ambivalent. Among those studies' conclusions: (i) there was "no evidence for contamination of the shallow wells near active drilling sites from deep brines and/or fracturing fluids,";[49] and (ii) "[t]he occurrences of saline water do not correlate with the location of shale-gas wells and are consistent with reported data before rapid shale-gas development in the region."[50] These conclusions are more consistent with the dominant theme of technical reports in the administrative record, concluding that "widespread and rapid upward migration of [hydraulic fracturing] fluid and brine through bedrock is not physically plausible."[51]

---

[44] U.S. Dep't of Energy, *How is Shale Gas Produced?* at 3 (Apr. 2013), https://energy.gov/sites/prod/files/2013/04/f0/how_is_shale_gas_produced.pdf .

[45] Bureau of Land Mgmt., *Pub. Lands Statistics*, Table 3-16, at 115 (FY 2016); Bureau of Land Mgmt., *Pub. Lands Statistics*, Table 3-16, at 116 (FY 2015); Bureau of Land Mgmt., *Pub. Lands Statistics*, Table 3-16, at 117 (FY 2014).

[46] 80 Fed. Reg. at 16,131 (estimating that ninety percent of wells drilled on federal lands in 2013 were stimulated using hydraulic fracturing).

[47] 82 Fed. Reg. at 34,467.

[48] 80 Fed. Reg. at 16,194.

[49] A.R. at DOIAR0004214, Stephen G. Osborn et al., *Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing*, Proc Nat'l Acad Sci USA 108:8172-8176 (2011).

[50] A.R. at DOIAR0009465, Nathaniel R. Warner et al., *Geochemical evidence for possible natural migration of Marcellus Formation brine to shallow aquifers in Pennsylvania*, Proc Nat'l Acad Sci 109:11961-11966 (2012).

[51] A.R. at DOIAR0056222. In moving papers filed in the lawsuit challenging the promulgation of the 2015 Rule, BLM referenced several other studies not included in the regulatory preamble. These studies, however, are just as equivocal as the citations included in the preamble. *See*, *e.g.*, A.R. at DOIAR0076071, Avner Vengosh et al., A Critical Review of the Risks to Water Resources from Unconventional Shale Gas Development & Hydraulic Fracturing in the United States, ENVTL. SCIENCE & TECH. (2014) ("Microseismic data suggest that the deformation and fractures developed following hydraulic fracturing typically extend less than 600 m above well perforations, suggesting that fracture propagation is insufficient to reach drinking-water aquifers in most situations."); A.R. at DOIAR0006644, Brian Mordick, *Risks to Drinking Water from Oil & Gas Wellbore Constr. & Integrity: Case Studies & Lessons Learned*, Natural Resources Defense Council (undated) (acknowledging hydraulic fracturing may occur when wellbore integrity is confirmed); A.R. at DOIAR0053075, R.E. Jackson et al., Groundwater Protection & Unconventional Gas Extraction: The Critical Need for Field-Based Hydrogeological Research, 51

---

continued on next page…

Perhaps most important, to the extent that any of the studies contained in BLM's original administrative record suggests a link between groundwater contamination and oil and gas production, the studies focus on well construction (not hydraulic fracturing) as the cause of that contamination. But BLM and each of the states in which federal oil and gas is produced well already had well construction rules. There was never any evidence in the administrative record that a ruled focused on hydraulic fracturing would have improved the degree of protection those existing rules related to well construction afford.

Analyses published subsequent to the close of the administrative record likewise confirm that potential risks to groundwater during oil and gas development were already regulated under existing state and federal law. In a comprehensive study of the effects of hydraulic fracturing on groundwater resources that EPA published in December 2016, EPA identified a number of factors associated with oil and gas development that EPA contended could, if handled irresponsibly, jeopardize groundwater resources: (i) water withdrawals in areas with low water availability; (ii) spills of chemicals and other hazardous substances at well sites; (iii) inadequate mechanical integrity of wellbores; (iv) injection of hazardous fluids directly into groundwater resources; (v) discharge of inadequately treated wastewater into surface water resources; and (vi) disposal of wastewater in inadequate pits.[52] Both before the 2015 Rule was issued and now: (i) states regulate water withdrawal through locally tailored systems of prior appropriation; (ii) hazardous waste from exploration and production activities is subject to regulation under Subtitle D of the Resource Conservation and Recovery Act and applicable state laws;[53] (iii) well construction is heavily regulated under state law;[54] (iv) injection of hazardous fluids into

---

…continued from previous page

GROUNDWATER 4 (July-Aug. 2013) (observing that "[t]here is no evidence that fracture propagation 'out-of-zone' to shallow groundwater has occurred from deep (> 1000m or >3000ft) shale gas reservoirs" and concluding that the "weight-of-evidence is that such fracture propagation is unlikely"); A.R. at DOIAR0084561, Thomas H. Darrah et al., *Noble gases identify the mechanisms of fugitive gas contamination in drinking-water wells overlying the Marcellus & Barnett Shales*, Proc Nat'l Acad Sci 111:14076-14081 (2014) ("Noble gas data appear to rule out gas contamination by upward migration from depth through overlying geological strata triggered by horizontal drilling or hydraulic fracturing."); A.R. at DOIAR0004638, Science Advisory Bd. Review, *DRAFT Hydraulic Fracturing Study Plan* (Feb. 7, 2011) (opining that horizontal drilling and hydraulic fracturing "may also have the advantage of limiting environmental disturbances on the surface because fewer wells are needed to access the natural gas resources in a particular area").

[52] Envtl. Prot. Agency, *Hydraulic Fracturing for Oil & Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States*, Exec. Summ. at 42 (Dec. 2016).

[53] 42 U.S.C. §§ 6941-6949a. *See also* Envtly. Prot. Agency, *Proper Mgmt of Oil & Gas Exploration and Production Waste*, https://www.epa.gov/hw/proper-management-oil-and-gas-exploration-and-production-waste (observing that oil and gas exploration and production wastes "are generally subject to non-hazardous waste regulation under RCRA Subtitle D and applicable state regulations").

[54] *See* Tables *infra* Part II.B.

groundwater resources is prohibited under federal and state regulation;[55] (v) both EPA and the states regulate wastewater discharges from field exploration, drilling, production, well treatment and well completion activities;[56] and (vi) states have comprehensive regulations of pits used to store oil and gas wastewater on both a temporary and permanent basis.[57] The notable conclusion from EPA's 2016 study is the acknowledgment that when identified risks are regulated in this manner, "impacts on drinking water resources from activities in the hydraulic fracturing water cycle could be prevented or reduced."[58]

While it is doubtless true that BLM need not wait until an adverse incident before taking regulatory action, it is equally true that BLM is not required to regulate simply because risk of an adverse incident is not zero. Because "FLPMA prohibits only unnecessary or undue degradation, not *all* degradation," BLM must ensure that regulatory measures do not prevent the extraction of federal minerals.[59] The Interior Board of Land Appeals has interpreted "unnecessary or undue degradation" to mean the occurrence of "'something more than the usual effects anticipated' from appropriately mitigated development."[60] More than speculation is required: "Without evidence that future injury will occur, it cannot be argued that degradation of the lands will occur, . . . or that the future degradation is unnecessary or undue."[61] Given the acknowledged rarity of adverse environmental impacts, BLM's decision to rescind the 2015 Rule is a reasonable action, consistent with the agency's mandate to promote multiple uses of the public lands.

B. HYDRAULIC FRACTURING IS HEAVILY REGULATED.

BLM has requested detailed information, "that would improve BLM's understanding of state and tribal regulatory capacity" with respect to hydraulic fracturing operations.[62] As BLM recognizes, "all 32 states with Federal oil and gas leases currently have laws or regulations that address hydraulic fracturing operations."[63] BLM has also observed previously that, from fiscal year 2010 to fiscal year 2013, more than 99.3 percent of all well completions on federal and Indian lands occurred in nine states: California, Colorado, Montana, New Mexico, North Dakota,

---

[55] *See* 43 C.F.R. § 3162.5-2(d)(2014) (requiring operators to "isolate freshwater-bearing [formations] and other usable water containing 5,000 ppm ["parts per million"] or less of dissolved solids . . . and protect them from contamination") and discussion *infra* Part IV.

[56] *See* 40 C.F.R. Part 435.

[57] *See* Tables *infra* Part II.B.

[58] *Hydraulic Fracturing for Oil & Gas*, *supra* n.52, at 42.

[59] *Theodore Roosevelt Conservation P'ship v. Salazar*, 661 F.3d 66, 78 (D.C. Cir. 2011) (holding setbacks that protected sage-grouse but which prevented natural gas extraction did not satisfy BLM's obligation to balance development with conservation).

[60] *Id.* ay 76 (D.C. Cir. 2011) (quoting *Biodiversity Conservation Alliance*, 174 IBLA 1, 5-6 (2008)).

[61] *Wyo. Outdoor Council*, 171 IBLA 108, 121-22 (2007) (internal quotations marks omitted).

[62] 82 Fed. Reg. at 34,467.

[63] *Id.*

Oklahoma, Texas, Utah, and Wyoming.[64] A review of *Public Lands Statistics* indicates that in the three years since, more than ninety-nine percent of all completions on federal lands occurred within the same nine states.[65] The tables below compare the regulations in these nine states to the 2015 Rule.

CALIFORNIA

2015 Rule	**Summary of 2015 Rule**	**Corresponding Cal. Law[66]**	**Analysis**
43 C.F.R. § 3160.0-5 Definitions.	• Adds definitions of terms related to hydraulic fracturing: *annulus*, *bradenhead*, *Cement Evaluation Log (CEL)*, *confining zone*, *hydraulic fracturing*, *hydraulic fracturing fluid*, *isolating or to isolate*, *master hydraulic fracturing plan*, and *proppant*. • Defines *usable water*, with some exceptions, as waters containing up to 10,000 parts per million of total dissolved solids.	§ 1761 § 1780 § 1781	• California rules or law apply or define each of the terms or variations thereof that BLM defined. (*See also* Cal. Pub. Res. Code §§ 3150 to 3159). • The California State Water Resources Control Board already defines "protected water" as water "with less than 10,000 milligrams per liter (mg/L) of total dissolved solids (TDS)" unless the water has been determined to be an exempt aquifer under federal regulations implementing the Underground Injection Control Program.[67]
43 C.F.R. § 3162.3-3(a)-(b) Subsequent well operations; Hydraulic fracturing.	• Applies operational standards associated with drilling and completion activity to "all hydraulic fracturing operations." • Extends normal requirements to isolate usable water and other minerals to all hydraulic fracturing operations.	§ 1761 § 1780 § 1782	• California rules apply to any well stimulation treatment "designed to enhance oil and gas recovery by increasing the permeability of the formation." "Well stimulation" includes: hydraulic fracturing, acid fracturing, and acid matrix stimulation (subject to certain acid volume threshold exemptions). • California requires, in addition to specific requirements in the well stimulation regulations, that "the

[64] *See* 80 Fed. Reg. at 16,187.
[65] Bureau of Land Mgmt., *Pub. Lands Statistics*, Table 3-16, at 115 (FY 2016) (2,156 out of 2,174 completions); Bureau of Land Mgmt., *Pub. Lands Statistics*, Table 3-16, at 116 (FY 2015) (1,572 out of 1,586 completions); Bureau of Land Mgmt., *Pub. Lands Statistics*, Table 3-16, at 117 (FY 2014) (709 out of 720 completions).
[66] The cited sections are from sections within Title 14 of the California Code of Regulations.
[67] State Water Resources Control Bd., *Model Criteria for Groundwater Monitoring in Areas of Oil and Gas Well Stimulation* (July 7, 2015), *available at:* http://www.waterboards.ca.gov/board_decisions/adopted_orders/resolutions/2015/notice_model_criteria.pdf.

2015 Rule	Summary of 2015 Rule	Corresponding Cal. Law[66]	Analysis
			operator shall follow all applicable well construction requirements." (§ 1782(b)).
43 C.F.R. § 3162.3-3(c) Subsequent well operations; Hydraulic fracturing.	• Requires pre-approval for all hydraulic fracturing. • Authorizes operator to submit a proposal for hydraulic fracturing with the operator's application for permit to drill or in a subsequent request for individual or multiple wells. • After initial approval of hydraulic fracturing operations, requires operator to submit new request if operator has "significant new information" about: (i) the geology of the area, (ii) the stimulation operation or technology to be used, or (iii) the anticipated impacts of the hydraulic fracturing operation to any resource.	§ 1783	• California rules require pre-approval for all well stimulation treatments and repeat well stimulation treatments (*see also* Cal. Pub. Res. Code § 3160(d)(1)) on an electronic form designated by the Oil & Gas Division. • California law authorizes the Division to consider well stimulation treatment permits with the original permit to drill or subsequent to the original permit. (Cal. Pub. Res. Code § 3160(d)(2)(A)). • Under California law, permits authorizing well stimulation treatments expire one year after issuance if operations have not commenced. (Cal. Pub. Res. Code § 3160(d)(4)).
43 C.F.R. § 3162.3-3(d) Subsequent well operations; Hydraulic fracturing.	• Requires operator seeking authorization for hydraulic fracturing to submit: (i) geologic information about the formation into which hydraulic fracturing fluids will be injected; (ii) measured or estimated depths of usable water; (iii) information about existing faults or fractures and other wells within one-half mile; (iv) information about the source of water to be used in hydraulic fracturing operations; (v) a proposed hydraulic fracturing design; (vi) proposed measured depths of perforations and estimated volume of fluid and pump pressure; and (vii) a plan for handling of recovered	§ 1783 § 1783.1 § 1783.2	• California requires operators intending to conduct well stimulation to submit a permit that contains comprehensive details regarding the hydraulic fracturing plan before commencing operations. (§ 1783.1). • Operators must notify the Division at least 72 hours before commencing stimulation activities to allow Division personnel to witness the activity and must notify the Division at least three hours before commencing to confirm that the operations are being conducted. (§ 1783). • Operators intending to stimulate a

611162170.7

2015 Rule	Summary of 2015 Rule	Corresponding Cal. Law[66]	Analysis
	fluids.		well must provide notice to nearby landowners detailing the nature and scope of intended activity and explaining the availability of baseline water testing and sampling at least 30 days in advance of commencing well stimulation activity. (§ 1783.2)
43 C.F.R. § 3162.3-3(e)-(f) Subsequent well operations; Hydraulic fracturing	• Before conducting hydraulic fracturing, requires operator to monitor flow rate, density, and treating pressure during cementing operations on any casing used to protect usable water and to submit a monitoring report at least 48 hours before hydraulic fracturing operations begin. • Requires operator to observe cement returns to the surface for surface casing. If there is any indication of inadequate cement, the operator must determine the top of cement with a cement evaluation log, temperature log, or other method approved by the authorized officer. • Requires operator to run a cement evaluation log, for casing not cemented to surface, to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone. • Requires operator to report "an indication of an inadequate cement job" within 24 hours of discovery and to run a cement evaluation log demonstrating that an inadequate cement job has been corrected before commencing hydraulic fracturing activities. • Requires operators to conduct a mechanical integrity test on	§ 1782 § 1784.1 § 1784.2	• California requires that "casing shall be sufficiently cemented or otherwise anchored in the hole in order to effectively control the well at all times." (§ 1782(a)(1)). • California requires operator to run a cement evaluation log or other cement test to demonstrate adequate cementing and isolation of geologic and hydrologic isolation of the producing formation before any well stimulation treatment. The results of the cement evaluation must be submitted to the Division 72 hours before well stimulation begins. (§ 1784.2(a)-(b)). • California requires that operators submit a drilling completion report, including the results of all cement tests, and all electrical, physical, or chemical logs, tests, or surveys within 60 days of ceasing drilling operations. (Cal. Pub. Res. Code § 3215(a)). • The Division is authorized to "order such tests and remedial work as . . . necessary to prevent damage to life, health, property, and natural resources," including "to prevent the infiltration of detrimental substances into underground or surface water suitable for irrigation or domestic purposes, to the best interests of the neighboring property owners and the public." (Cal. Pub. Res. Code § 3224). • California requires that "the

2015 Rule	Summary of 2015 Rule	Corresponding Cal. Law[66]	Analysis
	casing (testing to 100% of the anticipated surface pressure) or fracturing string (testing to 100% of the anticipated surface pressure minus the annulus pressure between the fracturing string and production casing) before hydraulic fracturing operations begin.		wellbore's mechanical integrity is tested and maintained." (§ 1782(a)(3)). • California requires pressure testing not more than 30 days before well stimulation treatment of all cemented casing strings and tubing strings to 100% of the maximum anticipated surface pressure. (§ 1784.1(a)(1)).
43 C.F.R. § 3162.3-3(g) Subsequent well operations; Hydraulic fracturing.	• Requires operators to continuously monitor annulus pressure during hydraulic fracturing operations. • Requires "immediate corrective action" if the annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation.	§ 1785	• California requires the operator to "continuously monitor and record" during well stimulation treatments: "(1) Surface injection pressure; (2) Slurry rate; (3) Proppant concentration; (4) Fluid rate; and (5) All annuli pressures." • California requires the operator to "terminate the well stimulation treatment and immediately provide the collected data to the Division" if an abnormal pressure event occurs. If an abnormal pressure event occurs, the operator must then perform "diagnostic testing" to ensure a breach has not occurred.
43 C.F.R. § 3162.3-3(h) Subsequent well operations; Hydraulic fracturing	• Requires storage of all recovered fluids in rigid and covered/netted tanks with no more than a 500 barrel capacity, subject to narrow exceptions for lined pits or larger tanks, unless a permanent disposal plan is approved.	§ 1775 § 1786 § 1788	• California requires all "well stimulation treatment fluid, additives, and produced water from a well that has had a well stimulation treatment" to "be stored in containers and . . . not be stored in sumps or pits." (§ 1786(a)(4)). • California requires oilfield wastes, including recovered fluids, must "be disposed of in such a manner as not to cause damage to life, health, property, freshwater aquifers or surface waters, or natural resources, or be a menace to public safety." (§ 1775).

2015 Rule	Summary of 2015 Rule	Corresponding Cal. Law[66]	Analysis
			• California requires, in applications for approval to stimulate a well, that operators must disclose "the disposal method identified for the recovered water in the flowback fluid." (§ 1788). • California requires operators to report the "source, volume, and specific composition and disposition of all water," including "all water used as base fluid during the well stimulation treatment and recovered from the well following the well stimulation treatment." (Cal. Pub. Res. Code § 3160(d)(1)(C)(iii)).
43 C.F.R. § 3162.3-3(i)-(j) Subsequent well operations; Hydraulic fracturing	• Requires operators to submit reports within 30 days after completing hydraulic fracturing operations that detail, among other items: (i) a description of the interval(s) or formation treated; (ii) the amount and type of materials injected at each phase of the operations; (iii) the actual and estimated depths and directions of the well and fractures; and (iv) information regarding water sources, total volumes of recovered fluids, and handling of recovered fluids. The submission should include the Chemical Abstract Service number for each chemical included. Disclosures are to be made to fracfocus.org. • Provides that if any information required is exempted from disclosure, operator may withhold the information and the exempted information of third parties and file a certification documenting that it is not disclosing the information and explaining the nature of the protection (*e.g.*, trade secrets). BLM may require that protected information be submitted to the agency even though the information is exempt from	§ 1788	• California requires operators to disclose the same details of their hydraulic fracturing operation, including among other items: (i) depth of the well; (ii) formation name and depth where well stimulation treatment occurred and estimated extent of the fracturing; (iii) the source, volume, and specific composition and disposition of all water associated with the well stimulation treatment; and (iv) extensive information regarding well stimulation fluids. California requires Chemical Abstract Service numbers in the operator's reporting, within 60 days of completing well stimulation activities. • Although operators are required to make full disclosures to the Division, public disclosures of well stimulation treatment fluid in California is limited to those items permitted to be disclosed under the California Evidence Code, the Uniform Trade Secrets Act, and the California Public Records Act. California law provides exceptions to the general disclosure protections in cases where more detailed information about the chemical is needed to respond to an environmental or health and safety

2015 Rule	Summary of 2015 Rule	Corresponding Cal. Law[66]	Analysis
	public disclosure.		incident. (Cal. Pub. Res. Code § 3160(j)). • California requires the operator to collect and store "[a]ll data on well stimulation treatments." (Cal. Pub. Res. Code § 3213).
43 C.F.R. § 3162.3-3(k) Subsequent well operations; Hydraulic fracturing	• Permits the authorized officer to grant an operator's (or a state's or a tribe's) written request for a variance from any specific operational requirement.	§ 1779	• California authorizes the Supervisor of the Division to establish, in individual cases, "other requirements where justified and called for." (§ 1779).

COLORADO

2015 Rule	Summary of 2015 Rule	Corresponding Colo. Law[68]	Analysis
43 C.F.R. § 3160.0-5 Definitions.	• Adds definitions of terms related to hydraulic fracturing: *annulus*, *bradenhead*, *Cement Evaluation Log (CEL)*, *confining zone*, *hydraulic fracturing*, *hydraulic fracturing fluid*, *isolating or to isolate*, *master hydraulic fracturing plan*, and *proppant*. • Defines *usable water*, with some exceptions, as waters containing up to 10,000 parts per million of total dissolved solids.	§ 404-1:100 § 404-1:216 § 404-1:317	• Colorado rules apply or define each of the terms or variations thereof that BLM defined. • Colorado allows for a version of the "master hydraulic fracturing plan" concept. Operators may choose to prepare and submit a "Comprehensive Drilling Plan" intended to identify and plan for foreseeable oil and gas activities in a defined geographic area. Once the plan is approved, subsequent drilling activity that is consistent with the terms of the plan is streamlined. (§ 216). • Colorado requires operators to employ a casing program sufficient to prevent the degradation of ground water. (§ 317(e)). In areas where pressure and formations are unknown, surface casing must be set to a

[68] The cited regulations are from sections within Volume 2, Title 400 of the Colorado Code of Regulations.

2015 Rule	Summary of 2015 Rule	Corresponding Colo. Law[68]	Analysis
			depth below all known or "reasonably estimated utilizable domestic fresh water levels." (§ 317(f)). Where subsurface conditions are known, casing must be set at a depth to protect all fresh water. (§ 317(g)). When it is impractical or uneconomical to set the full amount of surface casing, operators may stage cement the intermediate and/or production string to accomplish the required protection. (§ 317(h))..
43 C.F.R. § 3162.3-3(a)-(b) Subsequent well operations; Hydraulic fracturing.	• Applies operational standards associated with drilling and completion activity to "all hydraulic fracturing operations." • Extends normal requirements to isolate usable water and other minerals to all hydraulic fracturing operations.	§ 404-1:205A § 404-1:209 § 404-1:317	• Colorado applies operational regulations to technical aspects of hydraulic fracturing. • Colorado requires "due care in the protection of . . . water-bearing formations" (§ 209) and specifically requires casing programs to protect groundwater (§ 317).
43 C.F.R. § 3162.3-3(c) Subsequent well operations; Hydraulic fracturing.	• Requires pre-approval for all hydraulic fracturing. • Authorizes operator to submit a proposal for hydraulic fracturing with the operator's application for permit to drill or in a subsequent request for individual or multiple wells. • After initial approval of hydraulic fracturing operations, requires operator to submit new request if operator has "significant new information" about: (i) the geology of the area, (ii) the stimulation operation or technology to be used, or (iii) the anticipated impacts of the hydraulic fracturing operation to any resource.	§ 404-1:303 § 404-1:316C § 404-1:303.g	• Colorado requires approval before any person shall "commence operations for the drilling or re-entry of any well." (§ 303). • Colorado requires operators to give at least 48-hours advance notice to the COGCC before hydraulically fracturing any well. (§ 316C(a)). • Under Colorado law, permits to drill expire two years after issuance if operations have not commenced. (§ 303g(1))
43 C.F.R. § 3162.3-3(d) Subsequent well operations; Hydraulic fracturing.	• Requires operator seeking authorization for hydraulic fracturing to submit: (i) geologic information about the formation into which hydraulic fracturing fluids will be injected; (ii) measured or estimated depths of	§ 404-1:301 § 404-1:303.a § 404-1:316C § 404-1:317	• Colorado requires a pre-operation description of the producing zone regardless of whether hydraulic fracturing is going to occur. (§ 303.a). And Colorado requires operators to keep records of all "well operations," including

2015 Rule	Summary of 2015 Rule	Corresponding Colo. Law[68]	Analysis
	usable water; (iii) information about existing faults or fractures and other wells within one-half mile; (iv) information about the source of water to be used in hydraulic fracturing operations; (v) a proposed hydraulic fracturing design; (vi) proposed measured depths of perforations and estimated volume of fluid and pump pressure; and (vii) a plan for handling of recovered fluids.		"formations penetrated, the content and quality of oil, gas or water in each formation tested, and the grade, weight and size, and landed depth of casing used in drilling each well on the leased premises, and any other information obtained in the course of well operation." (§ 301). • Colorado rules provide that "[n]o portion of a proposed wellbore's [hydraulically fractured] treated interval shall be located within 150 feet of an existing (producing, shut-in, or temporarily abandoned) or permitted oil and gas wellbore's treated interval." If such a situation occurs, pre-approval must be obtained from the COGCC. (§ 317.s).
43 C.F.R. § 3162.3-3(e)-(f) Subsequent well operations; Hydraulic fracturing	• Before conducting hydraulic fracturing, requires operator to monitor flow rate, density, and treating pressure during cementing operations on any casing used to protect usable water and to submit a monitoring report at least 48 hours before hydraulic fracturing operations begin. • Requires operator to observe cement returns to the surface for surface casing. If there is any indication of inadequate cement, the operator must determine the top of cement with a cement evaluation log, temperature log, or other method approved by the authorized officer. • Requires operator to run a cement evaluation log, for casing not cemented to surface, to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone. • Requires operator to report "an	§ 404-1:308A § 404-1:317	• Colorado requires that operators submit a drilling completion report, including the results of all cement tests, within 30 days of setting the production casing. (§ 308A). • Colorado requires the operator run, at a minimum, a resistivity log with gamma-ray or other approved petro-physical log that adequately describes the stratigraphy of the wellbore. Operators must also run a cement bond long on all production casing. The logs must be submitted with the well completion report. (§ 317.p). • Colorado requires surface casing to be cemented to the surface. (§ 317.f, g, h). If surface casing cement falls below the surface, "to the extent safety or aquifer protection is compromised," Colorado requires that operators perform remedial cementing operations. (§ 317.i). • Colorado allows for stage casing and cementing to protect aquifers but requires, if the stage cementing

2015 Rule	Summary of 2015 Rule	Corresponding Colo. Law[68]	Analysis
	indication of an inadequate cement job" within 24 hours of discovery and to run a cement evaluation log demonstrating that an inadequate cement job has been corrected before commencing hydraulic fracturing activities. • Requires operators to conduct a mechanical integrity test on casing (testing to 100% of the anticipated surface pressure) or fracturing string (testing to 100% of the anticipated surface pressure minus the annulus pressure between the fracturing string and production casing) before hydraulic fracturing operations begin.		is not circulated to surface, that the operator conduct "a temperature log or cement bond log . . . "to determine the top of the stage cement to ensure aquifers are protected." (§ 317.h). • Colorado requires that surface, intermediate, and production casing cement must be allowed to set for a minimum of 72 hours, or until the casing develops 800 psi calculated compressive strength, before any completion operations may be conducted. (§ 317.i, j.). • Installed intermediate and production casing must be pressure tested for the conditions anticipated to be encountered during completion and production operations. (§ 317.k).
43 C.F.R. § 3162.3-3(g) Subsequent well operations; Hydraulic fracturing.	• Requires operators to continuously monitor annulus pressure during hydraulic fracturing operations. • Requires "immediate corrective action" if the annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation.	§ 404-1:341	• Colorado requires the operator to continuously monitor annulus pressure during stimulation operations and to notify the COGCC as soon as possible (and in no case more than 24 hours) if the annulus pressure increases by more than 200 pounds per square inch. If intermediate casing has been set on the well, the pressure in the annulus between the intermediate casing and the production casing must also be monitored and recorded. Operators are required to keep all well stimulation records on file and available for inspection for a period of not less than five years.
43 C.F.R. § 3162.3-3(h) Subsequent well operations; Hydraulic fracturing	• Requires storage of all recovered fluids in rigid and covered/netted tanks with no more than a 500 barrel capacity, subject to narrow exceptions for lined pits or larger tanks, unless a permanent disposal plan is approved.	§ 404-1:902 § 404-1:904 § 404-1:907 § 404-1:1004	• Colorado law offers operators operational flexibility to select the water management mechanism most suitable to the project. Colorado allows for the use of pits, but requires that pits be "constructed and operated to protect public health, safety, and welfare and the environment, including soil, waters of the state, and wildlife, from significant

2015 Rule	Summary of 2015 Rule	Corresponding Colo. Law[68]	Analysis
			adverse environmental, public health, or welfare impacts from E&P waste.” (§ 902.a). Unlined pits are prohibited “in areas where pathways for communication with ground water or surface water are likely to exist.” (§ 902.g). Production pits and multi-well pits used to contain produced water, drilling fluids, or completion fluids, among others, are required to be lined. (§ 904.a). And produced water must be treated before being placed in a production pit “to prevent crude oil and condensate from entering the pit.” (§ 907.c). Once oil and gas production waste is removed from a pit or treated, all production pits “must be back-filled to return the soils to their original relative positions.” (§ 1004.b)

MONTANA

2015 Rule	Summary of 2015 Rule	Corresponding Mont. Law[69]	Analysis
43 C.F.R. § 3160.0-5 Definitions.	• Adds definitions of terms related to hydraulic fracturing: *annulus*, *bradenhead*, *Cement Evaluation Log (CEL)*, *confining zone*, *hydraulic fracturing*, *hydraulic fracturing fluid*, *isolating or to isolate*, *master hydraulic fracturing plan*, and *proppant*. • Defines *usable water*, with some exceptions, as waters containing up to 10,000 parts per million of total dissolved solids.	• 36.22.302 • 36.22.608	• Montana rules apply or define each of the terms or variations thereof that BLM defined. (36.22.302) • Montana applies a variation of the “master hydraulic fracturing plan” concept. Operators may submit a final design of a “well treatment actually used for similar wells and which reflects the likely design for the well to be permitted” or may refer to “a prefiled generic design submitted for specific geologic formations, geographic areas, or well types likely to be used in a particular well.” (36.22.608)

[69] The cited regulations are to the Administrative Rules of Montana.

2015 Rule	Summary of 2015 Rule	Corresponding Mont. Law[69]	Analysis
			• Montana rules define freshwater as water containing less than 10,000 parts per million of total dissolved solids. (36.22.302)
43 C.F.R. § 3162.3-3(a)-(b) Subsequent well operations; Hydraulic fracturing.	• Applies operational standards associated with drilling and completion activity to "all hydraulic fracturing operations." • Extends normal requirements to isolate usable water and other minerals to all hydraulic fracturing operations.	• 36.22.608 • 36.22.1001 • 36.22.1010	• Montana's operational rules apply to all well stimulation activities, including hydraulic fracturing, acidizing, or other chemical stimulation. (36.22.608) • Montana requires surface casing sufficient to protect "all fresh water located at levels reasonably accessible for agricultural and domestic use."
43 C.F.R. § 3162.3-3(c) Subsequent well operations; Hydraulic fracturing.	• Requires pre-approval for all hydraulic fracturing. • Authorizes operator to submit a proposal for hydraulic fracturing with the operator's application for permit to drill or in a subsequent request for individual or multiple wells. • After initial approval of hydraulic fracturing operations, requires operator to submit new request if operator has "significant new information" about: (i) the geology of the area, (ii) the stimulation operation or technology to be used, or (iii) the anticipated impacts of the hydraulic fracturing operation to any resource.	• 36.22.604 • 36.22.608 • 36.22.1010	• Montana rules provide that "[w]ell completions which include hydraulic fracturing, acidizing, or other chemical stimulation done to complete a well are considered permitted activities under the drilling permit for that well only if the processes, anticipated volumes, and types of materials planned for use are expressly described in the permit." (36.22.608) • Montana rules provide that no well may be "reperforated, recompleted, reworked, chemically stimulated, or hydraulically fractured" without receiving prior approval. (36.22.1010) • Montana allows operators to include a proposal for hydraulic fracturing in a drilling permit or, if unable to determine what type of stimulation will be necessary at the time of permitting, to subsequently submit a notice of intent to stimulate or chemically treat the well before commencing stimulation activities. (36.22.608) • Under Montana law, drilling permits expire six months after issuance if operations have not

2015 Rule	Summary of 2015 Rule	Corresponding Mont. Law[69]	Analysis
			commenced. (36.22.604). Montana's approval process applies to re-completions. (36.22.1010)
43 C.F.R. § 3162.3-3(d) Subsequent well operations; Hydraulic fracturing.	• Requires operator seeking authorization for hydraulic fracturing to submit: (i) geologic information about the formation into which hydraulic fracturing fluids will be injected; (ii) measured or estimated depths of usable water; (iii) information about existing faults or fractures and other wells within one-half mile; (iv) information about the source of water to be used in hydraulic fracturing operations; (v) a proposed hydraulic fracturing design; (vi) proposed measured depths of perforations and estimated volume of fluid and pump pressure; and (vii) a plan for handling of recovered fluids.	• 36.22.608 • 36.22.1010 • Form No. 2[70] • From No. 22[71]	• Montana requires that operators seeking permission to stimulate a well submit a Form No. 22 for approval. Form No. 22 requires operators to include information regarding the storage, treatment, and disposal of pit fluids. • If an operator is unable to determine what type of stimulation will be necessary at the time of permitting, Montana requires operators subsequently submit a Form No. 2 notice of intent to stimulate or chemically treat the well before commencing stimulation activities. Form 2 requires operators to "describe planned . . . work in detail" and instructs that maps, well-bore configuration diagrams, analyses and other relevant information be attached as necessary. • Montana requires every well completion to be adequately described in either Form No. 2 or 22, including information regarding the processes, anticipated volumes, and types of materials planned for stimulating. The operator must: (i) estimate the total volume of treatment to be used; (ii) list the trade name or generic name of the principle components or chemicals; (iii) estimate the amount of principle

[70] *See* Mont. Bd. of Oil & Gas Conservation, Form 2, available here: http://bogc.dnrc.mt.gov/Forms/WebForms/Form%2002%20Sundry%20Notice/FORM%20NO%2002_Fillable.pdf.
[71] *See* Mont. Bd. of Oil & Gas Conservation, Form 22, available here: http://bogc.dnrc.mt.gov/Forms/WebForms/Form%2022%20Permit%20to%20Drill/FORM%2022_Fillable.pdf.

2015 Rule	Summary of 2015 Rule	Corresponding Mont. Law[69]	Analysis
			components; (iv) estimate the weight or volume of inert substances injected; and (5) provide the maximum anticipated treating pressure or a written description of the well construction specifications that demonstrate that the well is appropriately constructed for the proposed fracture stimulation. • Montana permits operators to submit a final design of a "well treatment actually used for similar wells and which reflects the likely design for the well to be permitted" or may refer to "a prefiled generic design submitted for specific geologic formations, geographic areas, or well types likely to be used in a particular well." (36.22.608)
43 C.F.R. § 3162.3-3(e)-(f) Subsequent well operations; Hydraulic fracturing	• Before conducting hydraulic fracturing, requires operator to monitor flow rate, density, and treating pressure during cementing operations on any casing used to protect usable water and to submit a monitoring report at least 48 hours before hydraulic fracturing operations begin. • Requires operator to observe cement returns to the surface for surface casing. If there is any indication of inadequate cement, the operator must determine the top of cement with a cement evaluation log, temperature log, or other method approved by the authorized officer. • Requires operator to run a cement evaluation log, for casing not cemented to surface, to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone.	• 36.22.1001 • 36.22.1106	• Montana requires surface casing to be cemented with "sufficient cement to circulate to the top of the well." Production casing must be cemented by the pump-and-plug method (or other method the agency approves) and must be pressure tested before cement plugs are drilled. • Montana requires that wells that will be stimulated through hydraulic fracturing be tested to "demonstrate suitable and safe mechanical configuration for the stimulation treatment proposed." • Montana requires that before hydraulic fracturing commences, "the operator must evaluate the well" and that "the casing must be tested to the maximum anticipated treating pressure." • Montana requires that if testing demonstrates any inadequacy in the casing, the casing must be repaired before hydraulic fracturing can occur.

2015 Rule	Summary of 2015 Rule	Corresponding Mont. Law[69]	Analysis
	• Requires operator to report "an indication of an inadequate cement job" within 24 hours of discovery and to run a cement evaluation log demonstrating that an inadequate cement job has been corrected before commencing hydraulic fracturing activities. • Requires operators to conduct a mechanical integrity test on casing (testing to 100% of the anticipated surface pressure) or fracturing string (testing to 100% of the anticipated surface pressure minus the annulus pressure between the fracturing string and production casing) before hydraulic fracturing operations begin.		
43 C.F.R. § 3162.3-3(g) Subsequent well operations; Hydraulic fracturing.	• Requires operators to continuously monitor annulus pressure during hydraulic fracturing operations. • Requires "immediate corrective action" if the annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation.	• 36.22.1106	• Montana requires the operator to monitor and record the annulus pressure during operations and prohibits pressurizing the annulus to any pressure exceeding the lowest rated component that would be exposed to pressure should the fracturing string fail.
43 C.F.R. § 3162.3-3(h) Subsequent well operations; Hydraulic fracturing	• Requires storage of all recovered fluids in rigid and covered/netted tanks with no more than a 500 barrel capacity, subject to narrow exceptions for lined pits or larger tanks, unless a permanent disposal plan is approved.	• 36.22.1005	• Montana law offers operators operational flexibility to select the water management mechanism most suitable to the project while at the same time requiring that the operator "must construct, close, and restore any reserve pits in a manner that will prevent harm to the soil and will not degrade surface waters or groundwater." All pits used in association with drilling and completion operations, "must be closed and the surface

2015 Rule	Summary of 2015 Rule	Corresponding Mont. Law[69]	Analysis
			restored to board specifications within one year after the cessation of drilling operations.”
43 C.F.R. § 3162.3-3(i)-(j) Subsequent well operations; Hydraulic fracturing	• Requires operators to submit reports within 30 days after completing hydraulic fracturing operations that detail, among other items: (i) a description of the interval(s) or formation treated; (ii) the amount and type of materials injected at each phase of the operations; (iii) the actual and estimated depths and directions of the well and fractures; and (iv) information regarding water sources, total volumes of recovered fluids, and handling of recovered fluids. The submission should include the Chemical Abstract Service number for each chemical included. Disclosures are to be made to fracfocus.org. • Provides that if any information required is exempted from disclosure, operator may withhold the information and the exempted information of third parties and file a certification documenting that it is not disclosing the information and explaining the nature of the protection (*e.g.*, trade secrets). BLM may require that protected information be submitted to the agency even though the information is exempt from public disclosure.	• 36.22.1011 • Form No. 4[72] • 36.22.1015 • 36.22.1016	• Montana requires the operator to submit a completion report (Form No. 4) within 30 days after completion of a well drilled for oil and gas (except for a wildcat or exploratory well) that identifies among other things: (i) a casing and tubing record; (ii)a description of perforated or open-hole intervals; (iii) simulation treatment information, including type of treatment, amount and type of material identified by additive type, maximum rate, and maximum pressure; (iv) the producing formation; (v) the bottom hole location; and (vi) the measured depth and total vertical depth of geological markers. • Montana requires operators to disclose the details of their hydraulic fracturing operation, including Chemical Abstracts Service numbers, and gives operators the option to report through a variety of methods, including directly to the State or to FracFocus. • Montana rules allow operators to protect proprietary chemical information and trade secrets from disclosure. For such information, operators identify the protected chemical by trade name (or other innocuous identifier) and document the amount of the chemical used. Montana law

[72] *See* Mont. Bd. of Oil & Gas Conservation, Form 4, available here: http://bogc.dnrc.mt.gov/Forms/WebForms/Form%2004%20Completion%20Report/FORM%20NO%2004_Fillable.pdf.

2015 Rule	Summary of 2015 Rule	Corresponding Mont. Law[69]	Analysis
			provides exceptions to the general disclosure protections in cases where more detailed information about the chemical is needed to respond to an environmental or health and safety incident.
43 C.F.R. § 3162.3-3(k) Subsequent well operations; Hydraulic fracturing	• Permits the authorized officer to grant an operator's (or a state's or a tribe's) written request for a variance from any specific operational requirement.	• 36.22.301	• Montana rules contemplate that "[s]pecial rules and orders will be issued when required and shall prevail as against general rules if in conflict therewith."

NEW MEXICO

2015 Rule	Summary of 2015 Rule	Corresponding N.M. Law[73]	Analysis
43 C.F.R. § 3160.0-5 Definitions	• Adds definitions of terms related to hydraulic fracturing: *annulus*, *bradenhead*, *Cement Evaluation Log (CEL)*, *confining zone*, *hydraulic fracturing*, *hydraulic fracturing fluid*, *isolating or to isolate*, *master hydraulic fracturing plan*, and *proppant*. • Defines *usable water*, with some exceptions, as waters containing up to 10,000 parts per million of total dissolved solids.	• 19.15.2.7 • 19.15.16.7 • 19.15.16.17 • 19.15.16.19	• New Mexico rules apply standard industry definitions or define each of the terms or variations thereof that BLM defined. • New Mexico generally defines *fresh water* to include all water under 10,000 parts per million of total dissolved solids unless there it is established, after notice and hearing, that there is no present or reasonably foreseeable beneficial use.
43 C.F.R. § 3162.3-3(a)-(b) Subsequent well operations; Hydraulic fracturing.	• Applies operational standards associated with drilling and completion activity to "all hydraulic fracturing operations." • Extends normal requirements to isolate usable water and other minerals to all hydraulic fracturing operations.	• 19.15.6.7 • 19.15.16.9 • 19.15.16.10 • 19.15.16.19(B)	• New Mexico requires all wells, regardless of completion techniques, if any, to comply with operational standards for drilling and completion. New Mexico rules also govern workover activity including "fracturing, acidizing or installing compression equipment." (19.15.6.7(T)(4)). • New Mexico requires that operators "ensure that fresh waters

[73] The cited regulations are to the Administrative Code of New Mexico.

2015 Rule	Summary of 2015 Rule	Corresponding N.M. Law[73]	Analysis
			and waters of present or probable value for domestic, commercial or stock purposes are confined to their respective strata and are adequately protected by division-approved methods." (19.15.16.9(B)).
43 C.F.R. § 3162.3-3(c) Subsequent well operations; Hydraulic fracturing.	• Requires pre-approval for all hydraulic fracturing. • Authorizes operator to submit a proposal for hydraulic fracturing with the operator's application for permit to drill or in a subsequent request for individual or multiple wells. • After initial approval of hydraulic fracturing operations, requires operator to submit new request if operator has "significant new information" about: (i) the geology of the area, (ii) the stimulation operation or technology to be used, or (iii) the anticipated impacts of the hydraulic fracturing operation to any resource.	• 19.15.16.19 • 19.15.25.8 • 19.15.25.12	• New Mexico requires operators to submit comprehensive hydraulic fracturing disclosure forms within 45 days after completion of the well. • New Mexico requires that operators plug and abandon a well after a period of one year in which the well has been continuously inactive. Operators may also apply for a temporary abandonment designation which may not be for a term of more than five years.
43 C.F.R. § 3162.3-3(d) Subsequent well operations; Hydraulic fracturing.	• Requires operator seeking authorization for hydraulic fracturing to submit: (i) geologic information about the formation into which hydraulic fracturing fluids will be injected; (ii) measured or estimated depths of usable water; (iii) information about existing faults or fractures and other wells within one-half mile; (iv) information about the source of water to be used in hydraulic fracturing operations; (v) a proposed hydraulic fracturing design; (vi) proposed measured depths of perforations and estimated volume of fluid and pump pressure; and (vii) a plan for handling of recovered fluids.	• 19.15.16.19	• New Mexico requires operators to file a hydraulic fracturing disclosure report for all wells that have been hydraulically fractured, including among other information: (i) gross fractured interval; (ii) true vertical depth; (iii) total fluid pumped; (iv) description of the hydraulic fluid composition and concentration; and (v) maximum ingredient concentration by mass.
43 C.F.R. §	• Before conducting hydraulic	• 19.15.7.14	• New Mexico requires that

611162170.7

2015 Rule	Summary of 2015 Rule	Corresponding N.M. Law[73]	Analysis
3162.3-3(e)-(f) Subsequent well operations; Hydraulic fracturing	fracturing, requires operator to monitor flow rate, density, and treating pressure during cementing operations on any casing used to protect usable water and to submit a monitoring report at least 48 hours before hydraulic fracturing operations begin. • Requires operator to observe cement returns to the surface for surface casing. If there is any indication of inadequate cement, the operator must determine the top of cement with a cement evaluation log, temperature log, or other method approved by the authorized officer. • Requires operator to run a cement evaluation log, for casing not cemented to surface, to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone. • Requires operator to report "an indication of an inadequate cement job" within 24 hours of discovery and to run a cement evaluation log demonstrating that an inadequate cement job has been corrected before commencing hydraulic fracturing activities. • Requires operators to conduct a mechanical integrity test on casing (testing to 100% of the anticipated surface pressure) or fracturing string (testing to 100% of the anticipated surface pressure minus the annulus pressure between the fracturing string and production casing) before hydraulic fracturing operations begin.	• 19.15.16.10 • 19.15.16.11 • 19.15.16.19	operators file cementing reports including test results within 10 days following the setting of each string of casing or liner. (19.15.7.14(D)). • New Mexico requires operators to file a hydraulic fracturing disclosure report for all wells that have been hydraulically fractured. (19.15.16.19(B)). • New Mexico requires that operators report any indications of inadequate cementing within five days and requires operators to "proceed with diligence to use the appropriate method and means to eliminate the hazard." Wells that cannot be remedied must be abandoned. (19.15.16.11). • New Mexico requires operators to test casing strings after cementing and before commencing other operations on the well. (19.15.16.10(I)).
43 C.F.R. §	• Requires operators to	• 19.15.16.12	• New Mexico requires blowout

2015 Rule	Summary of 2015 Rule	Corresponding N.M. Law[73]	Analysis
3162.3-3(g) Subsequent well operations; Hydraulic fracturing.	continuously monitor annulus pressure during hydraulic fracturing operations. • Requires "immediate corrective action" if the annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation.	• 19.15.16.18	preventers on workover rigs working on wells in which high pressures are known to exist. Operators must submit a blowout prevention plan and the district supervisor retains authority to modify such plans. • New Mexico requires wells to have christmas tree fittings or wellhead connections and valves in first class condition so that necessary pressure tests may easily be conducted on casing and tubing.
43 C.F.R. § 3162.3-3(h) Subsequent well operations; Hydraulic fracturing	• Requires storage of all recovered fluids in rigid and covered/netted tanks with no more than a 500 barrel capacity, subject to narrow exceptions for lined pits or larger tanks, unless a permanent disposal plan is approved.	• 19.15.17.8	• New Mexico prohibits the use of unlined pits. New Mexico allows closed-loop tank systems without prior approval but requires approval for below-grade tanks and lined pits.
43 C.F.R. § 3162.3-3(i)-(j) Subsequent well operations; Hydraulic fracturing	• Requires operators to submit reports within 30 days after completing hydraulic fracturing operations that detail, among other items: (i) a description of the interval(s) or formation treated; (ii) the amount and type of materials injected at each phase of the operations; (iii) the actual and estimated depths and directions of the well and fractures; and (iv) information regarding water sources, total volumes of recovered fluids, and handling of recovered fluids. The submission should include the Chemical Abstract Service number for each chemical included. Disclosures are to be made to fracfocus.org. • Provides that if any information required is exempted from disclosure, operator may withhold the information and the exempted information of third parties and file a certification documenting that it is not	• 19.15.16.19	• New Mexico requires operators to file a hydraulic fracturing disclosure report for all wells that have been hydraulically fractured, including among other information: (i) gross fractured interval; (ii) true vertical depth; (iii) total fluid pumped; (iv) description of the hydraulic fluid composition and concentration; and (v) maximum ingredient concentration by mass. • New Mexico requires operators to disclose the details of their hydraulic fracturing operation, and to include Chemical Abstract Service number in the operator's reporting along with trade name, supplier purpose, and maximum ingredient concentration by mass. • New Mexico does not require operators to report or disclose "proprietary, trade secret or confidential business information."

2015 Rule	Summary of 2015 Rule	Corresponding N.M. Law[73]	Analysis
	disclosing the information and explaining the nature of the protection (*e.g.*, trade secrets). BLM may require that protected information be submitted to the agency even though the information is exempt from public disclosure.		
43 C.F.R. § 3162.3-3(k) Subsequent well operations; Hydraulic fracturing	• Permits the authorized officer to grant an operator's (or a state's or a tribe's) written request for a variance from any specific operational requirement.	• 19.15.17.15	• New Mexico does not have a general variance provision in its oil and gas rules. There is a provision for obtaining variances to the rules governing pits, closed-loop systems, and tanks when the proposed variance "provides equal or better protection of fresh water, public health and the environment."

NORTH DAKOTA

2015 Rule	Summary of 2015 Rule	Corresponding N.D. Law	Analysis
43 C.F.R. § 3160.0-5 Definitions.	• Adds definitions of terms related to hydraulic fracturing: *annulus*, *bradenhead*, *Cement Evaluation Log (CEL)*, *confining zone*, *hydraulic fracturing*, *hydraulic fracturing fluid*, *isolating or to isolate*, *master hydraulic fracturing plan*, and *proppant*. • Defines *usable water*, with some exceptions, as waters containing up to 10,000 parts per million of total dissolved solids.	• N.D. Cent. Code § 38-08-25 • 43-02-03-01 • 43-02-03-20	• North Dakota rules apply or define each of the terms or variations thereof that BLM defined.
43 C.F.R. § 3162.3-3(a)-(b) Subsequent well operations; Hydraulic fracturing.	• Applies operational standards associated with drilling and completion activity to "all hydraulic fracturing operations." • Extends normal requirements to isolate usable water and other minerals to all hydraulic fracturing operations.	• 43-02-03.20 • 43-02-03-27.1	• North Dakota applies operational regulations to technical aspects of hydraulic fracturing and requires comprehensive disclosures related to operators' hydraulic fracturing activities. • North Dakota rules mandate that "[a]ll freshwaters and waters of present or probable value for domestic, commercial, or stock purpose shall be confined to their respective strata and shall be adequately protected." (43.02-03.20).

2015 Rule	Summary of 2015 Rule	Corresponding N.D. Law	Analysis
43 C.F.R. § 3162.3-3(c) Subsequent well operations; Hydraulic fracturing.	• Requires pre-approval for all hydraulic fracturing. • Authorizes operator to submit a proposal for hydraulic fracturing with the operator's application for permit to drill or in a subsequent request for individual or multiple wells. • After initial approval of hydraulic fracturing operations, requires operator to submit new request if operator has "significant new information" about: (i) the geology of the area, (ii) the stimulation operation or technology to be used, or (iii) the anticipated impacts of the hydraulic fracturing operation to any resource.	• 43-02-03-16 • N.D. Cent. Code §§ 38.11.1-04.1 & 38-11.2-03	• North Dakota requires approval before any drilling activity can commence." (43-02-03-16). Operators must also provide no less than 20 days advance notice to surface owners before conducting any drilling operations. • Under North Dakota law, permits to drill expire one year after issuance if operations have not commenced.
43 C.F.R. § 3162.3-3(d) Subsequent well operations; Hydraulic fracturing.	• Requires operator seeking authorization for hydraulic fracturing to submit: (i) geologic information about the formation into which hydraulic fracturing fluids will be injected; (ii) measured or estimated depths of usable water; (iii) information about existing faults or fractures and other wells within one-half mile; (iv) information about the source of water to be used in hydraulic fracturing operations; (v) a proposed hydraulic fracturing design; (vi) proposed measured depths of perforations and estimated volume of fluid and pump pressure; and (vii) a plan for handling of recovered fluids.	• 43-02-03-16	• North Dakota requires approval before any drilling activity can commence." (43-02-03-16). The application for a drilling permit must contain, among other information: (i) well depth; (ii) estimated depths of important markers; (iii) estimated depth to the top of objective horizons; (iv) proposed mud program; (v) proposed casing program; (vi) proposed depth of each casing string; and (vii) amount and top of cement.
43 C.F.R. § 3162.3-3(e)-(f) Subsequent well operations; Hydraulic fracturing	• Before conducting hydraulic fracturing, requires operator to monitor flow rate, density, and treating pressure during cementing operations on any casing used to protect usable water and to submit a monitoring report at least 48 hours before hydraulic fracturing operations begin.	• 43-02-03-21 • 43-02-03-22 • 43-02-03-27.1 • 43-02-03-31	• North Dakota requires operators to pressure test casing strings after cementing and before commencing other operations on the well. (43-02-03-21). Before completing any well, operators are required to "run a log from which the presence and quality of bonding of cement can be determined in every well in which production or intermediate casing

2015 Rule	Summary of 2015 Rule	Corresponding N.D. Law	Analysis
	• Requires operator to observe cement returns to the surface for surface casing. If there is any indication of inadequate cement, the operator must determine the top of cement with a cement evaluation log, temperature log, or other method approved by the authorized officer. • Requires operator to run a cement evaluation log, for casing not cemented to surface, to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone. • Requires operator to report "an indication of an inadequate cement job" within 24 hours of discovery and to run a cement evaluation log demonstrating that an inadequate cement job has been corrected before commencing hydraulic fracturing activities. • Requires operators to conduct a mechanical integrity test on casing (testing to 100% of the anticipated surface pressure) or fracturing string (testing to 100% of the anticipated surface pressure minus the annulus pressure between the fracturing string and production casing) before hydraulic fracturing operations begin.		has been set." All such reports must be filed within 30 days of completing the work. (43-02-03-31) • North Dakota requires, if annulus space "is not adequately filled with cement," or if satisfactory test results are not achieved, that operators perform remedial work after obtaining approval. (43-02-03-21). • North Dakota requires that an operator report a well with defective casing or cementing and to obtain approval before attempting remedial work. The operator may have to conduct a pressure test "to verify casing integrity if its competence is questionable." (43-02-03-22). • North Dakota requires the application of an appropriate cement evaluation tool to test well bore and casing integrity before conducting hydraulic fracturing activity. (43.02-03-27.1).
43 C.F.R. § 3162.3-3(g) Subsequent well operations; Hydraulic fracturing.	• Requires operators to continuously monitor annulus pressure during hydraulic fracturing operations. • Requires "immediate corrective action" if the annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation.	• 43.02-03-27.1	• North Dakota requires the operator to continuously monitor annulus pressure during stimulation operations and to notify the North Dakota Industrial Commission as soon as possible (and in no case more than 24 hours) if the annulus pressure increases by more than 350 pounds per square inch.

2015 Rule	Summary of 2015 Rule	Corresponding N.D. Law	Analysis
43 C.F.R. § 3162.3-3(h) Subsequent well operations; Hydraulic fracturing	• Requires storage of all recovered fluids in rigid and covered/netted tanks with no more than a 500 barrel capacity, subject to narrow exceptions for lined pits or larger tanks, unless a permanent disposal plan is approved.	• 43-02-03-19.3	• North Dakota prohibits storage of recovered fluids in earthen pits or open receptacles "except in an emergency and upon approval by the" Commission.
43 C.F.R. § 3162.3-3(i)-(j) Subsequent well operations; Hydraulic fracturing	• Requires operators to submit reports within 30 days after completing hydraulic fracturing operations that detail, among other items: (i) a description of the interval(s) or formation treated; (ii) the amount and type of materials injected at each phase of the operations; (iii) the actual and estimated depths and directions of the well and fractures; and (iv) information regarding water sources, total volumes of recovered fluids, and handling of recovered fluids. The submission should include the Chemical Abstract Service number for each chemical included. Disclosures are to be made to fracfocus.org. • Provides that if any information required is exempted from disclosure, operator may withhold the information and the exempted information of third parties and file a certification documenting that it is not disclosing the information and explaining the nature of the protection (*e.g.*, trade secrets). BLM may require that protected information be submitted to the agency even though the information is exempt from public disclosure.	• 43.02-03-27.1	• North Dakota law requires that within 60 days of hydraulic fracturing being performed, the owner operator or service company must "post on the fracfocus chemical disclosure registry all elements made viewable by the fracfocus website." • North Dakota regulations do not expressly provide any exceptions to reporting requirements for trade secrets or otherwise confidential information.
43 C.F.R. § 3162.3-3(k) Subsequent well operations; Hydraulic fracturing	• Permits the authorized officer to grant an operator's (or a state's or a tribe's) written request for a variance from any specific operational requirement.	• 43-02-03-02	• North Dakota rules provide that the Commission "may grant exceptions to [the oil and gas rules], after due notice and hearing, when such exceptions will result in the prevention of waste and operate in a manner to

2015 Rule	Summary of 2015 Rule	Corresponding N.D. Law	Analysis
			protect correlative rights."

OKLAHOMA

2015 Rule	Summary of 2015 Rule	Corresponding Okla. Law[74]	Analysis
43 C.F.R. § 3160.0-5 Definitions.	• Adds definitions of terms related to hydraulic fracturing: *annulus*, *bradenhead*, *Cement Evaluation Log (CEL)*, *confining zone*, *hydraulic fracturing*, *hydraulic fracturing fluid*, *isolating or to isolate*, *master hydraulic fracturing plan*, and *proppant*. • Defines *usable water*, with some exceptions, as waters containing up to 10,000 parts per million of total dissolved solids.	165:10-1-2	• Oklahoma rules or law apply or define each of the terms or variations thereof that BLM defined. • Oklahoma defines "treatable water" to mean "subsurface water in its natural state, useful or potentially useful for drinking water for human consumption, domestic livestock, irrigation, industrial, municipal, and recreational purposes, and which will support aquatic life, and contains less than 10,000 mg/liter total dissolved solids or less than 5,000 ppm chlorides."
43 C.F.R. § 3162.3-3(a)-(b) Subsequent well operations; Hydraulic fracturing.	• Applies operational standards associated with drilling and completion activity to "all hydraulic fracturing operations." • Extends normal requirements to isolate usable water and other minerals to all hydraulic fracturing operations.	165:10-3-4 165:10-3-10	• Oklahoma requires operators to comply with operational standards associated with drilling and completion and requires additional standards for hydraulic fracturing treatments. • Oklahoma requires that operators isolate treatable water and prohibits hydraulic fracturing operations from polluting subsurface fresh water.
43 C.F.R. § 3162.3-3(c) Subsequent well operations; Hydraulic fracturing.	• Requires pre-approval for all hydraulic fracturing. • Authorizes operator to submit a proposal for hydraulic fracturing with the operator's application for permit to drill or in a	165:10-3-1 165:10-3-10	• Oklahoma requires the operator to give notice at least 5 business days before hydraulic fracturing operations commence to all operators of producing wells within a half mile of the completion interval of the subject

[74] The cited sections are from sections within Title 165, Chapter 10 of the Oklahoma Register.

2015 Rule	Summary of 2015 Rule	Corresponding Okla. Law[74]	Analysis
	subsequent request for individual or multiple wells. • After initial approval of hydraulic fracturing operations, requires operator to submit new request if operator has "significant new information" about: (i) the geology of the area, (ii) the stimulation operation or technology to be used, or (iii) the anticipated impacts of the hydraulic fracturing operation to any resource.		well and which are completed in the same common source of supply as the horizontal well. • Oklahoma requires the operator to give notice to the Conservation Division District Office or Field Inspector at least 48 hours before commencing hydraulic fracturing operations. • Under Oklahoma law, drilling permits expire 6 months after issuance, subject to a 6 month extension if there has been no material change of condition.
43 C.F.R. § 3162.3-3(d) Subsequent well operations; Hydraulic fracturing.	• Requires operator seeking authorization for hydraulic fracturing to submit: (i) geologic information about the formation into which hydraulic fracturing fluids will be injected; (ii) measured or estimated depths of usable water; (iii) information about existing faults or fractures and other wells within one-half mile; (iv) information about the source of water to be used in hydraulic fracturing operations; (v) a proposed hydraulic fracturing design; (vi) proposed measured depths of perforations and estimated volume of fluid and pump pressure; and (vii) a plan for handling of recovered fluids.	165:10-3-10 165:10-3-25 Form 1002A[75]	• Oklahoma collects comprehensive reports for hydraulic fracturing treatments that include, among other information: (i) total vertical depth of well; (ii) total volume of water and base fluid used; (iii) name of each additive with trade name, supplier, and description; (iv) each chemical ingredient used; (v) the maximum concentration of each chemical; (vi) the Chemical Abstract Service number for each chemical; (vii) casing and cement information; and (viii) descriptions of the producing formation.
43 C.F.R. § 3162.3-3(e)-(f) Subsequent well operations;	• Before conducting hydraulic fracturing, requires operator to monitor flow rate, density, and treating pressure during	165:10-3-4 Form 1002C[76]	• Oklahoma requires the operator to cement using the tubing and pump, pump and plug, or displacement method. Oklahoma

[75] Oklahoma Corporation Commission Form 1002A, available at: http://www.occeweb.com/og/OGforms/form%201002A.pdf.
[76] Oklahoma Corporation Commission Form 1002C, available at: http://www.occeweb.com/og/OGforms/form%201002C.pdf.

2015 Rule	Summary of 2015 Rule	Corresponding Okla. Law[74]	Analysis
Hydraulic fracturing	cementing operations on any casing used to protect usable water and to submit a monitoring report at least 48 hours before hydraulic fracturing operations begin. • Requires operator to observe cement returns to the surface for surface casing. If there is any indication of inadequate cement, the operator must determine the top of cement with a cement evaluation log, temperature log, or other method approved by the authorized officer. • Requires operator to run a cement evaluation log, for casing not cemented to surface, to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone. • Requires operator to report "an indication of an inadequate cement job" within 24 hours of discovery and to run a cement evaluation log demonstrating that an inadequate cement job has been corrected before commencing hydraulic fracturing activities. • Requires operators to conduct a mechanical integrity test on casing (testing to 100% of the anticipated surface pressure) or fracturing string (testing to 100% of the anticipated surface pressure minus the annulus pressure between the fracturing string and production casing) before hydraulic fracturing operations begin.		allows bradenhead cementing only with written permission from the Conservation Division District Office. • Oklahoma requires the operator to notify the appropriate Conservation Division District Office or Field Inspector 24 hours before running surface casing. • Oklahoma requires, if the operator did not circulate cement to the surface or if the cement falls back more than 5 feet, to determine the top of the cement using a method the District Manager or Field Inspector Supervisor approves. • Oklahoma requires the operator to notify the appropriate Conservation Division District Office within 24 hours of: (i) any mechanical failure of the surface casing or cement; or (ii) discovery of a treatable water formation below the shoe of the surface casing. • Oklahoma rules also allow flexibility for the operator to seek approval of alternative casing and cementing procedures. • Oklahoma requires the operator to submit cement logs 30 days after completion of operations. • Oklahoma requires the operator to pressure test all casing strings. • Oklahoma requires the operator to, if it is determined that a treatable water-bearing formation has not been properly cased and cemented, take such measures the Director of Conservation designates or the Commission orders.
43 C.F.R. § 3162.3-3(g) Subsequent well	• Requires operators to continuously monitor annulus pressure during hydraulic	165:10-3-4 165:10-3-10	• Oklahoma does not require additional monitoring requirements specific to hydraulic

2015 Rule	Summary of 2015 Rule	Corresponding Okla. Law[74]	Analysis
operations; Hydraulic fracturing.	fracturing operations. • Requires "immediate corrective action" if the annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation.		fracturing operations.
43 C.F.R. § 3162.3-3(h) Subsequent well operations; Hydraulic fracturing	• Requires storage of all recovered fluids in rigid and covered/netted tanks with no more than a 500 barrel capacity, subject to narrow exceptions for lined pits or larger tanks, unless a permanent disposal plan is approved.	165:10-7-16	• Oklahoma allows for operational flexibility for recovered fluids and allows for lined pits.
43 C.F.R. § 3162.3-3(i)-(j) Subsequent well operations; Hydraulic fracturing	• Requires operators to submit reports within 30 days after completing hydraulic fracturing operations that detail, among other items: (i) a description of the interval(s) or formation treated; (ii) the amount and type of materials injected at each phase of the operations; (iii) the actual and estimated depths and directions of the well and fractures; and (iv) information regarding water sources, total volumes of recovered fluids, and handling of recovered fluids. The submission should include the Chemical Abstract Service number for each chemical included. Disclosures are to be made to fracfocus.org. • Provides that if any information required is exempted from disclosure, operator may withhold the information and the exempted information of third parties and file a certification documenting that it is not disclosing the information and explaining the nature of the protection (*e.g.*, trade secrets). BLM may require that protected information be submitted to the agency even though the information is exempt from public disclosure.	165:10-3-10 165:10-3-25 Form 1002A	• Oklahoma requires extensive post-operations completion reports for hydraulic fracturing treatments that include, among other information: (i) total vertical depth of well; (ii) total volume of water and base fluid used; (iii) name of each additive with trade name, supplier, and description; (iv) each chemical ingredient used; (v) the maximum concentration of each chemical; (vi) the Chemical Abstract Service number for each chemical; (vii) casing and cement information; and (viii) descriptions of the producing formation. • Oklahoma allows for trade secret protection for chemical additives or ingredients but requires that the chemical family or other descriptor is provided if the identity and number are not disclosed. • Oklahoma allows the operator to disclose through fracfocus.org within 60 days after completion of hydraulic fracturing operations.
43 C.F.R. §	• Permits the authorized officer to	165:10-3-4	• Oklahoma regulations grant the

611162170.7

2015 Rule	Summary of 2015 Rule	Corresponding Okla. Law[74]	Analysis
3162.3-3(k) Subsequent well operations; Hydraulic fracturing	grant an operator's (or a state's or a tribe's) written request for a variance from any specific operational requirement.		Conservation Division authority to consider alternative methods of compliance, including among other requirements casing and cementing procedures.

TEXAS

2015 Rule	Summary of 2015 Rule	Corresponding Tex. Law[77]	Analysis
43 C.F.R. § 3160.0-5 Definitions.	• Adds definitions of terms related to hydraulic fracturing: *annulus*, *bradenhead*, *Cement Evaluation Log (CEL)*, *confining zone*, *hydraulic fracturing*, *hydraulic fracturing fluid*, *isolating or to isolate*, *master hydraulic fracturing plan*, and *proppant*. • Defines *usable water*, with some exceptions, as waters containing up to 10,000 parts per million of total dissolved solids.	§ 3.8 § 3.13 § 3.29 § 3.30 § 3.79	• Texas rules or law apply or define each of the terms or variations thereof that BLM defined. • Texas defines "Underground Source of Drinking Water" to mean an aquifer that is not classified as exempt and that: (i) supplies any public water system; or (ii) contains a sufficient quantity of water to supply a public water system and (a) currently supplies drinking water for human consumption or (b) contains fewer than 10,000 milligrams per liter of total dissolved solids." Texas regulations, however, provide flexibility to the Texas Railroad Commission's Groundwater Advisory Unit to determine the "usable water" zones that must be protected. (§§ 3.13, 3.30).
43 C.F.R. § 3162.3-3(a)-(b) Subsequent well operations; Hydraulic fracturing.	• Applies operational standards associated with drilling and completion activity to "all hydraulic fracturing operations." • Extends normal requirements to isolate usable water and other minerals to all hydraulic fracturing operations.	§ 3.13	• Texas requires operators to comply with operational standards associated with drilling and completion and requires additional standards for hydraulic fracturing treatments. • Texas requires that "all usable-quality water zones be isolated

[77] The cited sections are from sections within Title 16, Part 1, Chapter 3 of the Texas Administrative Code.

2015 Rule	Summary of 2015 Rule	Corresponding Tex. Law[77]	Analysis
			and sealed off to effectively prevent contamination or harm" regardless of completion technique. (§ 3.13).
43 C.F.R. § 3162.3-3(c) Subsequent well operations; Hydraulic fracturing.	• Requires pre-approval for all hydraulic fracturing. • Authorizes operator to submit a proposal for hydraulic fracturing with the operator's application for permit to drill or in a subsequent request for individual or multiple wells. • After initial approval of hydraulic fracturing operations, requires operator to submit new request if operator has "significant new information" about: (i) the geology of the area, (ii) the stimulation operation or technology to be used, or (iii) the anticipated impacts of the hydraulic fracturing operation to any resource.	§ 3.5	• Under Texas law, drilling permits expire two years after issuance.
43 C.F.R. § 3162.3-3(d) Subsequent well operations; Hydraulic fracturing.	• Requires operator seeking authorization for hydraulic fracturing to submit: (i) geologic information about the formation into which hydraulic fracturing fluids will be injected; (ii) measured or estimated depths of usable water; (iii) information about existing faults or fractures and other wells within one-half mile; (iv) information about the source of water to be used in hydraulic fracturing operations; (v) a proposed hydraulic fracturing design; (vi) proposed measured depths of perforations and estimated volume of fluid and pump pressure; and (vii) a plan for handling of recovered fluids.	§ 3.16 § 3.29	• Texas collects comprehensive reports about hydraulic fracturing treatments that include, among other information: (i) total vertical depth of well; (ii) total volume of water and base fluid used; (iii) name of each additive with trade name, supplier, and description; (iv) each chemical ingredient used; (v) the actual or maximum concentration of each chemical; and (vi) the Chemical Abstract Service number for each chemical.
43 C.F.R. § 3162.3-3(e)-(f) Subsequent well operations; Hydraulic fracturing	• Before conducting hydraulic fracturing, requires operator to monitor flow rate, density, and treating pressure during cementing operations on any casing used to protect usable	§ 3.13	• Texas requires that "[c]asing shall be sufficiently cemented or otherwise anchored in the hole in order to effectively control the well at all times."

2015 Rule	Summary of 2015 Rule	Corresponding Tex. Law[77]	Analysis
	water and to submit a monitoring report at least 48 hours before hydraulic fracturing operations begin. • Requires operator to observe cement returns to the surface for surface casing. If there is any indication of inadequate cement, the operator must determine the top of cement with a cement evaluation log, temperature log, or other method approved by the authorized officer. • Requires operator to run a cement evaluation log, for casing not cemented to surface, to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone. • Requires operator to report "an indication of an inadequate cement job" within 24 hours of discovery and to run a cement evaluation log demonstrating that an inadequate cement job has been corrected before commencing hydraulic fracturing activities. • Requires operators to conduct a mechanical integrity test on casing (testing to 100% of the anticipated surface pressure) or fracturing string (testing to 100% of the anticipated surface pressure minus the annulus pressure between the fracturing string and production casing) before hydraulic fracturing operations begin.		• Texas requires operators cement using the pump and plug method and to use sufficient cement to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. • Texas requires the operator, if cement does not circulate to the ground surface or the bottom of the cellar, to obtain approval of the district director to proceed with additional cementing operations, including cementing surface casing from the top of the cement to the ground surface. • Texas requires the operator to, within 30 days of completion or 90 days of cessation of drilling operations, to submit a cementing report to the Commission with complete data concerning the surface casing and cementing operations. • Texas authorizes the district director to approve alternative surface casing and cementing programs to protect fresh water and usable water. • Texas requires the operator to "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." • Texas requires "[a]ll casing strings or fracture tubing installed in a well that will be subjected to hydraulic fracturing treatments shall have a minimum internal yield pressure rating of at least 1.10 times the maximum pressure to which the casing strings or

611162170.7

2015 Rule	Summary of 2015 Rule	Corresponding Tex. Law[77]	Analysis
			fracture tubing may be subjected." • Texas requires pressure testing on the "casing (or fracture tubing) on which the pressure will be exerted during hydraulic fracturing treatments to at least the maximum pressure allowed by the completion method." The district director must be notified within 24 hours of a failed test, and hydraulic fracturing operations cannot be conducted until the district director approves a remediation plan and the operator has successfully re-tested the casing.
43 C.F.R. § 3162.3-3(g) Subsequent well operations; Hydraulic fracturing.	• Requires operators to continuously monitor annulus pressure during hydraulic fracturing operations. • Requires "immediate corrective action" if the annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation.	§ 3.13	• Texas requires the operator to monitor "all annuli" during hydraulic fracturing operations. • Texas requires that the operator "shall immediately suspend" hydraulic fracturing operations if the pressure deviated above the anticipated increases caused by pressure or thermal transfer and shall notify the district director within 24 hours of such deviation. Further completion operations may not recommence until the district director approves a remediation plan and the operator successfully implements same.
43 C.F.R. § 3162.3-3(h) Subsequent well operations; Hydraulic fracturing	• Requires storage of all recovered fluids in rigid and covered/netted tanks with no more than a 500 barrel capacity, subject to narrow exceptions for lined pits or larger tanks, unless a permanent disposal plan is approved.	§ 3.8	• Texas allows for operational flexibility for recovered fluids and allows for "completion/workover pits" under certain circumstances and requires an operator to obtain a permit for pits in other circumstances.
43 C.F.R. § 3162.3-3(i)-(j) Subsequent well operations; Hydraulic fracturing	• Requires operators to submit reports within 30 days after completing hydraulic fracturing operations that detail, among other items: (i) a description of the interval(s) or formation treated; (ii) the amount and type of materials injected at each phase of the operations; (iii) the	§ 3.29	• Texas requires extensive post-operations completion reports for hydraulic fracturing treatments that include, among other information: (i) total vertical depth of well; (ii) total volume of water and base fluid used; (iii) name of each additive with trade name, supplier, and description;

2015 Rule	Summary of 2015 Rule	Corresponding Tex. Law[77]	Analysis
	actual and estimated depths and directions of the well and fractures; and (iv) information regarding water sources, total volumes of recovered fluids, and handling of recovered fluids. The submission should include the Chemical Abstract Service number for each chemical included. Disclosures are to be made to fracfocus.org. • Provides that if any information required is exempted from disclosure, operator may withhold the information and the exempted information of third parties and file a certification documenting that it is not disclosing the information and explaining the nature of the protection (*e.g.*, trade secrets). BLM may require that protected information be submitted to the agency even though the information is exempt from public disclosure.		(iv) each chemical ingredient used; (v) the actual or maximum concentration of each chemical; and (vi) the Chemical Abstract Service number for each chemical. • Texas allows for trade secret protection for chemical additives or ingredients but requires that the chemical family or other similar description be provided. Trade secret information, however, may not be withheld from health professionals and emergency responders. • Texas allows disclosure through fracfocus.org.
43 C.F.R. § 3162.3-3(k) Subsequent well operations; Hydraulic fracturing	• Permits the authorized officer to grant an operator's (or a state's or a tribe's) written request for a variance from any specific operational requirement.	§ 3.13	• Texas regulations grant the district director authority to consider alternative methods of compliance, including among other requirements surface casing and tubing programs.

UTAH

2015 Rule	Summary of 2015 Rule	Corresponding Utah Law[78]	Analysis
43 C.F.R. § 3160.0-5 Definitions.	• Adds definitions of terms related to hydraulic fracturing: *annulus*, *bradenhead*, *Cement Evaluation Log (CEL)*, *confining zone*, *hydraulic fracturing*, *hydraulic fracturing fluid*, *isolating or to*	• R649-1-1 • R649-3-39	• Utah rules apply or define each of the terms or variations thereof that BLM defined.

[78] The cited regulations are to the Administrative Code of Utah.

2015 Rule	Summary of 2015 Rule	Corresponding Utah Law[78]	Analysis
	isolate, *master hydraulic fracturing plan*, and *proppant*. • Defines *usable water*, with some exceptions, as waters containing up to 10,000 parts per million of total dissolved solids.		
43 C.F.R. § 3162.3-3(a)-(b) Subsequent well operations; Hydraulic fracturing.	• Applies operational standards associated with drilling and completion activity to "all hydraulic fracturing operations." • Extends normal requirements to isolate usable water and other minerals to all hydraulic fracturing operations.	• R649-3-39	• Utah applies operational regulations to technical aspects of hydraulic fracturing and requires comprehensive compliance with all wellbore integrity rules on wells that are stimulated through hydraulic fracturing. • Utah requires operators install casing to a depth "below all known or reasonably estimated, utilizable, domestic fresh water levels." (§ 2.1).
43 C.F.R. § 3162.3-3(c) Subsequent well operations; Hydraulic fracturing.	• Requires pre-approval for all hydraulic fracturing. • Authorizes operator to submit a proposal for hydraulic fracturing with the operator's application for permit to drill or in a subsequent request for individual or multiple wells. • After initial approval of hydraulic fracturing operations, requires operator to submit new request if operator has "significant new information" about: (i) the geology of the area, (ii) the stimulation operation or technology to be used, or (iii) the anticipated impacts of the hydraulic fracturing operation to any resource.	• R649-3-4 • R649-3-39	• Utah requires operators submit a notice of intent to perform a workover or recompletion and to receive approval before conducting hydraulic fracturing on a well. (§ 2.6(1)). • Under Utah law, permits to drill expire twelve months after issuance if operations have not commenced. (§ 2.8(4)). If an operator intends to make change of location or drilling program, a new application for drilling permit must be submitted and approved. (§ 2.8(5)).
43 C.F.R. § 3162.3-3(d) Subsequent well operations; Hydraulic fracturing.	• Requires operator seeking authorization for hydraulic fracturing to submit: (i) geologic information about the formation into which hydraulic fracturing fluids will be injected; (ii) measured or estimated depths of	• R649-3-23 • R649-3-39	• Utah requires operators submit a notice of intent to perform a workover or recompletion and to receive approval before conducting hydraulic fracturing on a well. (§ 2.6(1)).

2015 Rule	Summary of 2015 Rule	Corresponding Utah Law[78]	Analysis
	usable water; (iii) information about existing faults or fractures and other wells within one-half mile; (iv) information about the source of water to be used in hydraulic fracturing operations; (v) a proposed hydraulic fracturing design; (vi) proposed measured depths of perforations and estimated volume of fluid and pump pressure; and (vii) a plan for handling of recovered fluids.		• Utah requires operators seeking approval to perform any type of enhanced recovery operation to submit "[a] full description of the particular operation for which approval is requested." (R649-3-39 § 3.4(2.3)).
43 C.F.R. § 3162.3-3(e)-(f) Subsequent well operations; Hydraulic fracturing	• Before conducting hydraulic fracturing, requires operator to monitor flow rate, density, and treating pressure during cementing operations on any casing used to protect usable water and to submit a monitoring report at least 48 hours before hydraulic fracturing operations begin. • Requires operator to observe cement returns to the surface for surface casing. If there is any indication of inadequate cement, the operator must determine the top of cement with a cement evaluation log, temperature log, or other method approved by the authorized officer. • Requires operator to run a cement evaluation log, for casing not cemented to surface, to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone. • Requires operator to report "an indication of an inadequate cement job" within 24 hours of discovery and to run a cement evaluation log demonstrating that an inadequate cement job has been corrected before commencing hydraulic fracturing activities.	• R649-3-7 • R649-3-13 • R649-3-21 • R649-3-39	• Utah requires that operators perform a pressure test to determine the integrity of the casing string before completing the well. • Operators must provide advance notice of an intent to test casing and must retain and make available for inspection all test results • Utah requires the operator to submit a well completion report and copies of all electric and radioactivity logs within 30 days of well completion. • If any well "appears to have defective, poorly cemented, or corroded casing" that may allow underground waste or may "contaminate underground or surface fresh water," Utah requires that operators perform remedial cementing operations to eliminate the hazard. When a hazard cannot be repaired the well must be abandoned.

2015 Rule	Summary of 2015 Rule	Corresponding Utah Law[78]	Analysis
	• Requires operators to conduct a mechanical integrity test on casing (testing to 100% of the anticipated surface pressure) or fracturing string (testing to 100% of the anticipated surface pressure minus the annulus pressure between the fracturing string and production casing) before hydraulic fracturing operations begin.		
43 C.F.R. § 3162.3-3(g) Subsequent well operations; Hydraulic fracturing.	• Requires operators to continuously monitor annulus pressure during hydraulic fracturing operations. • Requires "immediate corrective action" if the annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation.	• R649-3-39	• Utah requires that, for any operations involving the injection of fluids into a well, the operator pressure test the casing-tubing annulus to a pressure equal to the maximum authorized injection pressure or to a pressure of 1,000 psi (whichever is greater). As an alternative to pressure testing, and subject to approval, operators "may monitor the pressure of the casing-tubing annulus monthly during actual injection operations and report the results." (§ 3.8).
43 C.F.R. § 3162.3-3(h) Subsequent well operations; Hydraulic fracturing	• Requires storage of all recovered fluids in rigid and covered/netted tanks with no more than a 500 barrel capacity, subject to narrow exceptions for lined pits or larger tanks, unless a permanent disposal plan is approved.	• R649-3-16 • R649-3-39	• Utah allows for the use of pits, but requires that pits be "constructed in such a manner as to contain fluids and not cause pollution of waters and soils." Reserve pits must be closed within one year of completing any well and contents of pits "may require treatment to reduce mobility and/or toxicity in order to meet cleanup levels."
43 C.F.R. § 3162.3-3(i)-(j) Subsequent well operations; Hydraulic fracturing	• Requires operators to submit reports within 30 days after completing hydraulic fracturing operations that detail, among other items: (i) a description of the interval(s) or formation treated; (ii) the amount and type of materials injected at each phase of the operations; (iii) the actual and estimated depths and directions of the well and fractures; and (iv) information regarding water sources, total volumes of recovered fluids, and handling of recovered fluids. The submission should include the	• R649-3-39	• Utah law requires disclosure of "the amount and type of chemicals used in a hydraulic fracturing operation" to fracfocus.org. Operators must also submit a completion report within 30 days of performing any completion or workover activity on a well. Utah also requires operators to submit a monthly report for each well containing "a description of the operations conducted on the well during the month." • Utah regulations do not expressly provide any exceptions to

2015 Rule	Summary of 2015 Rule	Corresponding Utah Law[78]	Analysis
	Chemical Abstract Service number for each chemical included. Disclosures are to be made to fracfocus.org. • Provides that if any information required is exempted from disclosure, operator may withhold the information and the exempted information of third parties and file a certification documenting that it is not disclosing the information and explaining the nature of the protection (*e.g.*, trade secrets). BLM may require that protected information be submitted to the agency even though the information is exempt from public disclosure.		reporting requirements for trade secrets or otherwise confidential information.
43 C.F.R. § 3162.3-3(k) Subsequent well operations; Hydraulic fracturing	• Permits the authorized officer to grant an operator's (or a state's or a tribe's) written request for a variance from any specific operational requirement.	• R649-9-13	Utah rules authorize variances from any "requirements or standards" upon written request "provid[ing] information as to the circumstances that warrant approval of the requested variance and the proposed alternative means by which the requirements or standards will be satisfied."

WYOMING

2015 Rule	Summary of 2015 Rule	Corresponding Wyoming Law	Analysis
43 C.F.R. § 3160.0-5 Definitions.	• Adds definitions of terms related to hydraulic fracturing: *annulus*, *bradenhead*, *Cement Evaluation Log (CEL)*, *confining zone*, *hydraulic fracturing*, *hydraulic fracturing fluid*, *isolating or to isolate*, *master hydraulic fracturing plan*, and *proppant*. • Defines *usable water*, with some exceptions, as waters containing up to 10,000 parts per million of total dissolved solids.	• Ch. 1 § 2 • Ch. 3 § 1 • Ch. 3 § 8 • Ch. 3 § 45	• Wyoming rules apply or define each of the terms or variations thereof that BLM defined. (Ch. 1 § 2). • Wyoming applies a version of the "master hydraulic fracturing plan" concept for drilling and well stimulation. When operators seek multiple APD for several wells "to be drilled to the same zone within an area of geologic similarity," operators may submit a comprehensive drilling plan that duplicates required information on each APD. (Ch. 3 § 8(c)(xi)). "Where multiple stimulation activities will be undertaken for several wells proposed to be drilled to the same zone(s) within an area of geologic similarity," operators

2015 Rule	Summary of 2015 Rule	Corresponding Wyoming Law	Analysis
			may submit to the Secretary a comprehensive master drilling/completion/recompletion plan." Once the plan is approved, the approved master plan is referenced on each individual well's APD. (Ch. 3 § 45(b)). • Wyoming defines *fresh water* and *potable water* as "water currently being used as a drinking water source" or water with less than 10,000 parts per million total dissolved solids that "(i) [c]an reasonably be expected to be used for domestic, agricultural, or livestock use; or, (ii) [i]s suitable for fish or aquatic life." (Ch. 1, § 2(t)). Wyoming further defines *groundwater* as water that is unusable because of: (i) "excessive concentrations of total dissolved solids or specific constituents;" (ii) contamination that prevents economical or technological recovery of the water; and (iii) location, including depth below the surface, that makes use economically and technologically impractical. (Ch. 1 § 2(x)).
43 C.F.R. § 3162.3-3(a)-(b) Subsequent well operations; Hydraulic fracturing.	• Applies operational standards associated with drilling and completion activity to "all hydraulic fracturing operations." • Extends normal requirements to isolate usable water and other minerals to all hydraulic fracturing operations.	• Ch. 3 § 8 • Ch. 3 § 22 • Ch. 3 § 45	• Wyoming applies operational rules to "any well stimulation activity." • Wyoming dictates that "groundwater will be protected" except for that water that is "unusable or unsuitable for use," because it is "economically or technologically impractical to make water useable."(Ch. 3 § 8(c)(iv)).
43 C.F.R. § 3162.3-3(c) Subsequent well operations; Hydraulic fracturing.	• Requires pre-approval for all hydraulic fracturing. • Authorizes operator to submit a proposal for hydraulic fracturing with the operator's application for permit to drill or in a subsequent request for individual or multiple wells. • After initial approval of	• Ch. 3 § 1 • Ch. 3 § 8 • Ch. 3 § 45	• Wyoming requires approval to "acidize, cleanout, flush, fracture, or stimulate a well." • Wyoming allows operators to include a proposal for hydraulic fracturing in an APD or to subsequently submit a sundry notice requesting approval to stimulate the well before commencing stimulation activities. (Ch. 45 § 45(a)). • Under Wyoming law, permits to drill

2015 Rule	Summary of 2015 Rule	Corresponding Wyoming Law	Analysis
	hydraulic fracturing operations, requires operator to submit new request if operator has "significant new information" about: (i) the geology of the area, (ii) the stimulation operation or technology to be used, or (iii) the anticipated impacts of the hydraulic fracturing operation to any resource.		expire one year after issuance if operations have not commenced. (Ch. 3 § 8). Wyoming's approval process already applies to "any well stimulation activity." (Ch. 3 § 45(a)).
43 C.F.R. § 3162.3-3(d) Subsequent well operations; Hydraulic fracturing.	• Requires operator seeking authorization for hydraulic fracturing to submit: (i) geologic information about the formation into which hydraulic fracturing fluids will be injected; (ii) measured or estimated depths of usable water; (iii) information about existing faults or fractures and other wells within one-half mile; (iv) information about the source of water to be used in hydraulic fracturing operations; (v) a proposed hydraulic fracturing design; (vi) proposed measured depths of perforations and estimated volume of fluid and pump pressure; and (vii) a plan for handling of recovered fluids.	• Ch. 3 § 45	• Wyoming requires operators seeking permission to stimulate a well to submit, among information: (i) geological names, description, and depth of formation to be stimulated; (ii) information regarding base stimulation fluid source; (iii) stimulation fluid by additive type; (iv) chemical compound name and Chemical Abstracts Service number; (v) rate or concentration for each additive; (vi) anticipated surface treating pressure; (vii) maximum injection treating pressure; and (viii) estimated or calculated fracture length and fracture height. • The Supervisor also retains discretion to request additional information about any stimulation project before approving the stimulation activity. (Ch. 3 § 45(d)).
43 C.F.R. § 3162.3-3(e)-(f) Subsequent well operations; Hydraulic fracturing	• Before conducting hydraulic fracturing, requires operator to monitor flow rate, density, and treating pressure during cementing operations on any casing used to protect usable water and to submit a monitoring report at least 48 hours before hydraulic fracturing operations begin. • Requires operator to observe cement returns to the surface for surface casing. If there is any indication of inadequate cement, the operator must determine the top of cement with a cement evaluation	• Ch. 3 § 12 • Ch. 3 § 21 • Ch. 3 § 22	• Wyoming requires surface casing to be "cemented by the pump and plug or displacement or other approved method with sufficient cement to fill the annulus to the top of the hole." The Supervisor may require operator to pump a specified quantity of excess cement above the design volume if severe washed out hole conditions are known to exist. Wyoming requires operators to perform supplemental cementing operations if "cement is not circulated to the surface during primary operation." (Ch. 3 § 22). • Wyoming requires production string be cemented by the pump and plug method and be properly tested by the pressure

2015 Rule	Summary of 2015 Rule	Corresponding Wyoming Law	Analysis
	log, temperature log, or other method approved by the authorized officer. • Requires operator to run a cement evaluation log, for casing not cemented to surface, to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone. • Requires operator to report "an indication of an inadequate cement job" within 24 hours of discovery and to run a cement evaluation log demonstrating that an inadequate cement job has been corrected before commencing hydraulic fracturing activities. • Requires operators to conduct a mechanical integrity test on casing (testing to 100% of the anticipated surface pressure) or fracturing string (testing to 100% of the anticipated surface pressure minus the annulus pressure between the fracturing string and production casing) before hydraulic fracturing operations begin.		method before cement plugs are drilled. • Wyoming may require the operator to "provide cased hole bond logs to be run for casing strings to demonstrate isolation from the placement of cement across and above the productive intervals or above the last casing shoe in the well, if there is a demonstrated reason to believe an inadequate cement job was performed." • Wyoming requires operators file well logs within 30 days after the logs are run on any well or after further operation is conducted on a well, (e.g., drilling deeper or re-drilling a formation). Within 30 days of completing a well, operators must file "drill stem test charts, directional deviation surveys that portray the bottomhole location, formation water analyses, porosity, permeability or fluid saturations, core analyses, and lithologic log or sample descriptions and bottomhole pressure data." (Ch. 3 § 21). • Wyoming requires operators submit completion reports within 30 days after the completion of, among other activities, "formation fracturing." Such report must contain "a detailed account of the work done and the manner in which such work was performed," and must include "the daily production of oil, gas, and water both prior to and after the operation; the size and depth of perforations; the quantity of sand, crude, chemical, or other materials employed in the operation and any other pertinent information of operations which affect the original status of the well." (Ch. 3 § 12). • Before any well stimulation may occur, Wyoming may require an operator "to perform a suitable mechanical integrity test of the casing or of the casing-tubing annulus or other mechanical integrity test methods." (Ch. 3 § 45).
43 C.F.R. § 3162.3-3(g)	• Requires operators to continuously monitor	• Ch. 3 § 45	• Wyoming requires the operator to continuously monitor annulus pressure

2015 Rule	Summary of 2015 Rule	Corresponding Wyoming Law	Analysis
Subsequent well operations; Hydraulic fracturing.	annulus pressure during hydraulic fracturing operations. • Requires "immediate corrective action" if the annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation.		during hydraulic fracturing operations and to notify the Secretary as soon as possible (and in no case more than 24 hours) if the annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation. (Ch. 3 § 45(i)(i)).
43 C.F.R. § 3162.3-3(h) Subsequent well operations; Hydraulic fracturing	• Requires storage of all recovered fluids in rigid and covered/netted tanks with no more than a 500 barrel capacity, subject to narrow exceptions for lined pits or larger tanks, unless a permanent disposal plan is approved.	• Ch. 3 § 45	• Wyoming law requires the storage of recovered pits in tanks or lined pits (Ch. 3 § 45(j)).
43 C.F.R. § 3162.3-3(i)-(j) Subsequent well operations; Hydraulic fracturing	• Requires operators to submit reports within 30 days after completing hydraulic fracturing operations that detail, among other items: (i) a description of the interval(s) or formation treated; (ii) the amount and type of materials injected at each phase of the operations; (iii) the actual and estimated depths and directions of the well and fractures; and (iv) information regarding water sources, total volumes of recovered fluids, and handling of recovered fluids. The submission should include the Chemical Abstract Service number for each chemical included. Disclosures are to be made to fracfocus.org. • Provides that if any information required is exempted from disclosure, operator may withhold the information and the exempted information of third parties and file a certification documenting that it is not disclosing the	• Ch. 3 § 45	• Wyoming requires post-well stimulation logs that must detail, among other information: (i) the actual total well stimulation treatment volume pumped; (ii) each fluid stage pumped, including actual volume by fluid stage, proppant rate or concentration, actual chemical additive name, type, concentration or rate, and amounts; (iii) actual surface pressure and rate at the end of each fluid stage and the actual flush volume, rate, and final pump pressure; and (iv) instantaneous shut-in pressure and the actual 15-minute and 30-minute shut-in pressures when these pressure measurements are available. Wyoming also allows an operator to submit the actual well stimulation service contractor's job log, without any pricing data, to fulfill the above-listed post-well stimulation log. • Wyoming requires operators to disclose the details of their hydraulic fracturing operation, and to include Chemical Abstract Service numbers in the operator's reporting. (Ch. 3 § 45(d)(i)-(vi)). • Subject to justification provided in writing, operators in Wyoming need not disclose "trade secrets, privileged information and confidential

2015 Rule	Summary of 2015 Rule	Corresponding Wyoming Law	Analysis
	information and explaining the nature of the protection (*e.g.*, trade secrets). BLM may require that protected information be submitted to the agency even though the information is exempt from public disclosure.		commercial, financial, geological or geophysical data furnished by or obtained from any person." (Ch. 3 § 45(f)).
43 C.F.R. § 3162.3-3(k) Subsequent well operations; Hydraulic fracturing	• Permits the authorized officer to grant an operator's (or a state's or a tribe's) written request for a variance from any specific operational requirement.	• Ch. 3 § 46	• Wyoming does not have a general variance provision in its oil and gas rules. Subject to the provision of necessary supporting documentation, a variance may be authorized from the requirements that an operator conduct baseline sampling, monitoring, and analysis of groundwater. (Ch. 3 § 46(d)).

The adequacy of the states' regulations is evident when one considers the focus of the 2015 Rule. According to BLM, the 2015 Ruled focused on: (i) well bore integrity; (ii) public disclosure of chemical additives injected during production operations; and (iii) management of water produced during oil and gas operations.[79] In other words, BLM focused on processes that the states have been regulating successfully for decades. As the tables demonstrate clearly, BLM can be assured that withdrawing the rule will not leave federal lands without adequate environmental protection.

III. BLM LACKED STATUTORY AUTHORITY TO ISSUE THE 2015 RULE.

The Property Clause of the United States Constitution affords Congress "Power to dispose of and make all needful Rules and Regulations respecting the Territory or other Property belonging to the United States."[80] Congress' control over federal property, however, "does not place the exclusive control of the federal public domain in the United States Government."[81] The Property Clause "only confers this power on Congress and leaves to Congress the determination of when and where and to what extent this power will be exercised."[82] "Although the Constitution empowers Congress to regulate federal lands, Congress determines whether or not to exercise this power."[83] And BLM is not Congress. Like all executive branch entities, BLM possesses only the power that Congress delegates to the agency. Because Congress has chosen

[79] 82 Fed. Reg. at 34,464.
[80] U.S. Const. art. IV, § 3, cl. 2.
[81] *Tex. Oil & Gas Corp. v. Phillips Petroleum Co.*, 277 F. Supp. 366, 368 (W.D. Okla. 1967).
[82] *Id.*
[83] *Kirkpatrick Oil & Gas Co. v. United States*, 675 F.2d 1122, 1124 (10th Cir. 1982) (internal citation omitted).

affirmatively not to exercise federal regulatory authority over most forms of hydraulic fracturing, the 2015 Rule should never have been issued.

A. CONGRESS INTENDED EPA TO REGULATE HYDRAULIC FRACTURING UNDER THE SAFE DRINKING WATER ACT.

Congress enacted the Safe Drinking Water Act ("SDWA") to "(1) authorize the Environmental Protection Agency to establish Federal standards for protection from all harmful contaminants, which standards would be applicable to all public water systems, and (2) establish a joint Federal-State system for assuring compliance with these standards and for protecting underground sources of drinking water."[84] To implement protection for underground sources of drinking water, Congress established a cooperative federalism scheme to regulate all underground injection of contaminants in Part C of the SDWA.[85] Under Part C, states can submit underground injection control ("UIC") programs for EPA's approval; once EPA approves such a program, primary regulatory jurisdiction over underground injection rests with the state.[86]

The essence of UIC programs under Part C is the prohibition of "any underground injection" without a permit.[87] The SDWA defines "underground injection" as "the subsurface emplacement of fluids by well injection."[88] The SDWA's legislative history reflects Congress' intention that the SDWA cover a wide range of municipal, industrial, and energy extraction injection activity.

> [U]nderground injection of contaminants is clearly an increasing problem. Municipalities are increasingly engaging in underground injections of sewage, sludge, and other wastes. Industries are injecting chemicals, byproducts, and wastes. *Energy production companies are using injection techniques to increase production* and to dispose of unwanted brines brought to the surface during production. Even government agencies, including the military, are getting rid of

---

[84] H.R. Rep. No. 93-1185 (1974), *as reprinted in* 1974 U.S.C.C.A.N. 6454, 6455.

[85] *See* Pub. L. No. 93-523, pt. C, 88 Stat. 1660, 1674-80 (codified at 42 U.S.C. §§ 300h – 300h-8).

[86] *See* 42 U.S.C. §§ 300h – 300h-8. In addition to private parties and state entities, Part C requires that every federal agency "engaged in any activity resulting, or which may result in, underground injection which endangers drinking water" to comply with the UIC program. 42 U.S.C. § 300j-6(a)(4). Under this provision, federal agencies must comply with requirements of applicable underground injection control programs and ensure that state or federal regulators will treat "underground injection wells on Federal property the same as any other . . . underground injection well and will enforce applicable regulations to the same extent and under the same procedures." H.R. Rep. No. 93-1185 at 574, 1974 U.S.C.C.A.N. at 6494. Where a state has earned primary jurisdiction for a UIC program, therefore, even federal agencies may not evade the state's jurisdiction over underground injection on federal lands within the state's borders. The Associations note that most oil and gas producing states – including all nine states in which ninety-percent of well completions occur on federal lands – exercise primary enforcement authority for injection wells associated with oil and gas production. *See* Mary Tiemann & Adam Vann, Cong. Research Serv., R41760, *Hydraulic Fracturing and Safe Drinking Water Act Regulatory Issues* 15 (2015).

[87] 42 U.S.C. § 300h(b)(1)(A), (C).

[88] 42 U.S.C. § 300h(d)(1).

> difficult to manage waste problems by underground disposal methods. Part C is intended to deal with *all* of the foregoing situations insofar as they may endanger underground drinking water sources.[89]

Pertinent here, Congress understood that "any underground injection" included energy companies' use of injection techniques both to stimulate increased production and to dispose of fluids recovered during the extraction process.[90] The SDWA's legislative history is clear that Congress crafted Part C to regulate injection techniques energy companies use to increase production, including hydraulic fracturing.[91]

Despite this congressional directive to regulate hydraulic fracturing, EPA failed to do so. In *LEAF v. EPA*, the Legal Environmental Assistance Foundation challenged EPA's approval of Alabama's UIC program, arguing Alabama's program was ineligible for approval because the program failed to address hydraulic fracturing.[92] EPA defended its approval of the state UIC program, contending that hydraulic fracturing did not fall within the regulatory definition of "underground injection" and that oil and gas production wells were not required to be regulated under UIC programs because the "principal function of these wells is not the underground emplacement of fluids."[93]

The United States Court of Appeals for the Eleventh Circuit disagreed. Looking to the dictionary definition of "injection,"[94] the Eleventh Circuit observed that "[t]he process of hydraulic fracturing obviously falls within this definition, as it involves subsurface emplacement of fluids by forcing them into cavities and passages in the ground through a well."[95] The Eleventh Circuit explained that EPA could not "exclude from the reach of the regulations an activity (i.e., hydraulic fracturing) which unquestionably falls within the plain meaning of the definition" of underground injection merely because "the well that is used to achieve that activity is also used – even primarily used – for another activity (i.e., methane gas production)."[96] Because "Congress directed EPA to regulate 'underground injection' activities, not 'injection wells,'" the Eleventh Circuit concluded that hydraulic fracturing fell squarely within the scope of the regulatory authority Congress endowed to EPA in the SDWA.[97]

---

[89] H.R. Rep. No. 93-1185, 1974 U.S.C.C.A.N. at 6481 (emphasis added).

[90] *See id.* at 6483 (emphasizing that Congress "intended [the definition] to cover, among other contaminants, the injection of brines and the injection of contaminants for extraction or other purposes").

[91] *See Legal Envtl. Assistance Found., Inc. v. Envtl. Prot. Agency*, 118 F.3d 1467, 1474-75 (11th Cir. 1997) ("*LEAF*").

[92] *See* 118 F.3d at 1469-72.

[93] *Id.* at 1471.

[94] "[W]e readily find that the word 'injection' means the act of 'forcing (a fluid) into a passage, cavity, or tissue.'" *LEAF*, 118 F.3d at 1474 (quoting *The Random House Dictionary of the English Language* 983 (2d ed. Unabridged 1987)).

[95] *LEAF*, 118 F.3d at 1474-75 (footnotes omitted).

[96] *Id.* at 1475.

[97] *Id*.

Responding to the Eleventh Circuit's holding in *LEAF* and EPA's preparations to exercise its previously neglected regulatory authority over hydraulic fracturing under the UIC program, Congress amended the SDWA by passing the Energy Policy Act of 2005.[98] The amendment excluded from the definition of "underground injection" in the UIC program "the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities."[99] Opponents of the Energy Policy Act noted that Congress' removal of "hydraulic fracturing for oil and gas production activities" from the definition of "underground injection" was done with the intention that this removal would "eliminate[] existing statutory authority under SDWA to ensure that hydraulic fracturing does not endanger underground sources of drinking water."[100]

B. BLM HAS NEVER REGULATED UNDERGROUND INJECTIONS.

BLM appears to suggest that, upon rescission of the 2015 Rule, BLM may still have some authority to regulate "non-routine" hydraulic fracturing operations under 43 C.F.R. § 3162.3-2 (2014).[101] To the extent BLM believes that this regulatory provision could be used to regulate hydraulic fracturing, that understanding is incorrect. 43 C.F.R. § 3162.3-2 (2014) requires operators to seek approval of all "nonroutine fracturing jobs,"[102] but provides that, "[u]nless additional surface disturbance is involved and if the operations conform to the standard of prudent operating practice, prior approval is *not* required for routine fracturing or acidizing jobs, or recompletion in the same interval."[103] Contrary to the implication in BLM's current proposal, BLM has never treated the "fracturing" referred to in 43 C.F.R. § 3162.3-2 as equivalent to hydraulic fracturing. Even proponents of the 2015 Rule have recognized that under 43 C.F.R. § 3162.3-2 "companies generally treated all hydraulic fracturing operations as routine" and BLM did not exercise approval authority over hydraulic fracturing.[104] The administrative record compiled in association with the 2015 Rule does not include any examples of 43 C.F.R. § 3162.3-2 – or any other BLM regulation – being applied to a hydraulic fracturing operation.

Unlike BLM, since at least 1983, EPA *has* regulated the injection of fluids through wells to promote energy production. EPA classifies wells into which fluids are injected "for enhanced recovery of oil or natural gas" as "Class II" wells.[105] EPA's regulations establish, among other

---

98 *See* Pub. L. No. 109-58, § 322, 119 Stat. 594 (2005).
99 42 U.S.C. § 300h(b)(2)(B).
100 H.R. Rep. No. 109-215, at 490 (2005) (dissenting views).
101 82 Fed. Reg. at 34,468.
102 43 C.F.R. § 3162.3-2(a).
103 43 C.F.R. § 3162.3-2(b) (emphasis added).
104 *Wyoming v. Zinke*, Nos. 16-8068 & 16-8069 (10th Cir.), Intervenor-Rep't-Appellants' Opening Br. at 32 n.18 (Aug. 12, 2016) (*quoting Independent Petroleum Ass'n of Am. v. Jewell*, No. 2:15-CV-41-SWS (D. Wyo.), Decl. of Steven Wells ¶ 10, at 3 (June 1, 2015) (ECF No. 20-2)). *See also Wyoming v. Zinke*, 2017 WL 4173619, at *1.
105 40 C.F.R. § 144.6(b)(2).

provisions: (i) the period during which injections will be permitted;[106] (ii) conditions under which injections will be prohibited;[107] (iii) casing and cementing requirements that must be met before injection;[108] (iv) operating requirements;[109] (v) monitoring requirements;[110] and (vi) reporting requirements, including reports documenting any noncompliance.[111]

If BLM had jurisdiction over hydraulic fracturing, one would expect that, since at least 1974, both BLM and EPA would have written rules in a manner consistent with dual authority over well stimulation through hydraulic fracturing on federal lands. Both agencies have indeed re-written their operational rules since the enactment of the SDWA. Yet only one, EPA, drafted rules covering well injections to promote resource recovery. BLM's rules contain nothing more than a vague notification requirement that has never been applied to hydraulic fracturing; EPA, on the other hand, promulgated comprehensive regulations and a requirement that operators obtain a permit for operation of a Class II well.

Not only has BLM not issued hydraulic fracturing regulations, it has affirmatively denied that it has authority to regulate any of the forms of "underground injection" that EPA regulates under the SDWA. For purposes of oil and gas production, the term "underground injection" relates to at least four categories of injections on federal lands: (i) injections for what is conventionally known as "enhanced oil recovery"; (ii) injections to dispose fluids recovered from a well during oil and gas production operations; (iii) hydraulic fracturing using diesel; and (iv) non-diesel hydraulic fracturing. At least before the rulemaking preceding the 2015 Rule, BLM has consistently acknowledged that EPA, and not BLM, is the executive agency with regulatory authority over these injections.

In Onshore Order No. 7, BLM recognizes that the term "[i]njection well means a well used for disposal of produced water or for enhanced recovery operations,"[112] and emphasizes that "[f]or an injection well proposed on Federal or Indian leases, the operator shall obtain an Underground Injection Control (UIC) permit pursuant to 40 CFR parts 144 and 146 from the Environmental Protection Agency or the State/Tribe where the State/Tribe has achieved primacy."[113] The 2015 Rule itself confirmed this understanding of the agencies' respective regulatory responsibility. The 2015 Rule's definition section explains that "[h]ydraulic fracturing *does not include* enhanced secondary recovery such as water flooding, tertiary recovery, recovery through steam injection, or types of well stimulation operations such as acidizing."[114]

---

[106] 40 C.F.R. § 144.21(b).
[107] 40 C.F.R. § 144.21(c).
[108] 40 C.F.R. § 144.28(e).
[109] 40 C.F.R. § 144.28(f).
[110] 40 C.F.R. § 144.28(g).
[111] 40 C.F.R. § 144.28(b).
[112] 58 Fed. Reg. 47,354, 47,362 (Sept. 8, 1993).
[113] 58 Fed. Reg. at 47,363.
[114] 43 C.F.R. § 3160.0-5 (2015) (emphasis added).

And BLM acknowledged in the regulatory preamble that "disposal of recovered fluids is generally done . . . under the authority of other agencies such as the EPA (for underground injection)."[115]

BLM has taken an identical position with respect to hydraulic fracturing using diesel. During the rulemaking for the 2015 Rule, numerous commentators requested that BLM ban the use of diesel in hydraulic fracturing operations. BLM rejected these entreaties, emphasizing that the "regulation of diesel fuel in hydraulic fracturing fluids is committed to EPA under the SDWA and Energy Policy Act of 2005."[116] In fact, the 2015 Rule represents BLM's only ever attempt to regulate any form of underground injection, as the SDWA defines that term. But EPA's original source for authority over all forms of underground injection is the SDWA. BLM concedes that it cannot regulate enhanced oil recovery, disposal wells, or hydraulic fracturing using diesel because Congress has designated EPA as the agency with regulatory authority over those forms of underground injection in the SDWA and the same conclusion should apply with respect to non-diesel hydraulic fracturing. Given that BLM lacked the authority to issue the 2015 Rule in the first place, withdrawal of the rule at this point is appropriate.

IV. THE 2015 RULE'S REDEFINING OF "USABLE WATER" DISREGARDED EXISTING LAW AND PRACTICE.

The heart of the 2015 Rule is the identification and isolation of "usable water." Since 1982, operators have been required to "isolate freshwater-bearing [formations] and other usable water containing 5,000 ppm ["parts per million"] or less of dissolved solids . . . and protect them from contamination."[117] Under the 1982 rule, "fresh water" is defined to mean "water containing not more than 1,000 ppm of total dissolved solids" or other toxic constituents.[118] The 1,000 ppm standard for "fresh water" is double the secondary maximum contaminant level EPA has designated for total dissolved solids ("TDS") in drinking water (500 ppm).[119]

The 2015 Rule would have redefined "usable water," modifying the term's definition to include "those waters containing up to 10,000 parts per million (ppm) of total dissolved solids."[120] This despite a lack of any empirical evidence or science-based support for a need to protect water that is so saline that it can kill livestock, and which expands the scope of protected waters well beyond EPA's regulations under the Safe Drinking Water Act. Equally important, because the 2015 Rule was premised on an inaccurate view of the law, BLM did not properly account for any of the significant costs complying with the new standards would have caused operators to incur.

---

[115] 80 Fed. Reg. at 16,166.
[116] 80 Fed. Reg. at 16,191.
[117] 43 C.F.R. § 3162.5-2(d) (2014).
[118] 43 C.F.R. § 3160.0-5 (2014).
[119] *See* 40 C.F.R. § 143.3.
[120] 43 C.F.R. § 3160.0-5 (2015).

The 2015 Rule would have amended 43 C.F.R. § 3162.5-2(d), revising the first sentence of the subsection to require the operator to "isolate all usable water and other mineral-bearing formations and protect them from contamination."[121] The 2015 Rule defines "usable water" as "[g]enerally those waters containing up to 10,000 parts per million (ppm) of total dissolved solids."[122]

The Associations challenged BLM's reasoning for expanding the concept of "usable water" during the rulemaking process for the 2015 Rule. The Associations noted that a TDS concentration of 2,000 ppm is the highest recommended for irrigation and livestock consumption.[123] The Associations cited authorities emphasizing that water "with 10,000 ppm or more 'may cause brain damage or death' in livestock."[124] Other commenters noted that, "[i]n defining 'fresh water,' the World Health Organization's upper limit of acceptable palatable water for human consumption is 1,000 ppm TDS and North Dakota State University Extension Service advises farmers and ranchers that water quality is 'good' if it generally has less than 2,000 ppm TDS."[125]

BLM contended during the rulemaking process for the 2015 Rule that it need not address these arguments because, despite the final rule containing an express revision to Section 3162.5-2(d), the 2015 Rule did not represent any change from previously existing requirements. BLM observed that Onshore Order No. 2, effective since December 1988, provides that "casing and cementing programs shall be conducted as approved to protect and/or isolate all usable water zones,"[126] and defines "usable water" as "generally those waters containing up to 10,000 ppm of total dissolved solids."[127] BLM asserted that the 1982 regulation (still in the Code of Federal Regulations) "was *superseded* by the Onshore Order 2 definition in 1988."[128] Relying on that assertion, BLM alleges that "[b]ecause the definition of usable water has not substantially changed" in the final rule, "there will be no significant changes in costs of running casing and cement."[129]

As a matter of law, Onshore Orders cannot "supersede" a rule. Nor did Onshore Order No. 2 purport to supersede or repeal the fresh-water rule. BLM may issue Onshore Orders "when

---

[121] 80 Fed. Reg. at 16,222.
[122] 43 C.F.R. § 3160.0-5 (2012).
[123] *See* A.R. at DOIAR0056230-31.
[124] *Id.* at DOIAR0056231 (quoting G. Lardy et al., *Livestock & Water*, Table 9 (N.D. State Univ. Extension Serv. June 2008)).
[125] A.R. at DOIPS0365300, Pub. Cmt., Devon Energy Corp. (Aug. 23, 2013).
[126] Onshore Order No. 2 § III.B
[127] Onshore Order No. 2 § II.Y, 53 Fed. Reg. at 46,805.
[128] 80 Fed. Reg. at 16,196 (emphasis added).
[129] 80 Fed. Reg. at 16,142 & 16,196 (attributing an "incremental cost" of "$0" to the change in the usable water standard).

necessary to implement and supplement the regulations in this part [43 C.F.R. Part 3160]."[130] But "implement and supplement" does not mean "supersede." In fact, rather than repeal any element of the 1982 regulations, Onshore Order No. 2 expressly cites the fresh-water rule as one of the authorities the Order implements.[131] And though BLM represented that "Onshore Order 2 superseded the existing regulations in 1988, because it was promulgated pursuant to notice-and-comment rulemaking,"[132] that position is inconsistent with the express statement in the Code of Federal Regulations that Onshore Order No. 2 did *not* supersede any existing authority.[133]

The suggestion that the 2015 Rule did not change previously existing law is also inconsistent with the understanding of senior BLM officials who did acknowledge that the 2015 Rule represented a meaningful change in applicable law.[134] Given that the regulatory preamble to

---

[130] 43 C.F.R. § 3164.1(a).

[131] *See* 53 Fed. Reg. at 46,804 ("Specific authority for the provisions contained in this Order is found at . . . § 3162.5-2.").

[132] 80 Fed. Reg. at 16,176.

[133] *See* 43 C.F.R. § 3164.1(b). The Association's research has not disclosed any case in which BLM required an operator after 1988 to protect water zones with greater than 5,000 ppm when the operator's casing and cement was sufficient to protect water zones with less than 5,000 ppm. The only decision that appears relevant is a ruling BLM's State Director for the Montana State Office issued in 1994. *David L. Robertson*, SDR No. 922-94-05 (BLM Mont. State Office, April 21, 1994), available at:
http://www.blm.gov/style/medialib/blm/mt/blm_programs/energy/oil_and_gas/operations/sdrs.Par.38840.File.dat/922-94-05.pdf. In *Robertson*, field officers had objected to an operator's proposed casing depth for the initial surface casing string because it was not deep enough to "protect shallow sources of usable water." On appeal, the operator showed that the proposed casing depth would "isolate the fresh water zones." The BLM State Director reversed the field officer's determination, agreeing that "setting the surface casing to a depth of 450 feet would isolate the fresh water sands in the glacial till from deeper aquifers with poorer water quality." *Id.* at 3. Given that "fresh water" was defined by rule as water with less than 1,000 ppm of TDS, this decision is not consistent with BLM's assertion during the 2015 rulemaking that the agency has always enforced a 10,000 TDS standard.

[134] *See, e.g.*, A.R. at DOIAR0005111, Decision Mem. for the Sec'y from Robert V. Abbey (Feb. 25, 2011) ("According to 43 CFR 3162.5-2(d) the operator is, at all times, responsible for ensuring that freshwater-bearing zones are isolated and protected from contamination during drilling and subsequent activities."); *id.* at DOIAR0005309, Mem. from Elizabeth Klein to Jason Bordoff & Dan Utech (Mar. 17, 2011) (same). It is clear that, at the minimum, BLM was aware that the regulated community considered the final rule to effect a change in the law. *See*, *e.g.*, A.R. at DOIAR0021777, E-mail from David E. Blackstun to Steven Wells & Nicholas Douglas (May 22, 2012) (confirming Blackstun's understanding that the hydraulic fracturing rule would "broaden the scope of waters that operators must protect by raising the TDS concentration for usable water to 10,000 ppm"); *id.* at DOIAR0022886, E-mailed notes of Samuel B. Boxerman to Nancy DenHerder & Steven Wells (May 31, 2012) (explaining that under the hydraulic fracturing rule "[u]sable water would be redefined from 5,000 ppm or less of dissolved solids to water containing up to 10,000 ppm of dissolved solids") (citing 43 C.F.R. § 3160.0-5); *id.* at DOIAR0080261, Key Changes in the Hydraulic Fracturing Rule from Supplemental (May 2013) to Draft Final Rule (June 5, 2014) (acknowledging that the final rule "adopts standards set in the SDWA and Onshore Order No. 2"); *id.* at DOIAR0027276, Outline for Meeting Between ConocoPhillips and BLM (Aug. 23, 2012) (raising as a discussion issue that the "Proposed rule replaces current definition of 'fresh water' with 'usable water', defined as water 'containing up to 10,000 ppm of total dissolved solids'"); *id.* at DOIAR0027483, Meeting Notes: Industry Stakeholder Meeting to Discuss BLM's Proposed Hydraulic Fracturing Rule (June 28, 2012) (documenting industry understanding that "measures to protect usable water when operating at a depth that does not affect water introduces a new regulatory scheme"); *Wyoming v. Zinke*, No. 2:15-CV-043-SWS (D. Wyo.), Tr. of Prelim. Inj. Proceedings at

---

continued on next page…

the 2015 Rule recognizes an "inconsistency" between the 5,000 ppm standard contained in 43 C.F.R. § 3162.5-2(d) and the 10,000 ppm standard in Onshore Order No. 2's definition of usable water, it is clear that the former remained viable at the time the 2015 Rule was issued.[135]

Notwithstanding any disagreement regarding whether the 2015 Rule would have changed the *existing law* defining "usable water," there has never been any disagreement over what the rule's impact would have been on *existing practice* for locating and protecting usable water. For decades, state oil and gas agencies and BLM field offices have informed operators about the location of usable water that must be protected – taking into account local geology – and directed the depths at which it is acceptable to set well casing. Under the 2015 Rule, operators would have been assigned an affirmative obligation to identify the location of usable water to be protected based on a quantitative TDS calculation.[136] This would have posed a new burden.

The approach the 2015 Rule would have adopted disregards the difficulty and expense of measuring the numerical quality of water with the precision the 2015 Rule would have required. No logging tool directly measures TDS. Logs are essential for identifying rock properties, but do not represent an effective tool for measuring water salinity. Operators often run resistivity logs for intermediate and production casing, and these logs might allow the qualitative identification of high-salt-content zones. These logs do not, however, directly measure TDS, and there are too many variables for the signature these logs record to be converted into accurate TDS data.[137] A notable omission from administrative record prepared for the 2015 Rule is a description of any alternative means to comply with the requirement to determine the location of water meeting the agency's numerical definition of "usable water."[138]

…continued from previous page

105:8-106:15 (June 23, 2015) (Sgamma) (testifying that BLM field officials presented information materials to oil and natural gas operators indicating that the final rule modified the standard for water to be protected).

[135] *See* 80 Fed. Reg. at 16,141 & 16,196.

[136] *See* 43 C.F.R. § 3162.3-3(d)(1)(iii) (requiring identification of the "estimated depths (measured and true vertical) to the top and bottom of all occurrences of usable water").

[137] *See* A.R. at DOIAR0056164, Pub. Cmt., ConocoPhillips Co. (Aug. 22, 2013) (explaining that that while in controlled conditions one might determine TDS measurements from well logging tools, there has been "little success applying the techniques") (quoting *Borehole Geophysical Techniques for Determining the Water Quality & Reservoir Parameters of Fresh & Saline Water Aquifers in Tex.*, Report 343, Tex. Water Dev. Bd.); A.R. at DOIPS0301574, Pub. Cmt., ANGA & AXPC (Aug. 23, 2013) (observing that while logs may allow an inference that salty water is present, they cannot do so "clearly enough to determine . . . an unambiguous 10,000 [ppm] TDS cutoff").

[138] *See* A.R. at DOIAR0079317, Hydraulic Fracturing Meeting Notes (May 21, 2014) (posing question: "who is going to supply BLM with the usable water TDS information to determine usable water?"); *id.* at DOIPS0435828, Pub. Cmt., Marathon Oil Corp. (Aug. 23, 2013) (noting that "the revised proposed definition would require operators to collect new information regarding aquifers that have little or no potential to be considered future sources of drinking water or water to be used in industrial or agricultural application" and emphasizing that "[t]his would be a significant cost to Operators"). The 2015 Rule also fails to account for the rule's impact on operators that drilled and cased existing wells under the former practice, which includes, under BLM's calculation, any well drilled since at least 1988. The 2015 Rule would have regulated all future hydraulic fracturing in both new and existing

---

continued on next page…

V. THE 2015 RULE'S DISCLOSURE REQUIREMENTS ARE CONTRARY TO FEDERAL PUBLIC RECORDS LAW.

The 2015 Rule would have represented a significant expansion of the information that oil and gas developers are required to disclose publicly both before and after operations. Before commencing hydraulic fracturing operations, producers would have been required to disclose to BLM operational information about the location where drilling will take place, water resources in the vicinity of operations, the location of other wells or natural fractures or fissures in the area, and the producer's fracturing plans (including the amount of fluid to be injected, the pressure to be applied to the formation, and the estimated length, height, and total vertical depth of the fractures).[139] After hydraulic fracturing operations, operators would have been required to disclose detailed operational information including the components of hydraulic fracturing fluid used in stimulation, the pressures applied to geologic formations, the length, height, and direction of fractures, and the actual depth of perforations.[140] Much of this information, and particularly information regarding local geology and the operators' technical designs for extracting resources from that geology, is highly proprietary and represents economically valuable commercial information. Presumably because of the value and proprietary nature of this data, the 2015 Rule provided a mechanism for operators to protect the information that is required to be submitted in the completion reports submitted after hydraulic fracturing. But the rule did not provide any protection for the very similar information that operators would have been required to be submit before hydraulic fracturing.

In the regulatory preamble to the 2015 Rule, BLM suggested that when submitting information to the agency, an operator "may segregate the information it believes is a trade secret, and explain and justify its request that the information be withheld from the public."[141] The plain language of the 2015 Rule itself, however, is much more limited than implied in the preamble. The provision that allows operators to withhold information from disclosure, 43 C.F.R. § 3162.3-3(j), applied only to the information that an operator would have been required to submit under paragraph (i) of Section 3162.3-3.[142] Paragraph (i) was the provision that identifies the "[i]nformation that must be provided to the authorized officer after hydraulic fracturing is completed," i.e., the information in the post-hydraulic fracturing completion report.[143] There is no analogous provision in the 2015 Rule that provides a method for operators

---

…continued from previous page

wells. *See* 43 C.F.R. § 3162.3-3(a). Having relied on prior government instruction about casing depths, operators of existing wells would have been at risk of having to add casing or cement to comply with the new requirement.

[139] *See* 43 C.F.R. § 3162.3-3(d)(1)-(7).

[140] *See* 43 C.F.R. § 3162.3-3(i).

[141] 80 Fed. Reg. at 16,173.

[142] *See* 43 C.F.R. § 3162.3-3(j) (establishing procedure to assert exemption from disclosure "[f]or information required in paragraph (i) of this section").

[143] 43 C.F.R. § 3162.3-3(i).

to withhold information that the rule required to be submitted before hydraulic fracturing operations or in any other reporting associated with development activities.[144]

Neither the 2015 Rule nor the regulatory preamble prepared in association with the rule provided any explanation for drawing a distinction between pre- and post-hydraulic fracturing information. BLM acknowledged receiving comments that information required in the pre-hydraulic fracturing reports represents confidential information.[145] Yet BLM rejected those concerns on that basis that "BLM believe[d] that the submission of these estimated values would not routinely meet any of the criteria within the Freedom of Information Act regulations (43 CFR part 2) which would require such information to be held as confidential information."[146] BLM did not explain the reasoning it employed to reach this conclusion or the bases for its belief.

The position BLM offered during the 2015 rulemaking is contrary to federal law. The Freedom of Information Act ("FOIA") contains nine exemptions that protect specific categories of information from disclosure.[147] The 2015 Rule implicated at least two of those exemptions.

The 2015 Rule would have required operators to submit, among other information: (i) detailed information "regarding wellbore geology" including "a geologic description, and the

---

[144] Not only would this information have been collected, BLM acknowledged that "[i]nformation that would be required to be submitted as part of [the 2015] rule will be made available to the public, consistent with the requirements of Federal Law." 80 Fed. Reg. at 16,182.

[145] *See*, *e.g.*, A.R. at DOIAR0056262, Pub. Cmt., IPAA (emphasizing that operators consider geologic information and well completion design plans to be trade secrets and asserting that the rule's withholding mechanism is insufficient "because the cross-references in the exemption provision indicate that claims can only be made for information submitted following the hydraulic fracturing operation"); *id.* (requesting an analogous provision be added allowing operators to seek protection "for information required to be included with the Notice of Intent Sundry requesting approval of a hydraulic fracturing operation"); *id.* at DOIPS0365294, Pub. Cmt., Devon (observing that "[s]ubmitting [fracture extent] information to the BLM, and therefore making it available to the public, would render the intellectual property value of the information nil" and requesting that, "[s]hould this requirement be retained in a Final Rule, the BLM should allow a mechanism in the rule that ensures that this information, if submitted, is held confidentially"); *id.* at DOIPS0179035, Pub. Cmt., Encana (explaining that submission of fracture mapping "could also undercut an individual company's competitive advantage by publicly providing insight into well designs and prospective geology"); *id.* at DOIPS0364932, Pub. Cmt., Noble Energy, Inc. (Aug. 23, 2013) (stating that "[t]he proposed rule affords trade secret protection . . . only to information that would be submitted after a hydraulic fracturing operation" and requesting that "BLM expand the trade secret provisions to information required to be submitted in the Notice of Intent Sundry, such as fracture length and orientation data"); *id.* at DOIPS0365626, Pub. Cmt., Ultra Petroleum (Aug. 23, 2013) (stating that "[t]he proposed rule affords trade secret protection . . . only to information that would be submitted after a hydraulic fracturing operation" and requesting that "BLM expand the trade secret provisions to information required to be submitted in the Notice of Intent Sundry, such as fracture length and orientation data"); *id.* at DOIPS0301588, Pub. Cmt., ANGA (observing that "[s]ubmitting [fracture extent] information to the BLM, and therefore making it available to the public, would render the intellectual property value of the information nil" and requesting that, "[s]hould this requirement be retained in a Final Rule, the BLM should allow a mechanism in the rule that ensures that this information, if submitted, is held confidentially").

[146] 80 Fed. Reg. at 16,154.

[147] 5 U.S.C. § 552(b).

estimated depths (measured and true vertical) to the top and bottom of the formation into which hydraulic fracturing fluids are to be injected";[148] (ii) the estimated depths to the top and bottom of confining zones and all occurrences of usable water;[149] and (iii) a "map showing the location, orientation, and extent of any known or suspected faults or fractures within one-half mile (horizontal distance) of the wellbore trajectory that may transect the confining zone(s)."[150] This information falls squarely within the plain language of FOIA's Exemption 9, a provision that protects from disclosure "geological and geophysical information and data, including maps, concerning wells."[151] Exemption 9 recognizes that "disclosure of seismic reports and other exploratory findings of oil companies would give speculators an unfair advantage over the companies which spent millions of dollars in exploration."[152] The regulatory preamble to the 2015 Rule made no reference to Exemption 9 or to case law applying the exemption to protect as confidential the type of geological information operators would have been required to disclose under the 2015 Rule.[153]

BLM also fails to account for Exemption 4, a provision that protects "trade secrets and commercial or financial information obtained from a person that is privileged or confidential."[154] BLM acknowledged that the 2015 Rule would have "add[ed] to existing requirements by providing information to the BLM and the public on the location, geology, water resources,

---

[148] 43 C.F.R. § 3162.3-3(d)(1)(i).

[149] *See* 43 C.F.R. § 3162.3-3(d)(1)(ii)-(iii).

[150] 43 C.F.R. § 3162.3-3(d)(2).

[151] 5 U.S.C. § 552(b)(9).

[152] *Black Hills Alliance v. U.S. Forest Serv.*, 603 F. Supp. 117, 122 (D.S.D. 1984) (quoting H.R.Rep. No. 1497, 89th Cong.2d Sess. 11 (1966), U.S. Code Cong. & Admin. News 1966, p. 2418, *reprinted in* Freedom of Information Act Source book: Legislative Materials, Cases, Articles, Subcomm. on Admin. Practice & Procedure of the Comm. on the Judiciary, 93d Cong. 2d Sess. 32 (1974)).

[153] *See Starkey v. U.S. Dep't of the Interior*, 238 F. Supp. 2d 1188, 1196 (S.D. Cal. 2002) (applying Exemption 9 to exempt from disclosure information in table and narrative form related to ground water inventories, well yields, and the thickness of a particular formation).

[154] 5 U.S.C. § 552(b)(4). Like Exemption 4, the federal Trade Secrets Act prohibits the disclosure of information that "concerns or relates to the trade secrets, processes, operations, style of work, or apparatus, or to the identity, confidential statistical data, amount or source of any income, profits, losses, or expenditures of any person, firm, partnership, corporation, or association." 18 U.S.C. § 1905. In applying the broad language of the Trade Secrets Act, federal courts look to the scope of Exemption 4; to determine whether Section 1905 prohibits any particular disclosure, a Court must first determine whether the information falls within Exemption 4. *See* U.S. Dep't of Justice, Freedom of Information Act Guide (May 2004) (quoting 5 U.S.C. § 552(b)(4)), available at: http://www.justice.gov/oip/foia-guide-2004-edition-exemption-4#N_1_. *See also Gen. Motors Corp. v. Marshall*, 654 F.2d 294, 297 (4th Cir. 1981) (characterizing the scope of Section 1905 and Exemption 4 as "the same" and "coextensive" and concluding that "material qualifying for exemption under [Exemption 4] falls within the material, disclosure of which is prohibited under [Section] 1905"). If material would qualify for protection under Exemption 4, an agency *must* prohibit public disclosure. The Department of Justice has recognized that Section 1905 "stands as a potent barrier to the disclosure of any information that falls within the protection of Exemption 4." U.S. Dep't of Justice, Discretionary Disclosure & Exemption 4 (1985), available at: http://www.justice.gov/oip/blog/foia-update-oip-guidance-discretionary-disclosure-and-exemption-4. The Supreme Court has explained that disclosures violating Section 1905 are "not in accordance with law" within the meaning of the Administrative Procedures Act, 5 U.S.C. § 706(2)(A). *See Chrysler Corp. v. Brown*, 441 U.S. 281, 318 (1979).

location of other wells or fracture zones in the area, and fracturing plans for the operation before the well is permitted."[155] Because the operational and design information that the 2015 Rule would have required oil and gas operators to disclose falls squarely within the categories of information that Exemption 4 protects, the 2015 Rule is directly contrary to law.

The federal courts recognize that Exemption 4 "protects persons who submit financial or commercial data to government agencies from the competitive disadvantages which would result from its publication."[156] And when the submission of that information is involuntary, "the information is protected from disclosure by FOIA if disclosure will either: "[i] impair the government's ability to obtain necessary information in the future or [ii] cause substantial harm to the competitive position of the person from whom the information was obtained."[157]

To satisfy this second prong, all that is needed "is actual competition and the likelihood of substantial competitive injury."[158] That standard is easily satisfied in this context. The compilation of geologic data and the development of technical plans for extracting resources from that geology is the very essence of how oil and gas companies compete. Geologic assessments identifying the location and accessibility of oil and gas deposits represent oil and gas companies' most closely held commercial information and form the framework for all operators' decisions regarding where to invest and the tools and strategies used to explore for and develop specific assets.

Nor is the potential of competitive injury in doubt. The 2015 Rule would have required, as part of an operator's request for authorization to conduct hydraulic fracturing activities, that the operator submit "[a] map showing the location, orientation, and extent of any known or suspected faults or fractures within one-half mile (horizontal distance) of the wellbore trajectory that may transect the confining zone(s)."[159] To the extent that this information is available at all,[160] it is closely held and confidential. Operators would not willingly share this information

---

[155] 80 Fed. Reg. at 16,130.

[156] *Nat'l Parks & Conservation Ass'n v. Morton*, 498 F.2d 765, 768 (D.C. Cir. 1974). *See also Herrick v. Garvey*, 298 F.3d 1184, 1193 (10th Cir. 2002) ("The purpose of Exemption 4 is "to protect the confidentiality of information which is obtained by the Government ..., but which would customarily not be released to the public by the person from whom it was obtained.") (quoting *Critical Mass Energy Project v. Nuclear Regulatory Comm'n*, 975 F.2d 871, 877 (D.C. Cir. 1992)).

[157] *Utah v. U.S. Dep't of Interior*, 256 F.3d 967, 969 (10th Cir. 2001).

[158] *Id.* at 970.

[159] 43 C.F.R. § 3162.3-3(d)(2).

[160] The mapping information that the 2015 Rule sought will only be available in circumstances where seismic mapping has been conducted. Seismic analyses constitute intensive surveys that cannot be conducted on every well; these surveys are normally run in the early phase of field development, and on only a few wells, to help calibrate the drainage area and evaluate the most effective spacing between wells. When seismic mapping has not been conducted, operators will not be able to produce maps, except along well-mapped, well-known faults and fault structures where information has already been published publicly. Under these conditions, BLM will already have access to the same publicly available geologic information as operators. But because no data sharing center for

---

continued on next page…

with offset operators who did not participate in the time and expense of a seismic shoot required to obtain this data. That is because this geological understanding influences the productivity of development and the value of regional assets. When operators drill wells in a less favorable direction, for example, those wells may not perform optimally and that inferior well performance may motivate decisions to re-assign resources to other locations, to sell acreage to competitors, or to enter cooperative operating or farmout agreements.

And direction is only one feature of an operator's extraction plan. The design and details of hydraulic fracturing plans have a substantial effect on the recoveries that oil and gas operators can achieve. The 2015 Rule would have required that operators submit significant aspects of these plans: (i) the volume of fluid to be used; (ii) the pressure that will be applied; (iii) the trajectory in the wellbore into which hydraulic fracturing fluids are to be injected; (iv) the direction and length of the fractures that will be propagated; and (v) the depth of perforations.[161] Companies spend millions of dollars annually in research and development to formulate designs that maximize recovery, reduce operational costs, and minimize environmental impact. The features of a hydraulic fracturing plan, and the ability to adjust those features in a manner that promotes operational objectives, are what separate oil and gas producers from their competition. Making those features public and accessible to competitors would have undermined the value of that ability and diluted the investment of producers who are constantly striving to extract oil and gas with less waste, less costs, and more environmental sensitivity.

Information is not public simply because the government wishes to collect it. The 2015 Rule failed to account both for the confidential nature of the information the rule required to be disclosed and the commercial consequences of that disclosure. Because the 2015 Rule would have required public disclosure of highly confidential and commercially valuable information, the rule is contrary to federal public records law and its rescission is appropriate.

VI. THE 2015 RULE IS CONTRARY TO EXECUTIVE GUIDANCE.

The Department of the Interior serves a critical function as the custodian of much of the nation's natural resources wealth. As discussed earlier,[162] the Department's agencies are required to perform daily a myriad of tasks to ensure the prudent and efficient development of resources in a manner that optimizes public benefits, promotes national security, and protects treasured landscapes. Under the best circumstances, meeting each of these objectives is a complex and onerous task. Yet Interior rarely, if ever works under "the best circumstances." And too often, it

---

…continued from previous page

seismic information on federal lands exists, publicly available seismic information exist only a very small percentage of federal and Indian lands.

[161] *See* 43 C.F.R. § 3162.3-3(d)(4).

[162] *See* discussion *supra* Part I.

is Interior itself that is responsible for creating obstacles that delay, compromise, or defeat the Department's ability to complete essential functions.

BLM's management of the federal oil and gas development program represents a clear example of how Interior's agencies struggle to accomplish their statutorily defined mission. Since the turn of the new century, technical advancements that allow producers to identify promising sources of oil and gas and to extract hydrocarbons from previously inaccessible geologic formations, combined with the entrepreneurial ingenuity of American industry, have resulted in American energy companies reaching production levels once thought impossible. The accessibility of abundant oil and gas resources has transformed conventional understandings of the energy landscape, leading some to predict both millions of new jobs and total energy independence for the United States. But while domestic production has grown in recent years, the percentage of that production that is extracted from federal lands has declined in the same period.[163]

Figure 1. U.S. Crude Oil Production: Federal and Nonfederal Areas FY2006-FY2015

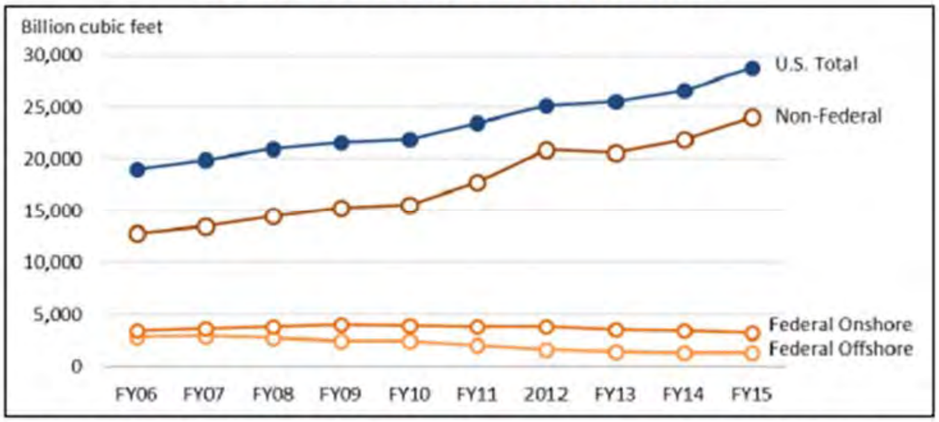
(million barrels per day)

Source: Federal data obtained from ONRR Production Data, http://www.onrr.gov. Nonfederal from EIA. Figure created by CRS.

---

[163] Congressional Research Serv., *U.S. Crude Oil & Natural Gas Prod. in Fed. & Nonfed. Areas*, Figs. 1-2, at 3, 5 (June 22, 2016).

Figure 2. U.S. Natural Gas Production:
Federal and Nonfederal Areas FY2006-FY2015



Source: Federal data obtained from ONRR Statistics, http://www.onrr.gov (using sales year data). Figure created by CRS.

The reasons for this divergence are not open to reasonable dispute. Under the previous administration, executive agencies undertook an unprecedented campaign to expand the regulatory burdens imposed on oil and gas producers operating on federal lands. These regulatory initiatives touched every component of oil and gas development, impacting, among other aspects: (i) the manner in which operators construct and complete wells; (ii) the requirements for maintenance and repair of wells; (iii) the methods by which produced oil and gas is transported to market; (iv) the value of production for royalty reporting; and (v) the contractual terms of federal leases. These regulatory requirements – along with logistical efficiencies inherent in the federal government's management of the nation's public lands – represent an enormous incentive for operators to focus their efforts on state and private lands.

Given this background, both the President and the Secretary of the Interior have recently directed executive agencies to evaluate whether existing rules and policies impose unreasonable burdens on the production of federal minerals. On March 28, 2017, President Trump signed an Executive Order directing all federal agencies to enact policies "to promote clean and safe development of our Nation's vast energy resources" and to avoid "burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation."[164] The President's Order expressly directs the Secretary of the Interior to, "as soon as practicable," publish for notice and comment "proposed rules suspending, revising, or rescinding" the hydraulic fracturing rule.[165]

On the next day, March 29, 2017, Secretary Zinke issued Secretary's Order No. 3349. Order No. 3349 states that the Department of the Interior's objective "is to identify agency actions that unnecessarily burden the development or utilization of the Nation's energy resources

---

[164] Exec. Order 13,783, *Promoting Energy Independence & Econ. Growth* (Mar. 28, 2017).
[165] *Id.* § 7(b)(i).

and support action to appropriately and lawfully suspend, revise, or rescind such agency actions as soon as practicable." Consistent with that approach, the Secretary indicated that BLM "shall proceed expeditiously with proposing to rescind the final [hydraulic fracturing] rule."[166]

On July 6, 2017, the Secretary issued Secretary's Order No. 3354. The purpose of Order No. 3354 was to "promote the exploration and development of both Federal onshore oil and gas resources and Federal solid mineral resources."[167] Among other directives, Order No. 3354 charges BLM with responsibility to "develop an effective strategy to address permitting applications efficiently and effectively as well as develop clear and actionable goals for reducing the permit processing time."[168]

The reference to permitting times in Order No. 3354 is notable because BLM consistently fails to meet existing statutory obligations to timely process operational permits. The Mineral Leasing Act requires that, no later than ten days after the date on which BLM receives an application for permit to drill ("APD"), BLM shall: (i) notify the applicant that the application is complete; or (ii) notify the applicant that information is missing and specify any information that is required to be submitted for the application to be complete.[169] BLM almost never meets this deadline and, indeed, rarely if ever prepares and transmits any formal notice that an application is complete.

Then, not later than thirty days after the applicant for a permit has submitted a complete application, BLM must issue the permit, if the requirements under the National Environmental Policy Act and other applicable law have been completed.[170] Federal courts have held that processing permits consistent with this timeline is statutorily required.[171] But again, BLM almost never meets this controlling thirty-day deadline. To the contrary, the former BLM Director, Neil Kornze, has testified that, even after improvements in BLM's efficiency, the average processing time for a drilling permit on federal lands is approximately 200 days.[172] The Associations' members report that, for several field offices – particularly those in areas where the demand for permits is high – Mr. Kornze's 200-day estimate is quite low.[173]

---

[166] U.S. Dep't of the Interior, Sec'y Order 3349 § (c)(1).
[167] U.S. Dep't of the Interior, Sec'y Order 3354 § 1.
[168] *Id.* § (3)(c).
[169] *See* 30 U.S.C. § 226(p)(1)(A)-(B).
[170] *See* 30 U.S.C. § 226(p)(2)(A).
[171] *See EnerVest, Ltd. v. Jewell*, No. 2:16-cv-01256-DN, 2016 WL 7496116 (D. Utah Dec. 30, 2016).
[172] Breaking the Logjam at BLM: Hearing on S. 279 and S. 2440 Before the S. Comm. on Energy & Natural Resources, 113th Cong. 491 at 20 (July 29, 2014) (testimony of Neil Kornze) (explaining that since 2011, average processing times have ranged between 196 and 300 days).
[173] There is substantial evidence in the record documenting operators' frustration with, and BLM's awareness of, administrative delays attendant to development on federal and Indian lands *See* A.R. at DOIAR0078785, Internal Working Document, Diane Rhem [sic] Show Background: Fed. Land Mgmt. & BLM Energy Prod. on Pub. Lands (May 11, 2014) (stating that in FY2013, "it took an average of 194 days to process an APD, down from 228 in 2012, and faster than any time since 2005"); *id.* at DOIAR0028197, E-mail from Benjamin A. Nussdorf, Senior Counselor,

---

continued on next page…

Rather than ameliorate issues that cause these delay, the 2015 Rule would have exacerbated the existing problems in a manner totally inconsistent with the executive guidance that the President and Secretary have issued. The 2015 Rule would have added an additional authorization request and decision-making process to BLM's administrative responsibilities — i.e., yet *another* permit. Equally problematic, BLM assumed only de minimis values to the expense and time necessary to prepare and review applications for permission to conduct hydraulic fracturing.[174] This extraordinarily low estimate was presumably based on the assumption that BLM "fully expect[ed] to process requests for hydraulic fracturing concurrently with the processing of drilling applications."[175] BLM conceded that, "[i]f an operator submits a request [to conduct hydraulic fracturing] in [a notice of intent], . . . further processing time should be expected."[176]

The assumption that an operator is likely to submit a request for authorization to conduct hydraulic fracturing at the time an operator submits an APD was misguided. Given that there are often many months, if not years, between the time an APD is submitted and the time BLM approves the APD, it is rare that an operator will have all the information related to hydraulic fracturing that the final rule requires at the time an APD is submitted. It is not uncommon for significant aspects of the hydraulic fracturing design to change during that period because of changes in, among other factors, commodity prices, material availability, vendor availability, and geological information acquired during the drilling and logging process. Designs can also change based on what an operator has learned from developing other nearby wells — information that is not always available at the time an APD is submitted. And designs can change based on information gathered from drilling the well itself, which by definition occurs after the APD is approved.

Even if an operator could be convinced to submit an application to conduct hydraulic fracturing at the time the operator submits an APD, it is still doubtful that BLM is capable of processing applications in the efficient manner that the President's and Secretary's executive guidance demands. BLM estimated that the "review of information associated with the application, subsequent report, remedial action report (when applicable), and variance request (when applicable) will pose an additional workload to the BLM of about 25,400 hours per year."[177] And while the regulatory preamble to the 2015 Rule offered conclusory statements

---

…continued from previous page

Mineral & Realty Mgmt. to Robyn Shoop (Sept. 4, 2012) ("A number of commenters have brought up BLM delays and inexperience."); *id.* at DOIAR0056224, Pub. Cmt., IPAA (documenting delays between receipt of an APD and approval of the APD in eleven BLM field offices).

[174] *See* 80 Fed. Reg. at 16,196 (calculating an incremental cost of $643 per application and assuming only 8 hours of preparation time and 4 hours of review time).

[175] *Id.* at 16,186.

[176] *Id.* at 16,177.

[177] 80 Fed. Reg. at 16,207.

rejecting commenters' concerns that BLM does not have the staffing, budget, or expertise to administrate the rule,[178] BLM officials conceded that, given the combination of increases in workload associated with the hydraulic fracturing rule and reductions in the agency budget, "getting the work done could be an issue."[179] Among other problems, BLM recognizes that "skills gaps" are a "program vulnerability" for BLM's existing oil and gas programs.[180]

Rescission of the 2015 Rule is entirely appropriate given the admonitions of agency leaders that BLM does not have the expertise in the field to administer the rule.[181] Rescission will also allow BLM to shift resources that would have been necessary to administer the 2015 Rule to meet the agency's other responsibilities, including satisfying the objectives of the recently-issued executive guidance.[182]

VII. THE 2015 RULE WAS NOT RATIONALLY STRUCTURED.

A regulation must be structured in a manner that permits the regulated community to comply with the regulation's terms.[183] The 2015 Rule, however, contains numerous provisions that cannot be administered technically, do not represent rational regulation of oil and gas development activities, and/or fail to optimize environmental sensitivity. Because requiring oil and gas operators to comply with these provisions would impose costs that cannot be recovered and discourage development that would benefit the public, without any demonstrable environmental or administrative benefits, rescinding the rule is a sensible step at this time.

---

[178] *Id.* at 16,177.

[179] A.R. at DOIAR0009106, E-mail from James V. Scrivner, Deputy State Dir., Energy & Minerals, Cal. State Office to Steven Wells (Dec. 20, 2011).

[180] A.R. at DOIAR0078643, BLM's Oil & Gas: Program Introduction - Revenue Generation (May 7, 2014) (characterizing "skills gaps" as a "program vulnerability" for BLM's oil and gas program and observing that: (i) several field offices, including the field office that oversees the Bakken, have no petroleum engineers on staff; (ii) BLM's 'Top 4 leasing specialists' are set to retire within six months; (iii) there is a 10% vacancy for petroleum engineers in the agency and that it often takes twelve months to fill any vacancy; and (iv) there are thirty vacant inspector positions and that it takes "too long to recruit, too long to certify," and that BLM "lose[s] [candidates] to higher paying other Federal agencies, and [to] industry during boom times").

[181] *See* A. R. at DOIAR0009166, Cmts. from Wesley W. Ingram, Supervisory Petroleum Engineer, Carlsbad Field Office (observing that "[n]one of the engineers in the Carlsbad Field Office have designed a frac job and probably only one has even been on location for a frac").

[182] *See* A.R. at DOIAR0009170, Mem. from Jerry Stranahan, Branch Chief, Fluid Minerals, Colo. State Office to Steven Wells (Dec. 22, 2011) (expressing concern "that the bulk of this rulemaking is duplicative of State of Colorado processes and procedures and that the time spent on these reviews will negatively impact [the BLM Colorado State Office's] work that cannot be duplicated by other agencies or the state").

[183] *See RxUSA Wholesale, Inc. v. Dep't of Health & Human Servs.*, 467 F. Supp. 2d 285, 305 (E.D.N.Y. 2006) (granting preliminary injunction of regulation requiring re-sellers of prescription drugs to certify the pedigree of drugs the distributors sold because the manufactures and authorized distributors from whom the re-sellers obtained the drugs were not required to maintain pedigree records).

A. THE RECOVERED FLUIDS STORAGE REQUIREMENTS ARE NON-SENSICAL.

The 2015 Rule would have required that "all fluids recovered *between* the commencement of hydraulic fracturing operations and the authorized officer's approval of a produced water disposal plan under BLM requirements must be stored in rigid enclosed, covered, or netted and screened above-ground tanks."[184] But no regulatory mechanism exists for the "approval of a produced water disposal plan" on an individual well basis. The limitations the 2015 Rule purports to apply to recovered fluids storage are premised on an administrative approval process that does not exist. Equally important, even if the recovered fluids requirements were enforceable, limiting operators to the use of small tanks for recovered fluid storage precludes operators from choosing the most environmentally sensitive and cost-effective measures for handling recovered fluids.

Under Onshore Order No. 7, BLM approves a "disposal method" — whether by injection, storage in long-term pits, or other method including treatment and recycling — in association with the permitting of "disposal facilities" on a lease basis.[185] Assuming that fluids recovered from a hydraulically fractured well are to be ultimately disposed of in accordance with a method and in a facility that has previously been approved under Onshore Order No. 7, e.g., in an EPA-approved injection well consistent with the terms of an authorized Underground Injection Control permit, there is no time "between the commencement of hydraulic fracturing operations and the authorized officer's approval of a produced water disposal plan."[186]

BLM has acknowledged that, when an operator's disposal method and disposal facility have been approved under Onshore Order No. 7, the provision of the final rule requiring recovered fluids stored at the well site be held in above-ground tanks is "inapplicable."[187] That is because "Onshore Order 7 generally applies to all recovered fluids, including those fluids recovered immediately after hydraulic fracturing," and "[u]nder Onshore Order 7, section III.a, an operator has permission to temporarily dispose produced water from newly completed wells for up to 90 days, until an application for the disposal of produced water is approved by the authorized officer."[188] Yet in the litigation challenging the issuance of the 2015 Rule, BLM also contended that "BLM promulgated the temporary storage provision in the final rule for operations for which there is a gap between completion of hydraulic fracturing operations, and approval of a permanent disposal plan" and represented that "the final rule provision fills a regulatory gap in Onshore Order 7, which otherwise allows produced water to be stored in

---

[184] 43 C.F.R. § 3162.3-3(h) (emphasis added).
[185] Onshore Oil and Gas Order No. 7, Disposal of Produced Water § III.B, 58 Fed. Reg. 47,354-01, 47,362-63 (Sept. 8, 1993).
[186] 43 C.F.R. § 3162.3-3(h).
[187] *Indep. Petroleum Ass'n of Am. v. Zinke*, No. 2:15-CV-00041-SWS (D. Wyo.), Resp'ts' Br. in Opp'n to Pet'rs' Mot. for Prelim. Inj. at 20-21, filed June 1, 2015 (ECF No. 20).
[188] 80 Fed. Reg. at 16,164.

reserve pits for up to 90 days."[189] To the extent BLM might have interpreted the 2015 Rule to require operators whose disposal plan has previously been approved to use above-ground tanks for the temporary storage of recovered fluids at the well-site (until those fluids can be transported to the permanent disposal site), that approach would have violated both the express terms of Onshore Order No. 7 and contradicted BLM's recognition that the final rule is inapplicable under those circumstances.

Equally problematic, the 2015 Rule's recovered fluids provisions undermine operators' ability to design hydraulic fracturing operations in a manner that promotes environmental sensitivity and economic efficiency. In 2015, BLM estimated an average incremental cost of using tanks instead of a pit for recovered fluids storage to be $74,400 per operation, but applied that figure to "only those operations where we do not estimate that the operator will voluntarily comply."[190] BLM represented that "[o]perations that are most likely to incur this cost are in states where 0.8% of all oil and gas activity on public lands occurs."[191] There is no support for this representation.

BLM previously attributed no incremental costs to the tank requirement in New Mexico and Texas, for example, "based on state regulations."[192] This approach made little sense given that, both states "allow operators to apply for permits to use pits,"[193] and some operators do indeed use pits in those states. Even absent a requirement to use tanks, BLM indicated that it has assumed voluntary compliance with the tank provision "in situations where tanks would cost the same as or less than pits, and this may be largely dependent on the volume of recovered fluids expected."[194] On this basis, BLM: (i) attributed no incremental cost to the tank requirement in Alaska, California, South Dakota, and Utah; and (ii) assigned very limited incremental costs in other states with significant activity on public lands including Colorado, Montana, North Dakota, Oklahoma, and Wyoming.[195]

The supposition that costs represent the dominant factor in an operator's selection of a recovered fluids storage method is contrary to the evidence in the 2015 administrative record. Cost is one factor; but an operator's preference often "varies on a project-by-project basis, depending on a wide variety of economic, geographic, logistical, and environmental factors."[196] Although BLM's 2015 analysis appears to have considered the rental cost of tanks and some

---

[189] Resp'ts' Br., *supra* n.187, at 20.
[190] *Id.* at 16,201-02.
[191] 80 Fed. Reg. at 16,202.
[192] *Id.*
[193] *Id.* at 16,199.
[194] *Id.* at 16,200.
[195] *See id.* at 16,202. BLM contemplated an impact on 28.3% of operations in Colorado, 20.4% of operations in Montana, 24.9% of operations in North Dakota, 38.1% of operations in Oklahoma, and 7.7% of operations in Wyoming. *See id.*
[196] A.R. at DOIAR0056255-56, Pub. Cmt., IPAA.

transportation costs,[197] the analysis supporting the 2015 Rule omits numerous other economic and environmental factors attendant to the use of tanks. The administrative record compiled in support of the 2015 Rule lacks information about: (i) the likelihood that operations would be located in reasonable proximity to allow tanks to service multiple operations simultaneously; (ii) transportation costs between various well sites; and (iii) whether dispersing tanks to multiple well sites simultaneously would leave enough tanks in any one place to service each individual location. To the extent there is evidence in the record related to operators' preferences, it demonstrates that pits often present an operational advantage when servicing recovered fluids from multiple wells;[198] reduce transportation risks;[199] limit environmental impacts on well pads, roads, rights of way, and surrounding ecosystems;[200] and promote water treatment and recycling.[201]

Viewed broadly the concern with the 2015 Rule's provisions related to recovered fluids was the rule's elimination of operational flexibility and imposition of a rigid and prescriptive mandates for handling produced water. Because there are economic, environmental, and operational advantages to both tanks and lined pits – and operators should therefore have the flexibility to choose the solution most appropriate under various circumstances – rescinding the 2015 Rule will actually promote production and increase environmental sensitivity.

---

[197] BLM indicated that it assumed transportation to and from the operating site will take four hours. *See* 80 Fed. Reg. at 16,201. BLM did not indicate how the agency derived this assumption. Given that operations in the western public land states are often quite far from population centers, an estimate of four hours does not appear reasonable.

[198] *See* A.R. at DOIAR0056256 (demonstrating that pits often present an operational advantage when servicing recovered fluids from multiple wells because: (i) tanks used for the management of returned fluids typically cannot store the entire volume of fluids returned from the well; and (ii) a tank's contents must be transferred for disposal throughout the recovery period to make space for operations to continue); *id.* (explaining that a pit can generally be sized to handle the entire volume of recovered fluids, which facilitates reuse and decreases impacts on fresh water resources).

[199] *See* A.R. at DOIAR0056256, Pub. Cmt., IPAA (observing that setting, emptying, and removing tanks will also result in increased truck traffic compared to pits).

[200] *See* A.R. at DOIAR0056256 (explaining that tanks do not necessarily reduce the potential for leaks because manifolding tanks together involves more piping than is required to transfer fluids to and from a pit.); *id.* (noting that increased amount of piping connections poses a release threat, even with the implementation of best management practices to ensure the integrity of transfer lines); *id.* at DOIPS0365304-05, Pub. Cmt., Devon (discussing the increased costs and impacts of storing fluid in tanks compared to the benefits of pits); *id.* at DOIPS0389023, Pub. Cmt., Anadarko (Aug. 23, 2013) (explaining that ponds used to store fluids are typically "completely reclaimed in under 8 months," and noting that "use of closed tanks adds significantly to water treatment costs, tank-hauling traffic and potential spills during transport").

[201] *See* A.R. at DOIPS0301581, Pub. Cmt., ANGA (asserting that the "Associations' members have made significant investments in the development of recycling technologies to increase the utility of recovered fluids," observing that "[s]uch investments have also led to a reduction in the total fresh water burden, reductions in truck traffic, and reduction in surface footprint from hydraulic fracturing operations," and emphasizing that "[l]arge, open topped, storage tanks and pits are vital to the economic practicality of recycling technologies").

B. OPERATORS CANNOT COMPLY WITH THE 2015 RULE'S CERTIFICATION REQUIREMENTS.

The 2015 Rule would have required that operators certify, in the completion report that operators must file after conducting hydraulic fracturing on a well, that during the time hydraulic fracturing fluids were present on the lease, the fluids complied with all applicable permitting and notice requirements as well as all applicable federal, state, tribal, and local laws, rules, and regulations.[202] When an operator requested that certain confidential information be exempted from disclosure, the operator would have also certified that "the operator has been provided the withheld information from the owner of the information and is maintaining records of the withheld information, or that the operator has access and will maintain access to the withheld information held by the owner of the information."[203]

The regulatory preamble to the 2015 Rule acknowledged that the "common practice is for operators to engage service companies to conduct hydraulic fracturing services."[204] It is often these service companies that own the trade secrets or confidential information related to hydraulic fracturing operations, and the "operator will not always be in the best position to declare why certain information should be withheld."[205] That is because, in the oil and gas industry, trade secret holders such as service companies generally do not provide operators — who may be competitors as well as clients — with access to the trade secret holder's trade secrets and confidential commercial information.[206] Both the certification and the affidavit requirements in the 2015 Rule fail to account for this commercial reality.[207]

---

202 *See* 43 C.F.R. § 3162.3-3(i)(8)(ii)-(iii). When submitting chemical information to FracFocus, operators would have also been required make this certification as part of the operator's submission to FracFocus. *See* 43 C.F.R. § 3162.3-3(i).

203 43 C.F.R. § 3162.3-3(j)(1)(iii).

204 80 Fed. Reg. at 16,173.

205 *See id.*

206 *See* A.R. at DOIAR0090028, Pub. Cmt., Halliburton Energy Servs., Inc. (Aug. 23, 2013); *id.* at DOIPS0365621, Pub. Cmt., Baker Hughes (Aug. 23, 2013) ("[Service companies], rather than the operators, are most often in a position to know whether these formulations are not otherwise publicly available, are not required to be publicly available under any applicable law and are not readily apparent through reverse engineering."); *id.* at DOIPS0393425, Pub. Cmt., Chevron (Aug. 23, 2013) (asserting that "a trade secret is [a] property right held by the owner of the information," and that "[t]his right does not transfer to the operator"); *id.* at DOIPS0365297, Pub. Cmt., Devon (Aug. 23, 2013) (characterizing the certification requirements as "unworkable" because "BLM has improperly limited the scope of proposed § 3162.3-3(j) to apply only to 'operators,'" overlooking that "[o]perators cannot provide affidavits containing the required affirmations on behalf of third parties"); *id.* at DOIPS0301592, Pub. Cmt., ANGA & AXPC (Aug. 23, 2013) ("Operators are not able to sign affidavits supporting claims of trade secret information, because they cannot affirm, with certainty, that information given to them by chemical providers meets the criteria enumerated in this section.").

207 Numerous commentators brought this concern to BLM's attention during the 2015 Rulemaking. *See supra* n.206; A.R. at DOIAR0056260, Pub. Cmt., IPAA ("[O]perators will never have the information necessary to know whether the fracturing fluid used on their wells complies with all applicable laws."); *id.* at DOIAR0056644, Pub. Cmt., API ("[T]he proposed rule asks operators to certify matters of which they may have no actual or constructive knowledge,

---

continued on next page…

Not only did commenters caution during the 2015 rulemaking that BLM "does not adequately distinguish the roles of operators, service providers, and vendors,"[208] but BLM's own staff also emphasized that the failure to make this distinction undermined the legal validity of the final rule's certification requirements.[209] BLM officials recognized that "[i]t's normally not the oil companies who will not disclose the amounts in the 'Secret Recipe,' it's the companies performing the actual fracturing procedure."[210] While it is true that operators assume legal responsibility for the conduct of the operators' contractors on the lease site, liability does not grant operators clairvoyance to make certifications of information the operators do not possess. Because the certification provisions were not rationally structured and impossible to comply with, rescinding the 2015 Rule is reasonable and prudent.

C. TESTING INTEGRITY OF THE LATERAL WELLBORE SERVES NO PURPOSE.

The 2015 Rule would have required that before hydraulic fracturing operations begin, the operator must perform a successful mechanical integrity test ("MIT") of any casing or fracturing string through which the operation will be conducted.[211] This requirement applies not only to vertical casing that is designed to protect usable water, but also to horizontal laterals.[212] BLM's Onshore Oil and Gas Order No. 2 already requires operators to conduct extensive casing integrity tests to ensure that all casing can withstand the pressures to which the wellbore will be subject during hydraulic fracturing.[213] The regulatory preamble to the 2015 Rule emphasizes, however, that the MIT required under the 2015 Rule "is not equivalent" to the casing pressure tests operators are currently conducting.[214] Aside from generalized assertions that the MIT requirement is consistent with industry guidance and state regulations (without citation to any particular regulations), the regulatory preamble did not include any explanation for modifying the pressure test requirement.

…continued from previous page

which the operator may have little or no legal expertise or due diligence resource to evaluate, and which have no bearing on the operator's activities or existing legal obligations.").

[208] A.R. at DOIPS0179037, Pub. Cmt., Encana.

[209] *See id.* at DOIAR009180, Draft Preamble (Dec. 5, 2011) (questioning "how far you can require an operator to submit Service Companies['] trade secret[s] in identifying chemical additives in their product" and cautioning that "I see a major lawsuit if we are not careful in what we require").

[210] A.R. at DOIAR0027283, Mem. from Barney A. Whiteman, Acting Field Office Manager, Great Falls, Mont. to Fort Belknap Tribal Council.

[211] *See* 43 C.F.R. § 3162.3-3(f).

[212] *See* 80 Fed. Reg. at 16,159 (explaining that the purpose of the MIT requirement is to ensure that "the entire length of casing or fracturing string, not just the vertical section, prior to the perforations or open-hole section of the well, is able to withstand the applied pressure").

[213] *See* Onshore Oil and Gas Order No. 2, Drilling Operations § III.B.h & i, 53 Fed. Reg. 46,798, 46,809 (Nov. 18, 1988) ("Onshore Order 2").

[214] 80 Fed. Reg. at 16,160.

During the rulemaking for the 2015 Rule, numerous commenters suggested that, if the agency were to distinguish an MIT from the current "casing pressure test," BLM should define the term "mechanical integrity test" for the purposes of the rule.[215] The 2015 Rule did not include any such definition, presumably because BLM assumed that "the term 'Mechanical Integrity Test' is widely understood by the industry."[216] That presumption is incorrect. No consensus definition of an MIT exists. [217]

BLM itself has used the term "mechanical integrity test" to mean: (i) "a casing pressure integrity test;" (ii) a casing inspection log such as a caliper log or casing wall thickness log; or (iii) fluid level surveys, temperature surveys, pressure gradient surveys, "or other methods generally consistent with professional engineering standards which may be acceptable to the [authorized officer]."[218] Like BLM, EPA also permits the use of various testing formats to demonstrate mechanical integrity. Acceptable tests for demonstrating internal mechanical integrity under EPA regulations include: (i) an annulus pressure or annulus monitoring test; (ii) a radioactive tracer test; (iii) a water-brine interface test; (iv) a pressure test with liquid or gas; or (v) monitoring records showing the absence of significant changes in the relationship between pressure and injection flow rate.[219] Acceptable tests for demonstrating external mechanical integrity include: (i) temperature log; (ii) noise log; (iii) oxygen-activation log indicating lack of fluid migration behind the casing; (iv) radioactive tracer survey indicating lack of fluid migration behind the casing; (v) cement bond log; or (vii) cementing records that demonstrate the presence of adequate cement.[220]

Illustrative examples of state law likewise demonstrate that tests to ensure mechanical integrity can vary based on local conditions, the phase of operations in which testing is being conducted, and operators' preferences.[221]

---

[215] *Id.*
[216] *Id.*
[217] *See Indep. Petroleum Ass'n of Am. v. Zinke*, No. 2:15-CV-00041-SWS (D. Wyo.), Mem. in Supp. of Mot. for Prelim. Inj. at 13-15, filed May 15, 2015 (ECF No. 13) (discussing various definitions of mechanical integrity test under numerous states' regulations and industry guidance documents); *Wyoming v. Zinke*, No. 2:15-CV-00043-SWS (D. Wyo.), Record Citations in Supp. of Mot. for Prelim. Inj. at 19-20, filed Sept. 18, 2015 (ECF No. 127) (collecting citations from the administrative record documenting numerous distinct usages for the term "mechanical integrity test").
[218] BLM Instruction Mem. No. CA-2002-011 at 5-6 (Dec. 3, 2001), available at:
http://www.blm.gov/ca/dir/pdfs/2002/im/CAIM2002-011.pdf.
[219] *See* 40 C.F.R. § 146.8(a)(1).
[220] *See* 40 C.F.R. § 146.8(a)(1); *see also* Jonathan Koplos et al., *UIC Program Mechanical Integrity Testing: Lessons for Carbon Capture & Storage?*, Dep't of Energy/Nat'l Energy Tech. Lab. Carbon Capture & Sequestration Conference Paper #139 (May 8-11, 2006),available at:
http://www.netl.doe.gov/publications/proceedings/06/carbon-seq/Tech%20Session%20139.pdf.
[221] Like state law, standard industry guidance does call for a "casing pressure test" before hydraulic fracturing is conducted, but that guidance is not prescriptive regarding how that test should be performed. The American Petroleum Institute, for example, recommends operators conduct a pressure test "at a pressure that will determine if

---

continued on next page…

Colorado	
MIT Provision	2 COLO. CODE REGS. § 404-326 ("[A] mechanical integrity test of a well is a test designed to determine if there is a significant leak in the casing, tubing, or packer of the well, and there is significant fluid movement into an underground source of drinking water through vertical channels adjacent to the wellbore.").
MIT Definition(s)	Any of the following tests are satisfactory to determine whether significant leaks are present in the casing, tubing, or packer of an injection well: (i) a pressure test with liquid or gas at a pressure of not less than 300 psi or the minimum injection pressure (whichever is greater), and not more than the maximum injection pressure; (ii) monthly monitoring and reporting of the average casing-tubing annulus pressure to the Colorado Oil and Gas Conservation Commission; or (iii) "any equivalent test or combinations of tests approved by the director." 2 COLO. CODE REGS. § 404-326(a)(1)(A)-(C). Any of the following tests are satisfactory to determine whether there are significant fluid movements in vertical channels adjacent to the wellbore of an injection: (i) cementing records; (ii) tracer surveys; (iii) cement bond log or other acceptable cement evaluation log; (iv) temperature surveys; or (v) "any other equivalent test or combinations of tests approved by the director." 2 COLO. CODE REGS. § 404-326(a)(2)(A)-(E). A mechanical integrity test of a shut-in well involves "[i]solation of the wellbore with a bridge plug or similar approved isolating device set one hundred (100) feet or less above the highest perforations and a pressure test with liquid or gas at a pressure of not less than three hundred (300) psi surface pressure" or "any equivalent test or combination of tests approved by the Director." 2 COLO. CODE REGS. § 404-326(b)(1)(A)-(B).

…continued from previous page

the casing integrity is adequate to meet the well design and construction objectives." 80 Fed. Reg. at 16,159 (quoting Am. Petroleum Inst., *Hydraulic Fracturing Operations—Well Constr. & Integrity Guidelines* § 7.3, at 11, API Guidance Doc. HF1 (Oct. 2009)). But API describes this test as a traditional "casing pressure test," *id.*, and, as referenced above, BLM noted expressly in 2015 that it considered a mechanical integrity test under the 2015 Rule to be something more than a traditional casing pressure test. *See* 80 Fed. Reg. at 16,160.

New Mexico	
MIT Provision	N.M. CODE R. § 19.15.26.11(2) (requiring operators to test injection wells at least once every five years to "assure [] continued mechanical integrity").
MIT Definition(s)	Under New Mexico law, tests demonstrating mechanical integrity include: (i) "measurement of annular pressures in a well injecting at positive pressure under a packer or a balanced fluid seal;" (ii) "pressure testing of the casing-tubing annulus for a well injecting under vacuum conditions;"; and (iii) "other tests that are demonstrably effective and that the division may approve for use." N.M. CODE R. § 19.15.26.11(2) (a)-(c).

North Dakota	
MIT Provision	N.D. ADMIN. CODE § 43-05-01-11.1(1) (providing that an injection well will be deemed to have mechanical integrity if "[t]here is no significant leak in the casing, tubing, or packer" and "[t]here is no significant fluid movement into an underground source of drinking water through channels adjacent to the well bore").
MIT Definition(s)	To evaluate the absence of significant leaks, the operator must conduct an initial annulus pressure test and then "continuously monitor injection pressure, rate, injected volumes, pressure on the annulus between tubing and long string casing, and annulus fluid volume." N.D. ADMIN. CODE § 43-05-01-11.1(2). To determine the absence of significant fluid movement, operators must use either an approved tracer survey or a temperature or noise log. *See* N.D. ADMIN. CODE § 43-05-01-11.1(3)(a)-(b).

Compounding the confusing lack of a definition, the 2015 Rule added a requirement – not part of the previously published proposed rules – that operators conduct a MIT on the lateral portion of horizontal wells.[222] The lateral part of a horizontal well is the part of the well that is in the producing formation. By definition, the producing formation is not a "usable water"

[222] *See* 80 Fed. Reg. 16,159 ("The requirement to only perform an MIT on vertical sections of the wellbore in the supplemental proposed rule is also deleted in the final rule.").

formation.[223] The administrative record prepared for the 2015 Rule does not contain comments regarding the efficacy, cost, or purpose of testing the lateral portion of the wellbore because that requirement was not part of the proposed rule.[224] It is impossible to reconcile a requirement to conduct an MIT on casing that does not protect usable water and that is to be intentionally perforated with BLM's stated objectives for the 2015 Rule.[225]

Not only is the requirement to test the horizontal portion of the wellbore needless, it will also be costly. BLM understood that "certain wellbore configurations may require modifications to perform this test."[226] For a horizontal well, where the lateral portion of the well is entirely in the zone to be completed, the MIT requirement is a mechanically onerous and expensive proposition. Modifications may be necessary, among other circumstances, "when the configuration contains a pressure-actuated valve or sleeve at the end of a lateral completion" or when an operator is using an "open-hole completion."[227] To conduct these tests, operators will have to use complicated tools to seal off the toe of the well during testing or rely on tubing conveyed perforation techniques after the pressure test. Either method is likely to increase costs of completing a well by \$75,000 to \$100,000 per well.[228] Given the absence of any benefit that will be derived from these costs, rescission of the 2015 Rule is reasonable and appropriate.

VIII. RESCISSION WILL RESULT IN SIGNIFICANT COST SAVINGS.

BLM estimates that rescission of the 2015 Rule will result in cost savings of between \$14 million and \$34 million per year.[229] This estimate significantly understates the economic benefit that will result from rescission of the 2015 Rule. A comprehensive analysis of the costs the 2015 Rule would have imposed demonstrates that costs savings resulting from the rule's rescission are likely to exceed \$220 million per year.[230]

---

223 *Id.* at 16,218.
224 *See* 78 Fed. Reg. at 31,676 (requiring that operator "perform a successful mechanical integrity test (MIT) of the vertical sections of the casing").
225 BLM acknowledged that when an operator tests an already perforated lateral in a re-fracturing operation, the perforated portion of the lateral need not be subject to the MIT, *see* 80 Fed. Reg. at 16,159. There is no technical basis for treating the same lateral differently in different fracturing operations.
226 *Id.*. at 16,160.
227 *Id.*
228 BLM had reason to know that these provisions would be expensive and to investigate the associated costs. Operators observed during the public comment period that "the proposed [MIT] requirement does not contemplate the use of down-hole tools (e.g. toe sleeve) for horizontal development, which may result [in] significant new cost and/or limit an operator's well design options." A.R. at DOIPS0179037, Pub. Cmt., Encana (Aug. 23, 2013).
229 82 Fed. Reg. at 34,468.
230 The Associations' costs estimates are calculated assuming 2,000 impacted wells per year. BLM's original cost estimate associated with the 2015 Rule were calculated using an assumed 2,814 wells completed with hydraulic fracturing. See U.S. Bureau of Land Mgmt., *Regulatory Impact Analysis for Hydraulic Fracturing Rule* § 4.1, at 82. In the two fiscal years since the issuance of the 2015 Rule, the number of total completions – both with and without hydraulic fracturing – on federal lands has been less than BLM's estimate: 1,586 completions in FY 2105 and 2,174 completions in FY 2016. *See* Bureau of Land Mgmt., *Pub. Lands Statistics*, Table 3-16, at 115 (FY 2016); Bureau of

---

continued on next page…

A. ADMINISTRATIVE COSTS.

Consistent with Onshore Order No. 1, operators currently provide BLM with approximately twenty-five different categories of information when submitting an APD:

1. A completed form 3160-3;

2. A well plot and geospatial database prepared by a registered surveyor;

3. A detailed drilling plan, including:
    a. Names and estimated tops of all geologic zones and formations
    b. Depth, thickness of zones either containing usable water, oil, gas, valuable minerals, and plans for protecting such resources
    c. Minimum specifications for blowout prevention equipment
    d. Proposed casing program (including design criteria)
    e. Estimated amount and type of cement expected to be used in each casing string
    f. Type and characteristic of the proposed circulating medium or mediums proposed for the drilling of each well bore section
    g. Testing, logging, and coring procedures proposed, including drill stem testing procedures, equipment, and safety measures
    h. Expected botton-hole pressure and anticipated abnormal pressures, temperatures, or potential hazards that the operator expects to encounter
    i. Any other items that the operator would like BLM to consider

4. A detailed surface use plan of operations, including:
    a. a map and plans of improvement for improvement and modification of existing roads
    b. a map, detailed descriptions, and plans for construction for all permanent or temporary access roads planned to be constructed

---

…continued from previous page

Land Mgmt., *Pub. Lands Statistics*, Table 3-16, at 116 (FY 2015). Since the time BLM first initiated a rulemaking related to hydraulic fracturing, there have been substantial changes in the oil and natural gas marketplace both in the United States and worldwide. Between May 24, 2013 – when the last proposed rule was published – and September 21, 2016, the WTI price per barrel of oil fell from $93.84 to $50.58, a drop of more than 46%. *See* U.S. Energy Info. Admin., *Petroleum & Other Liquids: Spot Prices*, https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm. The Henry Hub natural gas spot price has likewise fallen from $4.15 per million Btu to just $3.11 during the same period, a drop of more than 25%. *See* U.S. Energy Info. Admin., Natural Gas: *Henry Hub Natural Gas Spot Price*, https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm. Significant changes in commodity prices obviously impact the potential number of applications to drill on federal lands. By choosing a number of impacted wells within the actual range of completions over the last two years, and almost thirty percent lower than the number of wells that BLM used in its calculations, the Associations assert that their cost estimates are conservative and may understate the actual cost savings associated with rescinding the 2015 Rule.

c. Location of existing wells within one mile of the proposed location
d. Location of existing and/or proposed production facilities
e. Location and types of water supply
f. description of all construction materials to be used on the lease
g. written description of plans to handle all waste materials on site
h. a map of all ancillary facilities
i. a diagram of the well site layout
j. interim and final surface reclamation plans
k. surface ownership status for the well site and all access roads used to construct or maintain the well
l. any other information the agency may require

5. A surety bond; and

6. Certification that the APD is accurate.

Had the 2015 Rule become effective, operators would have been required to submit at least eight additional categories of information as part of the operator's application to conduct hydraulic fracturing:

1. Detailed information on the wellbore geology including estimated depths of both confining zones and potential occurrences of usable water;
2. A map showing the location and extent of known or suspected faults or fractures that may transect the project;
3. A water usage plan;
4. A detailed hydraulic fracturing plan;
5. A hydraulic fracturing map;
6. A detailed plan for fluid recovery;
7. A surface use plan; and
8. Documentation that casing and cementing are adequate to protect usable water.

The different elements of each of the applications are obviously not equal in terms of the cost and time needed to prepare materials and provide the pertinent information to BLM. Some, such as detailed drilling plans and plans for fluid recovery, are much more complex than, for example, a signed certification. Viewed broadly, the elements of the hydraulic fracturing plan tend to fall on the more complex end of the spectrum, consisting of detailed technical plans for sophisticated operations, geologic mapping, and engineering data. Notwithstanding the complex nature of the new information the 2015 Rule sought, the Associations have nevertheless calculated the increased administrative costs assuming the burden each information requirement imposes on the operator is equal; relying on that assumption, the Associations assume that the operator's administrative burden would increase by thirty-two percent (derived from the increase in required informational elements from twenty-five to thirty-three elements). Given that the requirement to submit a detailed hydraulic fracturing plan, a water usage plan, and a map of projected fracture propagations – among other requirements – are likely to impose a greater burden than, for example, a map of ancillary facilities, a diagram of a well site, or surface ownership information required under Onshore Order No. 1, the Associations' estimate of increased administrative burdens is likely very conservative.

A production model that John Dunham and Associates ("JDA") developed for Western Energy Alliance can be used to calculate the current administrative and regulatory cost per representative well in the thirteen western states included in JDA's analysis. Using data that the Bureau of Economic Analysis produced, the model suggests that these costs currently average about $19,100 for a representative oil well and $39,133 for a representative gas well.[231] Based on the assumed 2,000 wells and a distribution across the states being analyzed equal to the current distribution of approved APDs, the average administrative costs equal $27,881 per well. If costs are to rise in line with the number of informational elements requested (or about thirty-two percent) the increase would be $8,922 per well, or $17.844 million.[232] This value does not include any costs BLM itself would have incurred in association with reviewing and analyzing the additional information items that would have been submitted pursuant to the 2015 Rule.

B. DELAY COSTS.

BLM represented in 2015 that it believed that "the additional information that would be required under [the 2015 Rule] would be reviewed in conjunction with the APD and within the normal APD processing timeframe."[233] This representation provides little comfort given BLM's acknowledgement that the average processing time for a drilling permit on federal lands is at least 200 days, [234] and Secretary Zinke's Order No. 3354, emphasizing that permit processing times are currently unacceptable.[235] Using the thirty-two percent increase in the number of data elements required under the 2015 Rule as a proxy suggests it might take BLM as much as sixty-four days to process the paperwork that operators would have submitted as part of an application to conduct hydraulic fracturing. Assuming this figure, the delay cost per well could be as high as $3,369 – a total of $6.738 million. This includes the costs of delayed tax and royalty payments to leaseholders (primarily the federal government).[236]

---

[231] Representative wells include all oil and gas wells drilled in a state, including, among other categories, exploratory wells, dry holes, disposal wells, and production wells. A representative well should not be used to represent any single producing facility.

[232] In the Regulatory Impact Analysis prepared in association with the 2015 Rule, BLM calculated that the administrative burden on operators would be approximately $1,118. See U.S. Bureau of Land Mgmt., *Regulatory Impact Analysis for Hydraulic Fracturing Rule* § 4.4, at 88. As discussed above, BLM's original estimate is based on flawed presumptions. *See* discussion *supra* Part VI.

[233] 80 Fed. Reg. at 16,177. As discussed above, BLM's estimates regarding processing times are based on the unsupported assumption that operators are likely to submit an application to conduct hydraulic fracturing at the time the operator submits an APD. *See* discussion *supra* Part VI.

[234] *See* discussion *supra* Part VI.

[235] Sec'y Order No. 3354 § (3)(c).

[236] John Dunham and Associates calculations for the Western Energy Alliance, 2012.

C. CEL REQUIREMENTS.

The 2015 Rule would have required that operators run a cement evaluation log ("CEL") on intermediate casing that protects usable water, when that intermediate casing is not cemented to the surface.[237] BLM estimated that this requirement will impose costs of $111,200 per well, but concluded that this cost will rarely constitute an incremental burden associated with the final rule based on three assumptions: (i) operators are already required to perform this test under some states' laws; (ii) even where not required, running a CEL on intermediate casing is consistent with industry guidance; and (iii) only five percent of wells have intermediate casing that protects usable water.[238] Each of these assumptions was incorrect.

BLM's reliance on state laws is misplaced. BLM attributes zero additional costs associated with its enhanced CEL requirement for operations in Colorado, asserting that Colorado requires a CEL be conducted on intermediate casing.[239] But Colorado only requires a CEL when an operator uses a production liner,[240] and BLM did not offer any information on the frequency with which operators use production liners in Colorado. BLM assumed only 2.5% of wells would be impacted in Texas because "Texas specifies that the operator must identify the top of cement (with a CBL or temperature log) if it does not cement to the surface."[241] Texas does require that operators identify the top of cement for intermediate casing, but provides that this can be determined through calculation, a temperature survey, or a CEL.[242] BLM did not offer any information regarding the frequency that operators in Texas choose to use a CEL to satisfy this requirement. Nor did BLM offer any comparison between the relative costs of the various methods Texas allows to meet this requirement. And BLM stated that "California and Wyoming may require [a CEL] in certain circumstances."[243] But BLM did not identify the circumstances under which California or Wyoming "may require" operators conduct a CEL on intermediate casing.

The suggestion that, even where state rules do not require a CEL, industry guidance counsels that operators run a CEL on intermediate casing likewise lacks support. BLM cited the American Petroleum Institute's Guidance document HF1 for the proposition that if cement is not circulated to surface on intermediate casing, "operators may run a CEL or other diagnostic tools to determine the adequacy of the cement integrity and that the cement reached the desired height."[244] This unremarkable proposition, however, reveals nothing about the incremental costs a requirement to perform CELs on intermediate casing would impose. Guidance Document HF1

---

237 *See* 43 C.F.R. § 3162.3(e)(2)(ii).
238 *See* 80 Fed. Reg. at 16,197.
239 *See id.*
240 *See* 2 COLO. CODE REGS. § 404-317(o).
241 80 Fed. Reg. at 16,197.
242 *See* 16 TEX. ADMIN. CODE § 3.13(b)(2)(A)(i)-(iii).
243 80 Fed. Reg. at 16,197.
244 *Id.*

states only that, “[d]epending on the well design, it may be appropriate to run a CBL and/or other diagnostic tool(s) to determine that the cement integrity is adequate to meet the well design and construction objectives.”[245] BLM did not present any analysis considering how frequently well design will support a need to run a CEL on intermediate casing or made any comparison between the costs of a CEL requirement and the “other diagnostic tool(s)” that industry guidance contemplates. To the contrary, BLM acknowledged that it “does not have credible data on the prevalence of voluntary compliance or the prevalence of CEL requirements as conditions of approval.”[246]

A lack of data complicates another aspect of BLM’s 2015 cost calculation — BLM’s assertion that, “[b]ased on field experience, the BLM anticipates that only about [five] percent of wells have intermediate casing to protect usable water.”[247] There is no evidentiary or mathematical support for this supposition. Equally important, BLM’s “field experience” was based on BLM’s application of the rules that existed before the 2015 Rule was promulgated. But as discussed above,[248] the 2015 Rule re-assigns the burden to identify usable water from government agencies to operators and amends the method by which usable water is identified, requiring precise mathematical calculations. Had the 2015 Rule been adopted, these modifications were likely to result in an expansion of the number of wells with intermediate casing to protect this numerically-identified “usable water.”

In the end, based on the information that BLM compiled in 2015, and the recognition that individual oil and gas wells are uniquely designed and constructed, there is insufficient data to determine how many wells would incur additional costs for conducting a CEL on intermediate casing. To ensure the Associations’ estimates are as reasonable and conservative as possible, the Association have therefore not incorporated any cost in their estimates associated with the requirement to conduct a CEL on intermediate casing where cement is not returned to the surface.

D. ADDITIONAL CASING.

Since ground water levels vary greatly across states and geologic basins, it is not possible to determine exactly how much additional casing will be required under the 2015 Rule for a “typical well.”[249] Among other requirements, the new rule places the burden of identifying the location of usable water on operators, a task that state regulators and BLM field officers

---

[245] API HF1 § 7.4, at 12.
[246] 80 Fed. Reg. at 16,197.
[247] *Id.*
[248] *See* discussion *supra* Part IV.
[249] Calculating an exact figure would require an engineering examination of each of the geologic basins and the well designs in use – something which is not practical based on available data. The 2015 Rule’s numeric definition of “usable water” is so broad that in practical terms, casing would have been required to be run to significantly deeper depths than may be economically practical (particularly for gas wells).

currently perform.[250] The 2015 Rule would have required operators to obtain more hydrologic data which may or may not match data state and federal regulators currently rely upon to determine the depths at which protective casing and cement must be set. The 2015 Rule would have led to instances where operators faced the additional costs of casing and cementing associated with isolating formations that meet the numerical definition of usable water under the final rule, but which are located at depths deeper than the zones that state agencies and BLM field offices have previously designated as requiring isolation.[251]

Current laws in the states require operators to case their wells to protect drinking water aquifers and other “usable” water aquifers, with the recognition that for aquifers to be deemed usable, they should be economically viable. In North Dakota and Montana, for example, operators are currently directed to install protective casing to a depth below the Pierre Shale formation, but the 2015 Rule could have required additional casing and cement when water meeting the 2015 Rule’s numeric definition of “usable water” was found at depths deeper than that formation. In Wyoming, casing needs to be set to a level 100 feet below the deepest water well within a one mile radius of either an oil or gas well-- with some exceptions, drinking water aquifers are generally above 1,000 feet in Wyoming. Again, when water meeting the 2015 Rule’s definition of usable water is found below these depths, additional casing requirements would have applied.

Because of the significant differences in aquifer depth across states, JDA used a Monte Carlo simulation model based on the depths of existing water wells in each state to arrive at a conservative estimate of 2,350 feet of additional casing that might be required under the 2015 Rule. At a cost of $37 per foot, the additional casing would add $173.9 million in costs.

E. MECHANICAL INTEGRITY TESTS.

The 2015 Rule would have required that operators conduct a mechanical integrity test on all casing and fracturing string that will be subject to pressure during hydraulic fracturing operations, including the horizontal portion of the well that is located within the producing formation.[252] To conduct these tests operators will have to use complicated tools to seal off the toe of the well during testing or rely on tubing conveyed perforation techniques after the pressure test. Either method is likely to increase costs of completing a well, with the lowest potential additional cost being $10,000 per well. If any problems occur as a result of the MIT, these costs could rise by $75,000 to $100,000 per well.

---

[250] *See* discussion *supra* Part IV.

[251] BLM asserted in its 2015 Regulatory Impact Analysis that there would be no cost associated with additional casing requirements, since operators already have to protect usable water. As discussed above, this assertion was based on a fundamental misunderstanding of existing law and practice. *See* discussion *supra* Part IV.

[252] For a more complete discussion of the 2015 Rule’s MIT requirement, *see* discussion *supra* Part VII.C.

The overwhelming majority of new wells being proposed for federal leaseholds today are horizontal wells; using onshore rig counts as a proxy, the Associations have developed a conservative estimate of how frequently the additional costs associated with testing the horizontal portion of the lateral should apply. As of September 15, 2017, 795 of the 936 rigs operating in the United States, or approximately 85%, were drilling horizontal wells.[253]

Using 85% as a proxy, the Associations estimate that approximately 1,700 horizontal wells would be completed using hydraulic fracturing and would have incurred the additional MIT costs under the 2015 Rule. Assuming, to be conservative, the minimal additional cost of $10,000 per well, the MIT requirement would have resulted in $17 million in costs to operators.

F. RECOVERED FLUIDS COSTS.

JDA's production model can be used to calculate the differences in costs between tanks (which are generally rented for a short period during the completion process) and pits which once constructed can be used for a number of different wells. The model suggests that the costs of fluid storage tanks for a representative well in the thirteen western states is about $4,250 and the cost for digging and lining pits is $365.[254] Based on the assumed 2,000 wells and a distribution across the states being analyzed equal to the current distribution of approved APDs, the average cost to rent water storage tanks per representative well would be $5,111 and for preparing and lining pits $439. Absent any precise data, the Associations will assume that: (i) fifty-percent of operators would have voluntarily chosen to use the small, rigid steel tanks the 2015 Rule requires regardless of cost because those tanks were preferable operationally; and (ii) fifty-percent of operators would have used tanks only because the operator was obligated to select tanks under the 2015 Rule.[255] Applying the calculated difference in cost the Associations estimate between using tanks and lined pits, the Associations estimate that the total additional cost of the tank requirement would have been $4.887 million.

G. SUMMARY.

Cost Component	2015 Rule
Administrative Costs	$17.844 million
Delay Costs	$6.738 million
CEL Requirements	$0
Additional Casing	$173.9 million
Mechanical Integrity Tests	$17 million

---

[253] Williams, James L., *N. Am. Rotary Rig Counts,* WTRG Economics, available at: http://www.wtrg.com/rotaryrigs.html.

[254] *See* n.226, *supra*.

[255] Although the 2015 Rule provides criteria pursuant to which BLM might authorize use of lined pits, the regulatory preamble to the 2015 Rule emphasizes that any "exceptions should be limited and rarely granted." 80 Fed. Reg. at 16,163.

Cost Component	2015 Rule
Recovered Fluids Storage	$4.887 million
Total	**$220.369 million**

Based on highly conservative estimates, rescission of the 2015 Rule will result in cost savings in excess of $220 million per year. Given that the 2015 Rule has no discernible non-economic benefit, rescission of the rule to avoid these costs is rational and appropriate.