

Law Applicable to Hydraulic Fracturing in the Shale States

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Introduction

The substantial growth of U.S. unconventional shale resources in recent years has produced a corresponding increase in the use of hydraulic fracturing to develop those resources. Hydraulic fracturing is generally viewed as a completion technique that is a practical necessity to prevent underground and economic waste of unconventional shale reservoirs, particularly gas-shale, by facilitating hydrocarbon recovery. 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 location of the largest shale gas fields where hydraulic fracturing is currently widely used 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.

This report then examines the regulatory frameworks currently in place in thirteen states that are undergoing prolific shale gas drilling. This state-level analysis is made with an eye towards regulations specific to hydraulic fracturing and the fluids used, as well as more overarching regulations that include hydraulic fracturing, such as general pollution disposal regulations that cover used hydraulic fracturing fluid. In several instances, this report describes bills under consideration, as well as important opinions from state courts.

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—a fountain of oil caused by reservoir pressure underground. 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 contains hydrocarbons the formation typically remains tight 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

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).

techniques—that is, by making *artificial* fractures. Now, instead of relying on educated guesses on where the natural fractures zones could be found and what orientation they had, developers made their own fractures and have become less dependant on the natural fracture orientation of the target strata.

Hydraulic fracturing—known colloquially as “fracking,” “fracking” 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, aluminum 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 an entirely 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 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.

Drilling and Groundwater Protection

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

³ The American Petroleum Institute (“**API**”) maintains a short video of current fracing techniques at <http://www.api.org/policy/exploration/hydraulicfracturing/hydraulicfracturing.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).

well bore, keeps the drill bit cool and clean during drilling, carries out drill cuttings 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 fluid-thickeners.⁶

A main goal of any well is to ensure safe production of oil and gas in a way that protects groundwater 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, welded 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)

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.

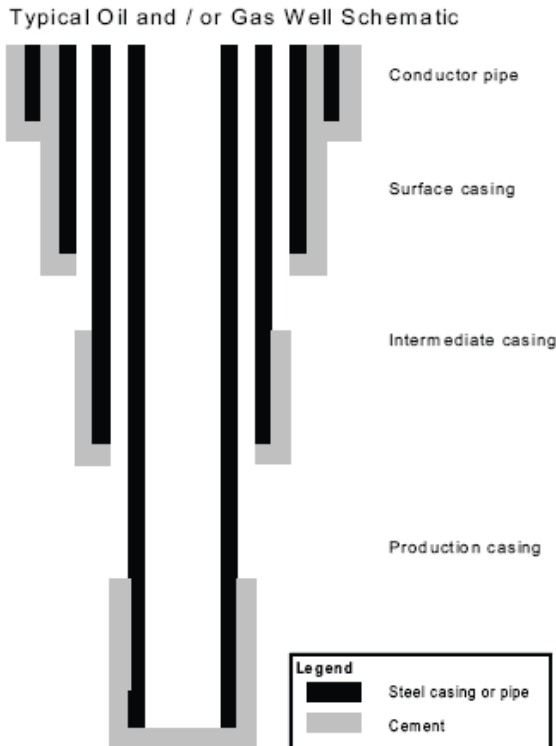


Figure 1—Typical Well Schematic

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 is usually drilled to a 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.¹¹

¹⁰ *Id.* at 4.

¹¹ *Id.* at 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. The end result is that the groundwater zones near the surface are separated from the borehole and the drilling/fracing fluid by several layers of steel augmented by cement. After the casing has been inserted into the hole, it is cemented in place. Cementing the casing provides further isolation between different formations and aquifers and provides structural support for the well. 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 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 hydraulic fracturing fluids and other stimulation techniques directly into the producing formation without affecting any other formation or aquifer in the well.¹⁴

The result of this process, if followed with care and thoroughness, is a completed borehole where the freshwater aquifers, which are typically within a couple hundred feet of the surface, 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

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).

¹⁴

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

¹⁵

Id.

Fracing Fluids and Operations

Fracing requires a “fracing fluid” to be pumped into the well’s production casing at a very high pressure and at a very high rate. Therefore, the production casing string and the cement holding it in place must be capable of withstanding the pressure that it will be subjected to during fracing. 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 will hold the fractures open, allowing the gas to flow. 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 further propel the proppant into the formation. The flushing fluid can be either water or the same material used to start the process.¹⁷

To immediately detect any significant leakage of the fracing fluid past the packers and away from the productive zone, the pressure in the hole is closely monitored throughout the process. 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. If this trend carries to other shall 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 the 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 a function of local law and is measured and controlled in multiple ways. One 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

¹⁶ *Id.* at 18.

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).

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 traffic to and from the drillsite. Typically, fracing fluid is mixed offsite in the yard of the contractor conducting the fracing operations, where the water is mixed with any additives before being trucked onsite. Such 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 ten to thirty percent of the fluid can be expected to return to the surface 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 into the earth 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 last 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 (H₂S) or iron sulfide (FeS) from returning with the flow back. Disposal of the fracing fluid is another option, with costs dependent on the number and proximity of disposal wells near the fracing 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

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

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.

²⁶ *Id.*

of the fluid to a crystallization/evaporation treatment plant—if either are available—are 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

Location of Fracing Operations

Fracing operations are found wherever the combination of tight shale reasonably close to the surface, trapped gas or oil, 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. Previous 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

While the Haynesville is a regional phenomena, 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

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.

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

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, 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

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" formation as well as and 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 billion barrels of oil that would not be recoverable without

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).

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.

it.³⁸ Two recent estimates of gas reserves located in the sprawling Marcellus Shale suggest more than 500 trillion cubic feet 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 fracturing fluids.⁴⁰ This led the federal government to exclude hydraulic fracturing and the associated fracturing fluids from coverage under the Safe Drinking Water Act. Environmentalists and some regulators attacked the findings of the study, saying it was limited to coalbed methane (“CBM”) wells. Industry answered by pointing out that the type of well and formation commonly stimulated by fracturing does not impact the basic finding of the EPA study—that injection of fracturing fluids posed minimal threat to drinking water.

Fracing and the Environment

Although hydraulic fracturing has been used for decades, the debate over the safety of fracturing has become a hot topic because of the current widespread use of the practice and large number of wells enhanced by fracturing. Opponents of fracturing, which include environmentalists and landowners, argue that fracturing should be regulated under the Safe Drinking Water Act and drilling companies should be required to disclose the chemicals used in fracturing fluid.⁴¹ According to The Environmental Working Group, a non-profit environmental agency organization, drilling companies are avoiding federal law and injecting toxic petroleum distillates into wells and threatening drinking water supplies.⁴² Opponents of fracturing allege that water supplies are threatened because “30 to 60% of the fracturing 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 fracturing fluids are highly poisonous, carcinogenic, and are known to cause cancer.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 fracturing.⁴⁶ The test showed that the water “contained benzene...in a concentration 1,500 times the level safe for people.”⁴⁷ According to ProPublica,

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. Env’tl. Prot. Agency, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, 4-15 (2004).

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.*

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 fracturing occurs are also complaining that their water is being contaminated. Landowners are claiming that the water used in fracturing 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 turned color and smelled of petroleum.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 hydraulic fracturing 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 fracturing causes water contamination. Energy in Depth, an industry group, argues that fracturing 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 60 years of service has yet to be credibly tied to the contamination of drinking water.”⁵⁴ Furthermore, the Environmental Protection Agency completed a study in 2004 regarding the environmental risks that are associated with hydraulic fracturing of coal bed methane wells and found that fracturing fluid poses little or no threat to underground sources of drinking water.⁵⁵ According to the Ground Water Protection Council, there have been no documented threats to underground sources of drinking water by hydraulic fracturing operations.⁵⁶ Moreover, industry groups claim that only about one-half of one percent (0.5%) of fracturing fluid is made up of chemicals and ninety-nine and a half percent (99.5%) of it is made up of water and sand.⁵⁷ Further, according to the Independent Oil and Gas Association of New York,

“0.5 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

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Id.

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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).

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Id.

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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).

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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).

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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).

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Id. at 1.

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

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

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Groundwater Protection Council, *supra* note 23.

portion of a micro emulsion element similar to those found in personal care products, such as shampoos, and cutting oils.”⁵⁸

Studies also show that eighty percent (80.0%) or more of the fracturing fluid used during the fracturing process are recovered from the well during the production process.⁵⁹ Additionally, industry groups further claim that fracturing does not cause water contamination because the fracturing fluids are pushed deep underground, thousands of feet below any aquifers being used for drinking water.⁶⁰

Fracturing 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 fracturing 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 fracturing-stimulated gas production.⁶¹

According to industry groups, hydraulic fracturing is essential to the viability of oil and gas production in the United States.⁶² Hydraulic fracturing is responsible for thirty percent of our domestic oil and gas reserves, and “is responsible for the addition of seven billion barrels of oil and 600 trillion cubic feet of natural gas.”⁶³ Industry groups warn that without hydraulic fracturing, America would be producing much less oil and gas, which would in turn increase dependence on foreign imports.⁶⁴ Furthermore, hydraulic fracturing 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 fracturing: (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.

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).

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).

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.*

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 all secondary and tertiary recovery techniques such as fracing, as this means income to him in the form of royalty payments. If the mineral estate has been separated from the surface, the surface owner may have no financial incentive to see minerals developed, and may be opposed if the development will cause her a nuisance or harm 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 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.

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/users. 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 question 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 concept that the surface owner owns the pore space.⁶⁷ Some states

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

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

have even memorialized this in their code.⁶⁸ The emerging minority view is that the mineral owner owns the pore space.⁶⁹

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 loudly. The advent of prolific fracking has produced for subsurface owners the classic paradox of a benefit and a curse, considering that the inevitable product of fracking 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 fractured 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 whether subsurface fracking can give rise to a damages 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”) in the decisional process. 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 Texas Railroad Commission 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

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); West Virginia: *Tate v. United States Fuel Gas Co.*

⁶⁸ New Mexico: SB 145; Wyoming: HB 89.

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).

⁷⁰ 268 S.W.3d 1 (Tex. 2008).

⁷¹ 344 S.W.2d 411 (Tex. 1961).

⁷² *Id.* at 414-15.

In *Railroad Comm'n of Tex. v. Manziel*,⁷³ the 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

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

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).

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.

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]hrough 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 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 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

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.

⁸⁸ *Id.* at 17.

⁸⁹ *Id.* at 19.

⁹⁰ *Id.*

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 to 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 hydraulic fracturing 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 It may be argued that sixty years of silence on the subject by the RRC is long enough.

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 "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 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 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.

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

⁹⁶ *Id.* at 16.

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 unit being drilled? 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.

State Regulation of Hydraulic Fracturing

Arkansas

Hydraulic fracturing in Arkansas is not formally regulated. Overarching oil and gas and environmental regulations however potentially 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

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

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)(*in press*).

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.

power of enforcement.¹⁰¹ The State of 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.¹⁰² 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.¹⁰³

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.¹⁰⁴ 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.¹⁰⁵ 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.¹⁰⁶

Fracing operations may also involve specific handling and disposal procedures with respect to flow-back water or other fluids used during fracing operations. In 2007, the ADEQ created a procedure by which 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.”¹⁰⁷ However, the ADEQ specifically excepted “frac water [and] flow-back water” from eligibility for a general land application permit.¹⁰⁸ The ADEQ further noted in the response to comments it had received from industry to the general land application permit that “[p]ermitted 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.”¹⁰⁹ 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 law appears to

¹⁰¹ 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.*

¹⁰² The ADEQ was also created by the Arkansas Water Pollution Control Act, Act 472 of 1949, codified at 8-4-101, *et seq.*

¹⁰³ 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).

¹⁰⁴ ARK. CODE ANN. § 8-4-202 (2009).

¹⁰⁵ *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).

¹⁰⁶ See APCEC Regulation No. 1 (effective March 16, 1993).

¹⁰⁷ 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).

¹⁰⁸ *See id.*

¹⁰⁹ 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).

specifically address 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 of Louisiana's Department of Natural Resources. The Office of Conservation has primary statutory responsibility for regulation and conservation of oil, gas, lignite, and other natural resources.¹¹⁰ Louisiana has limited regulations with regard to fracing, and most of those are applicable to all well and injection well construction.¹¹¹ Slurry fracture injection wells 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.¹¹²

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 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).¹¹³

Louisiana has also adopted specific rules related to the reuse of exploration and production waste in fracing operations.¹¹⁴ 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. Proposed changes to the current rule regarding reuse of exploration and production waste would eliminate the one-time usage limitation on the exploration and production waste and change the current surface owner affidavit requirement to an operator affidavit requirement.¹¹⁵ The purpose 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 before using groundwater from such a well for fracing operations or any other non-domestic purpose.¹¹⁶ The Office of Conservation has recently

¹¹⁰ LA. REV. STAT. ANN. § 30.1 and § 30.4.

¹¹¹ See Office of Conservation: General Operations, LA. ADMIN. CODE tit. 43, Part XIX.

¹¹² *Id.* at Chapter 4.

¹¹³ See Disposal of E&P Wastes by Slurry Fracture Injection, LA. ADMIN. CODE tit. 43, Part XIX § 433.

¹¹⁴ *Id.* at § 313.

¹¹⁵ Louisiana Register Vol. 36, No. 3, pp.679-680 (March 20, 2010).

¹¹⁶ LA. REV. STAT. ANN. 3097.3.

reaffirmed that a well owner's failure to properly notify the state could result in civil penalties.¹¹⁷ 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.¹¹⁸

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.¹¹⁹ 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.¹²⁰

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 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."¹²¹ 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.¹²² 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.¹²³

Michigan

Michigan oil and gas regulations are promulgated and enforced by the Michigan Office of Geological Survey (the "OGS") of the Michigan Department of Natural Resources & Environment (the "DNRE"),¹²⁴ pursuant to authority granted by the Natural Resources and

¹¹⁷ 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).

¹¹⁸ See News Release: "State Office of Conservation requiring reporting of water source in hydraulic fracturing operations," Department of Natural Resources Public Information Office, available at <http://dnr.louisiana.gov/sec/execdiv/pubinfo/newsr/2009/1008con-water-source.ssi> (last visited April 1, 2010).

¹¹⁹ LA. ADMIN. CODE tit. 43§ 315.

¹²⁰ *Id.* at § 405(b).

¹²¹ Louisiana Department of Natural Resources, Office of Conservation, Order No. U-HS, 3(l)(2)(b), available at <http://dnr.louisiana.gov/cons/orders/U-HS.pdf> (last visited April 1, 2010).

¹²² See *id.* at 3(F); 3(H).

¹²³ 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).

¹²⁴ 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).

Michigan's Environmental Protection Act.¹²⁵ 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 Wells's¹²⁶ 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 50 feet below the surface.¹²⁷ 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.¹²⁸ 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 a well location, survey of the area, and a written application.¹²⁹ 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.¹³⁰ After completion, the Supervisor of Wells may request copies of service records showing all instances of fracturing¹³¹ and within sixty (60) days of completion, the driller must file a list of all instances of perforating, acidizing, fracturing, shooting and testing.¹³² A driller using secondary recovery methods must monitor and record the injection pressure, injection rate and cumulative volume of the fluid injected for each injection well monthly, and report that data to the Supervisor of Wells annually.¹³³

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. There are about 9,900 Antrim wells in Michigan producing natural gas at depths of 500 to 2000 feet. Hydraulic fracturing has been used in virtually every Antrim well."¹³⁴

The frequency of hydraulic fracturing combined with the shallow Antrim Shale formation and the chemicals used in fracing has raised water pollution concerns.¹³⁵ Director Fitch has not

¹²⁵ MICH. COMP. LAWS § 324.101 *et seq.* (1994). Referred to as Act 451.

¹²⁶ As used in Michigan oil and gas regulations, the Supervisor of Wells is the DNRE or OGS. See MICH. COMP. LAWS § 324.61501 (definitions).

¹²⁷ Personal communication with Mike Bricker, Environmental Manager, Michigan Office of Geological Survey, April 5, 2010.

¹²⁸ MICH. COMP. LAWS § 324.61506.

¹²⁹ *Id.* § 324.201.

¹³⁰ *Id.*

¹³¹ *Id.* §324.416.

¹³² *Id.* §324.418.

¹³³ *Id.* §324.806.

¹³⁴ *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).

¹³⁵ 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).

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.”¹³⁶ 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 waterways¹³⁷ from oil and gas wells¹³⁸ 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.¹³⁹

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.¹⁴⁰ To date, no litigation directly related to fracing has been filed 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,¹⁴¹ has primary authority—also called “primacy”—over regulating and administering the Montana Underground Injection Control (UIC) Program for Class II injection wells.¹⁴² 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.”¹⁴³ It accomplishes this goal by, among other things, issuing drilling permits, classifying wells, and adopting and enforcing rules.¹⁴⁴

The purpose of the Montana UIC Program is to protect USDWs.¹⁴⁵ The Montana UIC Program for all wells in Montana had previously been implemented directly by the U.S. Environmental Protection Agency until, after several years of seeking delegation, Montana won

¹³⁶ IOGCC website, *supra* note 5.

¹³⁷ MICH. COMP. LAWS § 324.32301 (defining “connecting waterway” as the St. Mary’s river, Detroit river, St. Clair river, or Lake St. Clair).

¹³⁸ 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).

¹³⁹ GROUNDWATER QUALITY CONTROL RULES, R 325.1637, Rule 137(3) adopted pursuant to Part 127, Act 368, P.A. 1978, as amended.

¹⁴⁰ Michigan Department Of Environmental Quality, *Hydraulic Fracturing of Water Wells*, available at www.michigan.gov/documents/deq/deq-wd-gws-wcu-hydraulicfracturing_270750_7.pdf (last visited April 10, 2010)

¹⁴¹ MONT. CODE ANN. § 2-15-3303 (2009).

¹⁴² 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).

¹⁴³ MONT. CODE ANN. § 82-11-111(2)(a) (2009); *see also Id.*

¹⁴⁴ MONT. CODE ANN. §§ 82-11-111(2)(b)–(c), (5)(a) (2009).

¹⁴⁵ DNRC Montana Board of Oil and Gas Board Summaries, *supra* note 142.

primacy over Class II wells in 1996.¹⁴⁶ All lands within Montana, excluding communal or allotted Indian lands under federal or tribal jurisdiction, are regulated by the Montana UIC Program.¹⁴⁷

A Class II injection well is defined as “a well that is used to inject fluids for the enhanced recovery of oil or gas.”¹⁴⁸ No person may commence, construct, or operate a Class II injection well without a permit from the MBOGC.¹⁴⁹ An application for a permit must include a 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.¹⁵⁰ 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.¹⁵¹ Following notice and hearing requirements, a Class II injection well permit may be authorized by the MBOGC.¹⁵² The owner or operator of an approved Class II injection well must retain accurate drilling, production, and chemical analysis records for five years;¹⁵³ submit to having the well tested by a field representative of the MBOGC at least once every five years for mechanical integrity;¹⁵⁴ and pay an annual fee of \$200.00 per well.¹⁵⁵

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.¹⁵⁶ 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.¹⁵⁷ 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.¹⁵⁸ 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, including the immediate closure or shutdown of the injection well.¹⁵⁹

¹⁴⁶

Id.

¹⁴⁷

Id.

¹⁴⁸

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

¹⁴⁹

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

¹⁵⁰

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

¹⁵¹

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).

¹⁵²

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

¹⁵³

MONT. ADMIN. R. 36.22.1415 (1996).

¹⁵⁴

MONT. ADMIN. R. 36.22.1416–17 (1996).

¹⁵⁵

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).

¹⁵⁶

MONT. CODE ANN. § 82-11-147 (2009).

¹⁵⁷

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

¹⁵⁸

MONT. CODE ANN. § 82-11-148 (2009).

¹⁵⁹

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

Montana allows operators of Class II injection wells three basic options to dispose of the waste fluid generated through the hydraulic fracturing process. Operators can either (1) “discharge [the fracing fluid] into existing drainages;” (2) “put it in holding ponds and let it evaporate or seep into the ground;” or (3) “reinject it into the aquifer” from which it was originally pumped.¹⁶⁰ 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.¹⁶¹

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 hydraulic fracturing 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,¹⁶² pursuant to authority granted by the New Mexico Oil and Gas Act.¹⁶³ 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.¹⁶⁴ 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; and any other pertinent information.”¹⁶⁵ More elaborate notice is required in cases where operations may injure 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.”¹⁶⁶ The OCD may require the well to be plugged if the injury is irreparable.¹⁶⁷

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

¹⁶⁰ *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).

¹⁶¹ *Id.*

¹⁶² See Oil Conservation Division, available at <http://www.emnrd.state.nm.us/OCD/index.htm> (last visited Mar. 30, 2010).

¹⁶³ N.M. STAT. § 70-2-6 (2009).

¹⁶⁴ 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).

¹⁶⁵ *Id.* § 19.15.7.14(G) (2009).

¹⁶⁶ *Id.* § 19.15.16.16.

¹⁶⁷ *Id.*

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 & Gas Act.¹⁶⁸

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.¹⁶⁹ The Oil and Gas regulations provide for authorization of different concentration standards in some situations, such as when abatement of the pollution to required levels is technically infeasible.¹⁷⁰ If pollution exceeds the applicable levels, it must be abated pursuant to an Abatement Plan approved by the Director of the OCD.¹⁷¹ 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 incorporated municipality.¹⁷² 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.¹⁷³ 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.¹⁷⁴

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.¹⁷⁵ 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.¹⁷⁶

¹⁶⁸ N.M. STAT. § 74-6-12. See, e.g., N.M. CODE R. §§ 20.6.2.1201, .3105, .5003.

¹⁶⁹ 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.

¹⁷⁰ *Id.* § 19.15.30.9(E)-(F).

¹⁷¹ *Id.* § 19.15.30.11.

¹⁷² 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).

¹⁷³ *Id.* § 11.25.2, .3.

¹⁷⁴ *Id.* § 11.25.4.

¹⁷⁵ LOVINGTON, N.M., LOVINGTON MUNICIPAL CODE § 8.30.440(C).

¹⁷⁶ *Id.* § 8.30.440(F).

New York

Horizontal drilling and hydraulic fracturing techniques have been in common use for several decades in New York.¹⁷⁷ 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 such regulation.¹⁷⁸ 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),¹⁷⁹ 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.¹⁸⁰ The NYDEC’s discretionary approval of such a permit also triggers the application of the State Environmental Quality Review (the “SEQR”).¹⁸¹ A proposal to drill for oil or gas must either complete the full SEQR process,¹⁸² or conform to the conditions and thresholds established in a generic environmental impact statement.¹⁸³ 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.¹⁸⁴ Although the 1992 GEIS expressly identified and discussed hydraulic fracturing¹⁸⁵ and did not

¹⁷⁷ 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).

¹⁷⁸ N.Y. ENVTL. CONSERV. LAW §§ 23-0301, 23-0303(1) (2010).

¹⁷⁹ N.Y. ENVTL. CONSERV. LAW § 23-0303(2) (2010).

¹⁸⁰ N.Y. COMP. CODES R. & REGS. tit. 6, 552.1(a) (Sept. 6, 1991).

¹⁸¹ 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).

¹⁸² 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).

¹⁸³ 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).

¹⁸⁴ 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).

¹⁸⁵ The 1992 GEIS discussed hydraulic fracturing in the context of projects that: require 80,000 gallons of fracturing fluid or less; were not located in the eastern portion of the state, near the New York City watershed infrastructure; and, did not involve multiple wells drilled horizontally our of a single drilling pad. Anticipation of future projects that would exceed the scope of these factors

recommend any additional regulatory controls for it,¹⁸⁶ 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,¹⁸⁷ 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.¹⁸⁸

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 water¹⁸⁹ 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 its drilling permit application.¹⁹⁰ Depending on the method of disposal chosen by the applicant, an additional disposal permit or an acceptable disposal contingency plan may be required.¹⁹¹ 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.

Certain drilling fluids may be disposed of through use in 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.¹⁹² However, fracing fluids obtained during flowback operations may not be spread on roads and must be disposed of in an authorized manner.¹⁹³

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

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).

¹⁸⁶ *Id.* at 1-4.

¹⁸⁷ *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).

¹⁸⁸ 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).

¹⁸⁹ 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).

¹⁹⁰ N.Y. COMP. CODES R. & REGS. tit. 6, 554.1(c)(1) (Jan. 9, 1980).

¹⁹¹ N.Y. COMP. CODES R. & REGS. tit. 6, 554.1(c)(1) (Jan. 9, 1980).

¹⁹² 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).

¹⁹³ *Id.*

well operator when contamination of water wells occurs (rebuttable only by clear and convincing evidence); making the knowing discharge of fracturing fluids into surface waters a class E felony; designating fracturing 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 fracturing fluid to be used.¹⁹⁴

Other bills have also been introduced which aim to: ban non-organic materials from being used in fracturing fluid;¹⁹⁵ impose strict liability on well operators for any damage caused by hydraulic fracturing;¹⁹⁶ prohibit the use of chemicals that pose a risk to human health in fracturing fluids (including but not limited to chemicals that have been identified pursuant to the Federal Toxic Substances Control Act as persistent, bioaccumulative¹⁹⁷ and toxic or known mutagens);¹⁹⁸ and, establish moratoriums on hydraulic fracturing until either the Draft SGEIS is adopted¹⁹⁹ or the federal EPA releases a report on the effects of hydraulic fracturing on ground water and freshwater supplies.²⁰⁰

When the Draft SGEIS is adopted, additional standards will exist for SEQR of high-volume²⁰¹ fracturing operations. These operations will require an additional addendum to the required environmental assessment form.²⁰² Such addendum will require information related to fracturing including: depth of fracture zones; identification of proposed fracturing service companies and additive products; the proposed volume of fracturing 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 fracturing fluid; distances to nearby water wells, reservoirs, wetlands, lakes or ponds, and occupied structures.²⁰³ In addition, fluid disposal plans for fracturing will require additional information regarding: the planned transport of the fracturing 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

¹⁹⁴ S. 6244, 232nd Sess. (N.Y. 2009), A. 8748, 232nd Sess. (N.Y. 2009).

¹⁹⁵ A. 6953, 232nd Sess. (N.Y. 2009).

¹⁹⁶ S. 7377, 233rd Sess. (N.Y. 2010), A. 9414, 233rd Sess. (N.Y. 2010).

¹⁹⁷ "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).

¹⁹⁸ A. 10091, 233rd Sess. (N.Y. 2010).

¹⁹⁹ A. 1322, 232nd Sess. (N.Y. 2009).

²⁰⁰ A. 10490, 233rd Sess. (N.Y. 2010).

²⁰¹ 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).

²⁰² *Id.* at 3-8. In addition, additional locations will require site-specific SEQR. *Id.* at 3-12 – 3.13.

²⁰³ *Id.* at 3-8 – 3-12.

information for any proposed centralized flowback water surface impoundment located in New York.²⁰⁴

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 things.²⁰⁵ The NDIC 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").²⁰⁶ 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.²⁰⁷ 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:

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,²⁰⁸ ... [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.²⁰⁹

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.²¹⁰ 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.²¹¹ Recompletion of the

²⁰⁴ *Id.* at 3-10 – 3-11.

²⁰⁵ *Id.*

²⁰⁶ See North Dakota Oil and Gas Division available at <https://www.dmr.nd.gov.oilgas/> (last visited Apr. 6, 2010).

²⁰⁷ See North Dakota Industrial Commission available at <http://www.nd.gov/ndic/ic-about.htm> (last visited Apr. 6, 2010).

²⁰⁸ N.D. CENT. CODE § 38-08-04(1)(c) (2010).

²⁰⁹ N.D. CENT. CODE § 38-08-04.2.a and e (2010).

²¹⁰ N.D. CENT. CODE § 38-08-05 (2010); N.D. ADMIN. CODE § 43-02-03-16 (2010).

²¹¹ N.D. ADMIN. CODE § 43-02-03-16 (2010).

well or drilling horizontally requires an additional application for permit.²¹² 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.²¹³ The decision to deny such application may be appealed.²¹⁴

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.²¹⁵ The law generally prohibits long-term storage of saltwater, drilling mud, oil or other contaminants in any pit or open receptacle except in an emergency.²¹⁶ 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.²¹⁷ The reserve pit can only be used for drill cuttings and fluids used or recovered while actually drilling and completing the well.²¹⁸ Within one year of completing or plugging the well, any reserve pit must be reclaimed.²¹⁹ All pit water and oil on the pit must be removed prior to reclamation.²²⁰

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.²²¹ Water remaining in reserve pits must be removed and disposed of in an authorized disposal well or used in an approved manner.²²² The disposition of use of such water must be included on the notice that reports the reclamation plan.²²³

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.²²⁴ An operator must shut off and exclude water from the penetrated oil-bearing and gas-bearing strata.²²⁵ Water shutoffs are ordinarily made by cementing casing or landing casing with or without the use of

212

Id.

213

Id.

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Id.

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N.D. ADMIN. CODE § 43-02-03-19 (2010)

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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).

217

N.D. ADMIN. CODE § 43-02-03-19 (2010)

218

Id.

219

Id.

220

Id.

221

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

222

Id.

223

Id.

224

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.”

225

Id.

mud-laden fluid.²²⁶ 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 ...”²²⁷ 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.²²⁸

The NDO&GD director may prescribe pretreatment casing pressure testing or other operational requirements designed to protect wellhead and casing strings during treatment operations.²²⁹ 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.²³⁰ If the damage cannot be undone, the NDO&GD director may order the operator to plug the well.²³¹

Release Notifications. In the event hydraulic fracturing results in a fire, leak, spill or blowout, the regulations require the operator to verbally notify the NDO&GD director within twenty-four hours of discovery of the fire, leak, spill or blowout.²³² In addition to providing notice to the NDO&GD director, the operator must also notify the surface owners upon whose land the incident occurred.²³³ The notice requirements do not apply to any leak or spill or release of fluid that is less than one barrel total volume and remains onsite.²³⁴ Verbal notification must be followed by a written report within ten days after cleanup of the incident.²³⁵ The report must include the following information: the operator and description of the facility, the legal description of the location of the incident, date of occurrence, date of cleanup, amount and type of each fluid involved, amount of each fluid recovered, steps taken to remedy the situation, cause of the accident, and action take to prevent reoccurrence.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 Class II wells includes injections wells related to the recovery of oil and gas that are regulated

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Id.

227

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

228

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

229

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

230

Id.

231

Id.

232

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

233

Id.

234

Id.

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.

exclusively by the NDO&GD.²⁴⁰ The NDO&GD regulates the underground injection of fluids into Class II wells.

“Underground injection” means 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 ...²⁴¹

The regulations specifically prohibit any “[u]nderground injection that causes or allows movement of fluid into an underground source of drinking water.”²⁴² An underground injection may not be conducted without first obtaining a permit from the NDO&GD after notice and hearing.²⁴³

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.²⁴⁴ The law defines “waters of the state” to include “other bodies or accumulations of water on or under the surface of the earth.”²⁴⁵ 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.²⁴⁶ 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”²⁴⁷

Ohio

Ohio regulates activities related to the development and production of oil and gas through both a statutory and regulatory framework. Ohio statutes give the Division of Mineral Resources management (the “*OHDMR*”), a branch of the Ohio Department of Natural Resources, “the sole and exclusive authority to regulate...oil and gas activities.”²⁴⁸ The Chief of the *OHDMR* management (the “*DMR Chief*”), creates the rules for administration, implementation, and enforcement of the state’s oil and gas laws.²⁴⁹

Current Ohio Fracing Law: Current Ohio law does not directly regulate fracing specifically, although many of the laws regulating development already apply to fracing operations. In addition, new statutory revisions effective July 1, 2010 include provisions that

²⁴⁰ N.D. CENT. CODE § 33-25-01-02 (2010); N.D. ADMIN. CODE § 43-02-05 (2010).

²⁴¹ N.D. ADMIN. CODE § 43-02-05-01 (2010).

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

²⁴³ N.D. ADMIN. CODE § 43-02-05-04 (2010).

²⁴⁴ N.D. CENT. CODE § 61-28 (2010)

²⁴⁵ N.D. CENT. CODE § 61-28-02 (2010)

²⁴⁶ N.D. CENT. CODE § 61-28-03 (2010)

²⁴⁷ N.D. CENT. CODE § 61-28-04 (2010)

²⁴⁸ OHIO REV. CODE ANN. § 1509.02 (2009)

²⁴⁹ *Id.* § 1509.03.

directly affect fracing.²⁵⁰ Both the existing framework and the new statutory changes focus on establishing 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 disposal requirements applicable to all well production.²⁵¹ 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.”²⁵² 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.”²⁵³

The Administrative Code, promulgated by the OHDMR and the DMR Chief²⁵⁴, provides further guidelines for injecting fluids to aid in oil and gas recovery by imposing numerous regulations for saltwater injection or brine injection wells. Specifically, each saltwater injection well must meet specific construction and permit requirements.²⁵⁵ 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.²⁵⁶ A variance from these and other requirements may be obtained only if the volume of injection is sufficiently low and the DMR Chief makes the required statutory determination that fluid injection will not contaminate underground public water supplies.²⁵⁷ In addition, no saltwater injection well may be drilled within one hundred feet of an occupied private dwelling.²⁵⁸

Before completion, an operator must obtain a permit from the OHDMR subject to approval from the DMR Chief.²⁵⁹ 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.²⁶⁰ After the notice has been on file for fifteen days, the DMR

²⁵⁰ See OHIO REV. CODE ANN. §§ 1509.10, 1509.17, 1509.22 (effective July 1, 2010).

²⁵¹ See OHIO REV. CODE ANN. § 1509.22 (2009).

²⁵² *Id.* § 1509.21 (2009).

²⁵³ *Id.* § 1501.22.

²⁵⁴ *Id.* § 1509.02.

²⁵⁵ OHIO ADMIN. CODE §§ 1501:9-3-05, 9-3-06 (2009).

²⁵⁶ *Id.* § 1501:9-3-05.

²⁵⁷ *Id.*

²⁵⁸ *Id.* § 1501:9-3-09.

²⁵⁹ *Id.* §§ 1501:9-3-06 (A); 1501:9-3-12.

²⁶⁰ *Id.* § 1501:9-3-06(B)-(E).

Chief shall grant the permit if it complies with regulatory requirements and no objections have been filed.²⁶¹

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.²⁶² 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.²⁶³

2010 Fracing Revisions: The 128th General Assembly and the Governor of Ohio approved changes to the Oil and Gas law effective July, 2010. These changes incorporate many substantive changes in the law, including provisions which directly address fracturing.

First, the new statute defines “well stimulation” as “the process of enhancing well productivity, including hydraulic fracturing operations.”²⁶⁴ The statute then 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 record²⁶⁵ on a form approved by the DMR Chief, including a report on the type and volume of fluid used to stimulate the well.²⁶⁶ 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.”²⁶⁷

Oklahoma

Oklahoma oil and gas regulations are promulgated and enforced by the Oklahoma Corporation Commission (the “OCC”), a constitutional agency,²⁶⁸ through its Oil and Gas Conservation Division (the “OGCD”).²⁶⁹ Title 17 of the Oklahoma Statutes grants authority to the OCC to create and establish an Oil and Gas Department to regulate oil and gas drilling,

²⁶¹ *Id.* § 1501:9-3-06(E)(2).

²⁶² *Id.* § 1501:9-3-07(C)-(D).

²⁶³ *Id.* § 1501:9-3-07 (E)-(F).

²⁶⁴ OHIO REV. STAT. ANN. § 1509.01 (effective July 1, 2010).

²⁶⁵ The current statute requires a report within sixty days of “well completion.”

²⁶⁶ *Id.* § 15.10(A)(9).

²⁶⁷ *Id.* § 15.17(A).

²⁶⁸ “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).

²⁶⁹ 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).

production, and environmental compliance.²⁷⁰ The OCC rules and regulations are found in Title 165 of the Oklahoma Administrative Code (the “OAC”).²⁷¹

Hydraulic fracturing has been used for over sixty (60) years in Oklahoma and is currently more highly regulated than in most states. The primary concern in regulating fracturing operations in Oklahoma, as elsewhere, is the prevention of water pollution both during operations and by fracturing fluid returning to the surface after operations are complete. The general rule concerning fracturing 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 fracturing operations is found throughout the OAC. For instance, OAC § 165:10-3-19(a)(3) requires that an operator must obtain a permit to drill before fracturing operations begin.²⁷² Any operator who does not obtain a permit to drill may be fined.²⁷³ OAC § 165:10-3-3 through 10-3-4 regulate surface and production casing.²⁷⁴ Specifically, § 165:10-3-3 requires operators to report any event of rupture, break, or opening that occurs in the surface or production casing. Failure to report any such incidence may result in a fine up to \$1,000.00.²⁷⁵ Regulations also govern the use of commercial and noncommercial pits²⁷⁶ as well as plugging and abandonment.²⁷⁷

The OCC has adopted Oklahoma’s water quality standards²⁷⁸ established by the Oklahoma Water Resources Board.²⁷⁹ 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.”²⁸⁰ OAC § 165:10-7-5 also provide rules regarding reporting of nonpermitted discharges.²⁸¹ Failure to comply with provisions of OAC § 165:10-7-5 may result in a fine of \$500.00 per incident.²⁸² Municipalities or other governmental subdivision 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 and fresh water supplies.²⁸³

²⁷⁰ OKLA. STAT. tit. 17, § 51 (2000); see also OKLA. ADMIN. CODE § 165:10-1-6 (2003) regarding the duties and authority of the OGCD.

²⁷¹ OKLA. ADMIN. CODE § 165 (2003). Specifically, the oil and gas regulations are found in Title 165, Chapter 10 of the OAC.

²⁷² OKLA. ADMIN. CODE § 165:10-3-1 (2003).

²⁷³ In the March 2010 proposed amendments, the OCC amends § 165:10-3-1(a)(3) and includes “may be fined up to \$1000.00.”

²⁷⁴ OKLA. ADMIN. CODE § 165:10-3-3 through 10-3-4 (2003).

²⁷⁵ *Id.* at 10-3-3(c).

²⁷⁶ See OKLA. ADMIN. CODE § 165:10-7 through 10-9 (2003).

²⁷⁷ See OKLA. ADMIN. CODE § 165:10-11 (2003).

²⁷⁸ OKLA. ADMIN. CODE § 165:10-7-4 (2003).

²⁷⁹ The Oklahoma Water Quality Standards are published in OKLA. ADMIN. CODE § 785:45 (2003).

²⁸⁰ OKLA. ADMIN. CODE § 165:10-7-5 (2003).

²⁸¹ *Id.* at 10-7-5(c).

²⁸² *Id.* at 10-7-5(c)(2).

²⁸³ OKLA. ADMIN. CODE § 165:10-7-6.

In March 2010, the OCC submitted proposed amendments regarding its existing fracing rule to the Oklahoma legislature. These amendments include a provision which will provide a cross-reference to existing rules that affect the management of fracing operations. It also includes the amendments to OAC 165:10-7-16 establishing procedures for flow back water pits with capacity in excess of 50,000 barrels and new requirements for commercial recycling facilities.²⁸⁴

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.²⁸⁵ The Bureau of Oil and Gas Management has this authority pursuant to Pennsylvania’s Oil and Gas Act.²⁸⁶ 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.

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.²⁸⁷

The proposed rules—which are currently open to public comment pending hearing—are almost entirely devoted to protecting water supplies.²⁸⁸ 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 casing²⁸⁹ and impose a stricter obligation on operators to replace any water supplies they contaminate.²⁹⁰

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.”²⁹¹ Specifically, the operator is required to prevent “brine, completion and servicing fluids, and any other fluids from

²⁸⁴ See Oklahoma Corporate Commission, *available at* <http://www.occ.state.ok.us> (last visited March 31, 2010)

²⁸⁵ 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).

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

²⁸⁷ Hurdle, Jon, *Pennsylvania Plans More Gas Drilling Regulation*, REUTERS (Jan. 28, 2010), *available at* <http://www.reuters.com/article/idUSN2812147220100128> (last visited April 2, 2010) .

²⁸⁸ 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 April 2, 2010).

²⁸⁹ Section 78.73, *et seq.*

²⁹⁰ Section 78.51, *et seq.*

²⁹¹ Section 78.73(a).

lower formations from entering fresh groundwater”²⁹² Additionally, there is a proposal to require 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.²⁹³ Among other items, this plan must contain information regarding “anticipated fresh groundwater zones”²⁹⁴ and “casing type, depth, diameter, wall thickness and burst pressure rating.”²⁹⁵ This casing and cementing plan must be kept at the well site and be available for review by the Pennsylvania authorities.²⁹⁶

In the event that the casing and cementing plan fails, resulting in contamination of groundwater, the operator will face stricter, more detailed regulations concerning replacement of the water supply under the proposed regime. The regulations already contain a general 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.”²⁹⁷ 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 (1) deliver enough water to meet the user’s need or (2) connect to a public water system that supplies enough water to meet the user’s need.²⁹⁸ To be of adequate quality, the replacement water supply must (1) meet the standards established pursuant to the Pennsylvania Safe Drinking Water Act or (2) be of comparable quality to the prior water supply, if the prior water supply did not meet the Water Act standards.²⁹⁹

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 be approved by the Cecil Township Board of Supervisors.³⁰⁰ 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.³⁰¹ 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.”³⁰²

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

²⁹² Section 78.73(b).

²⁹³ Section 78.83a(a).

²⁹⁴ Section 78.83a(a)(1).

²⁹⁵ Section 78.83a(a)(3).

²⁹⁶ Section 78.83a(b).

²⁹⁷ Section 78.51(a).

²⁹⁸ Section 78.51(e)(3).

²⁹⁹ Section 78.51(e)(2).

³⁰⁰ 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).

³⁰¹ Oil and Gas Taskforce, available at <http://wcpaoilandgastaskforce.info/> (last visited April 5, 2010).

³⁰² *Id.*

contaminated with methane, the DEP ordered Cabot to fix cement well casings in the area by March 31, 2010.³⁰³ 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.³⁰⁴ 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.³⁰⁵ As the use of fracking increases in Pennsylvania, interested parties should expect regulation and oversight by localities to grow correspondingly.

Texas

In Texas, fracking is not formally regulated.³⁰⁶ The only regulations that apply to fracking 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.”³⁰⁷ 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.³⁰⁸

Like all oil and gas development in Texas, fracking operations require the RRC to issue a permit authorizing drilling and/or deepening of a well.³⁰⁹ Besides the standard permitting, two key areas where the RRC’s regulations have an impact on fracking operations (other than standard permitting): are, 16 TEX. ADMIN. CODE § 3.8 “Water Protection” and second, 16 TEX. ADMIN. CODE §3.13 “Casing, Cementing, Drilling, and Completion Requirements.” The RRC believes that additional regulation of fracking is not necessary due to the strictness of the current regulations and the absence of any evidence that fracking fluids have contaminated groundwater in the sixty (60) years since producers first began fracking in Texas.³¹⁰

In addition to permitting regulation, §3.8 also regulates the storage, transfer and disposal of oil and gas wastes. Presumptively, this includes any fracking fluids that are brought back to the

³⁰³ Allison, Jocelyn, *Cabot Ordered to Plug Wells in Pa. Pollution Probe*, LAW 360 (April 16, 2010).

³⁰⁴ *Id.*

³⁰⁵ Meyer, Elaine, *EPA Urged to Probe Fracking Water Pollution in Pa.*, LAW 360 (April 27, 2010).

³⁰⁶ *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.”).

³⁰⁷ TEX NAT. RES. CODE § 81.051 (2010).

³⁰⁸ 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.

³⁰⁹ 16 TEX. ADMIN. CODE §3.5 (2009).

³¹⁰ 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).

surface as part of oil and gas production.³¹¹ 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.³¹² However, if federal regulations are amended 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.³¹³ 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.³¹⁴ The RRC holds fast to its claim that any potential dangers posed by fracing operations are handled by the current regulatory framework.³¹⁵

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.³¹⁶ 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.³¹⁷ A permit is required before any person can commence any “well work.”³¹⁸ “Well work” is defined as including the stimulating or pressuring by injection of any fluid into a well.³¹⁹ To “stimulate” a well is “to increase the inherent productivity of an oil or gas well” by, among other actions, fracing the well.³²⁰

Specifically with respect to hydraulic fracturing, West Virginia runs its own Underground Injection Control (UIC) Program, which regulates underground injections by five classes of

³¹¹ § 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).

³¹² SMITH & WEAVER, *supra* note 306.

³¹³ 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).

³¹⁴ Loftis, *supra* note 310.

³¹⁵ *Id.*

³¹⁶ Office of Oil and Gas, Our Mission, available at <http://www.wvdep.org/item.cfm?ssid=23> (last visited Apr. 1, 2010).

³¹⁷ W. VA. CODE § 22-6-2(c)(12) (2009).

³¹⁸ W. VA. CODE § 22-6-6(a) (2009).

³¹⁹ W. VA. CODE § 22-6-1(v) (2009).

³²⁰ W. VA. CODE § 22-6-1(s) (2009).

wells.³²¹ “Class II” wells include wells “injecting fluids for enhanced recovery of oil or natural gas.”³²² Class II wells must either be authorized by rule (in limited instances), or by permit.³²³

Applications for a permit to stimulate a well must be accompanied by a bond,³²⁴ a plat,³²⁵ and a corrective action plan “to prevent movement of fluid into underground sources of drinking water.”³²⁶ The applicant must also demonstrate the mechanical integrity of the well,³²⁷ comply with notice requirements,³²⁸ and pay a \$150.00 fee for each activity for which an application is required.³²⁹ After a public comment period and hearing,³³⁰ the Director of the DEP will conduct a review of the application, including inspections if necessary.³³¹ 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.³³² 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*).³³³ Moreover, the operator is required to retain all records “concerning the nature and composition of injected fluids until three (3) years after completion of any plugging and abandonment” of the Class II well.³³⁴ Permits are effective for a fixed term not to exceed five years.³³⁵

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.³³⁶ 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.³³⁷ Additionally, the

³²¹ W. VA. CODE R. § 47-13-1.1 (2010).

³²² W. VA. CODE R. § 47-13-4.2.b (2010).

³²³ 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).

³²⁴ 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).

³²⁵ W. VA. CODE § 22-6-12(a) (2009).

³²⁶ W. VA. CODE R. § 47-13-13.9.a (2010).

³²⁷ W. VA. CODE R. §§ 47-13-6.2, -13.7.h (2010).

³²⁸ W. VA. CODE §§ 22-6-6(c)(11), -9, -13 (2009).

³²⁹ W. VA. CODE § 22-6-29(b) (2009).

³³⁰ W. VA. CODE § 22-6-10 (2009); W. VA. CODE R. §§ 47-13-13.24.b, -13.27 (2010).

³³¹ W. VA. CODE § 22-6-11(2009)

³³² W. VA. CODE §§ 22-6-6(h), -11 (2009).

³³³ 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).

³³⁴ W. VA. CODE R. § 47-13-13.6.b (2010).

³³⁵ W. VA. CODE R. § 47-13-13.13 (2010).

³³⁶ W. VA. CODE § 22-6-34(a) (2009).

³³⁷ W. VA. CODE § 22-6-34(b) (2009).

DEP Director is authorized to bring suit for injunctive relief to enjoin any violations or threatened violations.³³⁸ 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.³³⁹

West Virginia requires operators of Class II wells to permanently dispose of the waste water generated through the fracing process.³⁴⁰ 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.³⁴¹ 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.³⁴²

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 at www.dep.wv.gov/oil-and-gas.³⁴³ 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.³⁴⁴

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; and (5) the method and location of disposal, treatment, or recycling of the water. The form must be submitted within thirty days of the flow-back period.³⁴⁵

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

³³⁸ W. VA. CODE § 22-6-39 (2009).

³³⁹ W. VA. CODE § 22-6-3(a) (2009).

³⁴⁰ Ken Ward Jr., *DEP Rules on Hydraulic Fracturing Called Baby Steps*, CHARLESTON GAZETTE, July 16, 2009, at P1C.

³⁴¹ *Id.*

³⁴² Pam Kasey, *Pa., W. Va. Address Salt Problems Differently*, THE ST. J. (Morgantown), Jan. 8, 2010, at 21.

³⁴³ George Hohmann, *State Issues Guide for Natural Gas Drillers*, CHARLESTON GAZETTE, Jan., 14, 2010, at P2A.

³⁴⁴ Ken Ward Jr., *DEP Rules on Hydraulic Fracturing Called Baby Steps*, CHARLESTON GAZETTE, July 16, 2009, at P1C.

³⁴⁵ 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/OilandgascompaniesmustregisterMarcellusShalefracwaterus.aspx> (last visited Apr. 1, 2010).

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.³⁴⁶ 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.³⁴⁷ Currently, West Virginia surface owners are not required to be notified until the permit application has already been submitted and the land surveying completed.³⁴⁸

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.³⁴⁹ 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.”³⁵⁰

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,
- the depth of perforations or the openhole interval,
- the source of water and/or trade name of fluids,
- the type of proppants, and

³⁴⁶ Kasey, *supra* note 342.

³⁴⁷ Lawrence Messina, *W. Va. Lawmakers Again Try to Referee Gas Drilling*, THE ASSOCIATED PRESS ST. & LOC. WIRE (Charleston), Feb. 10, 2010, at State & Regional.

³⁴⁸ *Id.*

³⁴⁹ WYO. STAT. ANN. §§ 30-5-101 – 30-5-126.

³⁵⁰ Wyoming Oil and Gas Conservation Commission Rules and Regulations, Chapter 2, Section 1(b).

the estimated pump pressures.³⁵¹

The applicant must also provide information related to the drilling plan, “together with any other information which may be required by the Supervisor;”³⁵² 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).³⁵³

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.³⁵⁴ Production and intermediate casing design provide reservoir isolation; and casing must be cemented from bottom to top to ensure that there are no voids.³⁵⁵

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.³⁵⁶

Current Developments in Permitting Requirements for Fracing Operations: In what appears to be a response to complaints from two Wyoming communities of contaminated water supplies, the WOGCC is presently reviewing written comments on 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;³⁵⁷

³⁵¹ Wyoming Oil and Gas Conservation Commission Rules and Regulations, Chapter 3, Sections 1(a), 8(a) and 8(c).

³⁵² Wyoming Oil and Gas Conservation Commission Rules and Regulations, Chapter 3, Sections 8(c).

³⁵³ Wyoming Oil and Gas Conservation Commission 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.”

³⁵⁴ Wyoming Oil and Gas Conservation Commission Rules and Regulations, Chapter 3, Section 22.

³⁵⁵ *Id.*

³⁵⁶ Wyoming Oil and Gas Conservation Commission Rules and Regulations, Chapter 3, Section 12.

³⁵⁷ 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.

(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.³⁵⁸

The WOGCC hosted a public hearing on the new regulations and the referenced proposals on April 14, 2010.³⁵⁹ No ruling resulted, however, and the WOGCC said it would leave the matter open for fifteen (15) days and possibly schedule some type of work session to go over the draft rule changes with the WOGCC staff. The WOGCC will likely make a final decision on the rules in June.

Wyoming Rules and Statutes Governing Byproduct Water Use and Storage: Jurisdiction over water use and rights is vested with the Wyoming State Engineer.³⁶⁰ 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.”³⁶¹

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.³⁶²

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

³⁵⁸ 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); and see Dustin Bleizeffer, *Fracing Rules Sought By Panel*, Casper Star-Tribune, November 6, 2009 (where it was reported that Teton County Commissioners are seeking to address concerns about unknown but purportedly dangerous chemicals used in fracturing. Teton County commissioners are urging Congress to pass a bill that would mandate more public disclosure about chemicals used in the process, as well as further analysis to ensure the protection of drinking water. If it is determined that the contamination did result from drilling/fracing, this would become the first site where fracturing fluids have been scientifically linked to groundwater contamination).

³⁵⁹ Staff, *State Oil and Gas Commission Getting Input on Proposed Rule Changes*, Wyoming Energy News, March 29, 2010.

³⁶⁰ WYO. STAT. ANN. §§ 41-3-905 and 41-3-909.

³⁶¹ WYO. STAT. ANN. § 41-3-903 (West 2002).

³⁶² WYO. STAT. ANN. § 41-3-904.

surface water, depth to groundwater, subsoil type and type of sealing material.³⁶³ 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.³⁶⁴ 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.³⁶⁵

Federal Regulation of Fracing

The federal regulation of hydraulic fracturing, primarily under the Safe Drinking Water Act (the “SDWA”),³⁶⁶ has been the subject of much debate.³⁶⁷ 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.³⁶⁸ 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.³⁶⁹ ‘Underground injection’ is defined as the “subsurface emplacement of fluids by well injection.”³⁷⁰ In 2005, legislative amendments made clear that the SDWA does not regulate hydraulic fracturing operations.³⁷¹ 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.”³⁷²

³⁶³ Wyoming Oil and Gas Conservation Commission 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.”).

³⁶⁴ *Id.*

³⁶⁵ See Wyoming Oil & Gas Conservation Commission Rules and Regulations, Chapter 4, Sections 1(t) - (w).

³⁶⁶ 42 U.S.C. 8300f *et seq.*

³⁶⁷ 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) (*in press*) (against application of the SDWA to fracing)

³⁶⁸ 42 U.S.C. 8300h.

³⁶⁹ See 40 C.F.R. 145.11(a)(5).

³⁷⁰ 42 U.S.C. § 300h(d)(1).

³⁷¹ *Id.*

³⁷² Aug. 8, 2005, Pub.L. 109-58, Title III, § 322, 119 State. 694).

Many sources critical of the exception refer to it as the “Halliburton Loophole.”³⁷³ Thus, with the exception of fracing 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.³⁷⁴ 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.”³⁷⁵ 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.³⁷⁶ 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.³⁷⁷

In addition to the EPA study, Congressmen Henry Waxman (D-CA) and Ed Markey (D-MA) are launching a parallel inquiry into hydraulic fracturing.³⁷⁸ 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 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

³⁷³ “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).

³⁷⁴ See Senate Bill S. 1215, House Resolution H.R. 2766.

³⁷⁵ EPA Press Release, “EPA Initiates Hydraulic Fracturing Study: Agency seeks input from Science Advisory Board,” March 18, 2010.

³⁷⁶ “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).

³⁷⁷ 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/b5d8a1ce9b07293485257375007012b7/3B745430D624ED3B852576D400514B76/\\$File/Hydraulic+Frac+Scoping+Doc+for+SAB-3-22-10+Final.pdf](http://yosemite.epa.gov/sab/SABPRODUCT.NSF/b5d8a1ce9b07293485257375007012b7/3B745430D624ED3B852576D400514B76/$File/Hydraulic+Frac+Scoping+Doc+for+SAB-3-22-10+Final.pdf) (last visited April 17, 2010).

³⁷⁸ “Waxman, Markey Launch Hydraulic-Fracturing Inquiry” E&E News, Feb. 18, 2010.

hydraulic fracturing was not intended to be regulated under the SDWA.³⁷⁹ 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.³⁸⁰ The EPA rejected LEAF's request and LEAF appealed the EPA's decision.³⁸¹

In 1997, the Eleventh Circuit ruled on LEAF's appeal and concluded that hydraulic fracturing is included in the definition of 'underground injection.'³⁸² Alabama submitted a revised UIC program to the EPA, and the EPA approved the program.³⁸³ 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.³⁸⁴ 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.³⁸⁵

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 fluids in coalbed methane production wells.³⁸⁶

During this same time period, the EPA undertook a study of hydraulic fracturing and its impacts on drinking water sources.³⁸⁷ 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..."³⁸⁸

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

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

³⁸⁰ See Legal Environmental Assistance Foundation, Inc. v. United State Environmental Protection Agency, 118 F.3d 1467, 1471 (11th Cir. 1997).

³⁸¹ *Id.*

³⁸² *Id.* at 1478.

³⁸³ See Legal Environmental Assistance Foundation, Inc. v. United States Environmental Protection Agency, 276 F.3d 1253, 1256 (11th Cir. 2001).

³⁸⁴ *Id.* at 1365.

³⁸⁵ *Id.* at 1264.

³⁸⁶ 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).

³⁸⁷ Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, June 2004, United States Environmental Protection Agency.

³⁸⁸ *Id.* at ES-1.

Drinking Water Act.³⁸⁹ 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.”³⁹⁰ 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 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.”³⁹¹

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.

³⁸⁹ 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).

³⁹⁰ *Id.*

³⁹¹ See IOGCC, “Hydraulic Fracturing” *supra* note 55.