American Law and Jurisprudence on Fracing

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Introduction

The substantial growth of domestic unconventional shale resources in recent years has partially been a result of the increase in the use of hydraulic fracturing. Hydraulic fracturing is generally viewed as a completion technique that is a practical necessity to promote development of unconventional "tight" shale reservoirs, particularly gas-shale. Hydraulic fracturing entails treating water, oil, or gas wells to stimulate more production than otherwise would have been achieved using standard drilling and production techniques. This report deals with hydraulic fracturing and the legal and technical issues associated with it.

This report first covers what hydraulic fracturing is and why it is done. It identifies the current location of the largest shale gas fields where hydraulic fracturing is common and the effect of hydraulic fracturing on domestic production. It then covers the environmental issues, focusing on the anecdotal and evidentiary call and response among environmental groups, regulators, landowners, and producers. It then discusses how traditional oil and gas jurisprudence impacts hydraulic fracturing, emphasizing both surface versus mineral estate issues and disputes that arise between two adjoining mineral owners.

We examine the regulatory frameworks currently in place in thirteen (13) states where hydraulic fracturing is common. This state-level analysis is made with an eye towards regulations specific to hydraulic fractioning and the fluids used, as well as more overarching regulations that include hydraulic fracturing among other exploration and production activities, such as general pollution disposal regulations that cover used hydraulic fracturing fluid as well as other liquid waste from drilling. In several instances, this report describes bills under consideration, as well as

important opinions from state courts. We also consider hydraulic fracturing on semi-sovereign tribal land.

Finally, this report analyzes the current and contemplated laws and regulations governing hydraulic fracturing on the federal level. In particular, it discusses the history of the litigation and legislative efforts challenging the current federal exception enjoyed by hydraulic fracturing. It also highlights the friction between state and federal oversight.

Hydraulic Fracturing—an Overview

Most people are familiar with the "gusher" well where reservoir pressure underground pushes oil up the wellbore. Oil and gas are harder to extract from "tight" rock formations, which do not allow passage of oil and gas through and up a well. Such formations, often shale or coal, may be filled with gas or oil, but allow those fluids to flow only along preexisting cracks or "fractures."

Naturally-occurring fracture patterns have long been used to heighten development in otherwise uneconomic formations. One example is the Austin Chalk, a tight fossiliferous chalk and marl formation found in the Gulf Coast region of the United States. The Austin Chalk in Texas and coal seams in Appalachia are marked by zones of natural fractures which trend in a common direction.[1] While the Austin Chalk is often saturated with hydrocarbons, it typically remains uneconomic unless a horizontal borehole intersects a number of the fractures. Therefore, seismic and surfacial mapping techniques were developed to find these natural fracture zones and orientations.[2]

The usefulness and application of hydraulic fracturing only became apparent with the discovery that "tight" shale formations could be economically developed with hydraulic fracturing techniques—that is, by making *artificial* fractures. Now, instead of relying on natural fractures zones, developers made their own fractures.

Hydraulic fracturing—known colloquially as "fraccing," "fracking"

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1 *See* Byron R. Kulander and Stuart L. Dean, *Coal-cleat Domains and Domain Boundaries in the Alleghany Plateau of West Virginia*, American Association of Petroleum Geophysicists ("***AAPG***") Bulletin, 1374-1388 (1993), v. 77, no. 8.; *see also* Kevin P. Corbett, David R. Van Alstine and Janell D. Edman, *Stratigraphic Controls on Fracture Distribution in the Austin Chalk: an Example from the First Shot Field, Gonzalez Co., Texas*, 1997 AAPG Hedberg Research Conference.

2 *See e.g.* Ilyas Juzer Najmuddin, Austin Fracture Mapping Using Frequency Data Derived from Seismic Data (2003) (unpublished PhD. dissertation, Texas A&M University) (on file with Texas A&M University Library) *available at* http://repository.tamu.edu/bitstream/handle/1969.1/34/etd-12112002-153843-1.pdf?sequence=1 (last visited May 3, 2010).

and, in this report, as "fracing"—is a process in which fluid is injected into a well at very high pressures in order to either widen and deepen existing cracks or create new fractures in the tight formation.[3] Generally, increased fracturing will allow more oil or gas to be produced from a well previously thought dry or in decline. Petroleum companies vary the type of fluid used for fracing depending on the rock type, depth or other factors. The fluids used can include water, water mixed with solvents, or drilling mud. The fluid is mixed with the "proppant," which is typically sand, ceramic pellets or other small granular material that is carried into the fractures where it remains to prop the crack open thereby allowing the oil or gas to flow.

Fracing is not a new technology. Hydraulic fracing was first tested in 1903 and first used commercially in 1948. By 1988, hydraulic fracturing had been applied to one million wells.[4] It has also been used to enhance production from water wells. Currently, about 35,000 wells per year undergo some measure of hydraulic fracturing and a majority of oil and gas wells have undergone some form and level of fracturing during their productive lifetime.[5] The prevalence of horizontal drilling has also increased the importance of fracing as boreholes can now traverse through a much longer portion of a targeted horizon instead of the interval covered by vertical or slant drilling, making the return to the operator in increased production worth the cost of mobilization of a fleet of fracing equipment. Because fracing can be conducted all along the interval the borehole is in the productive zone, more gas can be drained from each well, meaning one horizontal well can replace multiple vertical wells, cutting back on the surface footprint necessary to exploit the gas assets in a given area.

Drilling and Groundwater Protection

To understand how fracing operations work and the relationship between fracing fluids and groundwater, it is first necessary to understand

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[3] The American Petroleum Institute ("*API*") maintains a short video of current fracing techniques at http://www.api.org/policy/exploration/hydraulicfracturing/hydraulic fracturing.cfm (last visited April 23, 2010).

[4] Howard, G.C. and C.R. Fast (editors), Hydraulic Fracturing, Monograph Vol. 2 of the Henry L. Doherty Series, Society of Petroleum Engineers New York, 1970; *also see* "History of Hydraulic Fracturing", Energy In Depth, *available at* http://www.energyindepth.org/in-depth/frac-in-depth/history-of-hf/ (last visited March 29, 2010).

[5] Interstate Oil & Gas Compact Commission ("*IOGCC*"), Resolution on Hydraulic Fracturing 09.011, January 2009 Special Meeting, *available at* http://www.iogcc.state.ok.us/2009-resolutions (last visited May 3, 2010). The IOGCC maintains a website devoted to hydraulic fracturing and other issues affecting the domestic oil and gas industry at http://groundwork.iogcc.org/ (last visited May 9, 2010).

the fundamentals of how drillers set casing, cement boreholes, and set up a production zone. Fracing fluids are not the first fluids to be introduced to a wellbore during drilling. During drilling operations, drilling fluid is circulated down and around the drill bit and stem connecting the bit to surface—the "drill string"—then out the bottom of the drill string through a hole in the drill bit and back up the space between the drill string and the surrounding rock. The drilling fluid prevents formation fluids from entering into the well bore, keeps the drill bit cool and clean during drilling, carries out drill cuttings (which help mud loggers determine what formation is currently being drilled through), and helps support the hole while drilling is paused and the drilling assembly is brought in and out of the hole. Drilling fluid can be either water, oil or synthetic-based and is generally a mixture of clays, fluid loss control additives, density control additives such as barite, and other fluid-thickeners.[6]

A main goal of any well is to ensure safe production of oil and gas in a way that protects groundwater and heightens production by keeping hydrocarbons inside the well and isolating the productive formations from aquifers and other formations. Sound well design and drilling ensure that no significant leakage will occur between any casing joints and that fluids introduced to the casing string at the surface or produced from the production zone must travel directly from the production zone to the surface inside the wellbore.[7]

Drilling a modern oil and gas well involves placement of tubes of steel, fitted together, into a borehole. These tubes are called "casing" and they are used to seal off the drilling and formation fluids from migrating into groundwater aquifers and to keep the wellbore from caving in.[8] The deeper one goes in the well, the smaller the diameter of the drill stem—complete wells are similar to an extended sea captain's monocular. The first hole to be drilled is for the biggest tube of steel, the conductor pipe. The conductor pipe can also be driven into place, like a structural caisson, by a cable-tool rig. This pipe is followed by (i) the surface casing, (ii) the intermediate casing (if necessary), and (iii) the production-zone casing. Each of these has a progressively smaller diameter.[9] (*See* Figure No. 1)

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6 HOWARD R. WILLIAMS AND CHARLES R. MEYERS, MANUAL OF OIL & GAS TERMS, section '*M*' (2D ED. 2009).

7 *Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines 4*, AMERICAN PETROLEUM INSTITUTE (API Guidance Document HF1, First Edition), October, 2009, at 3.

8 *Manual of Oil and Gas Terms,* Casing 131, 132 (13th ed. 2006).

9 *Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines 4*, *supra* note 7 at 2-4.

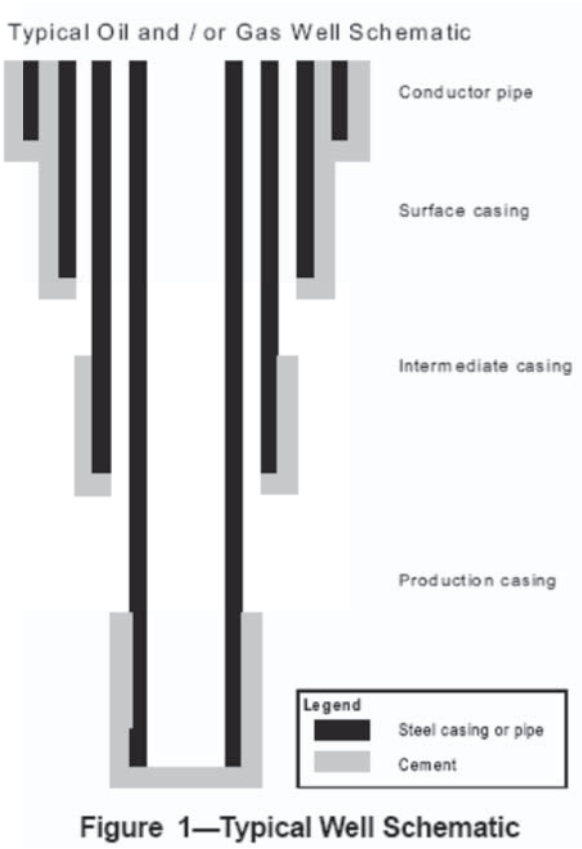

Figure 1—Typical Well Schematic

Source: American Petroleum Institute

The conductor pipe keeps out loose sediment at and near the surface and separates the groundwater zones from the drilling fluids. After the conductor pipe is installed and cemented into place, drilling continues and the surface casing is centered into the hole and cemented in place. Like the conductor pipe, the main purposes of the surface casing and cement are to provide stability for the subsequent deep drilling and completion operations and separation of potable groundwater found in near-surface aquifers.[10]

These first and second phases of drilling—constituting the "surface hole" portions of drilling—are often completed with a smaller, cheaper drill rig and are commonly drilled using freshwater-based drilling fluids to prevent groundwater contamination. The surface hole is usually drilled to a

[10] *Id.* at 4.

predetermined depth established by the deepest occurrence of groundwater resources and can range from a couple hundred feet to 1000 feet deep or more. State regulations dictate the minimal setting depth of surface casing, with nearly all states requiring the surface casing to be set below the deepest freshwater aquifer. Generally, the surface casing is set at least one hundred (100') feet below the deepest potable water encountered while drilling the well or the fresh/salt water boundary in the area, if known.[11]

In addition to the protection of the groundwater provided by the steel casing, the American Petroleum Institute (the "*API*") recommends that the surface casing be entirely cemented to completely isolate freshwater aquifers. This isolates the groundwater zones near the surface from the borehole and the drilling/fracing fluid with several layers of steel augmented by cement. After the casing has been inserted into the hole, it is cemented in place. The cement slurry is pumped into the well just like the drilling fluid, down through the casing and back up into place outside of the casing.[12]

Subsequent to completion of the surface hole and casing, a larger drill rig is typically moved into position and drilling of the "intermediate hole" and the "production hole" is commenced. The intermediate hole is the broad zone of strata encountered between the surface groundwater zones and the area from which production or horizontal drilling will take place. Casing in the intermediate zone provides hole stability and prevents hole collapse from high-pressure zones encountered while drilling to the productive zones. Unlike the surface casing zone, complete cementing of the intermediate hole back to the surface is not usually necessary, but hydrocarbon-bearing zones are generally always cemented. Once the intermediate zone is traversed by drilling, pressure testing is sometimes conducted to determine the maximum pressure that the casing string can withstand, to determine the integrity of previous cement job, and determine the maximum mud weight which can be used for the next casing setting depth.[13]

Finally, the production zone is reached. After the production zone is drilled and logged, if things look promising, production casing is run to the total depth (the "*TD*") of the well, and the producing formation is sealed

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11 *Id.* at 11.

12 *Id.*

13 Apiwat Lorwongngam, The Validity of Leak-Off Test for In Situ Stress Estimation; the Effect of the Bottom of the Borehole (2008) (unpublished M.S. thesis, University of Oklahoma), on file with the University of Oklahoma Library *available at* http://mpge.ou.edu/research/documents/Lorwongngam.pdf (last visited March 28, 2010).

off with expanding rings called "packers" and cemented in place. The production casing contains the downhole production equipment. In addition, like the casing in the intermediate zone, the production casing isolates the producing formations from other formations so that the only communication between the surface and the rock is through the perforated production casing. This isolation allows the drillers to recover the initial draw of oil and gas and, subsequently, to target the input of fracing fluids and other stimulation techniques directly into the producing formation without affecting any other formation or aquifer.[14]

The result of this process, if followed with care and thoroughness, is a completed borehole where the freshwater aquifers, are separated from communication with the fluids in the wellbore by two or three layers of steel tubing and one or two layers of impervious cement. The producing formations near the bottom of the hole are typically thousands of feet away from the uphole aquifers and separated by cement and packers.[15]

Fracing Fluids and Operations

Fracing requires a "fracing fluid" to be pumped into the well's production casing at a very high pressure and rate. Therefore, the production casing string and the cement holding it in place must be capable of withstanding the pressure. If the integrity of the production casing is in doubt, a high pressure "frac string" may be used to direct the fracing fluid to the prospective interval. The frac string is removed once operations are complete.[16]

The actual fracing takes place in three phases. The first phase, called the "pad," occurs when the hydraulic fluid is first pumped into the productive zone without any proppant. This is done to instigate the fractures in the rock and to prime the location so that any fluid leakage into immediately adjacent zones are accounted for. The second stage occurs when the proppant is added to the mix. Proppant can be simple sand or more complex materials such as ceramic beads or sintered bauxite. The proppant holds the fractures open, allowing the gas to flow after the fracing fluid is pumped out. Without the proppant, the pressures at depth could largely reseal the fractures, defeating the value of the operation. Finally, the last stage is the flushing of the reservoir to remove excess proppant from the borehole and to propel the proppant further into the formation.

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14 API Guidance Document HF1, *supra* note 7, at 12.

15 *Id*.

16 *Id*. at 18.

The flushing fluid can be either water or the same material used to start the process.[17]

The pressure in the hole is closely monitored throughout the process so that any significant leakage of the fracing fluid past the packers and away from the productive zone is immediately detected. If a leak is detected, the operation can be stopped. Leaks at or near the bottom of the casing string are separated by hundreds or thousands of feet of intervening strata from shallower freshwater aquifers.[18]

Nearly all oil and gas wells experience a gradual drop off in production over time; this is called a "decline curve" by petroleum engineers.[19] While the new "fraced" wells are initially prolific, their rates of production have been found to drop off quickly in the Barnett Shale and elsewhere. If this trend carries to other shale gas plays, the productive lifespan of shale gas wells will be shorter than traditional gas wells. This means that to maintain high and steady gas production from a portfolio of assets, developers must continuously drill wells to replace wells that quickly become uneconomic.[20]

Fracing operations are noisy. All natural gas production results in temporary noise from drilling and subsequent fracing that can last from two weeks to over a month. Noise curtailment is usually a function of local law and is measured and controlled in multiple ways. The simplest type of local noise ordinance sets a direct limit on noise caused by drilling and fracing operations. Such regulations typically prohibit noise greater than 70-90 decibels as measured from 200-400 feet from the edge of a site. To cut down on fracing noise, companies have put "sound blankets" resembling large, heavy quilts around the equipment. In other municipalities, an averaging method is used. For example, Ft. Worth, Texas requires that drilling and fracing be no more than five decibels higher during the day than the ambient (background) noise and no more than three decibels higher at night. In such cases, wellsites are usually situated as close to a road as possible to minimize access costs and to take advantage of a higher ambient noise level.[21]

Fracing operations require a great deal of personnel and materials and

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17 *Id*.

18 *Id*. at 21.

19 *Manual of Oil and Gas Terms, supra* note 8.

20 Arthur Berman, *Lessons from the Barnett Shale Suggest Caution in Other Shale Plays*, ASPO-USA, (August 10, 2009) *available at* http://www.aspousa.org/index.php/2009/08/lessons-from-the-barnett-shale-suggest-caution-in-other-shale-plays/ (last visited May 9, 2010).

21 Ft. Worth Municipal Code, Chapter 15, Article II, §§ 15-30 *et seq*. (2006).

traffic to and from the drillsite. Typically, fracing fluid is mixed offsite in the yard of the contractor conducting the fracing operations. Here, the water is mixed with any additives before being trucked onsite. Fracing operations often require one or two acres in addition to the original drilling pad where the multitude of tanker trucks and other vehicles and equipment can congregate.[22]

Oil companies typically hire specialized contractors to conduct fracing operations. These contractors are protective of the exact recipe of their fracing fluids, considering the ingredients and the ratio with which the ingredients are mixed with the water to make the fracing fluid to be trade secrets. The general constituents of fracing fluids are known, however, and in addition to the 99.5% sand and water, made be 0.5% salt, acid, distillates, ethylene glycol, isopropanol and sodium or potassium carbonate.[23]

A typical fracing operation in the Marcellus Shale requires between one to five million gallons of fracing fluid, mostly water, per well.[24] About twenty to forty percent (20%-40%) of the fluid can be expected to return to the surface through the borehole after the proppant has been injected and the water is being drawn out. In general, there are three ways to deal with fracing fluid left over from operations: (i) inject it back via a disposal well, similar to those used to dispose excess brine from more traditional operations; (ii) treat the fluid through evaporation and/or settling at the surface; or (iii) gather the used fracing fluid, dilute it with freshwater, and truck or pipe it to another project and reuse it again.[25]

The third method is the least expensive and is favored for its seemingly sound environmental underpinnings. However, the used fracing fluid typically must be treated upon its return to the surface. Used fracing fluid must have solids removed for optimum results upon re-injection and to prevent the hydrogen sulfide (H_2S) or iron sulfide (FeS) from returning with the "flowback" on the fracing fluid as it returns to the surface through the borehole. Disposal of the fracing fluid is another option, with costs dependent on the number and proximity of disposal wells near the fracing

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22 Michele Rodgers, et al., *Marcellus Shale: What Local Governments Need to Know*, Penn State College of Agricultural Sciences (2008) p. 11, *available at* www.naturalgas.psu.edu (last visited May 9. 2010).

23 Groundwater Protection Council, *Modern Gas Shale Development in the United States*, April 2009, p. 78, graphic representation *available at* http://www.energyindepth.org/frac-fluid.pdf (last visited May 1, 2010).

24 Michele Rodgers, et al., *supra* note 22, at 4.

25 Colter Cookson, *Technologies Enable Frac Water Reuse*, AMERICAN OIL & GAS REPORTER, March 2010, at 106.

operations.[26] This method is more difficult in areas such as the Appalachians as less disposal wells are currently available than in regions where prior development has occurred. Solids in the used fracing fluid are again a concern as they could block up disposal wells or contain naturally occurring radioactive materials ("*NORM*"). Treatment at the surface is potentially the most expensive, as pits for settling and transportation of the fluid to a crystallization/evaporation treatment plant—if either is available—is potentially expensive. However, such costly treatment may be necessary if environmental regulations require a complete reduction of additives and no reuse or injection outlets are allowed or available.[27]

Fracing Operations Nationwide

Fracing operations are found wherever the combination of tight shale reasonably close to the surface, trapped gas or oil within the shale, and, if necessary, a market for the produced gas can be found.[28] Most people are familiar with the Barnett Shale, which is found in and around the Ft. Worth, Texas region. Prior to economic fracing technology and higher gas prices, the Barnett Shale was considered a "cap rock" that held in oil and gas from more traditional reservoirs below it. By 2000, however, higher gas prices and better horizontal drilling technology led to a deluge of gas production in and around Denton, Tarrant, and Wise Counties in Texas. The Barnett Shale is not the only gas shale in Texas, as interest and activity is also found around the Haynesville Shale in East Texas, the Eagle Ford Shale in South Texas, and analogous Barnett Shale prospects in the western panhandle of Texas, among others.

After success in the Barnett Shale, the hunt was then on for analogous shale formations throughout North America. Prospective formations have since been identified, including the Haynesville Shale in East Texas and Louisiana, the Woodford Shale in Oklahoma, and the Marcellus/Needmore Shale in West Virginia, Pennsylvania, and New York. By February of 2010, around eleven percent (11.0%) of the almost 900 rigs drilling for gas in the onshore portions of the United States were operating in the Haynesville Shale in Northwest Louisiana, with half of those centered in DeSoto Parish alone.[29]

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[26] *Id*.

[27] *Id*. at 108.

[28] The U.S. Energy Information Administration maintains a map of shale gas plays which is periodically updated and *available at* http://www.eia.doe.gov/oil_gas/rpd/shale_gas.pdf (last visited May 10, 2010).

[29] Del Torkelson, *Marcellus and Haynesville Grab Industry's Attention as Gas Shale Giants*, AMERICAN OIL & GAS REPORTER, March 2010, at 74.

While the Haynesville is a regional phenomenon, the Marcellus Shale is truly enormous, extending from New York to Tennessee along a swath of territory larger than Greece. Drilling in the Marcellus only began in earnest in 2007, and currently drilling is concentrated in the Pennsylvania counties of Greene, Fayette, Washington and Westmoreland, the West Virginia counties of Wetzel and Marshall, the southern tier of western New York counties, and along the northern tier of Pennsylvania counties with Wellsboro in Tioga County becoming a major staging area for operations.[30] Drilling is also beginning in Northeast Ohio, with activity proliferating in Columbiana and Jefferson County.

North Dakota and Montana are also experiencing a surge in development spurred largely by the Bakken Shale in the Williston Basin. Production is largely focused in McKenzie County, North Dakota and Richland County, Montana. Neighboring Wyoming has a plethora of smaller productive and potential oil and gas shale, such as the Mowry Shale in the north central portion of the state near Thermopolis and the Green River Shale along the southern border with Colorado and Utah.

The Late-Devonian/Early-Mississippian-aged Woodford Shale is currently the biggest shale gas target in Oklahoma.[31] In 2004, only twenty-five (25) Woodford Shale gas wells were found in Oklahoma; by 2008, that number had rocketed to 750. Located in Southeastern Oklahoma in the region around Coal, Atoka, Pittsburg, and McIntosh Counties, the Woodford averages 50-300 feet in thickness and is located in the Arkoma Basin at an average depth of 6,000 to 12,000 feet, meaning most wells cost three to four million dollars to drill and complete.[32] Also in the Arkoma Basin is Arkansas' biggest shale gas producer, the Fayetteville Shale, a Mississippian-aged black shale found at a depth between 500 and 7,000 feet subsurface.[33] Producing in north central Arkansas, the Fayetteville is thought to contain over 50 trillion cubic feet ("*Tcf*") of gas reserves.[34]

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30 *Id*. *See also* Jon Hurdle, *Natural Gas Boom Brings Riches to a Rural Town*, Reuters, filed April 5, 2010.

31 Brian J. Cardott, Overview of Woodford Gas-Shale Play in Oklahoma, 2008 Update, (talk presented at Oklahoma Gas Shales Conference, October 22, 2008, Oklahoma City, Oklahoma).

32 *Id. Also see* Woodford Shale – Natural Gas Field – Arkoma Basin, *available at* http://oilshalegas.com/woodfordshale.html (last visited May 1, 2010).

33 Fayetteville Shale, Geology.Com, *available at* http://geology.com/articles/haynesville-shale.shtml, (last visited May 1, 2010).

34 J. Daniel Arthur and Bobbi Jo Coughlin, "Hydraulic Fracturing Consideration for Gas Wells of the Fayetteville Shale, Arkansas Oil & Gas Commission, *available at* http://www.aogc.state.ar.us/ALL%20FayettevilleFrac%20FINAL.pdf (last visited May 1, 2010).

Effect on Domestic Production

Fracing operations have helped make possible development of vast natural gas reserves in the United States. Estimates suggest that the U.S. has almost 1,750 Tcf of technically recoverable natural gas, including over 200 Tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place).[35] Technically recoverable unconventional gas—a category which includes gas derived from shale and "tight sandstone" formations as well as coalbed methane ("*CBM*")—accounts for approximately sixty percent (60%) of the onshore recoverable resource.[36] At the U.S. production rates for 2007, about 19.3 Tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next ninety (90) years. Separate estimates of the shale gas resource extend this supply to 116 years.

The use of hydraulic fracturing has been estimated to contribute to thirty percent (30%) of recoverable hydrocarbon reserves in the United States.[37] Fracing is believed to provide an additional 600 Tcf of gas and seven (7) billion barrels of oil that would not be recoverable without it.[38] Two recent estimates of gas reserves located in the sprawling Marcellus Shale suggest more than 500 Tcf of recoverable reserves.[39]

In June 2004, the U.S. Environmental Protection Agency (the "*EPA*") released the results of a study that found no confirmed instances of contamination of drinking water wells by fracing fluids.[40] This led the federal government to exclude hydraulic fracturing and the associated fracing fluids from coverage under the Safe Drinking Water Act (the "SDWA"). Environmentalists and some regulators attacked the findings of the study, saying it was limited to CBM wells. Industry answered by pointing out that the type of well and formation commonly stimulated by

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35 The Energy Information Administration (Department of Energy) *available at* http://www.eia.doe.gov/

36 "Modern Shale Gas Development in the United States: a Primer"—U.S. Department of Energy, Office of Fossil Energy *available at* http://fossil.energy.gov/programs/oilgas/publications/naturalgas_general/Shale_Gas_Primer_2009.pdf (last visited May 1, 2010).

37 "Hydraulic Fracturing: Effect on Energy Supply, the Economy, and the Environmental"—Independent Petroleum Association of America, April 2008.

38 "Hydraulic Fracturing"—American Petroleum Institute. *available at* http://www.api.org/policy/exploration/hydraulicfracturing/index.cfm (last visited May 1, 2010),

39 Torkelson, *supra* note 29, at 74.

40 U.S. Envtl. Prot. Agency, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs,* 4-15 (2004).

fracing does not impact the basic finding of the EPA study—that injection of fracing fluids posed minimal threat to drinking water.

Fracing and the Environment

Although hydraulic fracing has been used for decades, the debate over the safety of fracing has become a hot topic because of the current widespread use of the practice and the large number of wells enhanced by fracing. Opponents of fracing, which include environmentalists, politicians and landowners, argue that fracing should be regulated under the SDWA and drilling companies should be required to disclose the chemicals used in fracing fluid.[41] According to The Environmental Working Group, a non-profit environmental organization, drilling companies are avoiding federal law and injecting toxic petroleum distillates into wells and threatening drinking water supplies.[42] Opponents of fracing allege that water supplies are threatened because "30 to 60% of the fracing fluid stays in the geological strata and may escape through the existing or new fractures and contaminate surface groundwater."[43]

What is concerning, opponents claim, is that the additives in fracing fluids are highly poisonous and carcinogenic.[44] The fluids include, they claim, "potentially toxic substances such as diesel fuel, which contain benzene, ethylbenzene, toluene, xylene, naphthalene and other chemicals; polycyclic aromatic hydrocarbons; methanol; formaldehyde; ethylene glycol; glycol ethers; hydrochloric acid; and sodium hydroxide."[45] The non-profit agency, ProPublica, reported that in July 2008, a hydrologist sampled a water well in rural Sublette County, Wyoming–the home of one of the largest natural gas fields and has thousands of wells that have undergone hydraulic fracing.[46] The test showed that the water "contained benzene…in a concentration 1,500 times the level safe for people."[47]

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41 *See* The Environmental Working Group, *Drilling Around the Law*, *available at* http://www.ewg.org/files/EWG-2009drillingaroundthelaw.pdf (last visited April 15, 2010).

42 *Id*. at 2.

43 *See* http://www.huntergasactiongroup.com.au/hgfracc.html (last visited April 15, 2010).

44 *See* http://www.earthworksaction.org/FracingDetails.cfm (last visited April 15, 2010).

45 *Id.* citing to EPA's Evaluation of Impacts of Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs Table 4-2 (August 2002).

46 Abrahm Lustgarten, *Buried Secrets: Is Natural Gas Drilling Endangering U.S. Water Supplies?,* ProPublica (November 13, 2008) *available at* http://www.propublica.org/feature/buried-secrets-is-natural-gas-drilling-endangering-us-water-supplies-1113 (last visited April 15, 2010).

47 *Id*.

According to ProPublica, the Sublette County study is the first to be documented by a federal agency, the U.S. Bureau of Land Management.[48]

People living near areas where hydraulic fracing occurs are also complaining that their water is being contaminated. Landowners are claiming that the water used in fracing operations is being drawn from water sources that have been used for landfills.[49] Furthermore, many landowners claim that the water from their drinking wells changed color and smelled of petroleum after fracing.[50] Many landowners have also claimed that their health has been jeopardized due to the use and consumption of water that has been contaminated by fracing operations.[51] They claim that the chemical additives have caused symptoms ranging from eye and skin irritation to serious respiratory illnesses, such as emphysema, thyroid disorders, tumors, and birth defects.[52]

Industry groups have been quick to rebut allegations that fracing causes water contamination. Energy in Depth, an industry group, argues that fracing opponents need to establish a credible track record of danger.[53] "Unfortunately for them, in hydraulic fracturing they're running up against a technology that in sixty years of service has yet to be credibly tied to the contamination of drinking water."[54] Furthermore, an EPA completed a study in 2004 regarding the environmental risks that are associated with hydraulic fracing of coal bed methane wells and found that fracing fluid poses little or no threat to underground sources of drinking water.[55] According to the Ground Water Protection Council, no documented threats

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48 *Id*.

49 *See* Letter from Peggy Hocutt, resident of Jefferson County, Alabama, to Senator Jesse Bingaman, (D-NM) (date unknown) *available at* http://www.earthworksaction.org/cvPeggyHocutt.cfm (last visited April 15, 2010).

50 *Id*.

51 *Id*.; *see also* Letter from Laura Amos, resident of Garfield County, Colorado, to EarthWorks (date unknown) *available at* http://www.earthworksaction.org/cvLauraAmos.cfm (last visited April 15, 2010).

52 Tom Kenworthy, *Frack Attack: Drilling Technique Under Scrutiny*, American Progress, (June 25, 2009) http://www.americanprogress.org/issues/2009/06/frack_attack.html (last visited April 15, 2010).

53 *See* Energy In Depth, *Frac vs. Fiction* (May 2009), http://s3.amazonaws.com/propublica/assets/natural_gas/frac_fiction_may2009.pdf (last visited April 15, 2010).

54 *Id*. at 1.

55 *See* IOGCC, *Hydraulic Fracturing*, *available at* http://www.iogcc.state.ok.us/hydraulic-fracturing (last visited April 15, 2010).

exist to underground sources of drinking water by fracing operations.[56] Moreover, industry groups claim that only about one-half of one percent (0.5%) of fracing fluid is made up of chemicals and ninety-nine and a half percent (99.5%) of it is made up of water and proppant.[57] Further, according to the Independent Oil and Gas Association of New York,

> "Half a percent of the solution contains three primary additives: a friction reducer, similar to canola oil, which thickens the fluid, and a bactericide, like chlorine, which is used the same way chlorine is used in our drinking water. The fluid also contains a 0.1 percent portion of a micro emulsion element similar to those found in personal care products, such as shampoos, and cutting oils."[58]

In addition to the initial fracing fluid returns back up the wellbore during fracing, studies show that eighty percent (80.0%) or more of the fracing fluid used during the fracing process is eventually recovered from the well out of subsequent production.[59] Additionally, industry groups further claim that fracing does not cause water contamination because the fracing fluids are pushed deep underground, thousands of feet below any aquifers being used for drinking water.[60]

Fracing operations have been alleged to cause or contribute to surface subsidence and even man-made earthquakes. Surface subsidence caused by hydrocarbon and water production is a well-known phenomenon, and since fracing has proved to be such a successful catalyst to production, it may indirectly promote subsidence simply by enhancing the quantity of production. A series of very small temblors with magnitudes of approximately 2.8 on the Richter scale or less were reported on June 2, 2009 in Cleburne, Texas. Some have attributed this seismicity to fracing-stimulated gas production.[61]

According to industry groups, fracing is essential to the viability of oil

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[56] MarcellusFacts.com, *Get the Facts on Hydraulic Fracturing* (September 4, 2009), http://www.marcellusfacts.com/pdf/HydraulicFracturingQ&A.pdf (last visited April 15, 2010)

[57] Groundwater Protection Council, *supra* note 23.

[58] MarcellusFacts.com, *supra* note 56.

[59] Palmer, I.D., *et al., Comparison between gel-fracture and water-fracture simulations in the Black Warrior basin;* Proceedings 1991 Coalbed Methane Symposium, Univ. of Alabama (Tuscaloosa), pp. 233-242.

[60] Mike Lee, *Gas-removal method may be subject to more rules*, Fort Worth Star-Telegram (December 7, 2008) (Quoting API officials and industry consultants).

[61] Jeff Carlson, "Drilling Might Be Culprit Behind Texas Earthquakes," *Associated Press*. June 12, 2009, *available at* http://www.newsvine.com/_news/2009/06/12/2923921-drilling-might-be-culprit-behind-texas-earthquakes (last visited March 29, 2010).

and gas production in the United States.[62] Hydraulic fracing is estimated to be able to provide an additional seven (7) billion barrels of oil and 600 trillion cubic feet of natural gas to domestic reserves.[63] Industry groups warn that without fracing, America would be producing much less oil and natural gas, which would in turn increase dependence on foreign imports.[64] Furthermore, hydraulic fracing has brought economic gain for many communities due to production of oil and gas, such as increase of jobs or royalties and taxes paid to the counties and property owners.[65]

Oil and Gas Jurisprudence in the Realm of Fracing

Two basic relationships drive the dynamics of oil and gas jurisprudence as it relates to fracing: (i) the vertical relationship between the surface owner and the mineral owner, if the two estates have been separated, and (ii) the lateral relationship between one mineral owner and a neighboring mineral owner.

Surface Ownership vs. Mineral Ownership

If the surface owner is also the mineral owner, then the first question becomes moot. Typically, if the surface owner(s) also owns the mineral estate, he is happy to see the minerals developed as thoroughly as possible, including employment of all secondary and tertiary recovery techniques such as fracing, as this means income in the form of royalty payments. If the mineral estate has been separated from the surface, the surface owner may have no such financial incentive to see minerals developed, and may view the development as a nuisance or harmful to the value of the surface properties.

Historically, the mineral owner dominated the surface owner when the two owners collided over issues relating to land use and mineral development, including fracing. In its most unvarnished form, this dominance meant the mineral owner had "the right to use so much of the surface as may be reasonably necessary to enjoy the mineral estate."[66] Later, the dominance of the mineral owner was attenuated somewhat by

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62 Frac in Depth, Energy in Depth, *available at* http://www.energyindepth.org/in-depth/frac-in-depth (last visited March 29, 2010)

63 Independent Petroleum Association of America – *Hydraulic Fracturing: Effects on Energy Supply, the Economy, and the Environment*, *available at* http://www.energyindepth.com/PDF/Hydraulic-Fracturing-3-E's.pdf (last visited May 3, 2010).

64 *Id*.

65 *Id*.

66 Harris v. Currie, 176 S.W.2d 302, 305 (Tex. 1943).

the accommodation doctrine in most states, which introduced the circumstance that a disruption of the surface owner's use of the land by subsequent mineral development might require or force the mineral owner to use another "reasonable" method to develop the mineral estate. The accommodation doctrine kept intact, however, the overall doctrine of the dominance of the mineral estate—if no other reasonable method existed for mineral development, then the mineral owner could go ahead with the disruptive development without the surface owner's consent and without being liable for damages for the disruption.

At least ten states have enacted surface damage statutes ("*SDAs*") to help alleviate surface owners/users' displeasure with the perceived imbalance of power that mineral owners have over surface owners/users. They are designed to compensate for damage caused by the mineral owner. Across the states that have passed SDAs, the laws vary surprisingly little with regard to the major components. Most contain entry notification and negotiation requirements to facilitate contact between operators and surface owners and their tenants. Most also contain bonding requirements and protocols on determining surface damage costs. Case law related to such acts is, as yet, sparse. Another common requirement in SDAs is the need for entry negotiations. In these, the surface owner and the producer must begin negotiations before entry to determine what the payment will be for surface damages before the drilling begins—including damages that may be caused by fracing.

Some legal questions are raised by the concept of ownership of the pore space in the rock. If the surface owner owns the pore space, the oil and gas developer should consider whether his insertion of fracing fluid and proppants will disrupt the surface owner's use of the pore space for activities such as gas storage or CO2 sequestration, as well as production of materials that have been deemed to belong to the surface owner. This question of pore ownership is still largely the province of case law, with most courts dealing with the issue looking favorably upon the precept that the surface owner owns the pore space.[67] Some states have even

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[67] Louisiana: United States v. 43.42 Acres of Land, 520 F.Supp. 1042 (W.D. La. 1981); Mississippi River Transportation Corp. v. Tabor, 757 F.2d 662 (5th Cir. 1985); Michigan: Department of Transportation v. Goike, 560 N.W.2d 354 (Mich.App. 1996); New York: Miles v. Home Gas Co. Cf., 40 A.D.2d 896 (3d Dept. 1972); International Salt Co. v. Geostow 697 F.Supp. 1258 (W.D.N.Y. 1998), *aff'd by* 878 F.2d 570 (2d. Cir. 1989); Oklahoma: Sunray Oil Co. v. Cortez 112 P.2d 792 (Okla. 1941); Ellis v. Arkansas Louisiana Gas Co. 609 F.2d 436 (10th Cir. 1979); Texas: Getty Oil Co. v. Jones 470 S.W.2d 618 (Tex. 1971); Mapco, Inc. v. Carter 817 S.W.2d 686, 687 (Tex. 1991) (pore ownership in the case of sandstone or other non-mineral); West Virginia: Tate v. United States Fuel Gas Co.

memorialized this in their code.[68] The emerging minority view is that the mineral owner owns the pore space.[69] Thus far, no record exists of surface owners attempting to enjoin fracing based on their ownership of the pore space.

Neighboring Mineral Owners

Derived from the common law of England, the rule of capture is used to determine ownership of captured natural resources including groundwater, oil, gas, and—as originally applied—game animals. The rule of capture generally provides that the first person to "capture" a migratory natural resource that is free to roam or flow from property to property and which was never reduced to personal property is granted absolute title to that resource. Trespass, or other related causes of action, only occur when the drill bit "breaks the plane" of the subsurface boundary between two tracts of land.

While the rule of capture may seem like a quaint legal holdover from another era, it still resonates. The advent of prolific fracing has produced for subsurface owners the classic paradox of a benefit and a curse, considering that the inevitable product of fracing has been the legal issues arising from differences between competing subsurface owners over correlative rights. Further complicating matters is that the state law and regulatory framework in the states most affected (*e.g.* Texas, Louisiana, Oklahoma, North Dakota, West Virginia, Pennsylvania, and New York) are themselves non-uniform and, potentially, may face preemption by federal law. Consistent with its historical role as a leader in the development of domestic oil and gas resources, Texas, through its Supreme Court, has stepped forward to cast its lot with those favoring few restrictions on the use of hydraulic fracturing to enhance access to and production of hydrocarbons. The "jury is out" whether other states facing these issues will share a similar disposition.

In *Coastal Oil & Gas Corp. v. Garza Energy Trust*,[70] the Texas Supreme Court ironically delivered a fractured decision on the unprecedented question of whether subsurface fracing can give rise to an action for trespass. Earlier decisions by Texas' highest court had addressed the subsurface trespass question, emphasizing in their holdings the importance of the role of the Texas Railroad Commission (the "*RRC*")

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68 New Mexico: SB 208 (2009); Wyoming: HB 89 (2008).

69 Pennsylvania: United States Steel Corp. v. Hoge 468 A.2d 1380 (Penn. 1983); Texas: Mapco, Inc. v. Carter 817 S.W.2d 686, 687 (Tex. 1991)(pore ownership in the case of salt or other mineral).

70 268 S.W.3d 1 (Tex. 2008).

in regulation. In *Gregg v. Delhi-Taylor Oil Corp.*,[71] the Court held that, in the absence of (1) an explicit legislative grant of exclusive jurisdiction to the RRC and (2) RRC rules or orders governing secondary recovery operations, the courts have jurisdiction to decide the questions of liability and remedies for subsurface trespass, including whether injunctive relief is available to prevent a landowner from fracturing a common formation beyond his property lines for the purpose of increasing the productivity of the landowner's well.[72]

In *Railroad Comm'n of Tex. v. Manziel*, [73] the Texas Supreme Court determined that a mineral estate owner was not entitled to an injunction against an RRC order authorizing a well-spacing exception for conduct of a pressure maintenance project in the East Texas oil field (secondary recovery operations involving the injection of saltwater). [74] In *Manziel*, the Court found that in those circumstances "the subsurface invasion of adjoining mineral estates [sharing a common reservoir] by injected salt water is to be expected, and in the [injunction] case at bar we are not confronted with the tort aspects of such practices." [75] The Court further recognized one commentator's prediction that a "negative rule of capture" may be developing in the face of challenges to secondary recovery operations based on the law of trespass. [76] In examining the evidentiary basis for the RRC order, the Court found persuasive the fact that all other mineral and royalty owners had agreed to the well spacing and that, absent these secondary operations, the complainants' leases "[had], and [would] continue to, produce far in excess of [their] fair share of the oil in place originally recoverable through the use of such methods." [77] As such, the Court chose to defer to the RRC's decisions on such matters, relying heavily on the fact-finding in the RRC decision. [78] In a subsequent decision, the Court flirted with sustaining a subsurface-trespass claim for damages, but ultimately relented by withdrawing its original opinion, leaving intact (without comment or concurrence) the lower court's opinion. [79]

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71 344 S.W.2d 411 (Tex. 1961).

72 *Id*. at 414-15.

73 361 S.W.2d 560 (Tex. 1962)

74 *Id*. at 574.

75 *Id*. at 566.

76 *Id*. at 568.

77 *Id*. at 573.

78 *Id*. at 574.

79 Geo-Viking, Inc. v. Tex-Lee Operating Co., 817 S.W.2d 357 (Tex. App. – Texarkana 1991), *writ denied,* 839 S.W.2d 797 (Tex. 1992).

Thus, the stage was set when the Court granted the petition for review of the Corpus Christi Court of Appeal's decision in *Mission Res., Inc. v. Garza Energy Trust*, [80] a case involving a long-running dispute between a producer and the royalty owners of a natural gas lease in South Texas. The Plaintiffs/Respondents ("*Salinas*") were holding a substantial judgment for money damages against Coastal for subsurface trespass, wrongful drainage, breach of the implied covenant to develop and bad faith pooling. The focus of the original complaint was Coastal's hydraulic fracturing operation of a natural gas well on a lease adjacent to Salinas making it possible for gas to flow from the Salinas lease to the adjacent lease in which Coastal held a larger mineral interest. The Court recognized Salinas's standing to assert an action for trespass, holding that the mineral lessor's reversion interest in the minerals leased to Coastal gave standing to sue for "trespass on the case," a form of trespass that requires proof of actual injury. [81] Noting the limitations of its earlier decisions in *Gregg* and *Manziel*, the Court held that the rule of capture precluded a recovery for Salinas's only claim of injury for trespass, the drainage allegedly caused by Coastal's fracing operation. [82] The Court's limited holding was that "damages for drainage by hydraulic fracturing are precluded by the rule of capture." [83] This ruling, the Court held, made it unnecessary to decide the "broader issue" of whether subsurface fracing can give rise to an action for trespass. [84] The concurring opinion in *Coastal* urged the Court to adopt a bright line rule that "a claim for 'trespass-by-frac' is nonexistent in either drainage or nondrainage cases." [85] By contrast, the dissent complained of the majority's failure to "address Coastal's primary issue: does hydraulic fracturing across lease lines constitute subsurface trespass." [86]

The application of the rule of capture to foreclose Salinas's drainage claims was considered by the Court to be necessary to preserve "unimpeded" the RRC's "power to regulate production to assure a fair recovery by each owner … [which] role should not be supplanted by the law of trespass." [87] However, the Court went on to observe that "[t]hough

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[80] 166 S.W.3d 301, 310-311 (Tex. App. – Corpus Christi 2005), rev'd, 268 S.W.3d 1 (Tex. 2008).

[81] Coastal, 268 S.W.3d at 9-11.

[82] *Id*. at 12-13.

[83] *Id*. at 17.

[84] *Id*. at 11-12.

[85] *Id*. at 30 (Willett, J., concurring).

[86] *Id*. at 44 (Johnson, J., Jefferson, C.J., and Medina, J., concurring in part and dissenting in part).

[87] *Id*. at 15-16.

hydraulic fracturing has been commonplace in the oil and gas industry for over sixty years, neither the Legislature nor the [RRC] has ever seen fit to regulate it…."[88]

Salinas's other damage claims against Coastal (as operator of its lease) for breach of implied covenants (protect against drainage and lease development) and bad-faith pooling fared little better in the final analysis than the trespass claim. Finding no evidence of imprudent operatorship by Coastal and an improper form of jury instruction on the subject, Salinas's claim of a drainage covenant breach by Coastal was denied.[89] While Coastal's challenges to the jury's findings of breach of the development covenant and bad-faith pooling were rejected, the Court nonetheless ordered a new trial due to the trial court's harmful error in the admission of evidence which caused unfair prejudice to Coastal.[90]

The Aftermath of Coastal

The Texas Supreme Court in *Coastal* left open multiple options for future claims arising from fracing, as well as contractual options to lessors as protective measures against drainage. The majority opinion reserved judgment on whether trespass could ever qualify as the basis for a claim arising from fracing. While other tort claims are left open as theoretical options, a claimant will face a considerable challenge in meeting the proof requirements for liability and actual damages allegedly caused to a well or formation by fracing. Absent an intentional tort claim (*e.g.* trespass), a recovery of punitive damages is probably foreclosed. If the claimant can show a trespass that threatens imminent harm, other than drainage, injunctive relief remains an option. In the lessor-lessee context, a complaining lessor would have potential claims against the lessee for breach of the implied covenant to develop and bad faith pooling in circumstances similar to *Coastal* where the defendant was also a mineral owner of adjacent acreage.

As additional protective measures, prospective lessors may consider additional lease provisions to guard against a prospective lessee favoring its current or future mineral interests in neighboring lands. These protective measures may appear in the form of affirmative provisions where, *e.g.*, (1) the lessee is required to meet a specific drilling and development schedule and/or (2) the lease imposes on lessee a strict duty to drill an offset well (or take other steps) to protect against drainage where lessee is the operator of or has a working interest in a well on adjoining

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88 *Id*. at 17.

89 *Id*. at 19.

90 *Id*.

property. Some leases impose a strict duty to offset without regard to the "reasonably prudent operator" standard in an apparent effort to avoid the burden to a lessor of proving actual drainage and a duty to drill a protection well using the prudent operator standard (*i.e.*, the well will pay out and yield a return on investment).

The *Coastal* opinion may be a departure from the Court's earlier decisions regarding the role of the RRC. The *Gregg* opinion recognized the absence of legislative and RRC activity in the area of secondary recovery operations as a basis for judicial action.[91] The *Manziel* opinion relied on the RRC's exercise of its authority over secondary recovery projects as a basis to avoid judicial action and deny relief for trespass.[92] Neither the Texas legislature nor the RRC has found itself driven to legislate or regulate hydraulic fracturing practices since the Texas Supreme Court denied the Salinas's rehearing motion in November of 2008. The Texas legislature may well share the Supreme Court's view that the RRC is already charged with the dual responsibility to protect correlative rights and to prevent waste in the production of hydrocarbons. In the views of at least one commentator, the RRC would be ill-advised to regulate fracing.[93]

In oil and gas jurisprudence, often times as goes Texas so goes the majority of courts elsewhere. Thus, it may be that it falls to the Texas courts to further establish the framework for resolution of disputes arising from fracing. However, some may argue that *Coastal* highlights the need for legislative or administrative action to clarify the law regarding fracing and to provide a regulatory framework for its use. In his concurring opinion in *Coastal*, Justice Willett maintains that the Texas legislature has already conferred upon the RRC "sweeping jurisdiction over all Texas oil and gas wells" with the discretion to "weigh the competing interests and strike the proper regulatory balance" with respect to hydraulic fracturing.[94] Having been a chronic subject of controversy and, presuming its importance to Texas (as J. Willett insists), its regulation should not be left to piecemeal judicial resolution but "to the regulators as the Legislature intended."[95]

Portions of the *Coastal* opinion may be subject to change. One of the reasons the Court gives for protecting fracing from trespass actions is that

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91 Gregg, 344 S.W.2d at 418-19.

92 Manziel, 361 S.W.2d at 568-69.

93 Owen L. Anderson, *Coastal v. Garza and Its Impact on Subsurface Trespass Issues*, proceedings of the 60th Annual Oil and Gas Law Conference, Inst. for Energy Law, at Tab 8, pp. 20-21, 25-27.

94 Coastal, 268 S.W.3d at 38.

95 *Id*. at 40

"determining the value of oil and gas drained by hydraulic fracturing is the kind of issue the litigation process is least equipped to handle."[96] The Court, therefore, apparently believed that determination of intrusive fracing or drainage could not be achieved. Since the time of the ruling, however, seismic data gathering and interpretation techniques have advanced such that petroleum seismologists can much better determine the direction and extent of fracturing now than they could even five (5) years ago. These advances mean that, given the proper resources and seismological expertise, a landowner may present evidence that convinces a jury or judge that fracing from a neighboring tract has intruded across the boundary into the plaintiff's tract, and may even provide evidence of the amount of drainage that has occurred or that the fracing on the neighboring tract has caused other harm to his tract or fixtures and improvements thereon.

When looked through the prism of correlative rights instead of only the law of capture, the *Coastal* opinion may also present another challenge by leaving unanswered the effect of fracing on correlative rights and the prevention of waste. State conservation agencies are typically charged with promoting the orderly development of oil and gas while preventing waste and protecting the correlative rights of owners of adjoining tracts.[97] If fracing is found to be beneficial to the development of the entire reservoir, then it is both defensible under the law of capture and the protection of neighbors' correlative rights.

What would be the determination of *Coastal*, however, in the instance that the fracing resulted in harming the ultimate recovery of the entire reservoir, lowering the amount realizable by the neighboring tracts while enhancing only the recovery of the well being fraced? At least one commentator believes that, in such an instance, the correlative rights of the neighboring tracts, where "each owner possesses certain undivided rights within the reservoir," are not addressed by the *Coastal* opinion, and that conservation commissions should consider the ultimate recovery of the reservoir or field.[98] In that light, all the parties sharing the reservoir are co-tenants of a sort, and fracing that boosts one co-tenant's ultimate recovery to the detriment of others sharing reservoir rights may require further scrutiny by the appropriate conservation commission to protect the correlative rights of all the parties sharing the reservoir.

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96 *Id*. at 16.

97 See Kemp Wilson, *Conservation Acts and Correlative Rights: Has the Pendulum Swung Too Far?* 35 ROCKY MTN. NIN L. INST. (1989); see also ROBERT E. SULLIVAN, CONSERVATION OF OIL AND GAS, A LEGAL HISTORY (1960).

98 David E. Pierce, *Minimizing the Environmental Impact of Oil and Gas Development by Maximizing Production Conservation*, 85 N.D. L. Rev. 4 (2010).

State Regulation of Hydraulic Fracturing

Arkansas

Hydraulic fracturing has not been formally regulated in Arkansas. Overarching oil and gas and environmental regulations however currently impact fracing operations. The Arkansas Oil and Gas Commission (the "*AOGC*") regulates oil and gas in Arkansas and promulgates and administers regulations to "serve the public regarding oil and gas matters, prevent waste, encourage conservation, and protect the correlative rights of ownership associated with the production of oil, natural gas and brine, while protecting the environment during the production process."[99] Typical protective measures are required, such as requiring owners and operators to case off fresh water from oil- or gas-producing formations that an operator encounters while drilling, and the AOGC requires owners and operators to set and cement surface and down-hole casing to prevent contamination to any freshwater aquifers.[100]

The AOGC is currently drafting proposed rule changes and additions that specifically address fracing. It initiated regulations to require producers to disclose the constituents of hydraulic fracturing fluid. The proposed rule, dubbed "Commission Rule B-19," was submitted for public comment until November 1, 2010, with public hearings to be held in late October of 2010, and the nine commissioners are set to vote on the final rule in December, 2010. The rule makes design requirements on casing and cementing to protect aquifers and require the operator to report any change in annulus pressure that might indicate a casing failure or any exceeding of the rated casing pressure to the AOGC within a day.[101]

Under B-19, following the completion of a frac job, the operator must report maximum pump pressure, volumes and types of fluid and proppant, and even the estimated extent the fractures. B-19 would also require the operator to furnish the name, types and concentration of additives in the fracing fluid, as well as Material Safety Data Sheets and Chemical Abstracts Service numbers ("*CASs*") for same.[102]

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99 The AOGC was created by Act 1939, No. 105, codified at ARK. CODE ANN. § 15-17-101, *et seq*; AOGC, "Mission Statement," *available at* http://www.aogc.state.ar.us/mission.pdf, last accessed March 30, 2010.

100 ARK. CODE ANN. § 15-72-206 (2009); General Rule B-15 of the AOGC.

101 *See* draft of General Rule B-19, maintained at http://groundwork.iogcc.org/sites/default/files/AR%20B-19%20Markup_10-2010.pdf (last visited: October 31, 2010). See also J. Mark Robinette, *Arkansas Oil and Gas Commission Puts Hydraulic Fracturing Disclosure Rule Up for Comment*, available at http://robinetteslaw.blogspot.com/2010/09/arkansas-oil-and-gas-commission-puts.html (last visited: October 31, 2010)

102 *Id.*

Two governmental bodies are primarily responsible for overseeing environmental regulation in Arkansas. The Arkansas Pollution Control and Ecology Commission (the "*APCEC*") is responsible for creating and promulgating environmental regulations, but does not have any power of enforcement.[103] The Arkansas Department of Environmental Quality (the "*ADEQ*"), on the other hand, is responsible for administering and overseeing implementation of the policies promulgated by the APCEC.[104] The Arkansas Department of Health exercises limited jurisdiction over groundwater protection as the designated agency in charge of compliance with the federal Wellhead Protection Program.[105]

The ADEQ is specifically charged with enforcing the provisions of the Arkansas Water and Air Pollution Control Act (the "*Act*") and regulations promulgated pursuant to the Act by the APCEC.[106] The Act prohibits a number of pollution-related activities, including generally prohibiting "causing pollution," as that term is defined by the Act, in any of Arkansas' waters.[107] Additionally, Regulation 1 of the APCEC specifically applies to all oil and gas wells in the state and prohibits the discharge of salt water or other oilfield waste onto the ground or into state waters.[108] The proposed new Commission Rule B-19 addresses wastes not already regulated by the ADEQ, regulating storage in sound containment vessels, and the reporting of spills.[109]

Fracing operations may also involve specific handling and disposal procedures with respect to flowback water or other fluids used during fracing operations. In 2007, the ADEQ created a procedure by which

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[103] The APCEC was first established as part of the Arkansas Water Pollution Control Act, Act 472 of 1949, codified at ARK. CODE ANN. § 8-4-101, *et. seq.*

[104] The ADEQ was also created by the Arkansas Water Pollution Control Act, Act 472 of 1949, codified at 8-4-101, *et seq.*

[105] July 31, 1986 Letter from Arkansas Governor Clinton to U.S. EPA Administrator Lee M. Thomas (designating ADH as the lead agency in implementing 1986 amendments to the federal Safe Drinking Water Act, including the Wellhead Protection Program).

[106] ARK. CODE ANN. § 8-4-202 (2009).

[107] *Id.* at § 8-4-217. For purposes of the Arkansas Water and Air Pollution Control Act, pollution is broadly defined as "such contamination or other alteration of the physical, chemical, or biological properties of any waters of the state, or such discharge of any liquid, gaseous, or solid substance in any waters of the state as will, or is likely to, render the waters harmful, detrimental, or injurious to public health, safety, or welfare; to domestic, commercial, industrial, agricultural, recreational, or other legitimate beneficial uses; or to livestock, wild animals, birds, fish, or other aquatic life." *Id.* at § 8-4-102(6)

[108] *See* APCEC Regulation No. 1 (effective March 16, 1993).

[109] Draft Rule B-19 and Robinette, *supra* note 101.

owners and operators may apply for a general land application permit to dispose of "water based drilling fluids generated or utilized during oil and gas drilling operations."[110] However, the ADEQ specifically excepted "frac water [and] flow-back water" from eligibility for a general land application permit.[111] The ADEQ further noted in the response to comments it had received from industry to the general land application permit that "[p]ermittees are prohibited from storing fluids generated during the fracing process in clay-lined pits …[and that such fluids] must be disposed at an appropriately permitted facility."[112] As a result, it appears that the ADEQ may require that owners and operators arrange for off-site disposal of fracing fluids at proper disposal facilities. As yet, no Arkansas case specifically addresses fracing. Additionally, there are currently no legislative proposals that specifically address fracing.

Louisiana

Louisiana oil and gas regulations are promulgated and enforced by the Office of Conservation within the Louisiana's Department of Natural Resources. The Office of Conservation has primary statutory responsibility for regulation and conservation related to development oil, gas, lignite, and other natural resources.[113] Louisiana has limited regulations with regard to fracing, and most of those are applicable to all oil and gas wells and injection well construction and operations.[114] Slurry fracture injection wells, a type of waste disposal well that mixes the waste with water before injection, must comply with the applicable general requirements, public notice requirements, work permit requirements, legal permit conditions, permit transfer requirements, mechanical integrity pressure testing requirements, confinement of fluid requirements, and plugging and abandonment requirements of Louisiana law.[115]

Louisiana has passed detailed regulations dealing with disposal of exploration and production wastes by slurry fracture injection, including use of exploration and production wastes for fracing. The regulations

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[110] *See* ADEQ, Water Division, State Permits Branch, "Land Application of Water-Based Drilling Fluids – 00000 – WG – LA: Eligibility and Authorization," *available at* http://www.adeq.state.ar.us/water/branch_permits/nodischarge_permits/default.htm (last visited May 1, 2010).

[111] *See id.*

[112] ADEQ, Response to Comments to Permit Number 00000-WG-LA, Issue # 2, *available at* http://www.adeq.state.ar.us/water/branch_permits/pdfs/00000-WG-LA_response_to_comments.pdf, (last visited March 28, 2010).

[113] LA. REV. STAT. ANN. § 30.1 and § 30.4.

[114] *See* Office of Conservation: General Operations, LA. ADMIN. CODE tit. 43, Part XIX.

[115] *Id*. at Chapter 4.

mandate particular application requirements in §433(C) of Title 43, Part XIX; geological criteria for injection and confining zones in §433(E); construction requirements in §433(G); logging and testing requirements in §433(H); monitoring requirements in §433(I); operational requirements in §433(J); reporting requirements in §433(K); and permitting requirements in §433(L).[116]

Louisiana has also adopted specific rules related to the reuse of exploration and production waste in fracing operations.[117] Under the current regulations, an operator of record is entitled to a single use of exploration and production waste water to complete fracing operations on one well before being required to dispose of the waste. At the conclusion of fracing operations, all exploration and production waste must be disposed of onsite in accordance with §§311 and 313 or disposed of offsite in accordance with LA. ADMIN. CODE tit. 43, Part XIX, Chapter 5. Recently, the state has eliminated the one-time usage limitation on exploration and production waste, allowing unlimited recycling.[118] The purpose of the proposed changes is to ease restrictions on reuse of exploration and production effluent and decrease use of the limited freshwater aquifer resources of the Haynesville Shale region.

When fracing operations use groundwater instead of exploration and production waste, current regulations require that the owners of the well that is intended to provide the fracing water provide sixty (60) days notice to the Office of Conservation before using groundwater for fracing operations or any other non-domestic purpose.[119] The Office of Conservation has recently reaffirmed that a well owner's failure to properly notify the state could result in civil penalties.[120] Newly-enacted rules also add a reporting requirement that calls for operators conducting fracing to report the source of water and volume used in the process, including identifying either the water well number or water body name from which the water is drawn.[121]

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[116] *See* Disposal of E&P Wastes by Slurry Fracture Injection, LA. ADMIN. CODE tit. 43, Part XIX § 433.

[117] *Id*. at § 313.

[118] Louisiana Register Vol. 36, No. 6, pp. 1264-1265 (June 20, 2010).

[119] LA. REV. STAT. ANN. 3097.3.

[120] *See* News Release: "Office of Conservation reinforces that domestic water well owners must notify before selling water for industrial purposes," Department of Natural Resources Public Information Office, *available at* http://dnr.louisiana.gov/sec/execdiv/pubinfo/newsr/2009/1109con-water-selling.ssi (last visited April 1, 2010).

[121] *See* News Release: "State Office of Conservation requiring reporting of water source in hydraulic fracturing operations," Department of Natural Resources Public Information

To further protect groundwater resources, Louisiana regulations limit pump pressure to ensure that vertical fractures will not extend to the base of any underground source of drinking water ("*USDW*") or groundwater aquifer.[122] In addition, permit applications must include information showing that injection into the proposed zone will not initiate fractures through the overlying strata, which could enable the injection fluid or formation fluid to enter an underground source of drinking water.[123]

The Louisiana Commissioner of Conservation recently issued an order establishing "reasonable and uniform practices, safeguards and regulations for present and future operations related to the exploration for and production of gas from the Haynesville Zone in urban areas." The new regulations place specific limits on operating hours, noise pollution, and gas venting related to fracing. Operators covered under the rule must first record "a continuous seventy-two (72) hour ambient noise level at the drillsite." After this is established, no operator may "create any noise which causes the exterior noise level when measured at a distance of five hundred (500) feet from the well head, or other equipment generating noise" that "exceeds the daytime average ambient noise level by more than ten (10) decibels during fracturing or flowback operation."[124] The order also limits fracturing operations to daytime hours, as well as setting limits on the venting and flaring of gas associated with fracturing operations.[125] Municipalities and parishes that had initially resisted a statewide order in favor of more local control have instead adopted rules similar to and consistent with the Commissioner's order.[126]

Michigan

Michigan oil and gas regulations are promulgated and enforced by the Michigan Office of the Geological Survey (the "*OGS*") of the Michigan

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Office, *available at* http://dnr.louisiana.gov/sec/execdiv/pubinfo/newsr/2009/1008con-water-source.ssi (last visited April 1, 2010).

122 LA. ADMIN. CODE tit. 43 § 315.

123 *Id*. at § 405(b). (This evidence includes a plat showing the disposal well or enhanced recovery project, a copy of the Well History and Work Resume Report, a schematic diagram of the well, and all proposed operating data

124 Louisiana Department of Natural Resources, Office of Conservation, Order No. U-HS, 3(I)(2)(b), *available at* http://dnr.louisiana.gov/cons/orders/U-HS.pdf (last visited April 1, 2010).

125 *See id*. at 3(F); 3(H).

126 *See, e.g*., City of Shreveport Code of Ordinances, Chapter 25, *available at* http://library3.municode.com/default-test/home.htm?infobase=10151&doc_action=whatsnew (last visited April 1, 2010).

Department of Natural Resources & Environment (the "*DNRE*"),[127] pursuant to authority granted by the Natural Resources and Michigan's Environmental Protection Act.[128] The OGS reviews applications and issues permits to drill and operate wells for the production of oil and gas. However, other than the Supervisor of Well's[129] Letter of Intent, and more general laws and regulations related to exploration and development activities, hydraulic fracturing is unregulated as it relates to oil and gas production. The Letter of Intent is not a law or regulation, but rather an administrative directive limiting fracturing to a minimum depth of fifty (50) feet below the surface.[130] The Supervisor of Wells has the authority to regulate the secondary recovery methods of oil and gas, including pulling or creating a vacuum and the introduction of gas, air, water, and other substances into the producing formations.[131] Secondary recovery methods, such as fracing, are regulated by the same rules and regulations that generally regulate oil and gas drilling. No action is required before commencing fracing operations separate from the permits generally required before drilling an oil or gas well.

The permitting process to drill a well requires standard information such as well location, survey of the area, and a written application.[132] For injection wells, the application must include a statement that the injection of fluids will not exceed the fracture pressure gradient for the subsurface strata, which would appear to prevent fracing unless a well that is using fracing to increase production is not considered an injection well.[133] After completion, the Supervisor of Wells may request copies of service records showing all instances of fracturing[134] and within sixty (60) days of completion, the driller must file a list of all instances of perforating, acidizing, fracturing, shooting and testing.[135] A driller using secondary recovery methods must monitor and record the injection pressure, injection

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[127] *See* Office of Geological Survey, *available at* http://www.michigan.gov/deq/0,1607,7-135-3306_28607---,00.html (last visited Apr. 5, 2010).

[128] MICH. COMP. LAWS § 324.101 *et seq*. (1994). Referred to as Act 451.

[129] As used in Michigan oil and gas regulations, the Supervisor of Wells is the DNRE or OGS. See MICH. COMP. LAWS § 324.61501 (definitions).

[130] Personal communication with Mike Bricker, Environmental Manager, Michigan Office of Geological Survey, April 5, 2010.

[131] MICH. COMP. LAWS § 324.61506.

[132] *Id*. § 324.201.

[133] *Id*.

[134] *Id.* §324.416.

[135] *Id.* §324.418.

rate and cumulative volume of the fluid injected for each injection well monthly, and report that data to the Supervisor of Wells annually.[136]

Despite the language preventing fracturing in injection wells, Harold Fitch, Director of OGS reported in June 2009 that, "[h]ydraulic fracturing has been utilized extensively for many years in Michigan, in both deep formations and in the relatively shallow Antrim Shale formation. About 9,900 Antrim wells in Michigan produce natural gas at depths of 500 to 2000 feet. Hydraulic fracturing has been used in virtually every Antrim well."[137]

The frequency of hydraulic fracturing, relatively shallow average depth of the Antrim Shale formation and the chemicals used in fracing have raised water pollution concerns.[138] However, Director Fitch has not seen any reason for concern, stating, "[t]here is no indication that hydraulic fracturing has ever caused damage to ground water or other resources in Michigan. In fact, the OGS has never received a complaint or allegation that hydraulic fracturing has impacted groundwater in any way."[139]

No specific law or regulation exists relating to the impact of hydraulic fracturing of oil and gas wells on water quality separate from the laws and regulations generally relating to oil and gas drilling operations. Michigan does have laws protecting the surface waterways[140] from oil and gas wells[141] and, through them, any further damage caused by fracing. These regulations do not specifically address fracing, but generally prohibit any oil and gas activity from causing water contamination. Administrative rules relating to groundwater state that hydraulic fracturing of bedrock for water wells is not permitted without the prior written approval of the health officer.[142]

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136 *Id*. §324.806.

137 *Regulatory Statements On Hydraulic Fracturing Submitted By The States*, IOGCC website, June 2009 *available at* http://www.iogcc.state.ok.us/hydraulic-fracturing (last visited April 10, 2010).

138 Brian Creek, *WTF?* Hydraulic Fracturing in Antrim Shale will impact water resources*, March 19, 2010, The Round River, *available at* http://theroundriver.com/2010/03/19/wtf-hydraulic-fracturing-in-antrim-shale-will-impact-water-resources/ (last visited April 10, 2010).

139 IOGCC website, *supra* note 5.

140 MICH. COMP. LAWS § 324.32301 (defining "connecting waterway" as the St. Mary's river, Detroit river, St. Clair river, or Lake St. Clair).

141 MICH. COMP. LAWS § 324.61505a (preventing drilling under the Great Lakes or the connecting waterways), *Id.* § 324.61506 (instilling the supervisor of wells with the power to prevent the pollution of water by oil and gas and vice versa).

142 GROUNDWATER QUALITY CONTROL RULES, R 325.1637, Rule 137(3) adopted pursuant to Part 127, Act 368, P.A. 1978, as amended.

Local rules are being promulgated. For example, Marquette County Health Department created a Hydraulic Fracturing Request Review Policy that has been adopted by the State of Michigan.[143] To date, no case law related to fracing exists in Michigan.

Montana

The Montana Board of Oil and Gas Conservation (the "*MBOGC*"), a quasi-judicial body that is attached to the state's Department of Natural Resources and Conservation for administrative purposes only,[144] has primary authority—also called "primacy"—over regulating and administering the Montana Underground Injection Control (UIC) Program for Class II injection wells, defined below.[145] The MBOGC seeks to prevent harm to surrounding land or underground resources caused by oil and gas operations, "including but not limited to regulating the disposal or injection of water and disposal of oil field wastes."[146] It accomplishes this by, among other things, issuing drilling permits, classifying wells, and adopting and enforcing rules.[147]

The purpose of the Montana UIC Program is to protect USDWs.[148] The Montana UIC Program for all wells in Montana had previously been implemented directly by the EPA until, after several years of seeking delegation, Montana won state primacy over Class II wells in 1996.[149] All lands within Montana, excluding communal or allotted Indian lands under federal or tribal jurisdiction, are regulated by the Montana UIC Program.[150]

A Class II injection well is defined as "a well that is used to inject fluids for the enhanced recovery of oil or gas."[151] No person may commence, construct, or operate a Class II injection well without a permit from the MBOGC.[152] An application for a permit must include a

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[143] Michigan Department Of Environmental Quality, *Hydraulic Fracturing of Water Wells*, *available at* www.michigan.gov/documents/deq/deq-wd-gws-wcu-hydraulic fracturing_270750_7.pdf (last visited April 10, 2010)

[144] MONT. CODE ANN. § 2-15-3303 (2009).

[145] DNRC Montana Board of Oil and Gas, Montana Board of Oil and Gas Conservation, *available at* http://bogc.dnrc.mt.gov/BoardSummaries.asp (last visited Apr. 2, 2010).

[146] MONT. CODE ANN. § 82-11-111(2)(a) (2009); *see also Id.*

[147] MONT. CODE ANN. §§ 82-11-111(2)(b)–(c), (5)(a) (2009).

[148] DNRC Montana Board of Oil and Gas Board Summaries, *supra* note 145.

[149] *Id*.

[150] *Id*.

[151] MONT. ADMIN. R. 36.22.1401(4)(e) (2000); *see also* MONT. CODE ANN. § 82-11-101(3) (2009).

[152] MONT. ADMIN. R. 36.22.1402(1) (1996); *see also* MONT. CODE ANN. § 82-11-127(2) (2009).

description of the casing and cementing program that will be utilized to prevent migration of fluids into or between USDWs, as well as a description and analysis of the fluids to be injected to enhance production from the well.[153] The applicant must also demonstrate the mechanical integrity of any existing injection wells, submit a plan for corrective action should a USDW become threatened by an injection well, and to post a bond.[154] Following notice and hearing requirements, a Class II injection well permit may be authorized by the MBOGC.[155] The owner or operator of an approved Class II injection well must retain accurate drilling, production, and chemical analysis records for five years;[156] submit to having the well tested by a field representative of the MBOGC at least once every five years for mechanical integrity;[157] and pay an annual fee of $200.00 per well.[158]

The Montana legislature has authorized the MBOGC to prosecute violations or even threatened violations of MBOGC rules or orders by bringing suit, assessing civil or administrative penalties, or any combination of these remedies.[159] Civil fines range from $75.00 to $10,000.00 per day for each violation, while administrative fines could be as high as $125,000.00 total.[160] Moreover, a willful violation is deemed a misdemeanor and subjects the offender to criminal penalties of up to $10,000.00 per day of violation, imprisonment of up to six (6) months, or both.[161] Finally, violations which are causing or will cause substantial pollution such as would "represent an immediate threat to public health, safety, or welfare" are considered emergencies and authorize the MBOGC to order the immediate cessation or mitigation of the offending behavior,

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153 MONT. ADMIN. R. 36.22.1403(1)(h)–(i) (2000).

154 MONT. ADMIN. R. 36.22.1406 (1996); MONT. ADMIN. R. 36.22.1408 (2007); MONT. CODE ANN. § 82-11-123(5) (2009). The bond required of a Class II injection well applicant is the same bond required of all well permittees as security to properly plug and abandon the well once operations have permanently ceased. MONT. CODE ANN. § 82-11-123(5) (2009); MONT. ADMIN. R. 36.22.1408(1) (2007); MONT. ADMIN. R. 36.22.1308 (2007).

155 MONT. ADMIN. R. 36.22.1409 (1996); MONT. ADMIN. R. 36.22.1410 (2000); MONT. ADMIN. R. 36.22.1411 (1996).

156 MONT. ADMIN. R. 36.22.1415 (1996).

157 MONT. ADMIN. R. 36.22.1416–17 (1996).

158 MONT. ADMIN. R. 36.22.1423 (2000). The annual fee may be increased at the discretion of the MBOGC but cannot exceed $300 per injection well. MONT. CODE ANN. § 82-11-137(1) (2009).

159 MONT. CODE ANN. § 82-11-147 (2009).

160 MONT. CODE ANN. §§ 82-11-149, -147(1)(b) (2009).

161 MONT. CODE ANN. § 82-11-148 (2009).

including the immediate closure or shutdown of the injection well.[162]

Montana allows operators of Class II injection wells three (3) basic options to dispose of the waste fluid generated through the hydraulic fracturing process. Operators can either (i) "discharge [the fracing fluid] into existing drainages;" (ii) "put it in holding ponds and let it evaporate or seep into the ground;" or (iii) "reinject it into the aquifer" from which it was originally pumped.[163] Although reinjection is currently being given more consideration as the only environmentally safe disposal method of the three, it is also an expensive option and one that has not yet been used on a state-wide scale.[164]

While various state industry lobbyists, environmental groups, and members of the MBOGC itself are currently outspoken in debating the relative safety or dangers of utilizing fracing in Class II injection wells, there appears to be no case law discussing—or pending regulation aimed at changing—Montana's current Class II UIC Program.

New Mexico

New Mexico oil and gas regulations are promulgated and enforced by the Oil Conservation Division ("*OCD*") of New Mexico's Energy, Minerals and Natural Resources Department,[165] pursuant to authority granted by the New Mexico Oil and Gas Act.[166] However, other than notice requirements, and more general laws and regulations related to exploration and development activities, hydraulic fracturing is virtually unregulated. No action is required before commencing fracing operations. After completion, notice must be given to the OCD within thirty (30) days, using a form issued by the OCD.[167] The report must include "a detailed account of the work done and the manner in which the operator performed the work; the daily production of oil, gas and water both prior to and after the remedial operation; the size and depth of shots; the quantity and type of crude, chemical or other materials the operator employed in the operation;

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162 MONT. CODE ANN. § 82-11-151(1) (2009).

163 *Wyoming Federal Judge Overturns Montana Water Rules for Gas Drilling*, BILLINGS GAZETTE, Oct. 14, 2009, *available at* http://meic.org/water-quality/coal-bed-methane (last visited April 10, 2010). ("Existing drainages" includes streams and other waterways.)

164 *Id.*

165 *See* Oil Conservation Division, *available at* http://www.emnrd.state.nm.us/OCD/index.htm (last visited Mar. 30, 2010).

166 N.M. STAT. § 70-2-6 (2009).

167 N.M. CODE R. § 19.15.7.14(G) (2009). Notice is given using form C-103, attached. While some remedial work must be reported before commencing operations, fracing is not included. *Id*. § 19.15.7.14(A).

and any other pertinent information."[168] More elaborate notice is required in cases where operations may significantly impact the target or adjacent formations. If the operations actually injure the target or adjacent formations, or could create underground waste or contaminate any fresh water, notice must be given with five (5) working days of the operator's discovery of the situation, and the operator must then "proceed with diligence to use the appropriate method and means for rectifying the damage."[169] The OCD may require the well to be plugged if the injury is irreparable.[170]

Fracing can also raise water pollution concerns. While New Mexico has a Water Quality Act, it is pre-empted and does not apply in its own right to activities already subject to regulation by the OCD pursuant to its power to prevent water pollution. Water Quality Act regulations that could affect oil and gas activities each include a section that states it does not apply to activities regulated by the OCD under the Oil and Gas Act. [171]

In setting forth water quality standards, however, the OCD's oil and gas regulations refer back to the Water Quality Act regulations for guidance. For example, pollution must be controlled so that toxic pollutants, as defined by the Water Quality Act regulations, are not introduced into the water supply, and the concentration of other contaminants must meet the standards set forth in certain Water Quality Act regulations.[172] The Oil and Gas Act provide for authorization of different concentration standards in some situations, such as when abatement of the pollution to required levels is technically infeasible.[173] If pollution exceeds the applicable levels, it must be abated pursuant to an Abatement Plan approved by the Director of the OCD.[174] These regulations do not specifically address fracing, but generally prohibit any oil and gas activity from causing water contamination.

County and municipal regulations may also apply. For example, Santa Fe County enacted an oil and gas ordinance in December 2008 that, among other things, regulates fracing in the county that is not within an

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168 *Id*. § 19.15.7.14(G) (2009).

169 *Id.* § 19.15.16.16.

170 *Id*.

171 N.M. STAT. § 74-6-12. *See, e.g.*, N.M. CODE. R. §§ 20.6.2.1201, .3105, .5003.

172 N.M. CODE R. § 19.15.30.9(B). The applicable Water Quality regulations are §§ 20.6.2.7, 20.6.2.3103, and 20.6.4.

173 *Id*. § 19.15.30.9(E)-(F).

174 *Id*. § 19.15.30.11.

incorporated municipality.[175] Fracing activities are generally limited to the hours between 8:00 a.m. and 5:00 p.m., and may not exceed eighty (80) decibels at 300 feet from the source.[176] The contents of the fracing solution are also restricted. Fresh water meeting drinking standards is the only fluid that may be used. The solution may not contain hydrocarbons or other toxic contaminants, synthetic fracturing fluid, or brine. Other fluids may be authorized only if there is "clear and convincing evidence" that fresh water would damage the rock formation such that the oil and gas could not be recovered. [177]

As an example of municipal regulation, the city of Lovington in Lea County, a long-time center of oil and gas production in New Mexico, has also enacted an ordinance that affects fracing. The operator of a secondary recovery injection well must record monthly the injection pressure, injection rate, and cumulative volume of the fluid injected. The previous year's records must be submitted by March 1 of each year to the City Engineer, or operations must cease.[178] Any pressure test failure, significant pressure changes, or evidence of a leak must be verbally reported to the City Engineer within twenty-four (24) hours, and injection must cease if there is evidence that the fluid is not being injected into the correct strata.[179]

New York

Horizontal drilling and hydraulic fracturing techniques have been in common use for several decades in New York.[180] While general drilling regulations exist that affect fracing, anticipation of the development of the Marcellus Shale through high-volume hydraulic fracturing has lead to the proposal of several new laws and regulations.

Article 23 of the Environmental Conservation Law of the State of New York regulates generally the development, operation and utilization of oil and gas resources within the state and grants the Department of Environmental Conservation (the "*NYDEC*") the authority to administer

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[175] Santa Fe County, N.M., Santa Fe County Oil and Gas Amendment to the Santa Fe County Land Development Code, Ordinance No. 2008-19 (Dec. 9, 2008) (to be codified in the SANTA FE COUNTY LAND DEVELOPMENT CODE).

[176] *Id.* § 11.25.2, .3.

[177] *Id.* § 11.25.4.

[178] LOVINGTON, N.M., LOVINGTON MUNICIPAL CODE § 8.30.440(C).

[179] *Id.* § 8.30.440(F).

[180] N.Y. STATE DEP'T OF ENVTL. CONSERVATION, GAS WELL DRILLING IN THE MARCELLUS SHALE (2010), *available at* http://www.dec.ny.gov/energy/46288.html (last visited April 15, 2010).

such regulation.[181] The regulations enacted by the NYDEC are found in Title 6 of the New York Codes, Rules and Regulations and supersede all local laws relating to oil and gas regulation (except for local government jurisdiction over local roads and real property taxes),[182] however, all drilling and mining operations are still subject to all other laws that may be applicable (*e.g.* water use regulations, regulations on the transportation and storage of chemicals, etc.).

Any drilling project in New York State must pass an environmental review process, and drilling for oil or gas is prohibited without a permit issued by the NYDEC.[183] The NYDEC's discretionary approval of such a permit also triggers the application of the State Environmental Quality Review (the "*SEQR*").[184] A proposal to drill for oil or gas must either complete the full SEQR process,[185] or conform to the conditions and thresholds established in a generic environmental impact statement.[186] In 1992, the NYDEC adopted the Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (the "*1992 GEIS*") to establish the basis for environmental review and approval of oil and gas mining projects.[187]

Although the 1992 GEIS expressly identified and discussed hydraulic fracturing[188] and did not recommend any additional regulatory controls for

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181 N.Y. ENVTL. CONSERV. LAW §§ 23-0301, 23-0303(1) (2010).

182 N.Y. ENVTL. CONSERV. LAW § 23-0303(2) (2010).

183 N.Y. COMP. CODES R. & REGS. tit. 6, 552.1(a) (Sept. 6, 1991).

184 No agency may approve an action that may affect the environment by changing the condition of a natural resource until it has complied with the provisions of SEQR. N.Y. COMP. CODES R. & REGS. tit. 6, 617.3 (Jan 1, 1996).

185 *See* N.Y. COMP. CODES R. & REGS. tit. 6, 617.3 (Jan 1, 1996); *see also* N.Y. STATE DEP'T OF ENVTL. CONSERVATION, SEQR: GUIDING THE PROCESS (2009), *available at* http://www.dec.ny.gov/docs/permits_ej_operations_pdf/guidfnledits27409.pdf (last visited April 15, 2010).

186 When a generic environmental impact statement has been filed, no further SEQR compliance is required if a subsequent proposed action will be carried out in conformance with the conditions and thresholds established for such actions in the generic environmental impact statement or its findings statement. N.Y. COMP. CODES R. & REGS. tit. 6, 617.10(d)(1) (Jan. 1, 1996).

187 N.Y. STATE DEP'T OF ENVTL. CONSERVATION, FINAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM 1 (1992), *available at* http://www.dec.ny.gov/docs/materials_minerals_pdf/fgeisexecsum.pdf (last visited April 15, 2010).

188 The 1992 GEIS discussed hydraulic fracturing in the context of projects that: (i) require 80,000 gallons of fracturing fluid or less; (ii) were not located in the eastern portion of the state, near the New York City watershed infrastructure; and (iii) did not involve multiple wells drilled horizontally our of a single drilling pad. Anticipation of future

it,[189] in 2008, the NYDEC determined that some aspects of horizontal drilling and high-volume hydraulic fracturing warranted the further review in the form of a Supplemental Generic Environmental Impact Statement,[190] a draft of which has been released by the NYDEC (the "*Draft SGEIS*") for review and comment. In addition, on April 23, 2010 the NYDEC announced that drilling operations proposed within the watersheds relied on by New York City and Syracuse for drinking water would be unable to utilize generic environmental impact statements and would therefore require full, case-by-case SEQR reviews.[191] The form of SGEIS was released for public comment in 2009. Observers consider the SGEIS regulations potentially to be the strictest in the country, and many of the provisions overlap with the proposed legislation described above.

Hydraulic fracturing operators must prepare a fluid disposal plan to pass the NYDEC's SEQR review and be issued a permit. Any well-drilling operation that involves a risk that brine, salt water[192] or other polluting fluids will be produced in sufficient quantities to be deleterious to the surrounding environment requires a fluid disposal plan to be submitted in addition to the standard drilling permit application.[193] Depending on the method of disposal chosen by the applicant, an additional disposal permit or an acceptable disposal contingency plan may be required.[194] Hydraulic fracturing operations must then also pass the SEQR (through compliance with the 1992 GEIS, or otherwise through a project-specific determination of environmental impact) as any other gas drilling project would.

On August 5, 2010, the New York State Senate voted in favor of

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projects that would exceed the scope of these factors was the primary reason why the DEC determined that a Supplemental Generic Environmental Impact Statement (discussed below) was needed. N.Y. STATE DEP'T OF ENVTL. CONSERVATION, DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM 3-2 (2009), *available at* http://www.dec.ny.gov/energy/58440.html (last visited April 15, 2010).

189 *Id.* at 1-4.

190 *Id.*; A supplement to generic environmental impact statement is required when any action may have environmental impacts that were not addressed in that statement. N.Y. COMP. CODES R. & REGS. tit. 6, 617.10(d)(4) (Jan. 1, 1996).

191 Nick Malinowski, *NY Stiffens Rules for Fracking in Watersheds*, LAW360, Apr. 23, 2010, *available at* http://energy.law360.com/articles/164091 (last visited April 26, 2010).

192 Brine and salt water are both defined to mean any water containing more than 250 parts per million of sodium chloride or 1,000 parts per million of total dissolved solids. N.Y. COMP. CODES R. & REGS. tit. 6, 551.2(at) (May 28, 1985).

193 N.Y. COMP. CODES R. & REGS. tit. 6, 554.1(c)(1) (Jan. 9, 1980).

194 N.Y. COMP. CODES R. & REGS. tit. 6, 554.1(c)(1) (Jan. 9, 1980).

Senate Bill S 8129A, which provides for a moratorium on issuing drilling permits in the Marcellus until May 15, 2011. The New York State Assembly in slated to vote on their version of the bill within a month. Other moratoriums have been and are being considered which establish moratoriums on hydraulic fracturing until either the Draft SGEIS, defined below, is adopted[195] or the federal EPA releases a report on the effects of hydraulic fracturing on ground water and freshwater supplies, possibly as late as 2013.[196]

Certain drilling fluids may be disposed of through use for road de-icing, dust suppression or road stabilization. Production brine from oil or gas wells may be used for road spreading purposes after the proper permit and beneficial use determination applications have been filed and approved.[197] However, fracing fluids obtained during flowback operations may not be spread on roads and must be disposed of in an authorized manner.[198]

Several bills have been introduced in the state Senate and Assembly that seek to impose regulations specifically on hydraulic fracturing. One particular bill that has been introduced in both houses of the state legislature would increase the risks and burdens on gas well operators. Some of its provisions include: imposing a presumption of responsibility on a gas well operator when contamination of water wells occurs (rebuttable only by clear and convincing evidence); making the knowing discharge of fracing fluids into surface waters a class E felony; designating fracing fluids and drilling waste as hazardous waste; and creating additional requirements for the NYDEC to include in the permitting process, including the disclosure of all components of the fracing fluid to be used.[199]

Other bills have also been introduced which aim to: ban non-organic materials from being used in fracing fluid;[200] impose strict liability on well operators for any damage caused by hydraulic fracturing;[201] prohibit the use of chemicals that pose a risk to human health in fracing fluids

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195 A. 1322, 232nd Sess. (N.Y. 2009).

196 A. 10490, 233rd Sess. (N.Y. 2010).

197 N.Y. STATE DEP'T OF ENVTL. CONSERVATION, DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM Appendix 12 (2009), *available at* http://www.dec.ny.gov/energy/58440.html (last visited April 15, 2010).

198 *Id.*

199 S. 6244, 232nd Sess. (N.Y. 2009), A. 8748, 232nd Sess. (N.Y. 2009).

200 A. 6953, 232nd Sess. (N.Y. 2010).

201 S. 7377, 233rd Sess. (N.Y. 2010), A. 9414, 233rd Sess. (N.Y. 2010).

(including but not limited to chemicals that have been identified pursuant to the Federal Toxic Substances Control Act as persistent, bioaccumulative[202] and toxic or known mutagens).[203]

In addition, in June, 2010, Rep. Robert Sweeney sponsored legislation which would comprehensively change fracing regulations in New York.[204] Included in the bill are:

- a directive to state agencies to draft new regulations relating to the discharge of pollutants from facilities that treat wastewater from fracing facilities;
- clearance giving local governments more discretion in regulating fracing activities;
- further regulations of the plugging/abandonment and environmental reclamation of former fracing operations;
- requirements that operators disclose fracing fluid chemicals and imposition of strict financial liability on operators for any environmental damage caused by fracing; and
- new location restrictions on fracing, including setback restrictions; new fees on fracing; new air quality monitoring requirements; and new environmental assessment requirements.

When the Draft SGEIS is adopted, additional standards will exist for SEQR of high-volume[205] fracing operations. These operations will require an additional addendum to the required environmental assessment form.[206]

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202 "Bioaccumulation" is the process by which a substance or toxin accumulates in the tissues of a living organism. *See* United States Geological Survey, "Toxic Substances Hydrology Program" *available at* http://toxics.usgs.gov/definitions/bioaccumulation.html (last visited May 10, 2010).

203 A. 10091, 233rd Sess. (N.Y. 2010).

204 A. 11347, 233rd Sess. (N.Y. 2010).

205 High-volume hydraulic fracturing will be defined based on the total amount of fracturing fluid used in all stages of the fracturing operation: less than 80,000 gallons is not high volume and the operator only need comply with the mitigation measures outlined in the 1992 GEIS; between 80,000 and 299,999 gallons is possibly high volume and the DEC will determine which mitigation measures in the SGEIS must also be complied with; more than 300,000 gallons is always high volume and all SGEIS and GEIS mitigation measures are required to be taken to satisfy SEQR. N.Y. STATE DEP'T OF ENVTL. CONSERVATION, DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM 3-5 (2009), *available at* http://www.dec.ny.gov/energy/58440.html (last visited April 12, 2010).

206 *Id*. at 3-8. In addition, additional locations will require site-specific SEQR. *Id.* at 3-12 – 3.13.

Such addendum will require information related to fracing including: depth of fracture zones; identification of proposed fracturing service companies and additive products; the proposed volume of fracing fluid and the percent (by weight) of water, types of proppants and any other additives; the source of the water to be used in the fracing fluid; distances to nearby water wells, reservoirs, wetlands, lakes or ponds, and occupied structures.[207] In addition, fluid disposal plans for fracing will require additional information regarding: the planned transport of the fracing fluid off of the well pad; the planned disposition of the fracturing fluid (*e.g.*, treatment facility, disposal well, reuse, centralize surface impoundment, etc.); identification and permit numbers for any proposed treatment facility or disposal well located in New York; and location and details of construction and operational information for any proposed centralized flowback water surface impoundment.[208]

North Dakota

North Dakota's Legislative Assembly has not enacted any legislation specific to hydraulic fracturing. The North Dakota legislature gave the North Dakota Industrial Commission (the "*NDIC*") jurisdiction and authority over all persons and property, public and private, necessary to enforce legislation related to oil and gas conservation, the development and production of subsurface minerals, coal exploration, and lignite research, among other matters.[209] The NDIC has delegated the regulation of drilling and production of oil and gas to the Oil and Gas Division of the Department of Resources (the "*NDO&GD*").[210] The NDO&GD administers regulations of the drilling and plugging of wells, the restoration of drilling and production sites, the disposal of saltwater and oil field wastes, the spacing of wells, and the filing of reports on well location, drilling and production.[211] The NDO&GD is the administrative agency in North Dakota responsible for the enforcement of the rules and regulations that impact hydraulic fracturing.

Chapter 38-08 of the N.D. CENT. CODE regulates oil and gas resources, and vests the NDIC with the authority to require:

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[207] *Id*. at 3-8 – 3-12.

[208] *Id*. at 3-10 – 3-11.

[209] *Id*.

[210] *See* North Dakota Oil and Gas Division *available at* https://www.dmr.nd.gov.oilgas/ (last visited Apr. 6, 2010).

[211] See North Dakota Industrial Commission *available at* http://www.nd.gov/ndic/ic-about.htm (last visited Apr. 6, 2010).

> The drilling, casing, operation, and plugging of wells in such manner as to prevent the escape of oil or gas out of one stratum into another, the intrusion of water into the oil or gas strata, the pollution of freshwater supplies by oil, gas or saltwater, and to prevent blowouts, cavings, seepages, and fires;[212] … [and] to regulate: [t]he drilling, producing, and plugging of wells, the restoration of drilling and production sites, and all other operations for the production of oil or gas … disposal of saltwater and oilfield wastes.[213]

As seen in other states, although North Dakota's regulations do not directly address hydraulic fracturing, certain regulations related to preparation of the well site, the preservation of strata, and construction and completion of the well bore, and post-completion methods may effect hydraulic fracturing.

Drilling, Well Site Construction and Reclamation. Prior to commencing drilling operations, an operator must apply for and obtain the requisite permit from the NDO&GD.[214] The application must include the target depth, estimated depth to the top of important biostratigraphic markers, estimated depth to the top of objective horizons, the proposed mud and casing program, including the size and weight thereof, the depth at which each casing string is to be set, the proposed pad layout (including cut and fill diagrams), and the proposed amount of cement for completion, including the estimated top of cement.[215] Recompletion of the well or drilling horizontally requires an additional application for permit.[216] The NDO&GD director has the authority to deny an application for a permit if the proposal would cause, or is reasonably believed to cause, waste or violate correlative rights.[217] The decision to deny such application may be appealed.[218]

The NDO&GD may require the drill site to be sloped and a dike built to divert surface drainage when necessary to prevent pollution of the land surface and freshwaters.[219] The law generally prohibits long-term storage of saltwater, drilling mud, oil or other contaminates in any pit or open

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212 N.D. CENT. CODE § 38-08-04(1)(c) (2010).

213 N.D. CENT. CODE § 38-08-04.2.a and e (2010).

214 N.D. CENT. CODE § 38-08-05 (2010); N.D. ADMIN. CODE § 43-02-03-16 (2010).

215 N.D. ADMIN. CODE § 43-02-03-16 (2010).

216 *Id*.

217 *Id*.

218 *Id*.

219 N.D. ADMIN. CODE § 43-02-03-19 (2010)

receptacle except in an emergency.[220] However, to assure a supply of proper material or mud-laden fluid to confine oil, gas, or water to its native strata during the drilling of any well, each operator is required to provide a container or reserve pit to contain solids and fluids used and generated during well drilling and completion operations provided the pit can be constructed in a manner that prevents pollution of the land surface and freshwaters.[221] The reserve pit can only be used for drill cuttings and fluids used or recovered while actually drilling and completing the well.[222]

Generally, all waste associated with exploration or production of oil and gas other than drilling mud or drill cuttings must be properly disposed of in an authorized facility.[223] Water remaining in reserve pits must be removed and disposed of in an authorized disposal well or used in an approved manner.[224] The disposition of use of such water must be included on the notice that reports the reclamation plan.[225]

Casing, Tubing and Cementing Requirements. During the drilling of any oil or natural gas well, all oil, gas and water strata above the producing horizon must be sealed or separated where necessary to prevent their contents from passing into other strata.[226] An operator must shut off and exclude water from the penetrated oil-bearing and gas-bearing strata.[227] Water shutoffs are ordinarily made by cementing casing or landing casing with or without the use of mud-laden fluid.[228] The regulations prescribe specific casing, tubing and cementing requirements to "adequately protect and isolate all formations containing water, oil or gas or any combination of these; [and] protect the pipe through salt sections encountered … ."[229]

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220 N.D. ADMIN. CODE § 43-02-03-19.3 (2010) (such waste shall be removed from the pit or receptacle within 24 hours after being discovered and must be disposed of at an authorized facility).

221 N.D. ADMIN. CODE § 43-02-03-19 (2010)

222 *Id*.

223 N.D. ADMIN. CODE § 43-02-03-19.2 (2010)

224 *Id*.

225 *Id*.

226 N.D. ADMIN. CODE § 43-02-03-20 (2010). The regulation further provides that "[a]ll freshwaters and waters of present or probable value for domestic, commercial, or stock purposes shall be confined to their respective strata and shall be adequately protected by methods approved by [the Division]. Special precautions shall be taken in drilling and plugging wells to guard against any loss of artesian water from the strata in which it occurs and the contamination of artesian water by objectionable water, oil, or gas."

227 *Id*.

228 *Id*.

229 N.D. ADMIN. CODE § 43-02-03-21 (2010).

When casing or cementing becomes defective, the operator must conduct tests to evaluate the condition of the well bore and correct the defect, or, if the defect is irreparable, the operator must plug the well bore.[230]

The NDO&GD director may prescribe pretreatment casing pressure testing or other operational requirements designed to protect wellhead and casing strings during treatment operations.[231] When damage results from perforating, fracturing, or chemically treating a well, the operator must immediately notify the NDO&GD director and proceed with diligence to use the appropriate method and means for rectifying such damage.[232] If the damage cannot be undone, the NDO&GD director may order the operator to plug the well.[233]

Release Notifications. In the event fracing results in a fire, leak, spill or blowout, the operator verbally notify the NDO&GD director within twenty-four (24) hours of discovery of the fire, leak, spill or blowout.[234] In addition to providing notice to the NDO&GD director, the operator must also notify the surface owners.[235] Verbal notification must be followed by a written report within ten days after cleanup of the incident.[236]

Injection Control. Within the larger Department of Resources, the Division of Water Quality administers the standards and rules related to the Ground Water Protection Program.[237] The Ground Water Protection Program includes regulations that govern underground injection.[238] The Underground Injection Control Program classifies injection wells.[239] In turn, "Underground injection" is defined to mean the "subsurface emplacement of fluids…which are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production … unless those waters are classified as a hazardous waste at the time of injection…For enhanced recovery of oil or natural gas … .[240] The regulations specifically prohibit any "[u]nderground injection that

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230 N.D. ADMIN. CODE § 43-02-03-22 (2010).

231 N.D. ADMIN. CODE § 43-02-03-27 (2010).

232 *Id*.

233 *Id*.

234 N.D. ADMIN. CODE § 43-02-03-30 (2010).

235 *Id*.

236 *Id*.

237 *See* Division of Water Quality website at http://www.ndhealth.gov/WQ/ (last visited Apr. 7, 2010)

238 N.D. CENT. CODE § 61-28-02 (2010).

239 *Id*.

240 N.D. ADMIN. CODE § 43-02-05-01 (2010).

causes or allows movement of fluid into an underground source of drinking water."[241] An underground injection may not be conducted without first obtaining a permit from the NDO&GD after notice and hearing.[242]

Finally, in addition to the regulatory scheme administered by the NDO&GD, North Dakota's legislature enacted laws to control, prevent and abate pollution of North Dakota's waters.[243] The law defines "waters of the state" to include "other bodies or accumulations of water on or under the surface of the earth."[244] To advance the policy of the state to protect and maintain its waters, the law created a state water pollution control board to advise the state department of health with regard to water pollution issues.[245] In addition, the North Dakota state department of health is vested with the broad authority to "develop comprehensive programs for the prevention, control, and abatement of new or existing pollution of the water of the state"[246]

Ohio

Ohio statutes give the Division of Mineral Resources (the "*OHDMR*"), a branch of the Ohio Department of Natural Resources, "the sole and exclusive authority to regulate…oil and gas activities."[247] The Chief of the OHDMR (the "*DMR Chief*"), creates the rules for administration, implementation, and enforcement of the state's oil and gas laws.[248]

Current Ohio Fracing Law: New statutory revisions effective July 1, 2010 include provisions that directly affect fracing.[249] In addition, many of the laws regulating development of minerals generally also apply to fracing operations. Both the existing framework and the new statutory changes focus on safety requirements for drilling operations and protecting the integrity of potable water.

The current statute and administrative rules affect oil and gas developers engaged in fracing by heavily regulating the injection of saltwater, the fluid most commonly used in fracing. Currently, the only substantive statutory regulation explicitly affecting fracing is the waste

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241 N.D. ADMIN. CODE § 43-02-05-02 (2010).

242 N.D. ADMIN. CODE § 43-02-05-04 (2010).

243 N.D. CENT. CODE § 61-28 (2010).

244 N.D. CENT. CODE § 61-28-02 (2010).

245 N.D. CENT. CODE § 61-28-03 (2010).

246 N.D. CENT. CODE § 61-28-04 (2010).

247 OHIO REV. CODE ANN. § 1509.02 (2009).

248 *Id.* § 1509.03.

249 *See* OHIO REV. CODE ANN. §§ 1509.10, 1509.17, 1509.22 (effective July 1, 2010).

disposal requirements applicable to all well production.[250] The statute indirectly regulates fracing, however, by requiring the DMR Chief to issue a permit before any operator may inject saltwater as a part of "secondary or additional recovery operations."[251] The permit may not be issued for injection of fluids unless the DMR Chief concludes that:

> "the applicant has demonstrated that the injection will not result in the presence of any contaminant in underground water that supplies or can be reasonably expected to supply any public water system, such that the presence of any contaminant may result in the system's not complying with any national primary drinking water regulation or adversely affect the health of persons."[252]

The Administrative Code provides further guidelines for injecting fluids to aid in recovery by imposing numerous regulations for saltwater injection or brine injection wells. Specifically, each saltwater injection well must meet specific construction and permit requirements.[253] These requirements include that the surface casing be free of apparent defects and set at least fifty (50) feet below the deepest underground source of potentially potable water and that the well be inspected before initial injection.[254] A variance from these and other requirements may be obtained only if the volume of injection is sufficiently low and the DMR then makes the required statutory determination that fluid injection will not contaminate underground public water supplies.[255] In addition, no saltwater injection well may be drilled within one hundred feet of an occupied private dwelling.[256]

Before completion, an operator must obtain a permit from the OHDMR subject to approval from the DMR Chief.[257] The application for a permit must describe the casing in detail, include a map of the area (including the location of other wells), and must be accompanied by a notice to be filed with the OHDMR.[258] After the notice has been on file for fifteen days, the DMR then grants the permit provided it complies with

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250 *See* OHIO REV. CODE ANN. § 1509.22 (2009).

251 *Id.* § 1509.21 (2009).

252 *Id.* § 1501.22.

253 OHIO ADMIN. CODE §§ 1501:9-3-05, 9-3-06 (2009).

254 *Id.* § 1501:9-3-05.

255 *Id.*

256 *Id.* § 1501:9-3-09.

257 *Id.* §§ 1501:9-3-06 (A); 1501:9-3-12.

258 *Id.* § 1501:9-3-06(B)-(E).

regulatory requirements and no objections have been filed.[259]

The DMR Chief imposes additional operating requirements and reporting requirements on saltwater injection wells. First, operators may only inject saltwater or "standard well treatment fluid" into a well approved under the Administrative Code and may only do so up to a certain pressure.[260] Also, injection pressures, volumes, and the space between the well casing and tubing must be measured, and reports of the results must be submitted in a form supplied by the OHDMR once a year.[261]

2010 Fracing Revisions: The 128th General Assembly and the Governor of Ohio approved changes effective July, 2010. These changes include provisions which directly address fracturing.

First, the new statute defines "well stimulation" as "the process of enhancing well productivity, including hydraulic fracturing operations."[262] The statute creates new reporting and substantive requirements for activities relating to "well stimulation." Under the new law, within sixty (60) days of completing drilling operations to the proposed total depth of a well or discovery of a dry hole, the driller must file a well completion record[263] on a form approved by the DMR Chief. Among other details, the record needs to provide information about "the type and volume of fluid used to stimulate the reservoir of the well, the reservoir breakdown pressure, the method used for the containment of fluids recovered from the fracturing of the well, the methods used for the containment of fluids when pulled from the wellbore from swabbing the well, the average pumping rate of the well, and the name of the person that performed the well stimulation." In addition, the driller needs to include a copy of the log from the stimulation of the well, a copy of the invoice for each of the procedures and methods used on a well, and a copy of the pumping pressure and rate graphs.[264]

Aside from reporting requirements, the statute now explicitly requires the DMR Chief's written authorization before allowing "well perforation for purposes of stimulation in any zone that is located around casing that protects underground sources of drinking water."[265] In addition, new Ohio

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259 *Id.* § 1501:9-3-06(E)(2).

260 *Id.* § 1501:9-3-07(C)-(D).

261 *Id.* § 1501:9-3-07 (E)-(F).

262 OHIO REV. STAT. ANN. § 1509.01 (effective July 1, 2010).

263 The current statute requires a report within sixty days of "well completion."

264 *Id.* § 15.10(A)(9).

265 *Id.* § 15.17(A).

regulations require that pits or steel tanks to be used for "brine and other waste substances resulting from, obtained from, or produced in connection with drilling," to be constructed and maintained to prevent the escape of brine and other waste substances, as authorized by the chief of DMR. New statutes and regulations also impose restrictions on location of drilling with respect to distance of the site of drilling from an occupied dwelling or urban area.

Oklahoma

Oklahoma oil and gas regulations are promulgated and enforced by the Oklahoma Corporation Commission (the "*OCC*"), a constitutional agency,[266] through its Oil and Gas Conservation Division (the "*OGCD*").[267] The OCC rules and regulations are found in Title 165 of the Oklahoma Administrative Code (the "*OAC*").[268]

Hydraulic fracing has been used for over sixty (60) years in Oklahoma and is currently more highly regulated than in most states. The general rule concerning fracing fluid is OKLA. ADMIN. CODE § 165:10-3-10 (2003), which states "[i]n the completion of an oil, gas, injection, disposal, or service well, where acidizing or fracture processes are used, no oil, gas, or deleterious substances shall be permitted to pollute any surface and subsurface fresh water."

More specific management of fracing operations is found throughout the OAC. OAC § 165:10-3-3 through 10-3-4 regulate surface and production casing.[269] Specifically, § 165:10-3-3 requires operators to report any event of rupture, break, or opening that occurs in the surface or production casing. Regulations also govern the use of commercial and noncommercial pits[270] as well as plugging and abandonment.[271]

The OCC has adopted Oklahoma's water quality standards[272]

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[266] "The Corporate Commission was established in 1907 by Article 9 of the Oklahoma Constitution…." *See Oklahoma Corporation Commission History*, http://www.occ.state.ok.us/Divisions/COMM/commission-history.htm (last visited April 5, 2010).

[267] *See* Oklahoma Corporate Commission, http://www.occ.state.ok.us (last visited March 31, 2010); *see also* Oil and Conservation Division, http://www.occ.state.ok.us/Divisions/OG/newweb/og.htm (last visited March 31, 2010).

[268] OKLA. ADMIN. CODE § 165 (2003). Specifically, the oil and gas regulations are found in Title 165, Chapter 10 of the OAC.

[269] OKLA. ADMIN. CODE § 165:10-3-3 through 10-3-4 (2003).

[270] *See* OKLA. ADMIN. CODE § 165:10-7 through 10-9 (2003).

[271] *See* OKLA. ADMIN. CODE § 165:10-11 (2003).

[272] OKLA. ADMIN. CODE § 165:10-7-4 (2003).

established by the Oklahoma Water Resources Board.[273] Generally, OAC § 165:10-7-5 requires that "[a]ll operators, contractors, drillers, service companies, pit operators, transporters, pipeline companies, or other persons shall at all times conduct their operations in a manner that will not cause pollution."[274] The same section also provides rules regarding reporting of nonpermitted discharges.[275] Municipalities or other governmental subdivisions may also submit an application to the OCC requesting it to execute an order establishing special field rules within a particular area to protect and preserve fresh water supplies.[276]

In March 2010, the OCC submitted proposed amendments regarding its existing fracing rule to the Oklahoma legislature. These include a provision providing a cross-reference to existing rules that affect the management of fracing operations. It also includes the amendments establishing procedures for flowback water pits with capacity in excess of 50,000 barrels and new requirements for commercial recycling facilities.[277]

Pennsylvania

The Pennsylvania Bureau of Oil and Gas Management, a subdivision of the Pennsylvania Department of Environmental Protection (the "*DEP*"), oversees creation and enforcement of regulations related to exploration, development, and recovery of oil and gas resources in that state.[278] The Bureau of Oil and Gas Management has this authority pursuant to Pennsylvania's Oil and Gas Act.[279] As one of the original oil and gas producing states—oil has been extracted in the state since the middle of the 19th century—Pennsylvania has a well-developed system of common and statutory laws concerning oil and gas production, although much of the pertinent case law is over a century old. Despite the maturity and sophistication of the Pennsylvania oil and gas legal regime, there are practically no existing regulations that specifically target recovery through hydraulic fracturing.

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273 The Oklahoma Water Quality Standards are published in OKLA. ADMIN. CODE § 785:45 (2003).

274 OKLA. ADMIN. CODE § 165:10-7-5 (2003).

275 *Id.* at 10-7-5(c).

276 OKLA. ADMIN. CODE § 165:10-7-6.

277 *See* Oklahoma Corporate Commission, *available at* http://www.occ.state.ok.us (last visited March 31, 2010)

278 See Oil & Gas Programs, Pennsylvania Department of Environmental Protection *available at* http://www.depweb.state.pa.us/portal/server.pt/community/oil___gas/6003 (last visited Mar. 31, 2010).

279 58 PA. CODE SEC. 601, *et seq* (2009).

This will soon change, however. On January 28, 2010, Governor Ed Rendell proposed amendments to existing drilling regulations that, if adopted, will specifically affect the use of hydraulic fracturing. The governor also proposed the hiring of sixty-eight (68) inspectors to enforce the new rules.[280]

The proposed rules—which are currently open to public comment pending hearing—are almost entirely devoted to protecting water supplies.[281] Contamination of water supplies is commonly used as a basis for arguing that hydraulic fracturing should be limited or prohibited. The proposed amendments both strengthen the requirements for constructing well casing[282] and impose a stricter obligation on operators to replace any water supplies they contaminate.[283]

The proposed regulations add a general requirement that the operator construct and operate the well using "best engineering practices to ensure that the integrity of the well is maintained and health, safety, environment and property are protected."[284] Specifically, the operator is required to prevent "brine, completion and servicing fluids, and any other fluids from lower formations from entering fresh groundwater"[285] Also included is a proposal requiring the operator to prepare and maintain a "casing and cementing plan" that described how the well will be drilled and completed in compliance with the new regulations.[286] This plan must contain information regarding "anticipated fresh groundwater zones"[287] and "casing type, depth, diameter, wall thickness and burst pressure rating"[288] and a copy must be kept at the well site for review by authorities.[289]

In the event that the casing and cementing plan fails, resulting in contamination of groundwater, regulations concerning replacement of the water supply activate. The regulations already contain a general

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280 Hurdle, Jon, *Pennsylvania Plans More Gas Drilling Regulation,* REUTERS (Jan. 28, 2010), *available at* http://www.reuters.com/article/idUSN2812147220100128 (last visited September 13, 2010).

281 Advanced Notice of Proposed Rulemaking, 25 PA. CODE SEC. 78 Oil and Gas Wells, *available at* http://tjogel.org/wp-content/uploads/2009/10/King_Final.pdf (last visited September 13, 2010).

282 Section 78.73, *et seq*.

283 Section 78.51, *et seq*.

284 Section 78.73(a).

285 Section 78.73(b).

286 Section 78.83a(a).

287 Section 78.83a(a)(1).

288 Section 78.83a(a)(3).

289 Section 78.83a(b).

requirement that a well operator who contaminates or diminishes a water supply "replace the affected supply with an alternate source of water adequate in quantity and quality for the purposes served by the supply."[290] The proposed amendments, however, seek to add some specificity to this existing obligation. The new rules specify what it means for a replacement water supply to be of "adequate quantity" and "adequate quality." To be of adequate quantity, the replacement water supply must (i) deliver enough water to meet the user's need or (ii) connect to a public water system that supplies enough water to meet the user's need.[291] To be of adequate quality, the replacement water supply must (i) meet the standards established pursuant to the Pennsylvania Safe Drinking Water Act or (ii) be of comparable quality to the prior water supply, if the prior water supply did not meet the Water Act standards.[292]

On June 23, 2010, several Pennsylvania State Senators introduced a bill calling for the creation of an Emergency Drinking Water Support Fund.[293] The legislation would impose a $10 surcharge for every well permit.[294] That surcharge would accumulate in a fund, which would be used for "the testing of well water and purchasing of clean water for residents and businesses that have reason to believe their well water is contaminated from either an accidental spill of fracing water or chemicals, seepage of chemicals and fracing water or seepage of natural gas dislodged by the fracing process."[295] New legislation has been proposed to require more extensive environmental studies before Pennsylvania issues a drilling permit.[296] That same bill proposes to implement a fracing buffer zone, whereby fracing may not take place "within 3,000 feet of a reservoir that serves as a water source for a community water system," and would require each fracing operator to report the chemicals used in their fracing fluid.[297]

In addition to increased state-level regulation, operators are also finding themselves subject to new county and local government rules. For instance, Cecil Township in Washington County, Pennsylvania is in the process of enacting a zoning ordinance that treats all oil and gas development as a "conditional use" of land, meaning that the activity must

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290 Section 78.51(a).

291 Section 78.51(e)(3).

292 Section 78.51(e)(2).

293 S. 1416, 194th Sess. (Pa. 2010).

294 *Id.*

295 *Id.*

296 H. 2630, 194th Sess. (Pa. 2010).

297 *Id.*

be approved by the Cecil Township Board of Supervisors.[298] A number of Pennsylvania counties are becoming increasingly organized in their response to the increased drilling activity. For instance, Wayne County created an Oil and Gas Taskforce.[299] The mission statement of this taskforce is to "identify key issues, research facts, information, and review and provide public education regarding the economic, environmental and community impacts of oil and gas exploration of the Marcellus Shale in Wayne County."[300]

Despite the infancy of hydraulic fracturing laws and regulations in Pennsylvania, both state and federal environmental agencies have gone after various players in the Marcellus Shale, such as Cabot Oil & Gas. When water supplies near Cabot wells were found to be contaminated with methane, the DEP ordered Cabot to fix cement well casings in the area by March 31, 2010.[301] Cabot failed to meet this deadline and was fined $240,000, prohibited from drilling new wells in the area for one year, and will be fined an additional $30,000 a month until it fixes the well casings.[302] As a result of these events, Senator Bob Casey called on the U.S. Environmental Protection Agency to conduct an investigation on the impact of hydraulic fracturing on water sources in Pennsylvania.[303] As the use of fracing increases in Pennsylvania, interested parties should expect regulation and oversight by localities to grow correspondingly.

Texas

In Texas, fracing is not formally regulated.[304] The only regulations

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298 Proposed Ordinance of the Township of Cecil, Washington County, Pennsylvania, Providing for the Regulation and Zoning of Oil and Gas Drilling Operations, *available at* http://www.marcellus-shale.us/pdf/Cecil-Drill-Ord.pdf (last visited April 5, 2010).

299 Oil and Gas Taskforce, *available at* http://wcpaoilandgastaskforce.info/ (last visited April 5, 2010).

300 *Id*.

301 Allison, Jocelyn, *Cabot Ordered to Plug Wells in Pa. Pollution Probe,* LAW 360 (April 16, 2010).

302 *Id*.

303 Meyer, Elaine, *EPA Urged to Probe Fracking Water Pollution in Pa.,* LAW 360 (April 27, 2010).

304 *See Coastal Oil & Gas Corp. v. Garza Energy Trust*, 268 S.W.3d 1, 17 (Tex. 2008) ("Though hydraulic fracturing has been commonplace in the oil and gas industry for over sixty years, neither the Legislature nor the [RRC] has ever seen fit to regulate it, though every other aspect of production has been thoroughly regulated. Into so settled a regime the common law need not thrust itself."); ERNEST E. SMITH & JACQUELINE LANG WEAVER, 3 TEXAS LAW OF OIL AND GAS, §14.4(B) at 14-74 (2d. Ed. 2009) ("The Railroad commission has not yet taken any action to assert jurisdiction over hydraulic fracturing.").

that apply to fracing operations also apply to all other oil and gas operations. The RRC promulgates and enforces regulations related to oil and gas matters and has jurisdiction over all "oil and gas wells in Texas; persons owning or operating pipelines in Texas; and persons owning or engaging in drilling or operating oil or gas wells in Texas."[305] Contrary to the practice in other states, the Texas Commission of Environmental Quality is not the primary state regulatory agency with jurisdiction over oil and gas operations, nor the wastes produced during such operations.[306]

Like all oil and gas development in Texas, fracing operations require the RRC to issue a permit authorizing drilling and/or deepening of a well.[307] Besides the standard permitting, two key areas where the RRC's regulations have an impact on fracing operations (other than standard permitting): are, 16 TEX. ADMIN. CODE § 3.8 "Water Protection" and 16 TEX. ADMIN. CODE §3.13 "Casing, Cementing, Drilling, and Completion Requirements." The RRC believes that additional regulation of fracing is not necessary due to the strictness of the current regulations and the absence of any evidence that fracing fluids have contaminated groundwater in the sixty (60) years since producers first began fracing in Texas.[308]

In addition to permitting regulation, §3.8 also regulates the storage, transfer and disposal of oil and gas wastes. Presumptively, this includes any fracing fluids that are brought back to the surface as part of oil and gas production.[309] Although §3.46 is specifically intended to regulate injection of fluids as part of enhanced oil recovery or waste injection, the language of §3.46 could be interpreted to include fracing operations. Specifically, §3.46 states that a special fluid injection permit is required for "fluid injection operations in reservoirs productive of oil, gas, or geothermal resources." In spite of this language, in actual practice §3.46 does not currently create permitting duties for operators who engage in fracing within the State of Texas.[310] However, if federal regulations are amended

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[305] TEX NAT. RES. CODE § 81.051 (2010).

[306] 16 TEX. ADMIN. CODE §3.30 (2009). This regulation, called the Memorandum of Understanding, sets forth the jurisdictional boundaries between the Texas Commission of Environmental Quality and the RRC.

[307] 16 TEX. ADMIN. CODE §3.5 (2009).

[308] Randy Lee Loftis, *Loophole Lets Gas Drillers Inject Chemical; Texas Officials Say Water Untainted*, THE DALLAS MORNING NEWS, *available at* http://www.dallasnews.com/sharedcontent/dws/dn/latestnews/stories/012010dnmetbarnett.3d44452.html (last visited April 20, 2010).

[309] § 3.8 regulates drilling fluid pits, saltwater and brine storage pits, flare pits, sediment pits, etc. for the storage of oil and gas waste (as defined in § 3.8).

[310] SMITH & WEAVER, *supra* note 304.

to include fracing within the definition of Class II underground injection wells, then the RRC may be forced to follow suit.

Regulation of casing and cementing is the second way in which the RRC's standard oil and gas regulations affect fracing. The key concern of fracing opponents is the potential for fracing fluids to contaminate groundwater. The RRC is confident, however, that the current casing, cementing, drilling and completion regulations in 16 TAC §3.13 are sufficient to protect the State's groundwater resources from being contaminated by fracing fluids.[311] Therefore, unlike many states, the RRC does not require fluid injection permits for fracing similar to those required by 16 TEX. ADMIN. CODE § 3.46. No immediate plans exist for new State regulations specific to fracing.[312] The RRC holds fast to its claim that state rules for well construction have prevented even a single documented case of groundwater contamination from the injected fluids.[313]

West Virginia

The West Virginia Office of Oil and Gas (the "*OOG*") within the state's Department of Environmental Protection (the "*DEP*") is "responsible for monitoring and regulating all actions related to the exploration, drilling, storage and production of oil and natural gas," including ensuring that surface and groundwater is protected from drilling activities.[314] To that end, the OOG is the permitting authority for the state in all matters respecting the exploration, development, production, storage, and recovery of oil and gas.[315] A permit is required before any person can commence any "well work."[316] "Well work" is defined as including the stimulating or pressuring by injection of any fluid into a well.[317] To "stimulate" a well is "to increase the inherent productivity of an oil or gas well" by, among other actions, fracing the well.[318]

Specifically with respect to hydraulic fracturing, West Virginia runs its own Underground Injection Control (UIC) Program, which regulates

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311 Email from Ramona Nye, Media Relations Director, Railroad Commission of Texas, to J. Austin Frost, Associate, Haynes and Boone, LLP (April 13, 2010, 03:36 PM CDT) (on file with author).

312 Loftis, *supra* note 308.

313 *Id.* (Quoting Ramona Nye, spokeswoman for the Texas Railroad Commission)

314 Office of Oil and Gas, Our Mission, *available at* http://www.wvdep.org/item.cfm?ssid=23 (last visited Apr. 1, 2010).

315 W. VA. CODE § 22-6-2(c)(12) (2009).

316 W. VA. CODE § 22-6-6(a) (2009).

317 W. VA. CODE § 22-6-1(v) (2009).

318 W. VA. CODE § 22-6-1(s) (2009).

underground injections by five classes of wells.[319] "Class II" wells include wells "injecting fluids for enhanced recovery of oil or natural gas."[320] Class II wells must either be authorized by rule (in limited instances), or by permit.[321]

Applications for a permit to stimulate a well must be accompanied by a bond,[322] a plat,[323] and a corrective action plan "to prevent movement of fluid into underground sources of drinking water."[324] The applicant must also demonstrate the mechanical integrity of the well,[325] comply with notice requirements,[326] and pay a $150.00 fee for each activity for which an application is required.[327] After a public comment period and hearing,[328] the Director of the DEP will conduct a review of the application, including inspections if necessary.[329] Permits may be denied if the DEP Director determines that the applicant has previously committed a substantial violation of a previously issued permit, or if the proposed well work will constitute a hazard to human safety or to freshwater sources.[330] Once a permit has been issued and the well completed, the operator of the well must file a log that includes descriptions of the character, depth, and thickness of geologic formations encountered, (*including freshwater)*.[331] Moreover, the operator is required to retain all records "concerning the

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319 W. VA. CODE R. § 47-13-1.1 (2010).

320 W. VA. CODE R. § 47-13-4.2.b (2010).

321 W. VA. CODE R. § 47-13-9.1 (2010) ; *see also* W. VA. CODE title 22, art. 6 (2009) (governing criteria and standards for Class II wells).

322 W. VA. CODE §§ 22-6-6(b), -12(c), -26 (2009). The bond required of an applicant is the same bond required of all well operators and is conditioned on full compliance with all laws and rules related to, among others, the drilling, stimulating, and plugging and abandonment of the well. W. VA. CODE § 22-6-26(b) (2009).

323 W. VA. CODE § 22-6-12(a) (2009).

324 W. VA. CODE R. § 47-13-13.9.a (2010).

325 W. VA. CODE R. §§ 47-13-6.2, -13.7.h (2010).

326 W. VA. CODE §§ 22-6-6(c)(11), -9, -13 (2009).

327 W. VA. CODE § 22-6-29(b) (2009).

328 W. VA. CODE § 22-6-10 (2009); W. VA. CODE R. §§ 47-13-13.24.b, -13.27 (2010).

329 W. VA. CODE § 22-6-11(2009)

330 W. VA. CODE §§ 22-6-6(h), -11 (2009).

331 W. VA. CODE § 22-6-22 (2009). Section 22-6-22 was amended by the West Virginia legislature on March 8, 2010. The amendments include making filing requirements applicable only to "shallow wells" or "deep wells" drilled, and increase the types of information required to be included in the "completion report." The amended version of Section 22-6-22 will take effect on June 6, 2010. S.B. 382, 2010 Leg., Reg. Sess. (W. Va. 2010), *available at* http://www.legis.state.wv.us/Bill_Text_HTML/2010_SESSIONS/RS/BILLS/sb382%20enr.htm (last visited Apr. 5, 2010).

nature and composition of injected fluids until three (3) years after completion of any plugging and abandonment" of the Class II well.[332] Permits are effective for a fixed term not to exceed five years.[333]

Willful violations of any rule or order promulgated by the OOG are subject to a civil penalty—recoverable by the state through the filing of a civil lawsuit—of up to $2500.00 per day after notice of the violation is given by the DEP.[334] Willful violations of any provisions respecting drilling and casing of the well are deemed criminal misdemeanors and subject the offender to penalties of fines up to $5000.00, imprisonment for up to one year, or both.[335] Additionally, the DEP Director is authorized to bring suit for injunctive relief to enjoin any violations or threatened violations.[336] Finally, if an inspector of the OOG finds that, along with a violation or threatened violation, imminent danger to humans or freshwater sources exists from well operations, that inspector is authorized to issue an order requiring the well operator to immediately cease all well operations until the danger has been abated.[337]

Operators of Class II wells in West Virginia are required to permanently dispose of the waste water generated through the fracing process.[338] Operators will often temporarily store the fracing fluid in pits, although at least one operator unwittingly created environmental problems for the Monongahela River by sending its fracing fluid for treatment and disposal at a sewage treatment plant that was too small to handle the volume of effluent.[339] According to the OOG, while "a good bit of [fracing] water [is] reused," in volumetric terms most of the fracing fluid is ultimately disposed by reinjecting it underground through a UIC permit.[340]

The DEP—through the OOG and the Division of Water and Waste Management—has released a guidance document and permit addendum "designed to better manage water use and disposal [of fracing fluids] by the oil and gas industry when drilling in the Marcellus Shale formation." The guidance document and addendum can be found on the DEP's website

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332 W. VA. CODE R. § 47-13-13.6.b (2010).

333 W. VA. CODE R. § 47-13-13.13 (2010).

334 W. VA. CODE § 22-6-34(a) (2009).

335 W. VA. CODE § 22-6-34(b) (2009).

336 W. VA. CODE § 22-6-39 (2009).

337 W. VA. CODE § 22-6-3(a) (2009).

338 Ken Ward Jr., *DEP Rules on Hydraulic Fracturing Called Baby Steps*, CHARLESTON GAZETTE, July 16, 2009, at P1C.

339 *Id.*

340 Pam Kasey, *Pa., W. Va. Address Salt Problems Differently*, THE ST. J. (Morgantown), Jan. 8, 2010, at 21.

at www.dep.wv.gov/oil-and-gas.[341] Although other new rules recently proposed by the DEP would require synthetic liners for pits where toxic fluids used in fracing processes are stored, the proposed regulation would not require well operators to reveal what chemicals are added to the fracing fluids, nor would it reform disposal practices in the state.[342]

On March 5, 2010, the DEP released a "hydrofracturing reporting form." Applicable to wells that use over 750,000 gallons of water in the fracing process, the form requires information on: (1) the amount and location from which water was withdrawn; (2) the amount injected into the well; (3) the well's location; (4) the amount of flow-back water recovered;[343] and (5) the method and location of disposal, treatment, or recycling of the flow-back water. The form must be submitted within thirty days of the flow-back period.[344]

At the legislative level, the 2010 West Virginia legislature will be reconsidering a bill that would set an in-stream water quality standard of no more than 500 milligrams per liter for salt from produced water in surface waters. The bill, which was unsuccessfully first proposed in 2009, is aimed at protecting aquatic life after 22,000 fish and all of the mussels in Dunkard Creek in Monongalia County near Morgantown were killed. The cause of death was an algae bloom whose growth was alleged to be stimulated by high-salinity fracing fluid run-off from a point source upstream.[345] Another bill recently introduced in the state legislature would require, with some exceptions based on results of soil analyses, protective liners in all pits and impoundments used for holding fracing wastewater. A third bill in committee would require land owners to be notified before drilling companies could even apply for well work permits.[346] Currently, West Virginia surface owners are not required to be notified until the

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341 George Hohmann, *State Issues Guide for Natural Gas Drillers*, CHARLESTON GAZETTE, Jan., 14, 2010, at P2A.

342 Ken Ward Jr., *DEP Rules on Hydraulic Fracturing Called Baby Steps*, CHARLESTON GAZETTE, July 16, 2009, at P1C.

343 "Flow-back water" being fracing fluids returning to the surface after injection and fracing.

344 West Virginia State Agency Directory, News, Oil and Gas Companies Must Register Marcellus Shale Hydraulic Fracturing Water Use, *available at* http://www.dep.wv.gov/news/Pages/OilandgascompaniesmustregisterMarcellusShalefracwateruse.aspx (last visited Apr. 1, 2010).

345 Kasey, *supra* note 340.

346 Lawrence Messina, *W. Va. Lawmakers Again Try to Referee Gas Drilling*, THE ASSOCIATED PRESS ST. & LOC. WIRE (Charleston), Feb. 10, 2010, at State & Regional.

permit application has already been submitted and the land surveying completed.[347]

Other bills are pending before the West Virginia legislature. One bill requires the well operators withdrawing more than 210,000 gallons of water during any month from water resources of the state to submit information to the Office of Oil and Gas, including, *prior to drilling*, *fracturing or simulating gas wells,* identifying surface, ground, or purchased water sources, anticipated volume and time periods of water withdrawals, additives used in the water and anticipated methods for water withdrawal.[348] Another bill before the State Senate requires land owners to be notified before drilling companies could apply for work permits is under consideration by the current West Virginia legislature.[349]

Wyoming

Oil and gas drilling and production in Wyoming are regulated by the Wyoming Oil and Gas Conservation Commission (the "*WOGCC*") pursuant to authority granted by Title 30, Chapter 5 of the Wyoming Statutes.[350] The WOGCC's mission is to promote the beneficial and environmentally responsible development of Wyoming's oil and gas resources; its regulations are intended to protect human health and the environment "through the utilization of proven methods which are designed to avoid contamination of the soil, groundwater, and surface water at a drilling or producing location."[351]

Before any drilling or hydraulic fracturing work can begin in Wyoming, the operator must submit to the WOGCC's Supervisor (the "Supervisor"), and the Supervisor must approve, an Application for Permit to Drill or Deepen (Form 1), along with:

- an accurate plat showing the location of the proposed well and its total depth/endpoint,
- estimated depth to the top of important biostratigraphic markers and objective horizons,
- the proposed casing program, including size and width thereof,
- the depth at which each casing string is to be set and the amount of cement to be used,

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347 *Id*.

348 H.B. 4513, 79th Leg., 2nd Sess.

349 S.B. 682, 79th Leg., 2nd Sess.

350 WYO. STAT. ANN. §§ 30-5-101 – 30-5-126.

351 Wyoming Oil and Gas Conservation Commission ("*WOGCC*") Rules and Regulations, Chapter 2, Section 1(b).

- the depth of perforations or the openhole interval,
- the source of water and/or trade name of fluids,
- the type of proppants, and
- the estimated pump pressures. [352]

The applicant must also provide information related to the drilling plan, "together with any other information which may be required by the Supervisor;"[353] and the plan must be accompanied by a statement of compliance certifying that the oil and gas operator has (i) provided notice of the proposed oil and gas operations to the surface owner; (ii) engaged in good faith negotiations to reach a surface use agreement with the surface owner, and (iii) satisfied the conditions of WYO. STAT. ANN § 30-5-402(c).[354]

In addition, the applicant must comply with casing and cementing requirements promulgated by the WOGCC to ensure surface water isolation, reservoir isolation, and cased hole integrity for hydraulic fracturing.[355] Production and intermediate casing design provide reservoir isolation; and casing must be cemented from bottom to top to ensure that there are no voids.[356]

Finally, after the hydraulic fracture treatment is complete, the Supervisor must be provided with a "detailed account" of:

- the work done and the manner in which such work was performed;
- the daily production of oil, gas and water both prior to and after the operation;
- the size and depth of perforations;
- the quantity of sand, crude, chemical, or other materials employed in the operation; and
- any other pertinent information of operations which affect the original status of the well.[357]

Current Developments in Permitting Requirements for Fracing Operations: In what appears to be a response to complaints from two

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[352] WOGCC Rules and Regulations, Chapter 3, Sections 1(a), 8(a) and 8(c).

[353] WOGCC Rules and Regulations, Chapter 3, Sections 8(c).

[354] WOGCC Rules and Regulations, Chapter 3, Section 8(d). Section 30-5-402 is entitled "Entry upon land for oil and gas operations and nonsurface disturbing activities; notice; process; surety bond or other guaranty; negotiations."

[355] WOGCC Rules and Regulations, Chapter 3, Section 22.

[356] *Id.*

[357] WOGCC Rules and Regulations, Chapter 3, Section 12.

Wyoming communities of contaminated water supplies, the WOGCC considered proposed changes to the regulations and is considering additional requirements, including that (i) operators be required to disclose "proprietary chemical component detail" of the fluids used in the fracturing process;[358] (ii) wells undergoing hydraulic fracturing be cased in a way that prevents groundwater contamination; and (iii) operators be aware of all permitted water wells within a quarter-mile of a well undergoing fracing.[359]

After WOGCC hosted public hearings on the new regulations and the referenced proposals on April 14, 2010, and a public comment period thereafter, it promulgated new regulations which went into effect on September 15, 2010, requiring submission to WOGCC by operation of a complete of chemicals used in fracing operations for each well. Operators must now provide the names of chemical additives and the CAS number, compound type, and compound concentrations or rates proposed to be mixed and injected as part of the hydraulic fracturing process. Operators retain the right to claim that certain chemical specifications of the fracing fluid are proprietary and should be kept confidential by WOGCC. It remains unclear to what extent industry will make this claim.[360]

Wyoming Rules and Statutes Governing Byproduct Water Use and Storage: Jurisdiction over water use and rights is vested with the Wyoming State Engineer.[361] The office of the State Engineer directs water use and also enforces regulations related to water by-products, defined as:

"Water which has not been put to prior beneficial use and which is a by-product of some nonwater-related economic activity and has been developed only as a result of such activity. By-product water includes, but is not limited to, water resulting from the operation of oil well separator systems or mining activities such as dewatering of mines."[362]

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[358] According to Tom Doll, the WOGCC's Supervisor, "Now we're going to ask them to provide how much of that is a gelling agent, how much of that is a surfactant, how much of that is a biocide, and what is the biocide name and what is the concentration." Addie Goss, *Vote May Come on New Fracing Rules*, Wyoming Public Radio News, April 2, 2010.

[359] *See* Staff, *State Oil and Gas Commission Getting Input on Proposed Rule Changes,* Wyoming Energy News, March 29, 2010; *see also* Bob Moen, *Wyoming Community Blames Fracing for Water Problems*, The Billings Gazette, September 7, 2009 (where it was reported that the EPA has launched an investigation into the complaints of Pavillion, WY residents after it was determined that 11 of 39 wells in- the area were contaminated).

[360] Chapter 3 – Operation Rule, Drilling Rules in WOGCC's Current Rule and Regulations, filed August 17, 2010, *available at* http://soswy.state.wy.us/Rules/RULES/7928.pdf (last visited on October 31, 2010).

[361] WYO. STAT. ANN. §§ 41-3-905 and 41-3-909.

[362] WYO. STAT. ANN. § 41-3-903 (West 2002).

Any person intending to appropriate/use by-product water, including water from fracing operations, for beneficial use must file an application with the State Engineer on the forms and in the manner prescribed for groundwater applications. 'By-product water' is considered as being in the same class as groundwater for the purposes of administration and control.[363]

Storage of by-product water is also regulated by the State Engineer. If a surface impoundment will be used to store produced water for additional beneficial uses, a reservoir permit must be obtained from the State Engineer prior to commencement of construction of the impoundment. In particular, in addition to submitting a Form 14A application for a "Produced Water Pit," the applicant must provide a standard water analysis (Form 17), to include maximum and average estimated inflow, size of pit, freeboard capacity, origin of pit contents, method of disposal of pit contents, maximum fluid level above average ground level, distance to closest surface water, depth to groundwater, subsoil type and type of sealing material.[364] A plan view map and topographic map of sufficient size and detail to determine surface drainage system and all natural waterways and irrigation systems, if applicable, must also be attached.[365] The WOGCC may request additional information, as well. The WOGCC has also implemented rules and regulations governing the location, marking and construction of these produced water pits.[366]

Fracing in Indian Country

Indian Country consists of a patchwork of land owned and controlled by a variety of authorities.[367] In addition to the actual communally-owned

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363 WYO. STAT. ANN. § 41-3-904.

364 WOGCC Rules and Regulations, Chapter 4, Section 1(r) ("Because of the potential for direct communication with shallow groundwater resources of the state, application for approval of construction of percolation pits for containment and discharge of water produced in association with coalbed methane gas in the Power River Basin may be accompanied by a review of the groundwater issues by the Dept. of Environmental Quality as determined by the Supervisor. If the proposed construction meets with requirements of the Commission's rules, the application may be granted.").

365 *Id.*

366 *See* WOGCC Rules and Regulations, Chapter 4, Sections 1(t) - (w).

367 18 U.S.C. § 1151, a law within the federal criminal code but whose definition has gotten credence in civil cases such as *Alaska v. Native Village of Venetie Tribal Government*, 522 U.S. 520 (1998) and *Mustang Production Co. v. Harrison*, 94 F.3d 1382 (10th Cir. 1996) *cert. denied*, 520 U.S. 1139 (1997), defines the term "Indian Country" as:

reservation lands, there are plots owned by individual Indians both in trust with the federal government and by themselves in fee. In addition, non-Indians own land within the reservation boundaries. It is these non-Indian landowners—and who can govern them—that provide the greatest source of consternation regarding state, tribal, and federal regulation of exploration and development.

Most tribes in the United States look to the Bureau of Indian Affairs ("*BIA*") to provide regulation of oil and gas development on their reservation lands. Historically, this was the exclusive realm of the BIA to protect tribes from fraud. However, as some tribes became more sophisticated with regards to mineral development, they agitated for more control. Now, tribes may assert regulatory control over non-natives on reservation lands whether the specific land in question is considered tribal or is held in fee by non-Indians.[368] State regulation, particularly if a strong state interest is not implicated, is considered to be pre-empted by tribal and federal authority.[369] This is especially the case if state regulatory control would disrupt a pre-existing tribal regulatory scheme.[370]

The general rule is that a tribe's inherent government authority does not allow the regulation of non-native activity on non-native land within "Indian country."[371] This rule is subject to two major exceptions. The first is that non-natives can enter into consensual dealings with tribes, thus subjecting themselves to tribal regulation and liability. The second is that tribes can regulate non-native behavior in Indian country where the non-native behavior, such as the operations of a developer, significantly affects the health and welfare of a tribe.[372]

> "(a) all land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and, including rights-of-way running through the reservation, (b) all dependent Indian communities within the border of the United States whether within the original or subsequently acquired territory thereof, and whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a state, and (c) all Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same."

368 Judith V. Royster and Rory SnowArrow Fausett, *Control of the Reservation Environment: Tribal Primacy, Federal Delegation, and the Limits of State Intrusion*, 64 Wash. L. Rev. 581, 597 (1989).

369 New Mexico v. Mescalero Apache Tribe, 462 U.S. 324, 344 (1983), (holding that native control over regulation of non-native fishing and hunting on tribal land was exclusive.)

370 *Id.* at 338.

371 Montana v. United States, 450 U.S. 544, 565 (1981).

372 *Id.*

Development of the mineral estate sometimes entails both exceptions. The first is often seen in modern oil and gas leases executed by tribes operating under the auspices of the 1982 Indian Mineral Development Act (IMDA)[373] which allows tribes to negotiate and lease more-or-less directly with developers, subject to the ultimate approval of the Secretary of the Interior. The second exception would be entailed, at least in theory, when development activities led to surface damage or groundwater contamination that adversely affected a tribe.[374]

The SDWA and the Clean Water Act (CWA)[375] were amended to give tribes the same standing as states with regards to allowing tribes to assume responsibility for water quality control in Indian country.[376] The scope of tribal control granted reflected the complex landholding situation on many reservations, allowing the tribe to regulate reservation, trust lands, allotted lands, and fee lands of both Indians and non-Indians.[377]

A tribe can gain recognition as an entity which can invoke and enforce environmental regulations. The tribes-as-states (TAS) provisions in the SDWA and CWA require tribes to meet three criteria to be treated the same as states—*i.e.* given authority to implement programs allowed by the two acts.[378] First, the tribe must be federally recognized.[379] Second—and depending on the act invoked—the tribe must either show that the power to be exercised must be limited to lands held in fee by the tribe, held in trust by the federal government, held in fee by a tribal member, or are otherwise in Indian country or that the tribe exercise jurisdiction over the land in question.[380] Finally, the tribe must show that it is capable of carrying out the necessary duties and investigations to enforce regulations, such as providing adequate and qualified oversight personnel and drafting workable regulations.[381]

Currently, no Indian tribes have tribal statutes or regulations which touch directly upon fracing. Developers leasing from tribes should be become familiar with the production and environmental regulations of the

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373 25 U.S.C. §§ 2101-2108.

374 This second Montana exception has proved an elusive protection for tribes to invoke.

375 33 U.S.C. § 1251 *et seq.*

376 Clean Water Act Amendments, 33 U.S.C. § 1377 (1987)

377 *See id.* § 1377(e)(2)

378 Safe Drinking Water Act (SDWA) tribes-as-state provisions: 42 U.S.C. § 300j-11(a); Clean Water Act (CWA) tribes-as-states provisions: 38 U.S.C. § 1377(e)

379 SDWA: 42 U.S.C. § 300j-11(b)(1); CWA: 38 U.S.C. § 1377(e)(1)

380 SDWA: 42 U.S.C. § 300j-11(b)(2); CWA: 38 U.S.C. § 1377(e)(2)

381 SDWA: 42 U.S.C. § 300j-11(b)(3); CWA: 38 U.S.C. § 1377(e)(3)

appropriate tribe(s) or the current BIA regulations which will govern their operations.

Federal Regulation of Fracing

The federal regulation of hydraulic fracturing, primarily under the SDWA,[382] has been the subject of much debate.[383] Included within the SDWA is a program that provides for regulatory management of the injection of fluids whose injection may result in contamination of underground sources of drinking water.[384] This program is known as the Underground Injection control ("*UIC*") program. Under the SDWA, states can retain primacy over their own UIC own program of groundwater protection if they submit their proposed UIC program to the EPA for approval and unless the EPA determines that the state's UIC program does not meet the SDWA's standards. If approved, the state retains primacy, administers the program, and has responsibility for regulation and enforcement.

Under the SDWA and the EPA's associated rules, for a state program to be approved, states must prohibit underground injection unless it is authorized.[385] 'Underground injection' is defined as the "subsurface emplacement of fluids by well injection."[386] In 2005, legislative amendments made clear that the SDWA does not regulate hydraulic fracturing operations.[387] The Energy Policy Act of 2005 amended the SDWA to exclude from the definition of underground injection "the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations relating to oil, gas, or geothermal activities."[388] Many sources critical of the exception refer to it as the "Halliburton Loophole."[389] Thus, with the exception of fracing

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382 42 U.S.C. 8300rf *et seq*.

383 *Compare* New York Times Editorial, *Finding Natural Gas, Safely*, N.Y. TIMES, Mar. 20, 2010, at A20 (in favor application of the SDWA to fracing), *with* Christopher S. Kulander, *Feds Haven't Made Case for Oversight of Fracking*, HOUSTON CHRONICLE, Apr. 22, 2010, at B11, *and* Wes Deweese, *Fracturing Misconceptions: A History of Effective State Regulation, Groundwater Protection, and the Ill-Conceived FRAC Act*, 6 OKLA. J.L. & TECH. 49 (2010) (against application of the SDWA to fracing)

384 42 U.S.C. 8300h.

385 *See* 40 C.F.R. 145.11(a)(5).

386 42 U.S.C. § 300h(d)(1).

387 *Id*.

388 Aug. 8, 2005, Pub.L. 109-58, Title III, § 322, 119 State. 694).

389 "The Halliburton Loophole" New York Times (Nov. 9, 2009), *available at* www.nytimes.com/2009/11/03/opinion/03Tue3.html (last visited May 4, 2010).

using diesel fluids, the SDWA does not impose direct regulation.

Legislation has been introduced to bring hydraulic fracturing under federal oversight. Bills have been filed in both the U.S. House and Senate in the current legislative session to reverse the changes to the SDWA made in the Energy Policy Act of 2005 and bring hydraulic fracturing operations within the definition of underground injection.[390] The proposed legislation also would require the disclosure of the chemical constituents of the fracturing fluid and proppants, which then would be posted on a government-approved website. As of April, 2010, neither the House nor Senate version of the bill had been affirmatively voted out of committee.

Further scrutiny of fracing will undoubtedly occur as the EPA moves forward on a study of hydraulic fracturing risks. In the funding bill for environment agencies for fiscal year 2010, Congress urged the EPA to conduct a study on the relationship between hydraulic fracturing and drinking water. The EPA has announced that it will conduct a "comprehensive research study to investigate the potential adverse impact that hydraulic fracturing may have on water quality and public health."[391] News reports indicate that some members of the EPA's science advisory board guiding the research are advocating that the study be expanded beyond potential impacts on water supplies, to consider a "full life-cycle analysis" of hydraulic fracturing.[392] Items flagged in the scoping materials for the study include an evaluation of issues that seem to go beyond hydraulic fracturing, such as site preparation and well construction activities, issues associated with produced water storage, treatment and disposal, and air emissions from both hydraulic fracturing and associated gas production operations.[393]

In addition to the EPA study, Congressmen Henry Waxman (D-CA) and Ed Markey (D-MA) are launching a parallel inquiry into hydraulic fracturing.[394] In a February 18, 2010 memorandum, the two representatives announced that they have requested information from eight oil and gas service companies regarding the chemicals used in fracturing

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390 *See* Senate Bill S. 1215, House Resolution H.R. 2766.

391 EPA Press Release, "EPA Initiates Hydraulic Fracturing Study: Agency seeks input from Science Advisory Board," March 18, 2010.

392 "*EPA Advisory Panel Weighs Expansion of Fracing Study*" LAND LETTER, April 8, 2010, available at http://www.eenews.net/ll/2010/04/08/ (last visited April 17, 2010).

393 Scoping Materials for Initial Design of EPA Hydraulic Fracturing Research Study, U.S. Environmental Protection Agency, Office of Research and Development, March 2010, *available at* http://yosemite.epa.gov/sab/SABPRODUCT.NSF/b5d8a1ce9b0729348525 7375007012b7/3B745430D624ED3B852576D400514B76/$File/Hydraulic+Frac+Scopi ng+Doc+for+SAB-3-22-10+Final.pdf (last visited April 17, 2010).

394 "Waxman, Markey Launch Hydraulic-Fracturing Inquiry" E&E News, Feb. 18, 2010.

fluids, stating that the purpose of the inquiry is to assess whether the practices "poses any environmental or public health risks that Congress should address."

The hard look that fracing is now receiving is the latest in a long history of dispute and controversy over the regulation of hydraulic fracturing under the SDWA. Before litigation in 1997, the EPA had not regulated hydraulic fracturing under the SDWA and had believed that hydraulic fracturing was not intended to be regulated under the SDWA.[395] The dispute that changed the EPA's position started in 1994, when LEAF petitioned the EPA to withdraw the EPA's approval of Alabama's UIC program because it did not regulate hydraulic fracturing associated with coal bed methane production.[396] The EPA rejected LEAF's request and LEAF appealed the EPA's decision.[397]

In 1997, the Eleventh Circuit ruled on LEAF's appeal and concluded that hydraulic fracturing is included in the definition of 'underground injection.'[398] Alabama submitted a revised UIC program to the EPA, and the EPA approved the program.[399] LEAF again appealed the EPA's approval of Alabama's program. In this second appeal, the EPA was successful and the court generally upheld Alabama's program.[400] The court remanded one issue to the EPA for consideration—the EPA's classification of the hydraulic fracturing as not a Class II injection well, and remanded the compliance of Alabama's program with the Class II well program requirements.[401]

Following the LEAF decisions, bills were introduced to reverse the cases' requirements that fracing be regulated under the SDWA. However, until 2005, with the enactment of the Energy Policy Act, discussed above, the legislation was not passed. In the interim, the EPA entered into a Memorandum of Agreement with three hydraulic fracturing companies under which those companies agreed to eliminate diesel from fracturing

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395 65 Fed. Reg. 45774 (July 25, 2000).

396 *See* Legal Environmental Assistance Foundation, Inc. v. United State Environmental Protection Agency, 118 F.3d 1467, 1471 (11th Cir. 1997).

397 *Id*.

398 *Id*. at 1478.

399 *See* Legal Environmental Assistance Foundation, Inc. v. United States Environmental Protection Agency, 276 F.3d 1253, 1256 (11th Cir. 2001).

400 *Id*. at 1365.

401 *Id*. at 1264.

fluids in coalbed methane production wells.[402]

During this same time period, the EPA undertook a study of hydraulic fracturing and its impacts on drinking water sources.[403] This study involved a review of coalbed methane fracturing practices, literature review, and evaluation of reported instances of groundwater contamination from hydraulic fracturing operations. The EPA ultimately concluded that "the injection of hydraulic fracturing fluids into CBM wells poses little or no threat to USDWs…."[404]

Whether further EPA regulations will apply to fracing appears to be a point of contention between some states and the federal government. For example, in a resolution passed by the 61st Legislative Assembly of North Dakota, the legislature specifically noted that the EPA has never interpreted hydraulic fracturing as constituting 'underground injection' under the Safe Drinking Water Act.[405] The North Dakota legislature further observed that "regulation of hydraulic fracturing as underground injection under the Safe Drinking Water Act would impose significant administrative costs on the state, substantially increase the cost of drilling oil and gas wells, and potentially stop the development of our state's valuable natural resources include the Bakken and other formations with no resulting environmental benefits."[406] Thus, North Dakota currently rejects the contention that its regulatory scheme does not adequately protect against the environmental threats allegedly associated with hydraulic fracturing, and the notion that hydraulic fracturing should be regulated as an underground injection. Lynn Helms, director of North Dakota's Department of Mineral Resources, stated in a House Energy and Mineral Resources Subcommittee hearing in June of 2009:

> "As the head regulator of oil and natural gas development in the state of North Dakota and an officer of the IOGCC representing all oil and natural gas producing state regulators, I can assure you that we have no higher priority than the protection of our states' water resources. … It

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402 Memorandum of Agreement between the U.S. Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation (Dec. 12, 2003).

403 Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, June 2004, United States Environmental Protection Agency.

404 *Id*. at ES-1.

405 S. Con. Res. 4020, 61st Leg., Reg. Sess. (N.D. 2009). Legislative history *available at* http://www.legis.nd.gov/assembly/61-2009/bill-actions/ba4020.html (last visited Apr. 6, 2010).

406 *Id*.

> is my firmly held view and that of the IOGCC that the subject of hydraulic fracturing is adequately regulated by the states and needs no further study."[407]

Given that the EPA has never interpreted the injection of fracing fluids into a wellbore to be an 'underground injection' under the SDWA, and the increased costs with no resulting environmental benefit, it is likely that other states will also reject the argument that fracing comes within a regulatory scheme that addresses underground injection. However, a number of states have bifurcated coverage of environmental issues arising from oil and gas. A common arrangement, as seen above, is to have one state agency regulate oil and gas conservation and development, but to have limited environmental regulatory oversight, and to have a second state agency regulate environmental issues without considering oil and gas development except for downstream effects.

If there is a gap between the coverage of two such agencies wherein regulation of fracing operations (outside of common county and municipal ordinances, such as those governing noise and traffic control of production equipment) and the disposal of used fracing fluid falls, potential problems associated with fracing may go unaddressed. If such problems develop, the EPA or other agencies may attempt to step into this lacuna of regulatory coverage, imposing federal control of certain types of activities and disclosures.

For example, in Texas, fracing is not regulated by the RRC nor the Texas Commission of Environmental Quality. As described above, case law reflects a hesitant judiciary, unsure which, if any, agency or legislative body controls fracing. Such gaps have caused federal-level politicians and environmentalists to call for federal regulation of fracing. Senator Robert Casey of Pennsylvania has introduced a bill to repeal exemptions enjoyed by the industry and require disclosure of all chemicals used in fracing.[408]

Generally speaking, state regulators and industry players do not want such intrusion by federal agencies. In some cases, the potential for federal oversight may be dampened by increased state oversight. For example, in Pennsylvania, industry organizations such as the Marcellus Shale Coalition have supported the Pennsylvania DEP's significant increase of permit fees to fund the hire of more oil and gas inspectors.[409] Similar increases in the regulatory and enforcement powers of oil and gas and/or environmental

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[407] *See* IOGCC, "Hydraulic Fracturing" *supra* note 55.

[408] Mocarsky, Steve, *Officials Explain Marcellus Challenges, Opportunities*, TIMES LEADER, (August 20, 2010).

[409] *Id*.

agencies in other states would probably attenuate the current push for increased federal control.

Conclusions

Given the size of the potential reserves made available by fracing, the influence and capital of the producers of natural gas, the money made by the mineral owners in bonus and royalty, and the jobs and tax revenue that fracing make possible, widespread hydraulic fracturing will continue and the hunt for prospective shale oil and gas will proliferate. Some cities and counties—and perhaps even some states—will succeed in preventing fracing through the pressure of citizens' groups and environment organizations, but too many parties stand to gain too much from this technology for fracing to be entirely stopped.

From a jurisprudential standpoint, the biggest question that states will need to settle, probably through case law, is whether fracing that can be proven to cross property boundary lines and which facilitates draining of an unleased neighboring tract constitutes trespass. Case law in currently limited, but until now, the prevailing attitude seems to be that the rule of capture allows such drainage unless the owner of the drained tract can prove some kind of damages outside of lost ultimate recovery from his tract. Another question is whether fracing that enhances production for one tract, but is detrimental to ultimate recovery for an entire unit, will be found to run afoul of the conservation efforts of state agencies.

The lengthy discussion of state law herein, while complex in its sweep of differences from state to state, serves to highlight some basic patterns of state regulation of fracing. First, states are moving towards expressly including fracing under general statutes and regulations that cover all oil and gas exploration and development activities. Second, just as state regulatory agencies require drilling logs and data when producers bring in a well, similar logs and pressure test data from fracing are a growing target for disclosure requirements among state agencies. Third, perhaps responding to the concerns raised by surface owners and environmentalists, a growing number of states want the exact ingredients of fracing fluids disclosed in completion reports. Fourth, specific disposal regimens for fracing fluid that returns to the surface through the borehole are beginning to coalesce into law, focusing on the protection of existing surface and groundwater assets. Fifth, required replacement or remediation of contaminated surface or groundwater assets, already coming in Pennsylvania, will probably spread to other states.

The next five years will also likely see a gradual settlement made on what aspects of fracing regulation will be delegated from the state level down to the county and municipal level. As described above, county and municipal authorities have not been reticent to regulate fracing. Traffic

control, noise abatement, and permitted hours of operation have all been claimed by local authorities as areas subject to local control.

This flurry of state and local activity may attenuate the interest of EPA in federal oversight of fracing. On September 9, 2010, the EPA issued voluntary information requests to nine (9) service companies that provide fracing services, seeking information on the chemical composition of the fluids used in the fracing process, information on how these ingredients impact the environment, and the location of their fracing operations.[410] This request was made to assist the EPA in completing its second major study of hydraulic fracturing, due for release in late 2012. The authors believe that, in general, the chances of federal oversight of fracing will be diminished if, by the time of the release of the second EPA report, most of the states with shale gas and oil development will have passed or will then formulating robust regulatory schemes governing the use of fracing.

[410] The request by EPA is maintained at http://www.epa.gov/epahome/hydraulic fracturing/ (last visited on September 9, 2010).