Washington and Lee Journal of Energy, Climate, and the Environment

Volume 4 | Issue 2 Article 11

3-1-2013

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I. Introduction

On May 11, 2012, the Bureau of Land Management (BLM) proposed what would be the first new regulations of hydraulic fracturing on federal lands in several decades.[1] The proposed rules would affect, in addition to about 700 million acres of mineral estate across the country managed by BLM, 56 million acres of Indian mineral estate subject to federal oversight.[2] The proposal received a widely varied response from tribal governments, including strident criticism from both tribes that were enthusiastic about the economic benefits of energy development on tribal land[3] and those that were opposed to any and all fracturing on tribal lands.[4]

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1. *See* Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands, 77 Fed. Reg. 27691, 27691–92 (proposed May 11, 2012) (to be codified at 43 C.F.R. pt. 3160) ("[C]urrent BLM regulations governing hydraulic fracturing operations on public lands are more than 30 years old and were not written to address modern hydraulic fracturing activities.").

2. *See id*. (stating the scope of BLM's regulatory authority).

3. *See*, *e.g.*, *Bureau of Land Management's Hydraulic Fracturing Rule's Impacts on Indian Tribal Energy Development: Hearing Before the Subcomm. on Indian and Alaska Native Affairs*, 112th Cong. (2012) (statement of the Hon. Tex G. Hall, Chairman, Mandan, Hidatsa, and Arikara Nation of the Fort Berthold Reservation) [hereinafter Hall testimony] (criticizing the BLM for its failure to consult meaningfully with affected tribes, and criticizing the regulations themselves for creating additional obstacles in an already overburdened permitting process for resource development on tribal lands).

The extent of comment on the proposal was so great, from both tribal constituencies and the general public, that BLM withdrew its proposal in order to rewrite the rules,[5] releasing a revised version on May 16, 2013.[6]

The proposal and tribal responses illustrated the complexity of interests and issues raised by the prospect of hydraulic fracturing and expanded energy extraction on Indian lands: tribal economic development, pollution, environmental protection, tribal sovereignty, and national energy policy all enter into consideration,[7] rendering more complicated an issue that is already contentious outside Indian country. The stakes for energy-producing tribes are substantial, with tribes receiving over $414 million in revenue from oil and gas production royalties in the 2011 fiscal year[8] alone.

Moreover, in the area of the Bakken Formation—the focus of this note—six reservations with a total of over forty-five thousand residents stand to be directly affected by hydraulic fracturing and energy production on or near reservation lands.[9] Aside from the revenue directly generated for tribes by production royalties, the rise of substantial oil and gas production on reservation lands has been markedly beneficial for tribal economies, leading to the creation of not only jobs directly involved in extraction and production, but also Indian-owned businesses that service the mining

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4. *See Bureau of Land Management's Hydraulic Fracturing Rule's Impacts on Indian Tribal Energy Development: Hearing Before the Subcomm. on Indian and Alaska Native Affairs*, 112th Cong. (2012) (statement of Larry DeCouteau, Dist. Four Tribal Council Representative, Turtle Mntn. Band of Chippewa Indians) [hereinafter DeCouteau testimony] (criticizing the intrusion of a federal bureaucracy into a regulatory matter within the scope of tribal sovereignty).

5. *See* Darren Goode, *Interior Retooling Its Fracking Rule*, POLITICO (Jan. 18, 2013, 7:22 PM), http://www.politico.com/story/2013/01/interior-retooling-its-fracking-rule-86424.html (reporting the announced withdrawal and revision of the proposed rule, and projecting a release of the revised rules by March 31, 2013) (on file with the Washington and Lee Journal of Energy, Climate, and the Environment).

6. *See* Press Release, Bureau of Land Management, Interior Releases Updated Draft Rule for Hydraulic Fracturing on Public and Indian Lands for Public Comment, (May 16, 2013), *available at* http://www.blm.gov/wo/st/en/info/newsroom/2013/may/nr_05_16_2013.html. *See also* Oil and Gas; Hydraulic Fracturing on Indian Lands, at 1 [hereinafter revised rules], *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wo/Communications_Directorate/public_affairs/hydraulicfracturing.Par.91723.File.tmp/HydFrac_SupProposal.pdf (summarizing the basic changes to the revised rule).

7. *See supra* notes 1–4 and accompanying text.

8. *See* Office of Natural Resources Revenue, Reported Revenues, American Indian for FY 2011 by Accounting Year, *available at* http://statistics.onrr.gov/ReportTool.aspx (last visited Jan. 11, 2013). BLM estimates that hydraulic fracturing is used in 90 percent of existing wells on federal land to stimulate well production. *Supra* note 1, at 27693.

9. U.S. Census Bureau, American FactFinder, Profile of General Population and Housing Characteristics: 2010 Demographic Profile Data, *available at* http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=DEC_10_DP_DPDP1 (last visited Apr. 15, 2013) (compiling data reflecting the reservation populations as of the 2010 census in the Williston Basin).

operations.[10] In some areas, energy extraction both comprises a substantial segment of the current reservation economy[11] and represents an important sector for future economic growth.[12] But at the same time, such mining operations pose serious environmental risks, most notably groundwater contamination from the fracturing operation and subsequent wastewater disposal, as well as air pollution from surface operations at the mining site.[13] Such hazards led to the high-profile decision by the Turtle Mountain Band of Chippewa Indians to ban outright hydraulic fracturing, although not all oil production, until such time as mining companies could prove the practice would not endanger limited aquifers available on the reservation.[14] Concerns about groundwater safety also led the Environmental Protection Agency (EPA) to commission a nationwide study of the effects of hydraulic fracturing on drinking water supplies, although the results of that study are not expected until 2014.[15]

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10. *See* Comment Letter from Council of Energy Resource Tribes to Bureau of Land Management, at 14–15 (Sept. 10, 2012) [hereinafter CERT comment], *available at* http://www.regulations.gov/#!documentDetail;D=BLM-2012-0001-7204 (last visited Jan. 14, 2013) (compiling tribal reports showing dozens of businesses and hundreds of jobs on the reservations across the region tied to energy production, and arguing that these are jeopardized by the cost of the proposed regulations).

11. *See id*. at 14 (stating that of the 121 Indian-owned businesses registered with the Fort Berthold Reservation's Tribal Employment Rights Ordinance office, 101 serve oil and gas producers).

12. *See* Hall testimony, *supra* note 3, at 2 (stating that the MHA Nation projects that 300 new wells will be drilled on the reservation in 2013, or 120% of all wells in operation on the reservation as of April 2012).

13. *See* Dennis C. Stickley, *Expanding Best Practice: The Conundrum of Hydraulic Fracturing*, 12 WYO. L. REV. 321, 324–25 (2012) (summarizing the scientific community's concerns with the practice, including groundwater contamination, wastewater disposal, release of methane concentrations, and destabilization of geologic faults); Lisa M. McKenzie et al., *Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources*, 424 SCI. TOTAL ENV'T 79, 79–87 (2012) (projecting that residents in the vicinity of natural gas extraction operations were subject to a slightly elevated cancer risk, but an appreciable risk of non-cancer health effects, due to toxic chemicals released into the air by fracturing and extraction).

14. *See* Turtle Mountain Tribal Council Res. TMBC627-11-11 (Nov. 29, 2011), *available at* http://www.legis.nd.gov/assembly/62-2011/docs/pdf/ts032612appendixd.pdf (prohibiting any fracking on land that could affect the Shell Valley aquifer, and directing the cancellation of lease bids for which the fracking ban was not yet in effect); James C. Falcon, *Tribe Bans Fracking on Reservation*, MINOT DAILY NEWS, (Nov. 23, 2011), https://www.minotdailynews.com/page/content.detail/id/560660/Tribe-bans-fracking-on-reservation.html?nav=5010 (describing passage of the tribal council resolution banning the practice and the council's concern with polluting the Shell Valley aquifer, the reservation's primary water source); DeCouteau testimony, *supra* note 4, at 1–2 ("Fracking, as it's currently being done in the western part of the state of North Dakota is not a process that interests us at Turtle Mountain.").

15. *See* U.S. ENVTL. PROTECTION AGENCY, EPA/601/R-12/011, STUDY OF THE POTENTIAL IMPACTS OF HYDRAULIC FRACTURING ON DRINKING WATER RESOURCES:

This note examines the particular issues presented by hydraulic fracturing and hydrocarbon extraction on Indian lands, focusing on reservations overlapping the Williston Basin in the upper Midwest, an area in which extraction has accelerated significantly. Section Two will describe hydraulic fracturing in a broader context, including the historical use of the practice, a description of the technique, and its importance in relation to national energy policy. This section will also introduce the specific environmental concerns raised by hydraulic fracturing –in particular, toxic chemicals that are involved and the ways that the procedure, as deployed in the Williston Basin, may result in their release. Section Three will discuss state regulatory frameworks and requirements placed on energy producers, which govern operations outside Indian reservations on land under the states' jurisdiction. Section Four will discuss the Indian lands in the region, the details of the proposed BLM regulations on fracturing, and the current state of tribal jurisdiction over, and regulation of, hydraulic fracturing within the outer bounds of Indian reservations. Section Five will consider the existing tribal regulations, the availability of meaningful private causes of action, and the resulting importance of creating appropriate regulatory frameworks. Section Six will conclude by considering multiple potential solutions aimed at improving tribal control of resource extraction and environmental protection.

II. Hydraulic Fracturing: Technique, Geology, and Unintended Consequences

The basic principle of using hydraulic fracturing, or "fracking," to stimulate oil and natural gas wells has been employed for several decades, first appearing in 1947 and developing in the years thereafter.[16] In order to access resource-bearing rock strata, a well is excavated to the target depth; drilling then continues horizontally along the stratum, allowing one wellbore to access a larger segment of the deposit than would be possible with a straight well.[17] The recent increase in energy production in which fracking plays a role has been enabled by the development of "slickwater"

PROGRESS REPORT 247 (2012) (noting that EPA plans to release the results of its study, subject to peer review by its Science Advisory Board, in "late 2014").

16. *See* U.S. ENVTL. PROTECTION AGENCY, EVALUATION OF IMPACTS TO UNDERGROUND SOURCES OF DRINKING WATER BY HYDRAULIC FRACTURING OF COALBED METHANE RESERVOIRS App. A-1 (2004) ("The first hydraulic fracturing treatment was pumped in 1947 on a gas well operated by Pan American Petroleum Corporation . . . [and has since] become a standard treatment for stimulating the productivity of oil and gas wells.").

17. *See* U.S. DEPT. OF ENERGY, OFFICE OF FOSSIL ENERGY, MODERN SHALE GAS DEVELOPMENT IN THE UNITED STATES: A PRIMER 46–48 (2009) [hereinafter DOE Primer] (describing the process of well drilling and preparation for production).

hydraulic fracturing techniques during the last decade.[18] In slickwater hydraulic fracturing, the horizontal wellbores are used to inject acid into hydrocarbon-bearing shale formations, cleaning and preparing the rock for the injection of hydraulic fracturing fluid—composed primarily of water, "proppant," and various other chemicals.[19] The pressure of the injection fractures the surrounding rock, while the proppant—typically a sand-like medium—holds the fractures open to permit extraction of the oil or gas in the shale formation.[20]

This well stimulation process is necessary because the shale formations are not otherwise permeable enough to permit the extraction of oil and gas in quantities that make drilling economically feasible.[21] Hence, the shale formations are considered one of several types of "unconventional" reservoir, which are distinguished from the more porous "conventional" reservoirs in which oil and gas can be extracted from the existing formation.[22] Once the shale has been fractured, oil and gas can migrate through the fracking fluid and proppant to the surface for extraction.[23] When the fracturing operation is completed, a portion of the fracturing fluid flows back toward the surface; this flowback fluid, along with the remaining fracturing fluid, must be disposed of once production at the well is completed.[24] This may be accomplished by underground injection—essentially, returning the fluid to the well and attempting to seal it underground—or by treatment of the fluids, followed by either reuse or discharge into surface waterways.[25]

To the extent that fracturing operations pose a risk to groundwater, that risk arises either from failures in the well casing as it passes through

18. *See* Stickley, *supra* note 13, at 324 (stating that slickwater hydraulic fracturing permitted stimulated production in shale formations); Hannah Wiseman, *Beyond Coastal Oil v. Garza: Nuisance and Trespass in Hydraulic Fracturing Litigation*, 57 THE ADVOC. (TEX.) 8, 8 (2012) ("Slickwater fracturing . . . has allowed an astoundingly large number of new wells to be developed; in some cases, oil and gas companies are drilling and fracturing wells in areas that have not recently experienced heavy oil or gas production.").

19. *See* Wiseman, *supra* note 18, at 8 (describing slickwater hydrofracking).

20. *See* Stickley, *supra* note 13, at 323–24 (describing slickwater hydrofracking).

21. *See* DOE Primer, *supra* note 16, at 14 (discussing shale's low permeability and the limited speed with which it can travel through unfractured rock formations); Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands, *supra* note 1, at 27692–93 (discussing the commercial need for fracturing in these formations).

22. *See* DOE Primer, *supra* note 17, at 15 (describing conventional and unconventional reservoirs).

23. *See* Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands, *supra* note 1, at 27692–93 (describing the extraction process).

24. *See* DOE Primer, *supra* note 17, at 66–68 (summarizing water management considerations and techniques).

25. *See* DOE Primer, *supra* note 17, at 66–68.

aquifers—a hazard not unique to hydraulic fracturing[26]—or from the release of wastewater used in fracturing operations.[27] When a well is to be constructed, the hole is drilled first, followed by the installation of steel pipe secured by cement casing, intended to isolate the wellbore from the surrounding groundwater and withstand the stresses of injection and extraction during operation.[28] Multiple kinds of logging tools can thereafter be employed to judge the status of the well and test for well integrity issues.[29] Estimates of the likelihood of a well incurring a mechanical integrity failure have varied considerably, ranging from one in fifty million to one in ten.[30] Purely empirical reviews have shown that two percent of leaks into groundwater supplies are actually due to failures in the mechanical integrity of a well.[31] Rozell and Reaven estimate that the effects of such a failure would be relatively minimal, peaking at a worst-case release of about 60 cubic meters of water from a breached well.[32] By comparison, the average fracturing operation uses roughly 11,300 cubic meters of water per well.[33]

Far more serious are the risks associated with retention and disposal of the large quantities of wastewater—which include the additives and proppants used in fracturing—once they are pumped out of the well, usually into surface impoundments or tanks on site.[34] Although fracturing water may sometimes be recycled, it is often necessary to store wastewater (which fracturing produces in greater quantities than conventional production) on

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26. *See* Jeffrey C. King et al., *Factual Causation: The Missing Link in Hydraulic Fracture—Groundwater Contamination Litigation*, 22 DUKE ENVTL. L. & POL'Y F. 341, 351 ("If there is potential for groundwater contamination resulting from oil and gas production, a more likely source (other than a surface spill) is improper surface well casing. This is true whether or not a well is fracture stimulated.").

27. *See* Stickley, *supra* note 13, at 334–35 ("In the case of [fracking] fluids, the selection of the method of disposal raises concern about the contamination of soil and water due to the chemical constituents in the fluid, particularly where the produced water contains petrochemicals or BTEX [benzene, toluene, ethylebenzene, and xylene].").

28. *See* American Petroleum Institute, Guidance Document HF-1, at 2–4 (describing the process of well construction and engineering aims).

29. *See id.* at 8–10 (describing methods for testing the success of cement casing installation).

30. *See* Daniel J. Rozell & Sheldon J. Reaven, *Water Pollution Risk Associated with Natural Gas Extraction from the Marcellus Shale*, 32 Risk Analysis 1382, 1386–87 (citing an API finding that the lifetime risk of contamination from an oil & gas well is 1 in 50 million well-years, and a contrary study finding that 1 in 10 oil & gas wells failed a mechanical integrity test).

31. *See id*. at 1387 (citing a 1987 survey of wastewater injection wells by the Underground Injection Practices Council).

32. *See id.* at 1389 (modeling the contamination produced by well casing failure).

33. *See* DOE Primer, *supra* note 17, at 64 (stating that the average shale gas well using hydraulic fracturing requires three million gallons of water).

34. *See* American Petroleum Institute, Guidance Document HF2, at 17–19 (discussing best practices for fluid handling and storage).

site in preparation for treatment and/or transport for disposal.[35] Industry's best practices call for storage solutions designed to limit the extent to which wastewater might escape containment and discharge into surface water, including liners for open pits to prevent seepage into the ground or established standards for tanks.[36] Despite these precautions, Rozell and Reaven's modeling indicates that even in the best-case scenario, it is "very likely that an individual well would generate at least 200 m^3 of contaminated fluids," largely due to wastewater disposal issues; and at worst, a serious failure of a retention pond would result in the release of thousands of cubic meters of wastewater.[37]

The ultimate fate of this wastewater matters for water quality in the vicinity of production sites. Wastewater may include additives used for certain purposes in the fracturing process, such as acids, corrosion inhibitors, and biocides, as well as bacteria, minerals, hydrocarbons, and naturally-occurring radioactive material drawn from the shale strata themselves.[38] The flowback water may also be highly saline, depending on multiple factors including the properties of formation water in the target strata.[39] Not uncommonly, fracking fluid also contains low levels of benzene, ethylene glycol, and naphthalene.[40] Ingestion of these chemicals can have significant negative health effects, and—for benzene and naphthalene—chronic exposure has shown some evidence of carcinogenic effect.[41]

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35. *Id*.

36. *Id*. at 18–19 (describing the recommended standards, which are often reflected in state-law regulatory requirements).

37. Rozell & Reaven, *supra* note 30, at 1389–90.

38. *See* DOE Primer, *supra* note 17, at 64 (listing common fracturing additives); API, Guidance Document HF2, at 17 (describing the contribution of hydrocarbons, organic compounds, and NORMs to flowback water from formation water).

39. *See* API, Guidance Document HF2, at 17 (describing the salinity characteristics of wastewater).

40. *See* API, Guidance Document HF2, at 7 (including these chemicals in a list of fracking fluid additives, while noting that they are "seldom used and/or used in very small quantities").

41. *See* U.S. Nat'l Library of Med., *Naphthalene*, Hazardous Substances Data Bank, http://toxnet.nlm.nih.gov/cgi-bin/sis/search/f?./temp/~hGLY9u:1 (last visited Apr. 8, 2013) (detailing the cancer risk through oral and ingestion exposure, and blood disorders arising from general exposure) (on file with the Washington and Lee Journal of Energy, Climate, and the Environment); U.S. Nat'l Library of Med., *Ethylene Glycol*, Hazardous Substances Data Bank, http://toxnet.nlm.nih.gov/cgi-bin/sis/search/f?./temp/~8oITcL:1 (last visited Apr. 8, 2013) (noting the appearance of neurobehavioral and neurological disorders at significant doses) (on file with the Washington and Lee Journal of Energy, Climate, and the Environment); U.S. Nat'l Library of Med., *Benzene*, Hazardous Substances Data Bank, http://toxnet.nlm.nih.gov/cgi-bin/sis/search/f?./temp/~37YPRW:1 (last visited Apr. 8, 2013) (detailing toxic neurological and gastrointestinal effects, as well as established status as a human carcinogen responsible for multiple types of leukemia) (on file with the Washington and Lee Journal of Energy, Climate, and the Environment).

Although the concerns discussed to this point have dealt with accidental releases of wastewater, and although industry best practices prescribe treatment and disposal methods that account for environmental considerations,[42] accidental releases are not the only source of concern. Underground injection for permanent storage is currently the "principal method" of managing wastewater from oil and gas production,[43] with the prospect that local water quality could degrade as a result.[44] Likewise, the detrimental effects of wastewater discharge can, in principle, be prevented with appropriate terms in drilling permits or local water quality standards.[45] But those limitations cannot be considered foolproof, no less because of the practical difficulties of enforcement[46] than because of the potential for inadequate permitting standards in the first instance.[47]

The substantial water requirements of hydraulic fracturing also raises concerns about the availability of this resource, given that use of ordinary surface water sources "can possibly impact other competing uses and will be of concern to local water management authorities," who will seek to avoid interference with existing community uses.[48] In addition to the direct effects of development and oil and gas production, withdrawal and reintroduction of water can substantially reduce the surface water available to other local consumers, while also reducing its quality

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42. *See* API, Guidance Document HF2, at 20–23 (describing recommended approaches to treatment and disposal, including underground injection and treatment for industrial reuse).

43. GROUND WATER PROTECTION COUNCIL, STATE OIL AND GAS REGULATIONS DESIGNED TO PROTECT WATER RESOURCES 30 (2009).

44. *See* Stephen G. Osborn et al., *Methane Contamination of Drinking Water Accompanying Gas-Well Drilling and Hydraulic Fracturing*, 108 PNAS 8172, 8174–75 (stating that fracturing water that remains underground could displace formation water into shallow aquifers, increasing the presence of dissolved solids and trace toxins). *Cf.* Tom Myers, *Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers*, 50 GROUNDWATER 872, 879–80 (discussing hydrological models and the potential for contaminant flow from shale strata toward the surface over a period of years).

45. *See* API, Guidance Document HF2, at 20–22 (noting that most well permits require eventual removal of all fracture fluids and flowback water, and that municipal or industrial water treatment facilities may face limitations on their handling of flowback water).

46. *See* James R. Cox, *Revisiting RCRA's Oilfield Waste Exemption as to Certain Hazardous Oilfield Exploration and Production Wastes*, 14 VILL. ENVTL. L.J. 1, 25–26 (2002) (describing the prevalence of improper oilfield waste disposal and the "shortage of money and manpower" devoted to police compliance).

47. *See* Elizabeth Shogren, *Loophole Lets Toxic Oil Flow Over Indian Land*, National Public Radio, Nov. 15, 2012 (describing how EPA permits oil producers operating on Wyoming's Wind River Reservation to discharge untreated wastewater containing fracking additives if the water is needed by ranchers or wildlife).

48. *See* API, Guidance Document HF2, at 14.

(specifically, changes to sedimentation, temperature, and oxygen content).[49] In parts of the arid west, where oil shale extraction is increasing, production could quickly outpace the availability of water, leading either to the constraint of the industry's growth in that area or the acquisition of additional water rights from other stakeholders in the region.[50]

Because the positive economic consequences of increased oil and gas development are so important in Indian Country,[51] the social drawbacks for communities in the vicinity of new production sources also bears mention. The oil boomtowns of North Dakota have experienced significant strain on infrastructure—most notably, housing, water and sewage, and roads—as a result of the influx of people and activity associated with quickly expanded extraction activity.[52] Law enforcement and the local courts have been "swamped" by the sudden changes.[53] Elsewhere, while new production has bolstered local economies, it is also the case that most of the wealth associated with resource extraction has ultimately flowed out of the community, which is left with the costs of maintaining additional infrastructure and coping with any environmental problems that arise.[54] This goes to show that expectations of the very real economic gains to be made from capitalizing on new energy production must be tempered by the realities of administering those activities, and simply living with their consequences.

III. Good Fences: Neighbor States and their Regulations

The Bakken Formation is a large shale formation that overlaps a large portion of the Williston Basin, covering roughly the northeastern quarter of the state of Montana and the western two-thirds of the state of

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49. *See* U.S. GOV'T ACCOUNTABILITY OFFICE, GAO-11-35, ENERGY-WATER NEXUS: A BETTER AND COORDINATED UNDERSTANDING OF WATER RESOURCES COULD HELP MITIGATE THE IMPACTS OF POTENTIAL OIL SHALE DEVELOPMENT 10–12 (2010) (reciting these adverse impacts gleaned from expert consultations).

50. *Id*. at 25–26 (noting this problem for oil shale developers in Colorado and Utah).

51. *See supra* notes 8–12 and accompanying text (describing royalties and economic benefits).

52. *See* John McChesney, *Oil Boom Puts Strain on North Dakota Towns*, National Public Radio (Dec. 2, 2011), http://www.npr.org/2011/12/02/142695152/oil-boom-puts-strain-on-north-dakota-towns (describing the social costs and strain on infrastructure resulting from the influx of oilrig workers) (on file with the Washington and Lee Journal of Energy, Climate, and the Environment).

53. Joshua P. Fershee, *The Oil and Gas Evolution: Learning From the Hydraulic Fracturing Experiences in North Dakota and West Virginia*, 19 TEX. WESLEYAN L. REV. 23, 26 (2012).

54. *See id*. at 28–30 (describing West Virginia's experience with hydraulic fracturing to extract natural gas from the Marcellus Shale).

North Dakota.[55] This is an area of mostly flat land and rolling hills, shaped by the few large river systems that cover the area.[56] Because it receives little rain, leaving it a semiarid zone, energy developments are a large and growing consumer of the limited water resources in the region.[57] The Williston Basin has also historically had problems with brine contamination resulting from unlined mining wastewater pits leaking into groundwater, and the U.S. Geological Survey has indicated concern that further leakage from retention ponds, accidental spills, and surface water discharges could negatively affect wetlands, water quality, and livestock drinking water.[58]

Fracking in an area like the Williston Basin differs from fracking operations elsewhere, such as those in Pennsylvania's Marcellus Shale, despite the fact that both involve the hydraulic fracturing and extraction of resources from shale strata.[59] The particular geology of the region means that most aquifers used are confined to rock strata in the upper 2,000 feet, leaving a significant barrier between water-bearing layers and those strata of the Bakken Formation that would be targeted for resource extraction.[60] Whereas there is serious debate over whether fractures produced by well stimulation operations in areas like the Marcellus Shale can actually have a direct effect on groundwater supplies,[61] the fact that the Bakken Formation

55. *See* U.S. Geological Survey, Williston and Powder River Basins Groundwater Availability Study, http://mt.water.usgs.gov/projects/WaPR/ (last visited Mar. 22, 2013) (showing Bakken Formation, Williston Basin, and production wells) (on file with the Washington and Lee Journal of Energy, Climate, and the Environment).

56. *See id*. at "Background—Physiography" (describing the topography of the Williston Basin).

57. *See id*. at "Need for Study" and "Background—Physiography" (describing the water resources available in the area and the role of oil and gas production as a water consumer).

58. *See* U.S. Geological Survey, Examination of Brine Contamination Risk to Aquatic Resources from Petroleum Development in the Williston Basin 1–2 (2011), *available at* http://pubs.usgs.gov/fs/2011/3047/pdf/FS2011-3047.pdf (describing past and present problems with salinity and water quality due to oil and gas production).

59. *See* DOE Primer, *supra* note 17, at 17 (stating that the Marcellus shale in Pennsylvania begins at a depth of 4,000 feet, or 3,150 feet below the base of the layer of treatable water); Osborn et al., *supra* note 44, at 8173 (finding a strong relationship between significantly elevated groundwater methane levels and active extraction sites, as opposed to inactive extraction sites, in Pennsylvania); Julie A. LeFever, Montana—North Dakota? Middle Member Bakken Play, at 21 (2005) (showing that the upper member of the Bakken formation begins at a depth of about 10,580 feet) (on file with the Washington and Lee Journal of Energy, Climate, and the Environment).

60. *See* U.S. Geological Survey, Williston and Powder River Basins Groundwater Availability Study, *supra* note 55, at "Background—Hydrogeology" (discussing the locations of water-bearing strata in the region); LeFever, *supra* note 59, at 21 (showing the start of the Bakken formation several thousand feet lower).

61. *Compare* King et al., *supra* note 26, at 350 ("[I]t is physically impossible for hydraulic fracturing to create vertical pathways from oil and gas bearing shale formations into aquifers. There is simply too much vertical separation between the two geological structures.") *and* Tarek Saba & Mark Orzechowski, Letter, *Lack of Data to Support a*

is roughly twice as deep appears to make this a far less likely possibility.[62]

States are not the only sovereigns with lawmaking and regulatory power in the region: a number of Indian tribes have substantial reservations throughout both Montana and North Dakota.[63] Notwithstanding the extent to which tribes have the inherent authority to control activity within the boundaries of their reservations to the exclusion of states (a point that will be discussed later), state law and regulation obtain outside those boundaries.[64] The presence of a number of wells in relatively close proximity to reservation boundaries makes it important to consider what oversight protections are afforded by states in which tribes are located.[65]

North Dakota state agencies have made regulations of general applicability for oil and gas extraction operations that provide legal limits for fracking.[66] Applications must be filed, including a description of the

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Relationship Between Methane Contamination of Drinking Water Wells and Hydraulic Fracturing, 108 PNAS E633, E633 (criticizing Osborn et al. and the conclusions of their research) *with* Myers, *supra* note 44, at 874–75, 880 (arguing that hydraulic fractures could "contact higher conductivity sandstone, natural fractures, or unplugged abandoned wales above the target shale," permitting upward movement of brine and other fluid over a span of decades) *and* Scott Detrow, *Across Pa., Abandoned Wells Litter the Land*, Morning Edition, National Public Radio (Nov. 13, 2012), http://www.npr.org/2012/11/13/164139865/across-pa-abandoned-wells-litter-the-land (describing instances of current fracturing causing methane gas leaks and explosions from interaction with abandoned and unregistered wells) (on file with the Washington and Lee Journal of Energy, Climate, and the Environment).

62. *See* Richard J. Davies et al., *Hydraulic Fractures: How Far Can They Go?*, 37 MARINE & PETROLEUM GEOLOGY 1, 5 ("The maximum upward propagation recorded for a stimulated hydraulic fracture to date is ~588 m [1,929 feet] in the Barnett shale in the USA.").

63. *See* BIA Regional, Agency and Field Offices Map, *available at* http://www.bia.gov/cs/groups/public/documents/text/idc013422.pdf (last visited Mar. 22, 2013) (showing Indian reservations and BIA offices nationwide).

64. *See* COHEN'S HANDBOOK OF FEDERAL INDIAN LAW § 4.01[1][b], at 211 (Nell Jessup Newton ed., 2012) [hereinafter COHEN] ("Tribes have plenary and exclusive power over their members and their territory subject only to limitations imposed by federal law."); *id*. § 6.01[5], at 503 (noting that although state jurisdiction may be precluded within Indian country, nondiscriminatory state laws apply to events outside Indian country "unless federal law provides otherwise").

65. FracFocus, a collaborative registry of drilling sites using hydraulic fracturing, indicates that in the Williston Basin area, there are at least five wells operating within about two miles of the border of the Fort Peck reservation in Montana, and around 40 within two miles of the Fort Berthold reservation in North Dakota. *See* Ground Water Protection Council, *Find a Well*, FRACFOCUS, http://www.fracfocusdata.org/fracfocusfind/ (last visited Feb. 16, 2013) (displaying well locations of participating operators) (on file with the Washington and Lee Journal of Energy, Climate, and the Environment). Outside the Williston Basin, there are other reservations in similar proximity to wells, such as the Uintah and Ouray in Utah, and the Navajo and Ute in the Four Corners area. *See id*. (same).

66. *See* Christopher Kulander, *The States' Legal Framework: Texas/Louisiana Region American Law and Jurisprudence on Fracing*, Rocky Mountain Mineral Law Foundation: Hydraulic Fracturing Core Issues & Trends, at 30 ("[A]lthough North Dakota's regulations do not directly address hydraulic fracturing, certain regulations . . . may effect hydraulic

well's specifications and the operator's plan for constructing the well casing, and a permit granted based on that application, before a production well can be drilled.[67] Moreover, an additional application and permit is required in order to conduct well recompletion activities and to drill horizontal wells, and the regulators are entitled to impose on such permits "such terms and conditions on the permits issued under this section as the director deems necessary."[68] Regulators are also permitted to deny the operator a permit if the well, as proposed, "would cause, or tend to cause, waste . . . ."[69] The rules also provide specific minimum standards for well casing, tubing and cementing, along with the general requirement that all wells—including injection wells—"shall be properly cemented at sufficient depths to adequately protect and isolate all formations containing water, oil, gas or any combination of these" and shall be drilled using only methods "which will protect all freshwater-bearing strata."[70] Defective casings must be reported to regulators, who have the option to require testing to ensure well integrity, or otherwise to plug the well.[71]

On April 1, 2012, a number of new or amended regulations went into effect with specific relevance for hydraulic fracturing operations.[72] The regulations impose specific limitations on fracturing operations, including requirements for control and diversion of flowback fluids, limitations on treating pressure for some fracking operations to eighty-five percent of API's maximum rating for a particular well casing, requirements for casing and cement evaluation and inspection, and required pressure testing for intermediate casings and wellheads.[73] Under the rules, operators are also required to make full disclosure to FracFocus all elements of the operation tracked by the registry, and to do so within sixty days of the time the

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fracturing.") (on file with the Washington and Lee Journal of Energy, Climate, and the Environment). *See generally* N.D. ADMIN. CODE art. 43-02 (governing well construction standards, waste handling, and underground injection); *id*. ch. 32 (governing oil and gas production generally, permitting, exploration requirements, compensation for damages, and carbon storage).

67. *See* Kulander, *supra* note 66, at 30–31 (describing the permit application requirement); N.D. ADMIN. CODE § 43-02-03-16 (outlining the requirements).

68. N.D. ADMIN. CODE § 43-02-03-16. *See* Kulander, *supra* note 66, at 30–31 (discussing the code standards). This requirement appears to have substantial import for regulation of hydraulic fracturing wells, which typically require horizontal drilling in order to be effective in shale formations. *See* DOE Primer, *supra* note 17, at 46–47 (discussing how horizontal drilling is increasingly necessary in more mature shale plays, and is typically a more economical production method than vertical wells).

69. N.D. ADMIN. CODE § 43-02-03-16. *See* Kulander, *supra* note 66, at 31 (discussing the code standards).

70. N.D. ADMIN. CODE § 43-02-03-21.

71. *Id*. § 43-02-03-22.

72. *Id*. § 43-02-03-27.1 *et seq*.

73. *See id*. § 43-02-03-27.1 (enumerating the requirements specifically for hydraulic fracture stimulation).

stimulation is performed.[74] Likewise, operators are required to notify regulators within twenty-four hours if pressure in the casing exceeds a certain threshold.[75] The 2012 regulations include a new provision expressly prohibiting operators from allowing "any spill or leak . . . to flow over, pool, or rest on the surface of the land or infiltrate the soil," even within containment dikes around the well.[76] This rule complements an older provision requiring notification, within twenty-four hours, and subsequent written reporting in case of any fire, leak, spill, or blowout of more than one barrel.[77]

General regulations also control certain aspects of drilling byproducts, site containment, and waste disposal. Regulators may impose various requirements on the construction of the well site in order to avoid interference with water supplies or the surrounding landscape, including grading of the site, construction of dikes around the well, fencing, distancing from bodies of water or natural drainages, and reclamation of sites within six months of well completion.[78] Fencing is required for open pits and ponds containing saltwater or oil, while screening and netting must also be constructed for oil pits.[79] Perhaps most important, the regulations impose strict limitations on operators' ability to use open pits to store "saltwater, drilling mud, crude oil, waste oil, or other waste," permitting such storage only in cases of emergency with express approval of regulators.[80] Temporary use of such pits for storage is permitted "to retain oil, water, cement, solids, *or fluids generated in well completion*" for no more than seventy-two hours after the completion of the related operations, with the contents thereafter to be removed from the site.[81] Once removed, the contents must be "properly disposed of in an authorized facility" and/or "removed from the pit and disposed of in an authorized disposal well or used in a manner approved by the director."[82] Any such pits must be sufficiently impermeable to "provide adequate temporary containment" of

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74. *See id*. ("Within sixty days after the hydraulic fracture stimulation is performed, the owner, operator, or service company shall post on the fracfocus [*sic*] chemical disclosure registry all elements made viewable by the fracfocus website.").

75. *See id*. § 43-02-03-27.1(3) (imposing the requirement).

76. *Id*. § 43-02-03-30.1.

77. *See id*. § 43-02-03-30 (imposing the requirement).

78. *See id*. § 43-02-03-19 (imposing the requirements).

79. *See id*. § 43-02-03-19.1 (imposing the requirements).

80. *Id*. § 43-02-03-19.3.

81. *Id*. (emphasis added). The emphasized section would appear to include flowback water from fracturing operations when read alongside the definition of "completion" in § 43-02-03-01(13) of the North Dakota Administrative Code, which states that a well is considered completed when oil or gas begins to flow from the well after the casing has been run.

82. *Id*. § 43-02-03-19.2. *See also id*. § 43-02-03-19.3 (providing for disposal of materials temporarily stored in on-site pits in accordance with subsection 19.2).

the relevant material, must be reclaimed within thirty days of cessation of operations unless an extension is granted, and in no case may be left for more than one year thereafter.[83]

Taking these regulations at face value, there appear to be substantial curbs in North Dakota's law to prevent the kinds of releases from hydraulic fracturing operations that appear most likely to cause environmental damage. The various regulatory requirements, read together, make it appear that compliance (even for hydraulic fracturing operations) requires operation in such a way as to avoid the releases of pollutants onto surface soil or into groundwater.[84] However, this assumes that compliance is effectively and rigorously enforced –an assumption that may not be well founded.[85]

Looking only to what private means are available, state statutes do provide some measure of leverage for private landowners, in close proximity to a well, to seek recourse against polluters.[86] For damages stemming from oil and gas production generally, owners of property adjacent to a well may demand an inspection by the state if hydrogen sulfide is present, in which case the state is authorized to take remedial measures.[87] Surface owners of land, but evidently not others near a well,[88] are entitled to damages sustained by the surface owner to his land for "lost land value, lost use . . . and lost value of improvements caused by drilling operations."[89] Finally, any property owner with property one mile or less

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83. *Id*. § 41-02-03-19.3.

84. *See id*. § 43-02-03-30.1 (prohibiting spills or leaks from flowing over the surface or infiltrating soil). It would thus appear that oil and gas operators would have to fulfill the other requirements imposed on them—such as § 43-02-03-21 (requiring casing and cementing sufficient to protect nearby fresh water), § 43-02-03-19 (governing construction and design of drilling sites), or § 43-02-03-19.3 (governing temporary storage of fracturing fluids at drilling sites)—in such a way as to meet the requirements of subsection 30.1.

85. *See* Cox, *supra* note 46, at 25–26 (noting that the EPA has found that states have generally devoted inadequate resources toward compliance inspections and legal enforcement); *New Oil Inspectors to Step Up ND Oversight*, THE BISMARCK TRIBUNE, (May 19, 2011), http://bismarcktribune.com/news/new-oil-inspectors-to-step-up-nd-oversight/article_7ae659c8-8227-11e0-9418-001cc4c03286.html (reporting that the state Department of Mineral Resources intended to increase its inspection staff from fourteen, able to inspect a well every six months, to twenty-four by June 2013, allowing monthly inspections) (on file with the Washington and Lee Journal of Energy, Climate, and the Environment).

86. The viability of common-law causes of action will not be considered here, but are reviewed *infra* at 331–39.

87. *See* N.D. CENT. CODE § 38-11.1-03.1 (2011) (establishing the right "to protect the health and safety of the surface owner's health, welfare, and property.").

88. *See* Kartch v. EOG Resources, Inc., 845 F. Supp. 2d 995, 1001–02 (D.N.D. 2012) (treating the relevant context of the statute as involving the relationship between surface owners and mineral owners where ownership overlaps, because of the conflicts caused by treating the mineral estate as dominant).

89. N.D. CENT. CODE § 38-11.1-04 (2011).

away from an oil or gas well is entitled to costs and damages for diminution of water quality or actions taken to restore water availability.[90]

A similar scheme exists for damage caused by subsurface exploration, including hydraulic fracturing.[91] Surface owners and adjacent landowners are entitled to demand inspection of a well by the state "as necessary to ensure compliance with applicable environmental protection laws and regulations . . . ."[92] Substantially similar damages are afforded to surface owners from interference by owners of the mineral estate.[93] But as to groundwater, although damages rights are also afforded to all landowners within one mile of the mineral production site (subject, however, to a six-year statute of limitations), there is also an affirmative requirement on the operator to inventory groundwater wells within one-half mile of exploration sites and one mile of production sites.[94] Although these causes of action provide limited, if substantial, rights to landowners against operators, it should also be noted that none of the rights in either section excludes remedies under other causes of action.[95]

Montana law provides a number of requirements analogous to those in North Dakota, with certain key differences, particularly on the issues of holding and disposal of wastewater. In Montana, the state has established a Board of Oil and Gas Conservation that has the authority to oversee injection wells and hydraulic fracturing operations, and is tasked with preventing contamination of surrounding land or extraneous underground strata.[96] The statute compels the board to require operators to file well logs, drill and case wells in a way that prevents the movement of oil and gas into other strata and prevents pollution of fresh water, and restore surface land to its previous condition.[97] Issuance of a drilling permit depends on

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90. *See id*. § 38-11.1-06 (2011) (outlining the extent of the cause of action).

91. *See id*. § 38-11.2-01 (2011) (defining "drilling operations" within the context of the statute as including the drilling of an extraction well "and the injection, production, and completion operations ensuing from the drilling").

92. *Id*. § 38-22.1-02 (2011).

93. *See id*. § 38-11.2-04 (2011) (reiterating damages rights for harm and disruption caused by the operator).

94. *See id*. § 38-11.2-07 (2011) (establishing the requirements).

95. *See id*. §38-11.1-10 (2011) ("The remedies provided by this chapter do not preclude any person from seeking other remedies allowed by law."); § 38-11.2-08 (2011) (same).

96. *See* Kulander, *supra* note 66, at 25 (describing the board as the "primary authority" for Montana's Underground Injection Control program and hydraulic fracturing); MONT. CODE ANN. § 82-11-111 (2011) (establishing the board's duties, including "prevent[ing] contamination of or damage to surrounding land or underground strata," and powers, including revoking, denying, and conditioning permits, as well as inspection and monitoring of production operations).

97. *See* MONT. CODE ANN. § 82-11-123 (2011) (establishing statutory requirements for oil and gas production).

compliance "in all respects with the applicable rules of the board,"[98] which rules include requirements for well spacing, drilling procedures, well stimulation, and production.[99] A well at which hydraulic fracturing is to be conducted requires an application describing the location of the operation and the geologic conditions of the well, a description of the well casing and cementing (which must be sufficient to prevent fluid migration into potable waters), and a statement if surface pits will be used to store fluids prior to injection.[100]

Montana also imposes certain substantive standards for the quality of wells and casings required of operators. Wells are required to be drilled using freshwater drilling fluid or air when drilling a surface hole or through freshwater aquifers, and to have "sufficient casing . . . to protect all fresh water located at levels reasonably accessible for agricultural and domestic use."[101] For rotary drilling specifically, the rule requires casing to be set in an "impervious formation" and sufficiently cemented to withstand "a compressive strength of 300 pounds per square inch . . . ."[102] Moreover, operators are required to subject all new wells to a mechanical integrity test (at a pressure between 300 and 800 PSI, depending on actual injection pressure), in order to ensure that there are no significant leaks in the tubing or casing, or "significant movement of injected fluid in vertical channels adjacent to the wellbore" that would threaten fresh water supplies in higher strata.[103] The rules do not permit a well that has failed a mechanical integrity test or experienced one of several specified mechanical failures in the course of operation to continue operating until it can be repaired, and a successful integrity test completed.[104] Operators are also required to file a report detailing work done on a well within thirty days of the well's completion.[105]

Montana has also recently revised its oil and gas regulations in order to address issues related to hydraulic fracturing, promulgating several new requirements in 2011 that govern fracking operations.[106] For hydraulic fracturing to be permitted under an operator's permit, it must have been included in the initial application; or else (in the case of exploratory wells where the need for fracking was not anticipated) information about the

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98. MONT. ADMIN. R. 36.22.604 (2012).
99. *See id*. 36.22.701–36.22.1245 (establishing these requirements).
100. *See id*. 36.22.1403 (2012) (enumerating the required components of applications for Class II injection wells).
101. *Id*. 36.22.1001 (imposing these requirements on rotary-drilled wells), 36.22.1002 (imposing these requirements on cable-drilled wells).
102. *Id*. 36.22.1001 (describing the casing requirements).
103. *Id*. 36.22.1416 (describing the required integrity test).
104. *See id*. 36.22.1416(7)–(8) (barring both classes of failing well from service).
105. *See id*. 36.22.1011 (requiring the report).
106. *See* Kulander, *supra* note 66, at 25 (discussing the new regulations, which took effect Aug. 27, 2011).

proposed operation must be submitted at least forty-eight hours before it is to be commenced.[107] The rules further require the disclosure of the methods used for any and all well treatments, including type of treatment and maximum pressure recorded; and in the case of hydraulic fracturing, disclosure of all treatment fluids used, broken down by type, rate of use, and concentration of each chemical.[108] The fracking disclosure requirements may be satisfied by submission of the required information to FracFocus or "successor . . . publicly accessible Internet information repositories . . . ."[109] A separate casing integrity test is also required before an operator is permitted to conduct a fracturing operation.[110]

Montana's rules include comparable provisions for the disposal of wastewater from fracturing operations. The rules' treatment of flowback water is not entirely clear because, as a general matter, the rules prohibit storage of a variety of oil wastes and other "hazardous or deleterious substances" in "earthen storage pits or in open vessels," which is a definition that might capture flowback water in certain circumstances.[111] Use of open pits to store hazardous substances is limited to emergencies, not including "spills from an improperly or inadequately designed or maintained production facility," and must be disposed within forty-eight hours "in a manner that will not degrade surface water or groundwater or cause harm to soils."[112] However, the rules also contain provisions

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107. *See* MONT. ADMIN. R. 36.22.608 (2012) (discussing the extent to which permits cover well stimulation activities). *See also id*. 36.22.1010 (discussing prior notification, approval, and subsequent reporting required for chemical stimulation or hydraulic fracturing to be authorized).

108. *See id*. 36.22.1015 (2012) (describing the disclosure requirements).

109. *Id*. The rules permit less extensive disclosure in order to protect chemicals that are trade secrets, requiring more extensive disclosure only if needed to respond to a spill or release, diagnosis or treatment of an exposed individual, or treatment of a medical emergency. *See id*. 36.22.1016 (describing the trade secrets exception).

110. *See id*. 36.22.1106 (providing for casing pressure testing and other safety requirements prior to a fracturing operation, including use of a fracturing string if the casing fails the integrity test). *Compare id*. 36.22.1106 (requiring at 30-minute pressure test at the "maximum anticipated treating pressure minus the annulus pressure") *with id*. 36.22.1416 (requiring, for ordinary casing, a 15-minute pressure test at the greater of 100 PSI above the actual injection pressure at testing time or 300 PSI, but in no event greater than 800 PSI).

111. *See id*. 36.22.1207 (prohibiting storage in open pits or vessels); *id*. 36.22.302(37) (defining "hazardous substance" as any substance so defined in § 75-10-701 of the Montana Code); MONT. CODE ANN. § 75-10-710 (defining "hazardous or deleterious substance" as any substance constituting an "imminent and substantial threat to . . . the environment" and designated hazardous under CERCLA); 40 C.F.R. 302.4 (2012) (including benzene, ethylene glycol, and naphthalene among substances designated hazardous under CERCLA). No reported case law has been found interpreting these provisions.

112. MONT. ADMIN. R. 36.22.1207 (2012).

specifically for disposal of produced water[113] with more than 15,000 PPM of dissolved solids that permit disposal into a "board-approved . . . earthen pit" so long as the maximum amount disposed does not exceed five barrels daily over a monthly basis.[114] Alternatively, such water may be disposed of by underground injection into a Class II well or, if the concentration of dissolved solids is at or below 15,000 PPM, through "any manner allowed by law that does not degrade surface waters or groundwater or cause harm to soils."[115] Earthen pits, if used, must be expressly permitted by the board, and must be constructed in accord with a number of requirements provided by the rules.[116]

Montana law also includes remedial provisions for surface owners whose use of their land is disrupted by oil and gas development.[117] Oil and gas developers are also made generally liable for all damage to real or personal property resulting from "lack of ordinary care" or from "oil and gas operations and production."[118] Separate from damages, civil and criminal liability may attach to an individual who violates the state oil and gas statutes or an administrative rule to which the person is subject, although ability to bring suit is vested specifically in the Board of Oil and Gas Conservation.[119] The board is also authorized to take action in cases of emergency involving an actual or impending violation "that, if it occurs or continues, will cause substantial pollution" and produce enduring harmful effects that endanger public health, safety, or welfare.[120] Under that power, the board is entitled to close or shut down a well, or to impose restrictions on operation, and may do so without prior notice or hearing offered to the alleged violator.[121] Although Montana's law differs from North Dakota's, in

113. Although the rules do not define this term directly, they define "produced fluid" as "any fluid, including oil, gas, and water, originating from subsurface geologic sources." *Id*. 36.22.302(60).

114. *Id*. 36.22.1226.

115. *Id*.

116. *See id*. 36.22.1227 (requiring liners, dikes, use of specified materials, and compliance with fencing and netting provisions of the rules).

117. *See* MONT. CODE ANN. § 82-10-504 (2011) (providing the owners of surface estates with a cause of action for "loss of agricultural production and income, lost land value, and lost value of improvements from oil and gas operations.").

118. *Id*. § 82-10-505.

119. *See* Kulander, *supra* note 66, at 26 (describing the violation prohibitions); MONT. CODE. ANN. § 82-10-147 (granting the board the right to sue over violations, assess an administrative penalty up to $125K, issue compliance orders, and seek injunctions); *id*. § 82-10-148 (declaring violations and attempts to falsify records a misdemeanor subject to a maximum $10,000 fine per day an imprisonment up to six months); *id*. § 82-10-149 (declaring each day of noncompliance a misdemeanor subject to a maximum $10,000 fine per day).

120. MONT. CODE ANN. § 82-11-151(1) (authorizing board action in emergencies).

121. *Id*. § 82-11-151 (outlining the board's powers and providing for notice and hearing after the board's emergency action).

that Montana lacks the North Dakota provision entitling nearby landowners to take action against polluters,[122] oil and gas operators would nevertheless appear to be subject to the general state requirements for water quality, which entitle the state to issue orders to clean up any spills that may pollute state waters.[123]

The differences between these regulatory schemes are subtle, but they appear potentially significant. Whereas Montana permits the maintenance of wastewater storage pits in certain circumstances and to a limited extent beyond emergency situations,[124] North Dakota imposes a largely unqualified proscription of all non-emergency unenclosed surface storage.[125] Both states provide that their oil and gas regulatory agencies are charged with environmental protection as well as development, and are entitled to use permitting as a way to ensure environmental safety.[126] But Montana's rules provide only for environmental regulation by public agencies; there is no analogue in the rules governing mining to North Dakota's private causes of action for property owners other than the owners of surface estates.[127] In this regard in particular, Montana's law appears less favorable than North Dakota's, in that it would make it more difficult for private property owners, tribal or otherwise, in the border regions of a reservation to exercise leverage over off-reservation polluters without such a legal basis. The difference at least eliminates one potential remedy, were there to be a leak or spill, under Montana law.

IV. Reservation Jurisdiction, Federal Regulation, and the Trust Relationship

Although the state regulations discussed above are a necessary consideration—for the sake of comparison, as well as for property along jurisdictional borders where it is directly relevant—most significant for

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122. *See supra* notes 86–95 and accompanying text (discussing North Dakota law's private rights of action for damages to water quality and other land uses).

123. *See* MONT. CODE ANN. § 75-5-601 ("The department may issue an order to a person to clean up any material that the person or the person's employee, agent, or subcontractor has accidentally or purposely dumped, spilled, or otherwise deposited in or near state waters and that may pollute state waters."). *See also id*. §§ 75-5-601 *et seq*. (outlining the enforcement and penalty provisions).

124. *See supra* notes 111–16 and accompanying text (outlining the Montana rules for wastewater pits).

125. *See supra* notes 78–83 and accompanying text (outlining the North Dakota rules for wastewater pits).

126. *See supra* notes 66–69, 96–100 and accompanying text (discussing agency authority and permitting restrictions).

127. *Compare supra* notes 86–95 and accompanying text (summarizing the private causes of action in North Dakota) *with supra* notes 118–23 and accompanying text (imposing liability for property damages, but providing no specific private cause of action).

fracturing in Indian country are the rules directly applicable to reservations. BLM's new regulations specifically on fracturing[128] are part of these rules, but it is necessary to outline the jurisdictional framework of oil and gas regulation in Indian country before the new regulations may be considered.

In most respects, Indian tribes are in a position of jurisdictional parity with states—that is, state law and regulation does not apply within Indian reservation boundaries, generally leaving the reservations subject only to tribal and federal law.[129] This status reflects tribes' reserved sovereignty, or those powers of self-government derived from tribes' original status as independent nations.[130] Where civil and regulatory jurisdiction is concerned, matters relating to tribal member Indians in Indian country are subject to tribal jurisdiction, unless federal law creates an exemption.[131]The property or activities of nonmembers or non-Indians in Indian country also fall outside state regulation if state interference would hinder tribal government or federal law.[132] Tribes' ability to impose regulations on Indian land or federal trust land, even if it affects non-Indians, is generally unquestioned.[133] Tribes' ability to regulate may be limited if the regulation affects activities of nonmembers on non-Indian fee lands; however, under *Montana v. United States*, tribal regulation applies if the nonmembers have entered a consensual relationship with the tribe, or if the relevant activity has "some direct effect on the political integrity, the economic security, or the health or welfare of the tribe."[134] Given the economic prominence and potential ecological perils of oil and gas production generally, and hydraulic fracturing specifically, it is reasonable to presume that tribal regulatory jurisdiction would survive the *Montana*

128. *See supra* notes 1–5 and accompanying text (introducing the regulations).

129. *See* COHEN, *supra* note 64, § 3.04[1] ("'Generally speaking, primary jurisdiction over land that is Indian country rests with the Federal Government and the Indian tribe inhabiting it, and not with the States.'" (quoting *Alaska v. Native Vill. of Venetie*, 522 U.S. 520, 527 n.1 (1998))); *id*. §6.01[2] ("[S]tate law generally is not applicable to Indian affairs within the territory of an Indian tribe, absent the consent of Congress.").

130. *See id*. § 4.01[1][a], at 207–08 (noting that the basic principle of Indian law is that tribal sovereignty is not a delegated power, but is derived from the incidents of independent nationhood not defeated by the federal-tribal relationship).

131. *See id*. § 6.01[1], at 489 ("Congress's plenary authority over Indian affairs and the tradition of tribal autonomy in Indian country combine to preempt the operation of state law.").

132. *See id*. at 490 (describing the conditions for tribal regulation of non-Indians).

133. *See id.* § 6.02[2][a], at 506 ("[The Supreme] Court has never struck down a tribal tax or regulation of non-Indians engaged in a transaction or activity on Indian land."). *See also* Merrion v. Jicarilla Apache Tribe, 455 U.S. 130, 139–41 (1982) (upholding an oil & gas severance tax on a non-Indian company and noting the tribe's inherent power to tax as "an essential instrument of self-government").

134. *Id*. § 6.02[2][b], at 507–08 (quoting *Montana v. United States*, 405 U.S. 544, 565–66 (1981)).

test.[135] But it should also be noted that nonmember conduct or property does not necessarily fall under state jurisdiction simply because it falls outside tribal jurisdiction.[136] The state may not assert its authority when doing so would conflict with preemptive federal law or would interfere with reservation Indians' right to tribal lawmaking.[137]

Oil and gas development specifically is subject to a complex of federal and tribal interests, laws, and regulations. Mineral estates within reservation boundaries may be owned by tribes or individuals (particularly where lands were alienated from tribal holdings by allotment), while tribes may also have rights in mineral estates that extend outside reservation boundaries where land was ceded for homesteading or federal use.[138] Where lands are held in trust for the tribe or individuals by the federal government, which acts in a fiduciary capacity, the tribe or the individual is the beneficial owner of the mineral estate, and may have enforceable rights in cases of federal mismanagement.[139]

Under the Indian Mineral Development Act (IMDA),[140] tribes may enter into leases or other minerals agreements that provide for the exploration and production of oil and gas, among other resources, from any estate "in which such Indian tribe owns a beneficial or restricted interest," subject to the approval of the Secretary of the Interior.[141] Secretarial approval depends on a finding that the agreement "is in the best interest of the Indian tribe" or individual Indian parties, based on potential economic returns and "environmental, social, and cultural effects" on the tribe that

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135. *See also* Matthew L.M. Fletcher, *Fracking, Tribal Sovereignty, the Montana Test, and the Turtle Mountain Band*, TURTLE TALK (Nov. 28, 2011, 3:56 PM), http://turtletalk.wordpress.com/2011/11/28/fracking-tribal-sovereignty-the-montana-test-and-the-turtle-mountain-band/ (on file with the Washington and Lee Journal of Energy, Climate, and the Environment).

136. *See* COHEN, *supra* note 64, § 6.03[2][c], at 528–30 (discussing cases to the effect that tribal jurisdiction and state authority entail separate inquiries).

137. *See id*. § 6.03[2][a], at 517–18 (citing *Williams v. Lee*, 358 U.S. 219 (1959)) (discussing the dual barriers to state jurisdiction, beyond *Montana*'s provisions). States' rights to exercise civil jurisdiction over Indian country would be different if a reservation has been subject to Pub. L. No. 83-280, which provided a superseding federal vehicle for state jurisdiction; but this is not directly relevant for the purposes of this note, as Montana and North Dakota were not so subject. *See id*. § 6.04[3], at 537–78 (discussing the history and complex effects of the law).

138. *See id*. § 17.03[1], at 1120–22 (discussing mineral ownership).

139. *See id*. § 17.01, at 1106 (discussing generally beneficial rights to natural resources on tribal or allotted land); *id*. § 17.03[4], at 1137–41 (discussing cases of trust liability and mixed results).

140. Indian Mineral Development Act, 25 U.S.C. §§ 2102–2108 (2011).

141. 25 U.S.C. § 2102 (2011). *See also* COHEN, *supra* note 64, § 17.03[2][b], at 1129–30 (discussing these provisions of the IMDA). Secretarial approval would not be required if a tribe sought to develop such a resource on its own, without the involvement of extrinsic parties. *See id*. § 17.03[3], at 1134 n.128 ("If a tribe develops its own mineral resources, no secretarial approval is required . . .").

may result from approval.[142] Liability under the trust relationship could follow from a failure to make a best-interest determination, to conduct royalties accounting so as to maximize tribal interests, to consider potential economic benefit, or to consider factors other than economic benefit.[143] The IMDA also preserved tribes' ability to enter into minerals agreements under the Indian Mineral Leasing Act of 1938,[144] which had instituted uniform leasing procedures for tribal land: ten-year leases, requiring prior tribal consent and Secretarial approval.[145]

In the context of federal regulation, the authority of the Secretary of the Interior to manage Indian mineral leasing, and oil and gas operations on federal land generally, has been delegated to the Bureau of Land Management.[146] BLM, in turn, has issued seven Onshore Oil and Gas Orders, including orders that govern approval of operations, drilling, and disposal of produced water.[147] These orders apply to oil and gas leases on Indian trust or allotment trust land, as well as agreements under the IMDA.[148] Unlike the states' regulations, however, BLM's requirements for oil and gas exploration and production are not made part of the Code of Federal Regulations, but are instead kept as separate orders, and are partly

142. 25 U.S.C. § 2103 (2011). Because approval by the Secretary constitutes major federal action for the purposes of the National Environmental Policy Act, an Environmental Impact Statement must be prepared before the Secretary may approve a minerals agreement. *See* COHEN, *supra* note 64, § 17.03[3], at 1134 (discussing the NEPA implications of Secretarial approval).

143. *See id*. § 17.03[4], at 1138–39 (summarizing cases and holdings on federal government liability under the trust relationship).

144. 25 U.S.C. §§ 396a–396g (2011).

145. *See* COHEN, *supra* note 64, §17.03[2][a], at 1124–25 (summarizing the 1938 Act).

146. *See* Onshore Oil and Gas Order No. 1, 72 Fed. Reg. 10,329, 10,329 (Mar. 7, 2007) ("The Secretary of the Interior has delegated this [management] authority to the Bureau of Land Management . . . ."); 43 C.F.R. § 3164.1 (2011) (authorizing the BLM director to issue onshore oil and gas orders); 25 C.F.R. § 211.4 (2011) (authorizing BLM to approve and enforce drilling permits on tribal land); *id*. § 212.4 (authorizing BLM to approve and enforce drilling permits on allotted land). While BLM permitting is a practical reality, there are nevertheless credible arguments to be made that the present regulatory structure is unlawful because of the way BLM has come about its delegated authority. *See* CERT comment, *supra* note 10, at 4–5 (arguing that the Federal Land Policy and Management Act of 1976, 43 U.S.C. § 1702 *et seq.*, denies BLM authority over Indian land, invalidating the Secretary's delegation of authority as *ultra vires*); Tom Fredericks & Andrea Aseff, *When Did Congress Deem Indian Lands Public Lands?: The Problem of BLM Exercising Oil and Gas Regulatory Jurisdiction in Indian Country*, 33 ENERGY L.J. 199, 136–41 (2012) (arguing that, in addition to the statutory limitations, the secretarial delegation gives BIA, not BLM, authority over Indian minerals management, and that BIA's delegation of that authority to BLM through a memorandum of understanding was unlawful).

147. *See* 43 C.F.R. § 3164.1 (2011) (listing the orders currently in effect and their locations in the Federal Register).

148. *See*, *e.g.*, Onshore Oil and Gas Order No. 1, *supra* note 146, at 10,329 (stating that the order applies to onshore leases of "Indian oil and gas," defined as mineral interests on tribal or allotment trust land, and IMDA agreements).

summarized in the Bureau's "Gold Book" of standards and guidelines for operators.[149] With the exception of Order No. 1, concerning the application requirements for oil and gas producers, none of the orders has been updated in the last twenty years or more.[150]

As a precondition of approval, operators are required first to submit a plan detailing the scope of the project, targeted strata, means for preventing blowouts, proposed casings and cement design criteria, expected pressures encountered in the course of drilling and operation, testing and logging procedures, and any other relevant aspects of the proposal, all of which are expressly required to comply with Order No. 2.[151] Under that order, casing and cementing must be adequate to "protect and/or isolate all usable water zones" and must run to an adequate depth to contain the pressure experienced during normal operations.[152] Casing and cementing must also meet a variety of standard specifications and pass pressure testing, subject to compliance remedies also specified in the rule.[153] Order No. 1 further requires submission of a plan for surface use, which in part must be designed to provide "for safe operations, adequate protection of surface resources, groundwater, and other environmental components;" define locations for reserve pits to be located on site; identify prospective water supplies and intended methods of waste disposal; and make plans for surface reclamation.[154] Similarly, operators are required to "conduct operations to minimize adverse effects to surface and subsurface resources, prevent unnecessary surface disturbance, and conform with currently available technology and practice," as well as to comply with applicable statutes, including NEPA and the Endangered Species Act.[155] The rules affirmatively require "immediate action" by operators to "safeguard life or prevent significant environmental degradation," as well as notification of the surface managing agency, and surface owner if appropriate, within

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149. *See id*. at 10,328 ("The following Order would be implemented by BLM and the [Forest Service,] but will not be codified in the Code of Federal Regulations."); U.S. DEP'T OF THE INTERIOR AND U.S. DEP'T OF AGRIC., SURFACE OPERATING STANDARDS AND GUIDELINES FOR OIL AND GAS EXPLORATION AND DEVELOPMENT 1 (2007) [hereinafter Gold Book] ("The Gold Book provides operators with a combination of guidance and standards for ensuring compliance with agency policies and operating requirements, such as those found in the Code of Federal Regulations [and] Onshore Oil and Gas Orders . . . .").

150. *See* 43 C.F.R. § 3164.1 (listing the effective dates of each order, the most recent revisions being Order No. 1 in 2007 and Order No. 7 in 1993).

151. *See* Onshore Oil and Gas Order No. 1, *supra* note 146, at 10,331 (establishing the drilling plan application requirements).

152. *See* Onshore Oil and Gas Order No. 2, 53 Fed. Reg. 46,798, 46,808 (Nov. 18, 1988) (establishing the casing and cementing requirements).

153. *See id*. at 46,808–09 (describing the casing requirements, the gravity of violations, and the prescribed remedial action).

154. Onshore Oil and Gas Order No. 1, *supra* note 146, at 10,331–33.

155. Onshore Oil and Gas Order No. 1, *supra* note 146, at 10,335.

twenty-four hours of the emergency.[156] An environmental review that complies with NEPA and other applicable environmental regulations will be conducted following the agency's receipt of an application.[157]

If Indian land is involved, the Bureau of Indian Affairs (BIA) is established as the surface managing agency, and operators are required to go to BIA and tribal offices to obtain the appropriate use or access permits, or an appropriate surface access agreement in cases of divided estates.[158] Applicable statutes may require surveys in order to protect cultural resources prior to approval.[159] BLM will also take account of BIA and tribal recommendations for conditions to be placed on permits prior to approval.[160]

Order No. 7 provides generally applicable requirements for storage and disposal of water that mirror the regulations imposed by states.[161] The Order provides that disposal may be accomplished by underground injection (the preferred means), discharge into pits, or other methods approved by BLM officials including surface discharge pursuant to an NPDES permit; but in any event, no disposal is permitted without approval of the authorized official.[162] Authorized officers are also entitled to impose additional requirements upon operators' management of produced water, as when environmental problems have arisen or water quality has degraded so as to require other measures.[163] Water from well completion activities may be temporarily stored in reserve pits for up to 90 days, with storage thereafter requiring approval of the officer.[164] The Order also provides a

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156. Onshore Oil and Gas Order No. 1, *supra* note 146, at 10,335–36.

157. *See* Gold Book, *supra* note 149, at 2 ("Upon receipt of a complete APD . . . the BLM, the surface management agency, or the agency's or operator's environmental contractor will conduct an environmental analysis . . . in conformance with the requirements of NEPA and the regulations of the Council on Environmental Quality . . . .").

158. *See* Onshore Oil and Gas Order No. 1, *supra* note 146, at 10,336–37 (imposing requirements for Indian oil and gas leases). The rules also make provision for obtaining authorization for staking and surveying on Indian land, authorizing entry if a majority of owners consent or if BIA has approved access in cases of extensive fractionation. *See id*. at 10,330–31 (discussing access arrangements for staking and surveying).

159. *See* Gold Book, *supra* note 149, at 9–10 (discussing permit approval plans).

160. *See* Gold Book, *supra* note 149, at 12 (discussing BLM treatment of Indian lands).

161. *See* Onshore Oil and Gas Order No. 7, 58 Fed. Reg. 47,361, 47,361–65 (providing the final text of the Order).

162. *See id*. at 47,362 (discussing general requirements for water disposal). *See also* 43 C.F.R. § 3162.5-1 (requiring disposal by subsurface injection, approved pits, or other means approved by the authorized officer).

163. *See* Onshore Oil and Gas Order No. 7, *supra* note 161, at 47,362 (noting the officers' authorization to impose conditions upon written justification).

164. *See* Onshore Oil and Gas Order No. 7, *supra* note 161, at 47,362 (discussing general use of reserve pits).

variety of notice requirements and other provisions governing disposal requests in various circumstances.[165]

As to the substantive requirements for various disposal methods, the Order requires underground injection to be done in an injection well with a valid Underground Injection Control permit (issued by the relevant agency, which may be a tribe if it has "achieved primacy"), and to comply with the procedural requirements of Order No. 1 and the well engineering requirements of Order No. 2.[166] Disposal by surface discharge requires submission of the valid NPDES permit, as well as disclosure of a water quality analysis and the design of the disposal site.[167]

Disposal pits require extensive disclosure to the approving officer, including disclosure of the sources of produced water, a reclamation plan for the site, a contingency plan for emergencies, and samples of water from the discharge source for analysis.[168] Approval of lined pits requires disclosure of a map of the site, disposal rate, water contents (including dissolved solids and toxic constituents), method of disposing of precipitated solids, and the material used for and installation method of the pit liner.[169] Unlined pits are subject to a different set of criteria, which include a threshold showing that less than five barrels of water will be disposed per day, the water has no more dissolved solids than existing protected water, the water will not degrade area surface or subsurface waters, or that at least a substantial part of the water is being used for beneficial purposes and meets minimum standards for those uses.[170] Operators must further make disclosures comparable to those required for lined pits, as well as percolation rate of area soil, known aquifers and mineral deposits in the area, and further disclosures related to the threshold criterion underlying the application.[171] Applications for emergency pits are dealt with separately;

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165. *See* Onshore Oil and Gas Order No. 7, *supra* note 161, at 47362–63 (establishing different notice provisions depending on the disposal method and whether the disposal site is federal/tribal or state land, on-lease or off-lease).

166. *See* Onshore Oil and Gas Order No. 7, *supra* note 161, at 47,363 (imposing informational requirements for injection wells).

167. *See* Onshore Oil and Gas Order No. 7, *supra* note 161, at 47,365 (imposing requirements for surface discharges). Note that the Order requires unauthorized discharges to be disclosed to the authorized BLM officer. Onshore Oil and Gas Order No. 7, *supra* note 161, at 47,365.

168. *See* Onshore Oil and Gas Order No. 7, *supra* note 161, at 47,363 (imposing informational requirements for disposal pits generally).

169. *See* Onshore Oil and Gas Order No. 7, *supra* note 161, at 47,363 (imposing substantive requirements on lined pits, to be executed by the authorizing officer).

170. *See* Onshore Oil and Gas Order No. 7, *supra* note 161, at 47,363–64 (imposing substantive requirements on unlined pits).

171. *See* Onshore Oil and Gas Order No. 7, *supra* note 161, at 47,364 (imposing substantive requirements on unlined pits).

their use is limited to forty-eight hours unless an authorized officer permits otherwise.[172]

The Order also imposes substantive construction standards for pits of both kinds. Pits must be on level ground away from drainage pathways, with adequate storage capacity, fencing and means to prevent entry by birds, and must meet stated criteria for grading and free board.[173] Lined pits are further required to be lined with impervious materials that will be resistant to the contents of produced water and to have systems in place for the detection of leaks.[174] Pits that fall short of these standards are not approved unless a variance is issued.[175]

These regulations appear to have already imposed substantial controls on resource extraction from federal and tribal land, albeit not without pushback from some tribes.[176] As under state regulations, operators under the federal rules are subject to oversight of the nature and extent of drilling, as well as to substantive requirements for casing and wellbore integrity.[177] The federal rules also impose broadly comparable requirements on the use of pits to store flowback water, appearing to take a more permissive approach to their use while imposing more specific construction requirements.[178] But the current federal regulations are, in fact, substantially

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172. *See* Onshore Oil and Gas Order No. 7, *supra* note 161, at 47,364 (discussing requirements applicable to emergency pits).

173. *See* Onshore Oil and Gas Order No. 7, *supra* note 161, at 47,364 (imposing construction requirements for pits).

174. *See* Onshore Oil and Gas Order No. 7, *supra* note 161, at 47,364 (imposing construction requirements specific to lined pits).

175. *See* Onshore Oil and Gas Order No. 7, *supra* note 161, at 47,364 (imposing penalty for noncompliant proposals).

176. *See Bureau of Land Management's Hydraulic Fracturing Rule's Impacts on Indian Tribal Energy Development: Hearing Before the Subcomm. on Indian and Alaska Native Affairs*, 112th Cong. (2012) (statement of Wilson Groen, President and CEO, Navajo Nation Oil & Gas Co.) [hereinafter Groen testimony] (arguing that industry best practices are adequate protection, and that current rules already erect "unique hurdles" to tribal energy development); *Bureau of Land Management's Hydraulic Fracturing Rule's Impacts on Indian Tribal Energy Development: Hearing Before the Subcomm. on Indian and Alaska Native Affairs*, 112th Cong. (2012) (statement of T.J. Show, Chairman, Blackfeet Tribal Business Council) [hereinafter Show testimony] (discussing delays and costs of the current regulatory scheme).

177. *Compare supra* notes 151–53 and accompanying text (requiring operators to submit drilling plans and to meet established criteria for well casing, cementing, and pressure testing, in order to protect nearby water) *with supra* notes 67, 70, and accompanying text (discussing North Dakota's analogous regulations for well specification and casing plans, as well as casing and cementing requirements sufficient to protect nearby water) *and supra* notes 97, 100–105, and accompanying text (discussing Montana's analogous regulations, imposing more stringent standards for drilling so as to prevent water pollution, applications' requirement of drilling plans, and standards for casing, cementing, and well integrity).

178. *Compare supra* notes 164, 168–70, 172 (permitting temporary storage for 90 days and emergency storage for 48 hours in reserve pits, but requiring disclosure before approval,

less rigorous than their state counterparts in their treatment of hydraulic fracturing operations; a comparison of federal rules to state laws and regulations (many of which, on this point, are admittedly of recent vintage) reveal a lacuna in the federal rules, with many provisions of state law having no federal counterpart currently in force.[179] This disparity at least suggests the need for the federal rules to address hydraulic fracturing with specificity—North Dakota and Montana, no less than tribes, have an interest in the economic benefits of increased oil and gas production within their jurisdictions,[180] but have nevertheless seen fit to regulate the practice—although it does not automatically follow that Indian trust land should fall under the same regime as public lands.

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compliance with water quality and liner material standards, and fit within one of multiple compliance categories for unlined pits) *with supra* notes 79–81, 83 (discussing North Dakota regulations, limiting pit use to 72 hour emergency storage, while imposing fencing and screening requirements and only general requirements for pit impermeability) *and supra* notes 111–12, 114, 116 (discussing Montana regulations, prohibiting use of open pits to store frack fluids; limiting emergency use to 48 hours; and imposing dike, fencing, 5 gallon/day limit, and materials requirements on produced water pits).

179. *Compare* 43 C.F.R. § 3162.3-2 (requiring submission of the proposed operation beforehand only for "nonroutine" fracturing jobs, and a completion report for all jobs) *with supra* notes 73–75 (discussing North Dakota's specific fracking rules, including limits on treatment pressure, inspection and testing requirements, fracking chemical disclosure, official notification requirements, and prohibition of leaks) *and supra* notes 107–10 (discussing Montana's specific fracking rules, including pre-fracking information disclosure, disclosure of treatment methods and fracking chemicals, and requirements for separate casing integrity tests). It should be noted that this comparison does not take account of EPA or state regulation of hydraulic fracturing operations that use diesel fuels or fuel derivatives under the Underground Injection Control program of the Safe Drinking Water Act. *See* 40 C.F.R. Parts 144–47. With the exception of wells on the Fort Peck reservation, EPA administers the UIC program for all Indian lands in Montana and North Dakota. *See* 40 C.F.R. § 147.1351 (providing for EPA primacy over UIC wells in Indian Country in Montana, excepting Fort Peck); 40 C.F.R. § 147.1752 (providing for EPA primacy over UIC wells in Indian Country in North Dakota); 40 C.F.R. § 147.3200 (providing for tribal primacy over UIC wells on the Fort Peck reservation). Because EPA has estimated that only two percent of wells in states where it would administer the UIC program use diesel fuel in hydraulic fracturing, these rules are considered outside the scope of this note. *See* 77 Fed. Reg. 27,453 (May 20, 2012) ("[A] review of data available [through FracFocus] suggested that approximately 2% of wells that hydraulically fracture would be subject to SDWA UIC permitting requirements in states where EPA administers the UIC program.") Fort Peck's UIC rules will be discussed alongside other tribal regulation, *infra* notes 292–330 and accompanying text.

180. *See* Lauren Donovan, *Numbers Tell The Story of Oil in Bakken*, BISMARCK TRIBUNE, (Feb. 25, 2013), http://bismarcktribune.com/numbers-tell-the-story-of-oil-in-bakken/article_a75004fe-7f6a-11e2-9b71-001a4bcf887a.html (noting that new oil development has poised North Dakota to overtake Texas as the top national producer, resulting in record-high revenues of $317 million in 2012 from production on state-owned lands) (on file with the Washington and Lee Journal of Energy, Climate, and the Environment).

BLM's proposed regulations were an attempt to fill the void in the federal rules exposed by the rapid increase in the use of fracturing.[181] Although BLM has been widely criticized for proposing the rules after what was perceived to be inadequate tribal consultation,[182] the substance of the rules was ostensibly intended to align with the modern requirements of state regulation.[183] In their original form, the proposed rules required preapproval for all hydraulic fracturing, which may be obtained either during the existing application process for new wells or, for existing wells if fracking has not begun within five years of approval or if "significant new information" about area geology or the operation's effects has arisen.[184] The operator submission would now be required to include a description of the geology and formations where the proposed stimulation operation would take place; locations of "usable water" along with logs proving that the water supplies are protected from contamination; water sources or base fracking fluid used; types of proppant used; and a description of the stimulation, including volume of fluid used, maximum treating pressure, estimated fracture length and height, and proposed methods of handling and disposing flowback water.[185] Operators are further required to conduct a successful mechanical integrity test of casing or casing string prior to a

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181. *See* 77 Fed. Reg. 27,693 (May 11, 2012) (noting that BLM's current regulations on fracking were last amended in 1988, "long before the latest hydraulic fracturing technologies became widely used," and that the bureau is following states' lead in updating their regulations for public lands).

182. *Compare id*. (noting that BLM held four meetings in January 2012 that included 27 of 175 tribes invited to discuss the draft rules) *with* CERT comment, *supra* note 10, at 20–21 (arguing that BLM's initial meetings were inadequate, and that the bureau subsequently failed to respond to tribal inquiries or requests for meetings with their governments).

183. *See* 77 Fed. Reg. 27,693–94 (May 11, 2012) (asserting that BLM attempted to "minimize any duplication between the reporting required for state regulations and for this regulation," to integrate the disclosure regs with FracFocus, and to give effect to state rules where they are more stringent than federal regulations).

184. 77 Fed. Reg. 27709 (Oct. 19, 2012) (to be codified at 43 C.F.R. § 3162.3-3); *see also* 77 Fed. Reg. 27695 (May 11, 2012) (noting that the new regulation would supersede the current requirement limiting preapproval to "nonroutine" fracking and that the five-year requirement accords with Montana's regulations).

185. 77 Fed. Reg. 27709–10 (Oct. 19, 2012) (to be codified at 43 C.F.R § 3162.3-3); *see also* 77 Fed. Reg. 27695–97 (May 11, 2012) (discussing the public health and safety purposes of the various requirements). The federal regulations speak in terms of "usable water" because "BLM has sought to protect all usable waters during drilling operations, not just fresh water" with the intention "to be more protective" of lower-quality water. *Id*. at 27695. Whereas the Montana rules speak in terms of "prevent[ing] . . . pollution of fresh water supplies" in their imposition of administrative duties, MONT. CODE ANN. § 82-11-123(3), the North Dakota rules are broader, requiring confinement of "[a]ll freshwaters and waters of present or probable value for domestic, commercial, or stock purposes," N.D. ADMIN. CODE 43-02-03-20. The usable water standard has been criticized as imposing inordinate costs by requiring longer casings to provide adequate protection. *See* CERT comment, *supra* note 10, at 22–23 (projecting a cost increase of at least $74,000 per well).

fracturing operation.[186] Pressure must be monitored during the course of the operation, and unexpected increases in pressure reported if they exceed a specified threshold.[187]

After the fracturing operation is complete, operators would be required to report, within thirty days of the operation, the actual results of the operation, fluid sources used, and actual surface pressure experienced; actual fracture length and height; and the actual method of fluid disposal used from the site.[188] Use of unlined pits for the storage of recovered fluids is apparently made impermissible, as the proposed rule provides only for storage in tanks or lined pits.[189] Following completion, operators would also be required to disclose all additives used in the fracturing fluid, organized by trade name and purpose, as well as the chemical makeup by mass of all fracturing fluids used over the course of the completion operation.[190] The additive components would ultimately be publicly disclosed through FracFocus.[191]

The revisions to the proposed rules make substantive changes to the original proposal; but with a few exceptions that are significant for the purposes of this note, the amendments do not drastically depart from the original proposal.[192] The revision expressly requires fracturing operations to

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186. *See* 77 Fed. Reg. 27710 (Oct. 19, 2012) (to be codified at 43 C.F.R. § 3162.3-3(d)) (deeming said test successful if at least 90 percent pressure is maintained for 30 minutes). BLM has pointed out that this standard is already in effect under Onshore Oil and Gas Order No. 2. *See* 77 Fed. Reg. 27697 (May 11, 2012) ("This requirement is the same standard applied in Onshore Order Number 2 . . . to confirm the mechanical integrity of the casing.").

187. *See* 77 Fed. Reg. 27710 (Oct. 19, 2012) (to be codified at 43 C.F.R. § 3162.3-3(e)) (requiring monitoring of annulus pressure and reporting within 24 hours if pressure exceeds 500 PSI, and a subsequent report within 15 days). *See also* 77 Fed. Reg. 27697 (May 11, 2012) ("Unexpected changes . . . would provide an early indication of the possibility that well integrity has been compromised.").

188. *See* 77 Fed. Reg. 27710–11 (Oct. 19, 2012) (to be codified at 43 C.F.R. § 3162.3-3(g)) (requiring specified disclosures after well completion).

189. *See id*. at 27710 (to be codified at 43 C.F.R. § 3162.3-3(f)) (requiring recovered fluid to be stored in either lined pits or tanks). *See also* 77 Fed. Reg. 27697 (May 11, 2012) (noting that this requirement is consistent with API recommendations, and is made necessary by the potential presence of hydrocarbons or additives in flowback water that "might degrade surface and ground water if they were to be released without treatment"). BLM subsequently clarified that the rule was intended to supersede Onshore Order No. 7 in the context of hydraulic fracturing and to permit storage in only lined pits or tanks. *See* revised rules, *supra* note 6, at 82 ("Onshore Order No. 7 allows disposal of produced water in unlined pits in certain circumstances. The BLM does not believe that storage of hydraulic fracturing flowback fluids in unlined pits is appropriate . . . .")

190. *See id*. (to be codified at 43 C.F.R. § 3162.3-3(g)(4)–(5)) (requiring two tables describing the additive components as part of the post-completion disclosure).

191. *See* 77 Fed. Reg. 27698 (May 11, 2012) ("The BLM . . . is working with the Ground Water Protection Council in an effort to integrate this information into the existing Web site known as FracFocus.org.").

192. *See* revised rules, *supra* note 6, at 22–23 (summarizing the revisions).

comply with the performance standard for well operators to isolate usable water sources.[193] It also streamlines the pre-fracturing approval process by eliminating the requirements that a compliance certification and a cement bond log be submitted before fracturing begins, and by allowing multiple similar wells to be considered for approval in tandem.[194] Chemical disclosures may also be made through means other than FracFocus, and the chemical reporting burden has been substantially reduced.[195] Where fracturing chemicals' composition is a protected trade secret, the revision would permit operators to withhold details of the chemicals used, providing only an affidavit that the chemicals are exempt from disclosure.[196]

The revision also strengthens some aspects of the regulation, creating a new required report on the success of corrections to inadequate well cementing before fracturing operations begin.[197] Operators are also required to run at least one of a number of cement evaluation logs on casing segments that protect usable water,[198] as well as make additional disclosures for fracture mapping and operation monitoring, particularly where fractures approach usable water sources.[199] Tribes are also given authority to specify and exempt aquifers or water-bearing rock strata from the "usable water" classification that triggers some of the heightened requirements for operators.[200] Finally, the revision includes a variance procedure whereby tribes could make Indian land exempt from parts of the federal rules, so

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193. *See* revised rules, *supra* note 6, at 24 (to be codified at 43 C.F.R. § 3162.3-3(b)) (adding a new paragraph on isolation of usable water).

194. *See id*. at 24–25 (to be codified at 43 C.F.R. § 3162.3-3(d)) (making the amendments and deletion). The period for reporting incidents of excessive annulus pressure has also been lengthened from 15 to 30 days. *See id*. at 28 (to be codified at 43 C.F.R. § 3162.3-3(g)(2)) (lengthening the reporting period).

195. *See id*. at 29 (to be codified at 43 C.F.R. § 3162.3-3(i)) (allowing for reporting directly to BLM or another database specified by the bureau in place of FracFocus); *id*. at 55 (to be codified at 43 C.F.R. § 3162.3-3(d)(5)) (eliminating the requirement operators provide the estimated chemical composition of flowback water).

196. *See id*. at 32 (to be codified at 43 C.F.R. § 3162.3(j)) (summarizing the affidavit procedure).

197. *See id*. at 27–28 (to be codified at 43 C.F.R. § 3162.3-3(e)(4)) (requiring reporting of inadequate cementing within 24 hours and certification that the job was corrected at least 72 hours before fracturing commences).

198. *See id*. at 26–27 (to be codified at 43 C.F.R. § 3162.3-3(e)(2) (imposing the requirement and listing permissible CELs).

199. *See id*. at 25–26, 31 (to be codified at 43 C.F.R. §§ 3162.3-3(d)–(e), 3162.3-3(i)(7)) (requiring operators to provide more detailed mapping of fracture direction and propagation, conduct continuous monitoring of cementing and report within 30 days of the end of fracturing operations, and include cementing monitoring and CELs in the certification of wellbore integrity).

200. *See id*. at 18, 49-50 (to be codified at 43 C.F.R. § 3162.3-3(b)) (allowing tribes to designate water-bearing zones as exempt from any protective requirements that would otherwise be imposed on operators).

long as the variance is sufficiently protective to "meet or exceed the effectiveness of the rule provision it replaces."[201]

Although the proposed regulations would bring the federal rules up to speed with their state counterparts, they pose a variety of potential problems for tribes. For those tribes interested in development of their energy resources, new and more stringent federal regulations raise the danger of rendering oil and gas extraction in parts of Indian country uneconomical through delays and increased costs.[202] The extent to which those delays will be significant is in dispute: BLM has asserted that preapproval for hydraulic fracturing could be included in the existing permitting process without a significant increase in processing time,[203] while tribal parties have projected that the regulations could delay approval by several months at the busiest field offices.[204] Probable costs are similarly disputed: BLM estimates that implementation of the new rules would cost, in the most expensive scenario, about $44 million annually, but could save upwards of $50 million annually in remediation costs;[205] while CERT posits

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201. *Id*. at 33.

202. *See*, *e.g.*, Groen testimony, *supra* note 176, at 3 (arguing that federal compliance for extraction on Indian land already involves substantial obstacles, and that a new rule will result in "additional and extraordinary delays" in the approval of tribal projects); Hall testimony, *supra* note 3, at 9–10 (noting that approval of oil and gas permits on Indian land may take up to twenty times longer than elsewhere and already involves substantial environmental review, and that additional burdens will negatively impact tribal revenue); Show testimony, *supra* note 176, at 4 (noting that permit applications on the Blackfeet reservation may take up to eighteen months, and could be further delayed by the BLM standards, which leave too much discretion to local officials and require too extensive chemical disclosure to practically implement).

203. *See* 77 Fed. Reg. 27695 (May 11, 2012) ("The BLM understands the time sensitive nature of oil and gas drilling and well completion activities and does not anticipate that the submittal of additional well stimulation-related information with APD applications will impact the timing of the approval of drilling permits.").

204. *See* CERT comment, *supra* note 10, at 8–9, 13 (interpreting the proposed rule to require preapproval of acid job stimulation, increasing the number of approvals required by fifty percent, and producing an eight-month delay in the Vernal, Utah field office's 484-day turnaround time for Indian mineral approvals). CERT notes that delays could cost operators upwards of $25 thousand per day in rental fees for rigs and drilling equipment. *See id*. at 10–11 (noting that operators pay $25–30,000/day in rental fees even during delay downtime). It is worth noting that in the revised rules, BLM concedes that "some delays may be inevitable," particularly at high-volume offices, but argues that the streamlining amendments and the availability of remote assistance from other offices will limit such delays. Revised rules, *supra* note 6, at 40.

205. *See* 77 Fed. Reg. 27701, table 3 (May 11, 2012) (projecting a $44.18 million annualized cost at a three percent discount rate and a high estimated number of well stimulations, but a $50.27 million social benefit where environmental risk and remediation costs are high). Most of the projected social benefit arises from the requirement that operators line open storage pits, as social benefit drops by about $41 million in the alternative scenario where no pit liners are required; but as BLM points out, the projection does not account for certain benefits that are difficult to quantify, including the public

that these estimates overlook various annual compliance costs on operators in Indian country, including $1.3 million paid to technicians to provide detailed well designs and $41.2 million for longer casing to comply with the usable water protection requirements, as well as the administrative costs to BLM of application processing, and the costs to tribes from depressed drilling demand and diminished royalties.[206] Review of regulatory requirements for pre-fracturing approval will also impose administrative costs on tribes and the Bureau of Indian Affairs.[207]

Of more serious concern is the effect of more stringent regulations on tribes interested in resource development. Under the original proposed rule, as a precondition of permit approval, operators would have been required to submit "[a] certification . . . that the proposed treatment fluid complies with . . . all applicable Federal, tribal, state, and local laws, rules, and regulations" to BLM.[208] BLM purported to apply this regulation to all wells it administers, "including those on Federal, tribal, and individual Indian trust lands,"[209] and initially expressed its intention to "implement on public lands whichever rules, state or Federal, are most protective of Federal lands and resources and the environment."[210] Although this language was susceptible to multiple interpretations, in the context of the rest of the rule, it appeared that BLM intended to apply, for the sake of

benefits of chemical disclosure and "such benefits as avoiding harm to water users that cannot be compensated by later providing alternative water sources." *Id*. at 27700–02.

206. *See* CERT comment, *supra* note 10, at 10–14 (discussing the various expected costs resulting from the regulations, amounting to $48.9 million annually for operators on Indian land alone). It appears likely that many of CERT's cost estimates, while not unfounded, are overly generous, anticipating costs that either are already incurred to comply with other regulatory requirements or would be incurred by an operator following the industry's own best practices. *See* Onshore Oil and Gas Order No. 2, *supra* note 152, 53 Fed. Reg. 46,808 (requiring, since 1988, that casing and cementing be adequate "to protect and/or isolate all usable water zones"); API, Guidance Document HF1, at 20–22 (establishing that "sophisticated software should be used to design hydraulic fracture treatments prior to their execution," while pressure should be monitored for the duration of a stimulation and mechanical integrity monitored during the life of a well); *id*. at 8–10 (noting that well logs are "critical data gathering tools" and that cement bond logs are "the most common type of cement evaluation tool that is used"); *id*. at 15 (noting that when a fracturing treatment is designed, "[p]retreatment quality control and testing is carried out in order to ensure a high-quality outcome"); API, Guidance Document HF2, at 7 (describing the various additives that may be included in fracturing fluid, a "carefully formulated product" that service providers must design and compose for specific purposes in each operation); *id*. at 17–18 (suggesting that fracking fluids and flowback water be stored in "tanks or lined pits."). This makes it more likely that BLM is correct in its assertion that the new regulations will impose a cost of about $11,833 per well, or 0.3% of the total cost of drilling, and therefore will be "unlikely to have an effect on the investment decisions of firms . . . ." 77 Fed. Reg. 27702–03.

207. *See* CERT comment, *supra* note 10, at 10–11 (discussing tribal and BIA review).

208. 77 Fed. Reg. 27710 (to be codified at 43 C.F.R. § 3162.3-3(c)(4)).

209. *Id*. at 27693.

210. *Id*. at 27694.

uniformity, the most restrictive rule in a jurisdiction to a proposed well under its management.[211] In certain contexts, this approach could be beneficial: by incorporating tribal law and regulation into the federal permit approval rules, it would ensure compliance with tribal rules, where they are more restrictive than federal law; thus, when a tribe like the Turtle Mountain Band decides to prohibit hydraulic fracturing entirely, the federal rule would appear to operate to effectively apply the tribal regulation to operations on federal and fee land, even if its independent applicability would otherwise be in dispute.

The trouble would have arisen in the inverse scenario, where federal or state law would be incorporated into federal permitting requirements so as to impose *more* stringent effective requirements on tribal or individual Indian land under federal management, thus placing a greater burden on operators than tribes would on their own. BLM has, correctly, mooted this concern by eliminating the offending certification language and making clear that it does not intend to apply state or local laws to Indian land.[212] Because tribal sovereignty would typically prevent the operation of state law and regulation regarding such matters on Indian land,[213] the original language could have had a deleterious and undesirable effect on tribal sovereignty, contrary to national policy.[214] To the extent that policy entails giving tribal governments a free hand to "make their own laws and

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211. *See id*. at 27692 ("The BLM proposes to apply the same rules and standards to Indian lands so that these lands and communities receive the same level of protection provided for public lands.") Thus, although BLM clearly recognizes that Indian and public lands are two separate categories, it nevertheless seemed to propose applying uniform regulations to both. *But see* CERT comment, *supra* note 9, at 4 (arguing that because FLPMA excludes Indian and Native Alaskan trust land from its definition of "public lands," BLM lacks all regulatory authority therein); *Bureau of Land Management's Hydraulic Fracturing Rule's Impacts on Indian Tribal Energy Development: Hearing Before the Subcomm. on Indian and Alaska Native Affairs*, 112th Cong. (2012) (statement of Scott Russell, Secretary, Crow Tribe) (arguing that by imposing regulation, "BLM continues to treat tribal lands like public land"); *Bureau of Land Management's Hydraulic Fracturing Rule's Impacts on Indian Tribal Energy Development: Hearing Before the Subcomm. on Indian and Alaska Native Affairs*, 112th Cong. (2012) (statement of the Hon. Don Young, Chairman) ("It is a rule that wrongly treats land held in trust for the *exclusive use and benefit* of Indians as *public* land.").

212. *See* revised rules, *supra* note 6, at 25, 90–91 (creating separate certification clauses for certification on federal and tribal land, and specifying that "the revision is to clarify that this part does not apply State or local law to Indian lands.").

213. *See supra* notes 129–37 and accompanying text (discussing the jurisdictional division between tribal and state governments).

214. *See* COHEN, *supra* note 64, § 1.07, at 93–107 (discussing the trend of federal policy since the late 1950s toward strengthening of the government-to-government relationship with tribes and greater deference to tribal decisionmaking); Memorandum of Nov. 5, 2009, Tribal Consultation, 74 Fed. Reg. 57,881 (directing executive agencies to collaborate and consult with tribes on federal policies affect tribes, in order to strengthen the government-to-government relationship).

be governed by them,"[215] application of state law to tribes would be inconsistent with it; BLM was thus correct to heed commenters' requests for clarification, and reject the interpretation that would have allowed imposition of state law through the certification requirement.[216]

But even with this correction, the revised rule risks creating a competitive disadvantage for tribes. Even if state law is more stringent than federal or tribal rules, tribes would remain subject to the more complicated permitting regime surrounding federally-managed wells and Indian trust land, limiting their ability to compete effectively.[217] Alternatively, if federal law is more stringent, states would enjoy a competitive advantage by operation of law: the federal rules would not apply to land outside BLM's asserted authority—"the public mineral estate (including split estate where the Federal Government owns the subsurface mineral estate)" and Indian land subjected to the federal rules—leaving only the relaxed state standards to govern such land, and making it more attractive to developers than Indian land.[218] Although the former, rather than the latter, scenario appears to be applicable to tribes in the Williston basin—the rules in Montana and North Dakota apparently being more stringent than the federal regulations on most points[219]—either situation risks predisposing operators to look to private land, state land, or federal public land (i.e. federal jurisdiction outside Indian country) before seeking to develop tribal or Indian trust land.[220]

Although BLM's revision has reduced the competitive disadvantage by not subjecting tribes to both the cumbersome federal permitting procedure *and* more stringent state law, tribes are still left with the problem of cases where the federal rule is more restrictive than state rules, which could be solved by suspending its operation on tribal or tribal trust land, in which case BLM would defer to tribal regulation and/or allow tribes to opt into the federal regulations. Yet BLM has—needlessly—rejected this option as inconsistent with applicable law.[221] The bureau points to the Indian Mineral Leasing Act's authorization provision, which subjects mineral leases on Indian land to "the rules and regulations

215. Williams v. Lee, 358 U.S. 217, 220 (1959).

216. *See* CERT comment, *supra* note 9, at 5–7 (calling on BLM to clarify its treatment of its authority to implement state law on Indian land and its interpretation of whether state law is "applicable" under the terms of the regulation).

217. *See* CERT comment, *supra* note 10, at 8 (discussing current delays in federal permitting on Indian land).

218. 77 Fed. Reg. 27,692 (May 11, 2012).

219. *See supra* notes 179–91 (comparing the proposed federal rules with Montana and North Dakota state regulation).

220. *See* CERT comment, *supra* note 10, at 7 (discussing the economic factors leading operators to look outside Indian country for development opportunities).

221. *See* revised rules, *supra* note 6, at 17 (discussing commenter proposals for a tribal exemption or an opt-out provision in the regulations).

promulgated by the Secretary of the Interior."[222] The bureau takes the authorization to mean that, because Interior "has consistently interpreted this statutory directive as *allowing* uniform regulations," it would be inconsistent with Interior procedures to create a tribal exemption.[223]

Leaving aside the initial problem that the Department's *permissive* authorization of uniform regulations is not the same as a *mandate* of such regulations, there is nothing in the statutory language indicating that "the rules and regulations promulgated by the Secretary of the Interior" must treat tribal land identically to federal land.[224] It makes more sense to read this provision as merely placing Indian mineral leases under the Department's rulemaking authority in the broadest terms, particularly as the line immediately following gives the Secretary full discretion to subject Indian mineral leases to "any reasonable . . . plan approved or prescribed by said Secretary" before the lease is issued.[225] To the extent that the IMLA was concerned with regulatory uniformity, its focus was correcting the "haphazard" complex of legislation that had previously governed Indian mineral leasing up to that point; it sought uniformity in the regulations governing *Indian* mineral development, not *all* mineral development.[226] The IMLA was a response to the passage of the Indian Reorganization Act, which was itself focused on expanding tribal sovereignty, and merely authorized the Secretary to promulgate "rules and regulations under which the [Indian mineral leasing] program would operate."[227]

Given the weakness of BLM's statutory basis for rejecting a tribal exemption from the new rules, and the policy of tribal self-determination that has only grown stronger in modern times, BLM should recognize that federal regulation must yield to tribal policy on this question. Such an approach would maintain the status quo of allowing tribes to resolve,

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222. Revised rules, *supra* note 6, at 17 (citing 25 U.S.C. § 396d (2012)).
223. Revised rules, *supra* note 6, at 17 (emphasis added).
224. 25 U.S.C. § 396d (2012).
225. *Id*. BLM cites no authority for its counterintuitive reading of the plain language of the statute; and to the extent that courts have addressed the Department's ability to delegate authority to or create an exemption for tribes, their decisions provide only weak support, at best, for BLM's interpretation. *See* Assiniboine & Sioux Tribes of the Fort Peck Indian Reservation v. Bd. of Oil & Gas Conservation of Montana, 792 F.2d 782, 795-96 (9th Cir. 1986) (questioning BLM's delegation of authority to state agency, given statute's silence on subdelegation, but noting that delegations to tribes would differ because tribes have independent jurisdiction, the statute's purpose was increasing Indian leasing authority and economic returns, and statutes are to be broadly construed in Indians' favor); Kenai Oil & Gas, Inc. v. Dep't of Interior, 671 F.2d 383, (10th Cir. 1982) (noting that the Secretary's authority under § 396d is broadly construed but conditioned by the government's trust responsibility, which requires profitable management and imposes a duty to maximize revenues).
226. Peter F. Carroll, *The Dawning of a New Era: Tribal Self-Determination in Indian Mineral Production*, 9 PUB. LAND L. REV. 81, 85–86 (1988).
227. *Id*.

through their own political processes, how they intend to treat hydraulic fracturing on their land.[228] It is those decisions—as well as potential and proposed future options for tribes, tribal members, and reservation residents—to which this note now turns.

V. Regulations and Remedies: Tribal and Individual Influence of Fracking

Up to this point, this note has primarily considered oil and gas development or restriction thereof from the perspective of tribal governments; however, given potentially localized effects of fracking operations,[229] in some circumstances the priorities of tribal governments may diverge from those of non-Indian reservation residents,[230] as well as individual tribal members.[231] As such, it is necessary to consider not only tribes' approaches to regulating hydraulic fracturing, but also the remedies available to affected individuals.

A number of factors—significantly, the historical primacy of the federal government in managing Indian resources, and the lack of institutional and regulatory capacity in tribal governments—have hindered tribes' abilities to comprehensively manage their natural resources and administer regimes of environmental regulation.[232] In the area of the Williston basin, a number of tribes have enacted general environmental codes;[233] of those tribes, the Three Affiliated Tribes at Fort Berthold and the Fort Peck Tribes—where most development and hydraulic fracturing has

228. *See supra* notes 3–4 and accompanying text (discussing the divergence of tribal opinion on fracturing, from enthusiastic development to complete prohibition).

229. *See*, *e.g.*, Osborn, *supra* note 44, at 8173 (finding a correlation between proximity to hydraulically fractured active gas wells and methane concentrations in drinking water).

230. *See* COHEN, *supra* note 64, § 18.06, at 1185 ("[M]any non-Indians own fee land within reservation boundaries . . . ."); *cf.* Knight v. Shoshone and Arapahoe Indian Tribes of Wind River Reservation, 670 F.2d 900 (10th Cir. 1982) (affirming partial summary judgment in tribe's favor where it sued to enjoin non-Indian fee landowners' development of property, contrary to tribal zoning ordinance).

231. *Cf.* Dine Citizens Against Ruining Our Env't v. Klein, 439 Fed. App'x. 679 (10th Cir. 2011) (dismissing, for lack of jurisdiction, Navajo nonprofit's challenge of Interior agency's issuance of permit to company who leased mine from Navajo Nation).

232. See MAURA GROGAN, NATIVE AMERICAN LANDS AND NATURAL RESOURCE DEVELOPMENT 42–46 (2011) (discussing tribal challenges in shifting away from federal resource management in the self-determination era); THE HARVARD PROJECT ON AMERICAN INDIAN ECONOMIC DEVELOPMENT, THE STATE OF THE NATIVE NATIONS 165 [hereinafter HARVARD PROJECT] (discussing concerns that tribes "lack the institutional and enforcement mechanisms" and the human capital to properly deal with energy developers); *id*. at 184–87 (surveying tribal experience with environmental regulation and their efforts to build institutional capacity).

233. *See* Fort Peck Tribes Comprehensive Code of Justice, Title XXII [hereinafter CCOJ] ("Protection of the Environment"); Standing Rock Sioux Code, Title 29 ("Environmental Code"); Three Affiliated Tribes of the Fort Berthold Reservation Tribal Code, Title 15 ("Environmental Code").

been concentrated—have adopted regulations for oil and gas development, with implications for hydraulic fracturing.[234]

The explosion in exploration and extraction on the Fort Berthold reservation and in the surrounding area made a legislative response by the tribe urgently necessary.[235] The reservation's size and location has meant that, unlike the state of North Dakota, resource development (and the negative externalities associated with boomtowns and inadequate infrastructure) has ubiquitous effects throughout the jurisdiction.[236] Those effects, in turn, can present acute difficulties because the Three Affiliated Tribes have—as do practically all other Native groups—unique legal ties, as well as social and cultural ones, to their reservation as a homeland.[237] Because of those unique circumstances, the tribe began taking a more active role in regional oil and gas development, entering into development agreements on more favorable terms with operators, engaging in its own operations, and seeking to construct its own refinery on the reservation.[238] In 2010, the tribe settled a longstanding dispute with the state over taxation of oil and gas production on the reservation, entering into a permanent agreement that settled applicable tax rates and division of revenues.[239] The agreement provided for an equal division of revenues from production on tribal trust lands, diversion of twenty percent of state taxes on non-trust reservation lands to the tribe, and a tribal assessment of $100,000 in fees for each new well drilled on trust land.[240]

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234. *See* CCOJ Title XXII, Ch. 2 ("Underground Injection Control"); Three Affiliated Tribes Tribal Code tit. 15, ch. 15.1 ("Solid and Hazardous Waste Management and Remediation Code").

235. *See* Raymond Cross, *Development's Victim or its Beneficiary?: The Impact of Oil and Gas Development on the Fort Berthold Reservation*, 87 N.D. L. REV. (2011) 535, 537–38 (noting that the new hydraulic fracking and horizontal drilling technologies, in opening the Bakken formation to drilling, placed the Fort Berthold reservation at the center of the largest oil reserve in the continental United States).

236. *See id*. at 538–43 (comparing North Dakota's development approach of providing encouragement to developers and funding for improved infrastructure to Fort Berthold, where small land area results in a "disproportionate environmental burden" on a vulnerable population). *But see* Hall testimony, *supra* note 3, at 8–9 (noting that although the tribe "cannot just pick up and move to another reservation if our lands or waters are spoiled," energy development has improved reservation conditions and the tribal economy).

237. *See* Cross, *supra* note 235, at 543–46 (discussing the tribes' treaty ties to Fort Berthold, legally a central aspect of tribal sovereignty, and the land's distinctive connection to tribal culture and religion); HARVARD PROJECT, *supra* note 232, at 106–07 ("Land holds a special significance to Native nations that . . . goes far beyond the need to provide areas for tribal housing, community institutions, and business ventures.").

238. *See* Cross, *supra* note 235, at 552 (describing the tribe's shifting position).

239. *See* James MacPherson, *North Dakota, Three Affiliated Tribes Garner Millions of Dollars From Oil Tax Accord*, MINNEAPOLIS STAR–TRIBUNE, Jan. 15, 2010 (discussing the agreement, which made indefinite a prior temporary accord with the state).

240. *See* Oil and Gas Tax Agreement Between The Three Affiliated Tribes And State of North Dakota §§ D–F (Jan. 13, 2010), *available at*

Yet oil and gas development also resulted in the improper disposal and discharge on the reservation of wastes associated with drilling and exploration, for which the tribe had established no regulations as late as 2011.[241] In response, the tribe adopted interim regulations in July 2011 "governing the disposal of waste associated with the exploration and production of oil and gas on the Fort Berthold Reservation."[242] The tribe based its authority for the regulations on its inherent power, recognized in *Montana v. United States*.[243]

Under the interim regulations, the tribe prohibited disposal of waste "associated with the exploration or production of oil and gas on any lands" within the reservation boundaries, except at an "authorized facility," so defined to require prior approval by the tribal council of the facility for disposal.[244] The regulations took a broad view of the kinds of activities that could constitute "disposal" and were thus subject to the regulation, including any "discharge"—accidental or intentional "spilling, leaking, pumping . . . [and] injecting"—as well as any deposit or placement "into or on any soil, air or water."[245] Concurrent enforcement authority was given to six tribal agencies: the Energy Department, Environmental Department, Game and Fish Department, Tribal Employment Rights Office (TERO), Fire Management Department, and tribal law enforcement.[246] The TERO was given additional authority to audit the records of companies conducting oilfield waste disposal operations in order to ensure compliance with the rules.[247] The tribal court was given jurisdiction over complaints and appeals

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http://www.nd.gov/tax/oilgas/threeatribes/pubs/oilgastaxagreement.pdf?201303151452 23 (memorializing the state-tribal agreement).

241. *See* Tribal Bus. Council Res. 11-75-VJB, at 1 (2011) (noting that companies engaged in oil production on the reservation have begun improperly disposing of wastes, for which the tribe had no legal framework in place prior to the resolution's passage on July 14).

242. *Id*.

243. *See id*. at 2 (reciting the *Montana* standard).

244. *Id*. at 2–3.

245. *Id*. at 2. The interim rule, though evidently broad, was not consistent in its terminology, as the definition for "discharge" and the prohibition clause referred to "waste," and the definition for "disposal" referred specifically to "solid or hazardous waste," whereas the interim regulation defined "hazardous substance" (not hazardous waste) as any substance, the improper management of which "may pose a substantial present or future hazard to human health or the environment . . . ." *Id*. at 2–3. This discrepancy was probably more formal than functional for present purposes, as the undesirable byproducts of hydraulic fracturing would probably qualify under any of the applicable terminology. *Cf. supra* note 41 (discussing various hazardous substances commonly found in fracturing fluid); *supra* note 111 (discussing the definition of "hazardous substance" in the Montana rules on oil and gas production).

246. *See id*. at 3 (providing "joint responsibility" for enforcement to the six agencies).

247. *See id*. (providing for 24 hours' notice prior to a compliance audit, except in cases where the tribe was notified of a willful violation, in which case the audit is to be conducted immediately).

from citations.[248]

The interim regulation also provided substantial civil penalties for violations, categorized based on whether they were willful or merely negligent.[249] Negligent violations were subject to a $5,000 fine for the first offense, which doubled for the second violation and increased to $50,000 for each offense thereafter.[250] Willful violations are treated more severely, with a $10,000 fine levied for the first offense, which increases to $25,000 for the second offense and $1,000,000 for each willful offense thereafter.[251] Violators are also made liable for the costs of remediation needed to prevent environmental damage or risk to public health.[252] Repeated violations, failure to pay a fine, or failure to fulfill a remediation obligation is made grounds for suspension or revocation of an individual or company's TERO license.[253]

Many of these requirements were ultimately incorporated into the permanent version of the tribe's Solid and Hazardous Waste Management and Remediation Code, which went into effect in October 2011.[254] Although the permanent chapter has a much broader scope than the interim regulations, it was enacted in large part with oil and gas development in mind, the Tribal Council recognizing the "increasing volume and variety of solid and hazardous waste being generated on the reservation" and the need for appropriate "utilization of natural resources of oil and gas . . . while minimizing any adverse impacts to public health or the environment."[255]

The regulations adopt substantially the same definitions for approved disposal sites, "discharge," and "disposal" as in the interim regulations.[256] However, they create a much clearer status for the byproducts of hydraulic fracturing, and oil and gas production generally, by placing most of these under the specified category of "industrial wastes."[257]

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248. *See id*. (establishing tribal court jurisdiction).
249. *See id*. (establishing the schedule of fines).
250. *See id*. (establishing the schedule of fines).
251. *See id*. (establishing the schedule of fines).
252. *See id*. at 4 (imposing the remediation requirement).
253. *See id*. at 4 (authorizing suspension or revocation of the TERO license). A TERO license, under which employers are required to offer employment or contracting preference to tribal members, is mandatory under tribal law to conduct business on the reservation. *See* Three Affiliated Tribes of the Fort Berthold Reservation, Mandan Hidatsa and Arikara Nation Indian Employment Rights and Contract Preference Ordinance, Titles II, VII, *available at* http://mhatero.com/attachment/cms/AXT_3_IL6J.pdf (outlining the employment preference and providing for fines or denial of rights to conduct business for noncompliance).
254. *See* Three Affiliated Tribes Tribal Code tit. 15, ch. 15.1, at 1 (stating that the chapter was passed by the Tribal Business Council on Oct. 20, 2011).
255. *Id*. §§ 1.04.2–1.04.3.
256. *See id*. § 2.01 (defining terms).
257. *See id*. § 8.02.14 (classifying "[o]il and gas exploration and production wastes, to include petroleum or crude-oil contaminated soils" as industrial waste, and thereby subject

Industrial waste may not be stored or disposed of within the reservation boundaries except at a facility specifically authorized and permitted by the Environmental Division (ED).[258]

The terms of the rules are sufficiently broad to encompass fracturing fluid and flowback water in the scope of their regulation.[259] The rules would also capture any storage of fracturing fluid or flowback water in a surface pit or tank and treat such storage as solid waste management.[260] This would appear to mean that, as a general matter, such storage would be subject to the permitting requirements for solid waste management facilities;[261] however, the rules make specific provision for permits for oil and gas waste "accumulated, stored, or treated at the point of generation."[262] Such facilities are governed by the regulations' requirements for permits by rule, instead of the general permitting requirements.[263]

Under those requirements, operators must give the ED ten days' notice before beginning to generate waste, are limited to 180 days of waste management, and must conduct accumulation and storage in such a way as

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to specific compliance requirements). Hydrogen sulfide releases from production facilities are also treated as industrial waste. *See id*. § 8.02.16 (classifying hydrogen sulfide releases). "Industrial waste" is itself defined to include "residues or spills of any industrial or manufacturing process and waste resulting from . . . petroleum refining; oil and gas exploration and extraction; [and] other mineral extraction . . . ." *See id*. § 2.01 (defining "industrial waste").

258. *See id*. § 8.02 (discussing generally the management of special and industrial wastes). For the purposes of this discussion, and because the rules' treatment of oil and gas waste appears to so indicate, oil and gas waste is presumed not to be a "hazardous substance," in which case disposal within the reservation boundaries would be totally prohibited. *See id*. § 6.02 (enacting the prohibition); *id.* § 2.01 (defining "hazardous substance" by reference to the designations in CERCLA, the Clean Water Act, the Solid Waste Disposal Act, the Clean Air Act, or an EPA Administrator designation pursuant to the Toxic Substances Control Act).

259. *See id*. § 2.01 (defining "solid waste" to include "liquid . . . resulting from industrial, commercial, mining, oil and gas development and production").

260. *See id*. (defining "storage" broadly to include any "confining, containing, [or] holding . . . of solid waste for a limited period of time prior to" treatment or ultimate disposal); *id*. (defining "surface impoundment" to include liquid-bearing depressions used for containment or disposal, including holding, storage, settling, and aeration pits, ponds, and lagoons."); *id*. (defining "facility" to mean land, structures, and improvements involved in solid waste management, including surface impoundments).

261. *See id*. § 13.01(b) (requiring a general permit for solid waste disposal, collection, or transfer); *id*. § 14.05 (outlining the application requirements for management facilities at which solid waste is to be stored, collected, treated, or otherwise managed).

262. *Id*. § 13.03.7.

263. *See id*. § 8.02.14 (providing that oil and gas waste is to be treated as industrial waste and subject to compliance with Section 13's permit-by-rule requirements); *id*. § 13.03 (providing that permits by rule entail permission constructively issued without formal application, so long as the operator gives the ED timely notice, pays applicable fees, and remains in compliance with applicable rules).

to create no public nuisance or hazard.[264] Public access to the waste management units must be controlled, but the Environment Division director or a designee must be able to access the units at all times, and a sign must be posted identifying the date accumulation began.[265] Perhaps most significant, the rules require that the waste management unit be "bermed, lined and covered with an impermeable material which has a nominal thickness of 6 millimeters, at a minimum," and must also be covered if runoff from the unit is not controlled or a complaint about the unit's odor has been made.[266] The length of time during which a permit by rule shall be valid is left to the discretion of the Environment Division.[267] Permits by rule may be modified or suspended by the ED Director, based on the terms of the permit, and are subject to review and public comment at any time.[268] Permitees by rule are required to submit any permits or leases issued for operation of the facility, as well as documentation that these fulfill other tribal licensing requirements and that applicable fees have been paid, as well as any other forms or fees required by the ED.[269]

Presumably, waste that is not stored at the generation site is subject to the general requirements for waste management facilities.[270] These rules are somewhat more rigorous than for permits by rule, as prior application and approval pursuant to Section 14 is required.[271] Applicants must provide a description of the facilities and equipment to be used for storage, an evaluation of the geology and hydrology of the site, a statement of land uses on adjoining property, procedures in place to avoid leaks and spills, a description of programs used to train employees in proper management, plans for closure and post-closure maintenance of the facility, and other information deemed "necessary" by the ED or Natural Resources Committee.[272] These permits may be valid for up to five years.[273]

Both permits by rule and solid waste management facility permits depend on the ED's determination that "primary consideration is given to preventing environmental damage or health threats" and that long-term protection thereof has been the "guiding criterion."[274] To achieve these

264. *See id*. § 13.03.7–13.03.7.1 (outlining the requirements).
265. *See id*. § 13.03.7.2–13.03.7.3, 13.03.7.5 (outlining the requirements).
266. *Id*. § 13.04.7.4.
267. *See id*. § 15.03.3 ("Permit-by-Rule may be issued for a range of time periods to be determined by the TAT ED").
268. *See id*. § 15.21 (providing regulations specific to permits by rule).
269. *See id*. § 14.03 (outlining the permit application requirements).
270. *See supra* notes 259–62 and accompanying text (analyzing the general requirements and the carve-out for onsite storage).
271. *See* Three Affiliated Tribes Tribal Code tit. 15, ch. 15.1, § 13.01 (requiring permits for solid waste collection facilities, to be obtained by application pursuant to Section 14).
272. *See id*. § 14.05 (outlining the permit application requirements).
273. *See id*. § 15.03.1 (stating length of permit validity).
274. *Id*. §15.01.

purposes, the Director is authorized to prohibit or place conditions on further waste handling, for the sake of environmental quality; to require compliance by the applicant facility; and to place conditions on the permit, including the implementation of mitigation measures and contingency plans to minimize damage from waste handling.[275] The Director or a designee is entitled to inspect "any permitted premises" during regular operating hours or upon two hours' notice.[276] The rules expressly authorize denial of a permit in cases where the proposed method of waste handling poses a hazard to the environment, public health, or welfare or natural resources of the tribe; or where the applicant reasonably appears unlikely to comply with the tribal regulations, as because of a history of noncompliance with tribal or analogous state/federal regulations.[277]

If there is a violation, the Director is authorized to take informal action (if the violation does not pose an imminent risk and is non-repetitive); to issue a notice of violation summarizing the compliance issues, schedule of compliance, and potential penalties; and, if noncompliance continues, to issue orders to submit to fines or penalties, to cease and desist construction or operation, or to take remedial action.[278] Failure to comply with an administrative order and remedy a violation is declared grounds for suspension, modification, or revocation of a permit.[279] The Tribal Court is also authorized to issue injunctions and other relief as needed to secure compliance.[280]

Like the interim regulations, the permanent code also provides for civil penalties and liabilities, albeit with some alterations from the interim form.[281] The permanent regulations authorize the Director to impose civil penalties for unauthorized handling/disposal of waste on the reservation, noncompliant waste facilities, or violation of a statutory or administrative regulation.[282] Fines are assessed at a maximum rate of $25,000 per violation, per day that the violation continues, up to a per-incident maximum of $500,000 for negligent violations and $1,000,000 for willful

275. *See id*. § 15.01.1–15.01.5 (outlining the Director's permitting authority).
276. *See id*. § 15.07 (establishing this authority).
277. *See id*. § 15.11 *et seq*. (stating grounds for permit denial).
278. *See id*. § 17.04 *et seq*. (authorizing enforcement actions).
279. *See id*. § 17.08 (authorizing the Director to take such action).
280. *See id*. § 18.04 (establishing Tribal Court jurisdiction and authorization).
281. *Compare* Tribal Bus. Council Res. 11-75-VJB, at 3 (providing distinct schedules of fines for negligent and willful violations) *with* Three Affiliated Tribes Tribal Code tit. 15, ch. 15.1, § 18.01.1.1 (providing a single schedule of fines, but different penalty caps for negligent and willful violations).
282. *See* Three Affiliated Tribes Tribal Code tit. 15, ch. 15.1, § 18.01.1 (stating grounds for civil penalties).

violations.[283] A person may also be required to perform between eight and 200 hours of community service for a violation.[284] Notwithstanding imposition of administrative penalties, a violator may be liable for civil damages, if applicable; and may lose the right, temporarily or permanently, to continue engaging in activity on the reservation.[285] An operator may be required to perform mediation or to reimburse the tribe for the cost of remediation, if remediation is found to be necessary.[286] Finally, the regulations impose a notice requirement on operators if the release meets specified conditions.[287]

Admittedly, it cannot be seriously argued that these regulations are as rigorous as those present in the proposed federal fracking rules; they do not even begin to address substantive drilling requirements, such as those for wellbore integrity, or mandatory disclosure of chemicals used in the stimulation and extraction process.[288] In that sense, the rules take a conservative approach, and may not go as far as they should in the view of some observers.[289] Nevertheless, it rightly falls to tribes as a matter of self-determination to decide the extent to which the industry is to be regulated, just as it falls to tribes to determine the extent to which each tribe will pursue mineral development at all.[290] And as the prior assessment of the Three Affiliated Tribes' regulations demonstrates, tribes may reasonably choose to take a restrained approach while nevertheless enacting substantive restrictions on extractive industries, even if those restrictions are modest but credible back-end incentives to discourage environmentally

283. *See id*. § 18.01.1.1 (stating the schedule of fines, assessment of which requires the concurrence of the tribal Public Safety Commissioner, tribal CEO, Tribal Council, or Tribal Court).

284. *See id*. § 18.01.1.2 (establishing this as an alternative to monetary penalty).

285. *See id*. §§ 18.01.1.4–18.01.1.5 (imposing liability for civil damages and potential forfeit of rights to enter or conduct activity on the reservation).

286. *See id*. § 19.07 (authorizing required mediation and establishing reimbursement liability).

287. *See id*. § 19.13 *et seq*. (requiring notification of the tribal response program if a pollutant, contaminant, or hazardous substance is released that threatens health or the environment, is greater than 25 gallons, exceeds tribal or EPA water quality standards, is required by the Superfund amendments, or is otherwise required by the Director).

288. *See supra* notes 151–91 and accompanying text (making such provision in the current and proposed federal regulations).

289. *See* Cross, *supra* note 235, at 569 (arguing, in consideration of the interim regulations, that "the tribe may have to take further and more substantial regulatory steps if it wants to ensure that development is regulated in a legally and socially responsible manner . . .").

290. *See* Grogan, *supra* note 232, at 43 ("This is what tribal self-determination means: the power of individual Indian nations to make meaningful decisions that reflect their own priorities and values, and their own calculations about what best serves their long-term interests. Under conditions of self-determination, different nations may make different strategic choices.").

irresponsible behavior.[291]

The tribes at Fort Peck have similarly attempted to exercise some control over energy extraction on their reservation, but by assuming responsibility for underground injection control within their jurisdiction.[292] Briefly described, the Underground Injection Control Program was implemented in order to require states—or, in the absence of state primacy, the EPA Administrator—to promulgate permitting regulations for all underground injection wells, in order to "prevent underground injection which endangers drinking water sources . . . ."[293] The federal rules establish six categories of injection well, with Class II wells covering hydraulic fracturing for oil and gas extraction.[294] Congress added the option for Indian tribes to attain enforcement primacy in 1986,[295] and the Fort Peck tribes took over primacy for Class II wells on Nov. 26, 2008.[296] However, since 2005, hydraulic fracturing using fluids or proppants other than diesel fuels has been excluded from the scope of the UIC program.[297] This has meant that, at least within the context of hydraulic fracturing, the impact of the UIC program has been significantly curtailed.[298] It remains significant in the context of the Fort Peck reservation, however, which as of 2011 had 29 Class II wells within the reservation boundaries.[299]

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291. *See supra* notes 254–87 and accompanying text (outlining the tribal regulations).

292. *See* 40 C.F.R. § 147.3200 (establishing that the Assiniboine and Sioux Tribes at Fort Peck have assumed responsibility for administration of Class II wells within the reservation boundaries).

293. 42 U.S.C. § 300h(b)(1). *See also* 42 U.S.C. § 300h-1(c) (providing for EPA regulation in the absence of state primacy).

294. *See* 40 C.F.R. § 144.6 (establishing the six classifications); *id*. § 144.6(b)(2) ("*Class II*. Wells which inject fluids . . . [f]or enhanced recovery of oil and natural gas").

295. *See* Pub. L. No. 99-339, § 302(c), 100 Stat. 653, 666 (1986) (adding provision for primary enforcement responsibility by Indian tribes).

296. *See* 40 C.F.R. § 147.3200 (providing the effective date for the Assiniboine and Sioux program).

297. *See* 42 U.S.C. § 300h-1(d) (defining underground injection as excluding "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."); Pub. L. No. 109-58, § 322, 199 Stat. 694 (2005) (amending statute to include the current language).

298. *See* 77 Fed. Reg. 27,453 (May 20, 2012) ("[A] review of data available [through FracFocus] suggested that approximately 2% of wells that hydraulically fracture would be subject to SDWA UIC permitting requirements in states where EPA administers the UIC program.").

299. *See* EPA, UIC Inventory by Tribe—2011, at 3, *available at* http://water.epa.gov/type/groundwater/uic/upload/uicinventorybytribe2011.pdf (providing a list of tribes and the number of each class of well at each reservation). By way of comparison, Fort Berthold had only three Class II wells in 2011. *See id*. at 3 (listing tribes and well numbers). A search of FracFocus reveals only four wells in the database where fracking is known to have occurred, three of which used petroleum distillates in their fracking operations. *See* http://www.fracfocusdata.org/fracfocusfind/Map.aspx (providing access to information on API well numbers 25085218640000, 25085218210000,

The federal regulations impose fairly rigorous minimum standards for state regulations on permitting and conditions for operation. Permitting requires demonstration that casing and cementing is adequate for fluid containment, usually with a cement bond long; plans for plugging and abandonment, and a surety to guarantee completion; limitation on operating pressure, to ensure that no fluid enters drinking water supplies; mandatory monitoring and reporting; and mandatory mechanical integrity tests at least once every five years, failure of which triggers shutdown of operations.[300] For Class II wells specifically, a mechanical integrity test is required after every workover.[301] Injection pressure is not permitted to exceed "that which would initiate and/or propagate fractures in the confining zone adjacent to" a drinking water source.[302] Operators are required to test injection fluid to ensure compliance with permit parameters; to observe injection pressure, flow rate, and cumulative volume at least once monthly for enhanced recovery wells; and to submit an annual report of these observations.[303] A number of other reporting requirements are also imposed, including reporting before integrity tests, after workovers or temporary abandonments, before changes in ownership, and before plugging and abandonment.[304]

The Assiniboine and Sioux, in creating their own set of UIC regulations, have adopted many of the federal regulatory standards wholesale, by reference, but also included a number of original provisions, particularly for civil penalties and hearing procedures.[305] The regulations prohibit any underground injection or construction of a new well without a permit from the Fort Peck Office of Environmental Protection; in this way, they differ from the federal regulations, which would permit injection wells authorized by rule, without a new permit.[306] The tribes have also prohibited outright the operation of any Class I, III, or IV wells, which would include any wells injecting hazardous substances or nonhydrocarbon minerals

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25085218140000, and 25091219140000) (on file with the Washington and Lee Journal of Energy, Climate, and the Environment).

300. *See* EPA, Technical Program Overview: Underground Injection Control Regulations, at 65–66 (2001) (summarizing the regulatory requirements common to Class, I, II, and III wells).

301. *See id*. at 69 (discussing specifically Class II regulations).

302. *Id*.

303. *See id*. at 70 (discussing specifically Class II regulations).

304. *See id*. at 70 (discussing the reporting requirements for Class II wells).

305. *See generally* CCOJ, tit. XXII, ch. 2, §§ 200–81 (establishing the tribe's UIC regulations).

306. *Compare* CCOJ, tit. XXII, §§ 201, 211(c) (stating that injection wells without a permit are prohibited, and refusing to permit authorization by rule) *with* 40 C.F.R. §§ 144.22, 144.31(c)(1) (authorizing existing Class II permits by rule for the life of the well, and requiring applications within four years of promulgation of a UIC program).

mining.[307]

The tribal regulations adopt many of the federal general provisions by reference, including well classifications, provisions for confidentiality of submitted information, modes of identifying and exempting underground sources of drinking water, noncompliance reporting requirements, and prohibitions regarding Class II wells on the movement of fluid into drinking water sources.[308] Likewise, they adopt most of the federal permitting regulations, including those on area and emergency permits, permit duration and compliance effects, continuation, transfer, permit conditions, monitoring requirements, and corrective action.[309] The tribal regulations, however, set original requirements for operator requirements, monitoring, and notices. Permit applicants are required to include a surety bond, to report all owners of surface and mineral rights and operators of injection wells within ¼ mile of the applicant's well, and to perform a cement bond log if the well is a converted production well.[310] The tribal rules further require approval by the Office of Environmental Policy (OEP) Director before a permit may be transferred, performance of a cement bond long as a permit condition, and 24 hours' notice prior to the OEP before corrective action is taken.[311] Most notably, more stringent monitoring requirements are imposed: the rules require monitoring of injected fluids at least annually, as well as on any occasion where the source changes or the operator believes quality may have changed; recording of every observance of injection pressure, flow rate, and volume; and a daily record of volume, hours in service, maximum pressure, average pressure, and annulus pressure for produced fluid operations.[312] The tribal rules substantially assume the federal provisions for permit procedures, public comment, issuance, and state compliance evaluation programs.[313]

In regard to substantive technical requirements, the tribal rules adopt the federal technical criteria for Class II wells required of state enforcement programs, including those for exempted aquifers, mechanical integrity, plugging and abandonment, construction, operation, and monitoring.[314] But the tribe has also imposed additional substantive requirements of its own.[315] Operators are required to maintain gauges of

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307. *See* CCOJ, tit. XXII, § 204 (defining the well classes); § 211 ("Any underground injection into a Class I, III, or IV well is prohibited.").

308. *See id*. § 211(b) (adopting the CFR provisions on these points).

309. *See id*. § 221(b) (adopting the CFR provisions on these points).

310. *See id*. § 221(a) (imposing variations from the adopted federal regulations).

311. *See id*. § 221(b)(7), (8), (14) (imposing the requirements).

312. *See id*. § 221(b)(11) (imposing the requirements).

313. *See id*. §§ 231, 250 (adopting the CFR provisions on these points).

314. *See id*. § 241 (adopting the CFR provisions on these points). *See also supra* notes 176–79 and accompanying text (summarizing the federal provisions).

315. *See id*. § 242 ("Additional Requirements").

tubing and annulus pressure, and to notify the OEP whenever a well loses integrity or 24 hours before a workover.[316] Operators are also prohibited from commencing injection at any well until the OEP has approved of the submitted cement bond log.[317] Finally, annual inspections of temporarily abandoned wells are required, along with the requirement that owners and operators make a satisfactory showing that the well complies with the requirements for active wells and does not pose a risk to drinking water sources.[318]

In contrast to the other regulations, the tribe's enforcement provisions are almost entirely original, rather than incorporated by reference from the federal regulations with modification.[319] When a violation is discovered, the OEP may seek to obtain voluntary compliance through any appropriate means available.[320] The OEP is entitled to issue either a notice of the violation and a schedule of compliance requirements, or an administrative order imposing penalties and/or compliance requirements, subject to the opportunity for a hearing on the proposed order at which the alleged violator may contest the allegation or contents of the order.[321] The OEP is also authorized to subpoena alleged violators regarding the violation, or to seek criminal penalties or other judicial relief; and to seek civil penalties as an alternative to administrative order.[322] The Tribal Court is given authority, on application of the OEP, to compel compliance with a subpoena or testimony order, order payment of civil and administrative penalties, restrain or enjoin violations or behavior that endangers the environment or public health, and order compliance with a permit condition or well closure.[323]

Like the Three Affiliated Tribes' regulations, the Assiniboine and Sioux regulations entail substantial monetary penalties for violations of the injection requirements. Administrative penalties are to be assessed based on the seriousness of a violation, resulting economic benefits accruing to the operator, the operator's compliance history, good-faith efforts to comply, economic impact of the penalty, and "such other matters as justice may require."[324] Assessments must be between $1,000 and $5,000 per day of violation, with a maximum cumulative penalty of "$125,000 for all

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316. *See id*. § 242(a)–(b) (imposing the requirements).
317. *See id*. § 242(d) (imposing the requirement).
318. *See id*. § 242(c) (imposing the requirement).
319. *See generally id*. § 250–60 (establishing provisions for administrative enforcement, civil and criminal penalties, judicial relief, and appeals).
320. *See id*. § 251(h) (noting that OEP enforcement authority does not exclude option of soliciting voluntary compliance).
321. *See id*. § 251(a)–(d) (outlining OEP authority in regard to violations).
322. *See id*. § 251(f) (outlining courses of action in addition to or as alternatives from an administrative order).
323. *See id*. §§ 251(g), 255(a) (outlining Tribal Court authority).
324. *Id*. § 252(b).

violations."[325] Civil penalties may result from failure to comply with permit conditions or well regulations, and may be assessed at a rate between $1,000 and $25,000 per violation, per day.[326] Non-Indian violators may be precluded from conducting business on the reservation, at the OEP's discretion.[327] Yet the rule goes beyond monetary penalties, declaring each day of violation by an Indian violator to be a Class A misdemeanor, thus punishable by a maximum $500 fine or three months' imprisonment, and authorizes the OEP to refer violations by non-Indian violators to the EPA for appropriate criminal enforcement.[328]

Although the applicability of these rules in the context of hydraulic fracturing is necessarily limited in scope by the jurisdictional limitations of the SDWA,[329] they nevertheless demonstrate the fact that tribes can make and execute regulatory determinations to the extent they consider necessary.[330] But notwithstanding the importance of tribal regulation and policy judgments about how to treat and deal with energy resource development, tribal oversight may not be enough: tribal jurisdiction only extends so far, and where tribal government priorities are inconsistent with those of states or reservation residents, it may be necessary to look to other sources of protection.

For individuals, the obvious (and perhaps only) mode of recourse other than government regulation is judicial remedy; yet so far, the claims of plaintiffs who have alleged environmental damage from hydraulic fracturing operations have had a dismal track record, principally because of the difficulty of proving causation.[331] To the extent that cases have

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325. *Id*. § 252(a).

326. *See id*. § 253(a) ("[Compliance failure authorizes] civil penalties of at least $1,000 but not more than $25,000 per day. The maximum civil penalty shall be assessable for each instance of violation and if the violation is continuous, shall be assessable up to the maximum for each day of violation.").

327. *See id*. § 253(b) (authorizing the OEP to set a period of time during which the non-Indian violator's privilege of conducting business on the reservation is suspended).

328. *See id*. § 254(a)–(b) (outlining criminal penalties for Indian and non-Indian violators); CCOJ tit. VII, § 501(2) (establishing the penalty for a Class A misdemeanor). As a general matter, tribes lack criminal jurisdiction over non-Indians, and have jurisdiction over member and nonmember Indians only to the extent not limited by federal law. *See* COHEN, *supra* note 64, § 9.04, at 765–69 (discussing jurisprudential limitations on tribal criminal jurisdiction over non-Indians and federal statutory schemes creating federal jurisdiction for crimes involving only Indian parties); 25 U.S.C. §§ 1302(a)(7), 1302(b) (limiting tribes' authority to impose fines and terms of imprisonment in criminal cases).

329. *See supra* note 293 and accompanying text (excluding hydraulic fracturing not involving diesel fuels).

330. *See* Grogan, *supra* note 232, at 45–46 (arguing that tribes must build their own management capacities and that "the best way for the government to honor its trust obligations is to stop trying to determine what is in the best interest of tribes and instead support tribal efforts to make that decision autonomously.").

331. *See* King et al., *supra* note 26, at 344 ("To date, not one landowner's claim has succeeded, and at least two cases were voluntarily dismissed when the plaintiffs realized

concerned the stimulation and extraction operation itself, rather than a collateral part of the development process or legal issue,[332] they have most typically relied on either common-law causes of action in tort, breaches of contract, or fraud.[333] Courts have left open the possibility that, at least as a matter of law, fracturing itself could constitute a nuisance or trespass, with at least one court determining that the related activity of underground wastewater injection can constitute a nuisance by creating solely subsurface pollution.[334] Courts have also refused, when hydraulic fracturing specifically is at issue, to dismiss plaintiffs' claims when they brought strict liability, medical monitoring, and nuisance claims against an operator whose allegedly faulty well casing resulted in pollution.[335] A plaintiff may also have a viable cause of action for breach of contract, if the plaintiff has a surface or mineral estate lease with the defendant that includes covenants on water quality testing or condition of the land; or fraud, if a plaintiff can establish harm from "justifiable reliance on a misrepresentation or omission" regarding the risks of fracturing.[336]

Despite these as-yet hypothetical modes of recovery, no hydraulic fracturing case has been decided in a plaintiff's favor, and hence, there has been no finding of causality between hydraulic fracturing and an alleged harm; those cases that are not still ongoing have either been dismissed or

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they could not produce any evidence of causation."). It should be noted that, despite the extensive development of oil and gas in Montana and North Dakota, and despite both states' provision of specific statutory causes of action to certain landowners in the vicinity of production wells, no reported cases have been found regarding hydraulic fracturing and landowner damages. *See also* Dave Neslin, *Hydraulic Fracturing Litigation: Recent Developments and Current Issues in Cases Involving Alleged Water Supply Impacts*, ROCKY MOUNTAIN MINERAL LAW FOUNDATION, THE WATER–ENERGY NEXUS: ACQUISITION, USE, AND DISPOSAL OF WATER FOR ENERGY AND MINERAL DEVELOPMENT, at 4 (locating, in the three years before Sept. 2012, thirty-five cases in nine states regarding landowner allegations of damage due to hydraulic fracturing, but none in North Dakota or Montana) (on file with the Washington and Lee Journal of Energy, Climate, and the Environment).

332. *See* Neslin, *supra* note 331, at 11–15 (discussing unsuccessful cases that have hinged on the parties' ability to obtain treatment as a class, inadequacy of environmental review under NEPA or a state equivalent, or claims based on local ordinances that were preempted by statewide frameworks).

333. *See* Neslin, *supra* note 331, at 4–8 (discussing the various approaches to claims).

334. *See* Wiseman, *supra* note 18, at 9 (discussing the Texas case *FPL Farming v. Environmental Processing*, in which this was held).

335. *See* Wiseman, *supra* note 18, at 10 (discussing Pennsylvania case *Berish v. Southwestern Energy*, noting that defendants' decision only to challenge strict liability and medical monitoring claims may indicate the strength of the nuisance claim). *See also* Neslin, *supra* note 312, at 9 (noting that the *Berish* court, while declining to dismiss the strict liability claim, considered it unlikely to succeed but thought assessment on summary judgment motion post-discovery more appropriate).

336. *See* Neslin*, supra* note 331, at 7 (discussing these types of claims).

settled.[337] Whether these difficulties in proving defendants' responsibility for alleged pollution are caused by a substantive lack of merit or simply the evidentiary hurdles of proving causation, the results indicate that litigation is unlikely to be a promising source of protection for landowners seeking redress from fracturing injuries.[338] In the absence of a sea change in the available causes of action or applicable evidentiary standards, individuals will likely forced to "rely on public law solutions . . . that attempt to minimize and prevent nuisances from oil and gas drilling and fracturing . . . ."[339]

VI. Conclusion: Striking a Balance

If government regulatory systems are to be the primary check on hydraulic fracturing practices and the danger of pollution, they must be appropriately structured to provide substantive and adequate protection, while remaining consistent with the principles of tribal self-determination that guide Indian law and policy. As noted previously, one option might be to revise BLM's proposed regulations to provide a carve-out exemption for wells within reservation boundaries, subjecting them only to more stringent permitting and operating requirements if the tribe opts into the regulations for public land or imposes its own.[340] A similar result might be obtained if the exemption of non-diesel hydraulic fracturing from the UIC program were repealed, which would impose the same minimum standards for all hydraulic fracturing wells.[341] Such an approach would entail significant trade-offs, as it would mean the imposition of certain extra-tribal regulatory standards on the tribal government—a move that tribes often justifiably resist[342]—while affording tribal control over enforcement that may be more

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337. *See* Neslin*, supra* note 331, at 4 (noting that two water contamination cases were dismissed on defendants' motion, two on plaintiffs', and one by a state agency, while four others settled).

338. *Compare* King et al., *supra* note 26, at 349–50 (arguing that plaintiff-landowners lack an understanding of fracking technique and embellish the effects of fracking on their property, when the results they argue are "physically impossible") *with* Neslin, *supra* note 331, at 15 (noting that while causation difficulties appear to have discouraged new litigation, "the number of tort cases could increase if scientific studies provide reliable evidence linking hydraulic fracturing to ground water contamination or health impacts").

339. Wiseman, *supra* note 18, at 11.

340. *See supra* note 228 and accompanying text (discussing this approach to the proposed regulations). Taken to its logical conclusion, this principle of tribal control might also counsel the removal of BLM or BIA from the permitting process entirely, or at least to the greatest extent administratively feasible. *See* Fredericks & Aseff, *supra* note 146, at 120–24 (discussing the considerable costs and burdens associated with federal permitting, and the uncertain jurisdiction of the agencies in any case).

341. *See supra* notes 293–98 and accompanying text (discussing the aims of the UIC program and the 2005 amendment).

342. *See* Comment Letter from Tex Hall, Chairman, Three Affiliated Tribes, to Environmental Protection Agency, at 1–2 (Aug. 23, 2012), *available at*

difficult to challenge than tribal regulation under inherent powers.[343] In terms of practical politics, however, this appears unlikely to occur; revocation of the non-diesel fracking exception was proposed during the 112th Congress and left to die in committee.[344]

Even these solutions would still leave unresolved the problem of differential regulatory standards in tribal and state jurisdictions, and the possibility for undesirable cross-border effects. A tribe like the Turtle Mountain Band that would elect stronger environmental protections in lieu of economic development has no real means to take preventative action against an operator outside its jurisdiction, and would be forced to rely on remedial action after the fact in case of a spill or leak.[345] In some instances, however, Congress has given tribes the authority to be treated as states under federal environmental statutes for the purposes of administering those programs, as well as setting more stringent regulations than the minimum federal statutory requirements.[346] In some cases, this has meant that tribes can, in effect, project their regulations outside their reservation boundaries in order to give effect to them within the ordinary scope of tribal jurisdiction.[347] A similar approach could be taken in the context of fracturing, whereby federal law would give effect to tribal permitting and operation regulations that are more stringent than a state's regulations if the wells are sufficiently close to a reservation that a spill or leak would cause environmental degradation or a danger to public health within the

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http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OW-2011-1013-2701 (arguing that the proposed UIC guidance should only be applied to tribes if current operations are proved to be dangerous, and rejecting the notion that short-term fracking operations are properly within the scope of Class II well regulation).

343. *See* Cross, *supra* note 235, at 554 (noting that use of inherent authority is "more legally uncertain" than using delegated federal authority).

344. *See* H.R. 1084, 112th Cong. (1st Sess. 2011); Bill Summary & Status, 112th Congress (2011–2012), H.R. 1084, LIBRARY OF CONGRESS, THOMAS, http://thomas.loc.gov/cgi-bin/bdquery/z?d112:h.r.01084: (last visited Mar. 17, 2013) (stating that the last major action was reference to the House Subcommittee on Environment and the Economy on March 21, 2011).

345. *See* COHEN, *supra* note 64, § 4.01[2][f], at 222 (noting that "[t]ribes have traditionally had power over both their members and their territory," and thus have power over non-Indians only once they have entered reservation land) (internal quotations omitted). *Cf. id*. § 7.02[1][c], at 603 (noting that tribal courts' subject matter jurisdiction extends outside Indian country only when exercise of off-reservation treaty rights, or other matters involving internal concerns of tribal members or issues of core sovereignty, are under consideration).

346. *See id*. § 10.03[2][a], at 793–97 (discussing Congress' amendment of the Clean Water Act, Safe Drinking Water Act, and Clean Air Act to authorize tribal treatment as states, and subsequent court interpretations thereof).

347. *See* City of Albuquerque v. Browner, 97 F.3d 415, 418–19 (10th Cir. 1996) (upholding EPA's enforcement, via an NPDES permit, of Isleta Pueblo's elevated water quality standards for the Rio Grande against the City of Albuquerque's water treatment plant five miles upriver).

boundaries of the reservation. To avoid creating widespread jurisdictional uncertainty, tribal authority probably must be circumscribed by a bright line, limited to wells within a specified distance from a reservation boundary or water source used on the reservation. While such an approach would provide effective means to enforce the strongest tribal environmental protections, it raises a host of practical difficulties, not the least of which is political infeasibility and the likelihood of extensive litigation.

At the same time, negative environmental results of lower standards could work in both directions, with more relaxed state policies working to the detriment of a reservation like Turtle Mountain, where fracturing is entirely prohibited; while on a reservation like Fort Berthold, less stringent tribal/federal regulations could work to the detriment of the state. Because the tribes and states have a shared area of regulatory concern—orderly administration of energy development and environmental protection in their border regions—each side stands to gain from a cooperative relationship with the other that would provide adequate mutual respect for the regulations of each government.[348] Under such an arrangement, states and tribes might be able to negotiate terms that would maximize the ability of the less stringent regulator to foster energy production while assuring the more stringent regulator of the full benefits of its environmental protections. This could, for example, take the form of a buffer zone along a jurisdictional border—where development would be moderated by agreed-upon conditions, with the aim of insulating the more restrictive jurisdiction from air and water pollution on the other side—or a voluntary consensus on permitting and operation requirements for fracturing wells. Given that tribes have already taken steps in this direction, such as Fort Berthold's agreement resolving taxation schemes with the state, a cooperative agreement on development and environmental protection should not be considered farfetched.[349]

Wherever the current debate over hydraulic fracturing regulation ultimately leads, it should be clear from the preceding review that a homogenous approach, imposed from the top down by a federal authority, will prove unsatisfactory. While it may provide substantive protections for some stakeholders, it is largely unable to take into account specific tribes' judgments and goals regarding development of their energy resources. The fact that each tribe faces its own particular economic and environmental

348. *See* Cross, *supra* note 235, at 555–56 (noting that Fort Berthold's new status as a leading energy producer means that "the tribe will have to work with the state to ensure the efficient and responsible development of their shared energy resources" in a way that avoids serious legal/political dispute); Harvard Project, *supra* note 232, at 72–77 (describing how states and tribes have begun entering into a variety of negotiated intergovernmental arrangements to solve complicated policy problems, which have allowed economic growth for states and expanded services for tribes).

349. *See supra* notes 239–40 and accompanying text (discussing the tax agreement).

circumstances necessarily means that the appropriate regulations for each will be different. The proper role of the federal government is to enable tribes to make informed judgments for themselves, whether that means providing resources for tribes to develop local regulatory regimes, granting tribes proactive regulatory authority, or brokering voluntary agreements between tribes and states. While prudent environmental management calls for oversight and substantive regulation of fracturing, and while the proposed federal rules fill a void in public lands regulation on the subject, tribal self-determination requires federal restraint, not federal intervention. Each tribe must be left to decide for itself what place, if any, hydraulic fracturing will have in its development of energy resources.