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Fracking:
Formulation of Appropriate State Regulation Of Waste Disposal

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Earth and Environmental Sciences
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FORMULATION OF APPROPRIATE STATE REGULATION OF WASTE DISPOSAL

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INTRODUCTION

With the backdrop of a growing worldwide population, the attendant increasing energy needs, and the ongoing global warming controversy, a method of unconventional oil and gas production called hydraulic fracturing, also simply known as "fracking," has emerged a high profile method of unconventional oil and gas production. While fracking is an established technology that has been long used in various applications, including oil and gas production, more recently there has been a significant amount of controversy over whether high volume fracking, combined with the use of newer horizontal drilling technology, should be employed at all, and if used, how that use should be regulated. This paper mainly restricts its scope to the regulation of disposal of waste that is a byproduct of the fracking process, using Michigan and Ohio as examples. Michigan and Ohio were chosen because while they have different requirements from each other for regulating disposal of waste from fracking, they are both within the Great Lakes watershed, which means that contamination carries the potential for relatively far reaching negative impacts as compared with other states. At the time this paper was written neither Michigan or Ohio had a comprehensive fracking statute, yet both states host shale "plays." In discussing the regulation of disposal of fracking waste, this paper touches on some related topics and provides a general background to hydraulic fracturing and the targeted resources, a necessary context in order to appreciate and consider the policy recommendations in this paper, as well as the rapidly evolving State and Federal regulatory treatment of fracking in general.

Selected portions of this paper were published in July 2012 as part of a larger collaborative paper sponsored by the National Wildlife Federation entitled *Hydraulic Fracturing in the Great Lakes Basin: The State of Play in Michigan and Ohio*. Some descriptive portions of this paper borrow heavily from the collaborative paper.

THE TECHNOLOGY

Hydraulic fracturing is a well stimulation method used to extract oil and natural gas from shale formations. Unlike "conventional" reservoirs, in which the oil or gas is either trapped in a capped porous and permeable stratum, the product of structural or stratigraphic mechanisms, or less frequently in hydrodynamic traps, traps caused by differences in water pressure within a porous permeable formation which cause the oil to remain more or less stationary, the oil and gas in unconventional targets is trapped within tiny pores in fine-grained rock such as shale, or attached to organic material in the shale. To make a pathway for hydrocarbons to flow out of such impermeable shale through a well, well operators create permeability by inducing fractures in the formation. The more shale surface area opened to the well through drilling and fracturing, the better the flow potential. As mentioned above, Hydraulic fracturing is not a new technology. Vertical hydraulic fracking was developed in 1948.[1] Advances in fracking technology and the innovation of horizontal drilling have made many more areas of deep shale economically viable.

In preparing to produce oil or gas, the operator first drills vertically downward, and then turns the bore hole so that it runs horizontally within the target formation. A single well pad can

[1] Hyne, Norman J., Nontechnical Guide to Petroleum Geology, exploration, Drilling & Production. 3rd ed. PennWell Corporation, Tulsa, OK, 2012. pg. 440.

host one or multiple wells with horizontal "legs" which can be drilled in different directions to depths greater than a mile below the surface and up to two miles laterally within a target formation.[2] In a deep shale formation,[3] a single well pad with multiple horizontal wells can replace many separate vertical well pads, resulting in a smaller site footprint with fewer, albeit more concentrated, surface impacts. As the initial drilling proceeds, the operator places successively smaller steel pipes, called casing strings, into the wellbore. Each casing string is cemented into the formation or to the outside casing in accordance with the jurisdiction's regulatory provisions in order to seal the well from surrounding rock and prevent fluids, oil, or gas in the rock from flowing around the well pipe upward into overlying formations, some of which might contain groundwater.

Once the operator finishes drilling the well, a service company fracks the well by injecting fluid into the rock. In preparation for the actual treatment, the steel production casing is perforated with holes in designated locations, starting near the far end of the well and working back towards the wellbore. The hydraulic fracturing fluid "fracking fluid", as well as natural gas or oil, will flow out of the formation and into the well through these perforations.[4] There are three primary steps in the actual "frac" job. First, there is a large-volume injection of fracturing fluid composed of water and certain chemical additives, at a sufficiently high pressure to push out through the perforated holes in the casing, and these fluids fracture the surrounding target formation. Fracking fluids vary in composition; however, they are generally either a gel, foam, or slickwater pad. Next, after the reservoir has been fractured, a slurry of facking fluid and propping agents, or proppants, are injected to extend and hold open the fractures. By volume, the fracturing fluid consists of approximately 98% to more than 99.5% water and proppant, and less than 0.5 to 2% chemical additives and propping agens.[5] Propping agents are usually silica, or sand, but plastic proppants can be used as well. Finally, the well is flushed, or "backflushed," with the injection of water.[6]

The amount of fresh or brackish water needed for drilling and fracturing varies by length of thickness of the oil or gas-bearing shale and well length. A shale gas well typically requires 3 million gallons of water, although a multiple leg well may require up to 10 million gallons.[7] A far greater amount of water is used for fracturing than for drilling; depending on the shale

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[2] *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*, U.S. Environmental Protection Agency 13-14 (Nov. 2011), *available at* http://www.epa.gov/hfstudy/HF_Study__Plan_110211_FINAL_508.pdf [hereinafter EPA, *Draft Plan*].

[3] A depth of 4,000 feet or greater is generally considered "deep" as indicated by the use of different well spacing requirements in several jurisdictions. For an example see Illinois Oil and Gas Act, 62 Ill. ADM. CODE, CH I § 240.410.

[4] Brad Hansen, *Casing Perforating Overview*, Devon Energy Corporation, *available at* http://www.epa.gov/hfstudy/casingperforatedoverview.pdf.

[5] EPA, *Draft Plan*, *supra* note 14, at 28.

[6] Hyne, Norman J., Nontechnical Guide to Petroleum Geology, exploration, Drilling & Production. 3rd ed. PennWell Corporation, Tulsa, OK, 2012. pg. 440-42.

[7] ALL Consulting and the Groundwater Protection Council, *Modern Shale Gas Development in the United States: A Primer*, prepared for the U.S. Department of Energy Office of Fossil Energy and National Energy Technology Laboratory, 64 (April 2009), *available at* http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf; David M. Kargbo, Ron G. Wilhelm & David J. Campbell, *Natural Gas Plays in the Marcellus Shale: Challenges and Potential Opportunities*, Environmental Science & Technology, *available at* http://pubs.acs.org/doi/pdf/10.1021/es903811p. Shale oil wells in the Bakken formation are estimated to use .5 million gallons to 3 million gallons of water per well. Bakken Water Opportunities Assessment—Phase 1, Energy & Environment Research Center 1, *available at* https://cms.oilresearch.nd.gov/image/cache/g-018-036-fi.pdf.

formation, an operator may need only 60,000 gallons to 1 million gallons to drill the well.[8] Once the "frac job" is completed, pressure on the wellbore is removed. Over the following few weeks, a portion of the fracking fluid, together with brines in the formation and dissolved substances (collectively called "flowback"), returns to the surface through the wellbore; the rate of return is highest during the first few days.[9] Disposal of flowback is the focus of this paper, and is discussed in detail below. Depending on the characteristics of the target shale formation, this "flowback" can be as little as 3% of the amount of the fracking fluid injected, or it can be greater than 80%.[10] Once the well begins producing oil or natural gas, brines from the formation continue to rise through the wellbore; this "produced water" may also include some returned fracking fluid.[11] While the exact composition of flowback fluids varies from well to well, all flowback and continuing produced water must be treated or disposed of in order to prevent commingling with and contamination of drinking water sources. The remainder of the fracking fluid remains underground in the pores of the shale or in closed fractures.

A well in a shale formation may produce oil or natural gas for twenty to thirty years, although the life span of any one well depends on the continued economic viability of production. If production declines unexpectedly, operators may choose to hydraulically fracture the well again to reopen cracks in the shale. A shale gas well may be fracked many times over its production lifetime. Once a well has finished producing, the operator plugs the well and restores the impacted area in accordance with the applicable legal requirements.

THE RESOURCE RESERVE

As discussed above, the reasons for the sudden rapid growth of fracking are new technologies that allow exploitation of previously economically inaccessible unconventional resources. According to the Society of Petroleum Engineers, unconventional resources are petroleum accumulations that are pervasive throughout a large area, however are not significantly affected by hydrodynamic influences.[12] Unlike conventional resources in porous sandstone and carbonate reservoirs capped by an impermeable layer, unconventional shales are fine-grained, organic rich, sedimentary rocks where the host rock is not just a hydrocarbon container, but also the source of the oil or gas.[13] Because thermogenic natural gas deposits vary in composition, in addition to advances in technology, the market prices of oil versus gas also impact fracking applications. Natural gas can contain other light hydrocarbons such as ethane and propane. The exact composition of a given resource is determined by various factors,

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[8] ALL Consulting, *supra* note 17, at 64.
[9] *Id*. at 42-43.
[10] *Fracturing Fluid Management*, FracFocus, http://fracfocus.org/hydraulic-fracturing-how-it-works/drilling-risks-safeguards (last visited June 10, 2012).
[11] EPA, *Draft Plan*, *supra* note 14, at 43. In the industry, flowback is considered a subset of produced water. This report will distinguish between flowback and later produced water because they have different characteristics that affect risk management.
[12] *Petroleum Resources Management System*. Co-Sponsored by Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council, Society of Petroleum Evaluation Engineers. 2007. pg 13. Last accessed on May 6, 2013 at http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf.
[13] Andrews, Anthony et. al., Congressional Research Service, Unconventional Gas Shales: Development, Technology, and Policy Issues, October 30, 2009.

including the original carbon source and its thermal maturity. Oil and gas deposits are the result of organic matter that has been buried at a such depth such that it becomes subject to sufficient heat to "cook" the hydrocarbons out of the buried organic matter. Cooking encourages the breakdown of carbon compounds. As organic molecules break down into lower weight compounds the volatile products separate from the liquid products.[14] Greater depths and older resources are generally associated with higher temperatures and longer times for the maturation of the hydrocarbons. Once an environment capable of creating the higher temperature and pressure conditions has been achieved, the first form of hydrocarbon produced is oil. Generally, a minimum temperature of 150 °F is required to generate oil; at 300 °F, the hydrocarbons are released as natural gas.[15] As "cooking" continues, longer carbon chains are broken down and the methane and other light hydrocarbons separate out, creating first "wet gas" and then "dry gas." Wet gas contains a higher concentration of heavier gaseous hydrocarbons, such as ethane, propane, butane, isobutene, and pentane. The "drier" the gas, the closer it is in overall composition to pure methane. A resource is over cooked" or "over mature" when all of the hydrocarbons have been "cooked off" to the point that the gases are lost, and it is no longer economic. From a producer's perspective there are both advantages and disadvantages to wet and dry gas. Dry gas is more pipeline ready, while wet gas requires removal of the heavy hydrocarbons and evaporated liquids before it can be piped. However, depending on market demand, the compounds extracted from wet gas can be sold for extra revenue as a by-product. Natural gas from each shale play has a slightly different composition, and different geological environments can produce a "drier" or "wetter" resource within different zones of a single formation. For example, the Marcellus shale, currently the largest shale gas reserve in the U.S., underlies large areas of Pennsylvania, New York, West Virginia, Ohio, and to a lesser extent New Jersey, Maryland, and Canada. The Marcellus Shale is found as deep as 9,000 feet below the surface in northeastern Pennsylvania where it is as thick as 350 feet in places.[16] Following the formation west, the Marcellus Shale becomes increasingly shallow and thin, until it is at a depth of 1,500 feet and has a thickness of only a few feet in north central Ohio. In the deeper eastern part, the Marcellus Shale yields dry gas, while in the shallower western part there is wet gas.

Deep shale production was pioneered and developed in the Barnett Shale in Texas in the 1980s and 1990s.[17] By 2010, 20 separate target formations, or "shale plays" had been discovered across the lower 48 states.[18] The pace of exploration is fast and the cumulative known reserve growing, however a 2011 report estimates 750 trillion cubic feet of technically recoverable shale gas resources in the lower 48 states.[19] That estimate would undoubtedly be higher at the time of the writing of this paper. As of 2010, out the 32 states producing natural gas, 27 states hosted

[14] Chandra, Vivek. Gas Formation, NatGas.info, website: http://www.natgas.info/html/gasformation.html
[15] Hyne, Norman J., Nontechnical Guide to Petroleum Geology, exploration, Drilling & Production. 3rd ed. PennWell Corporation, Tulsa, OK, 2012. pg. xiv.
[16] Wet-Dry Gas, Penn State Marcellus Center for Outreach and Research, 2010, http://www.marcellus.psu.edu/images/Wet-Dry_Line_with_Depth.gif; Extent and Thickness of Marcellus Shale, Penn State Marcellus Center for Outreach and Research, 2010, http://www.marcellus.psu.edu/images/Marcellus_thickness.gif.
[17] Halliburton, U.S.ShaleGas, White Paper, 2006, p. 3.
[18] U.S. Energy Information Administration, Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays, "Background," p. 4 (Washington, DC, July 2011), website ftp://ftp.eia.doe.gov/natgas/usshaleplays.pdf.
[19] Id.

either active or proposed fracking operations.[20] [21] The three largest gas-producing plays are currently the Marcellus Shale (discussed above), the Haynesville Shale (LA and TX), and the Barnett Shale (TX).[22] In Michigan and Ohio, there are two additional shale plays, the Antrim Shale in Michigan, and the Utica Shale, which underlies much of the Marcellus Shale, but extends further west into Ohio.

THE ANTRIM SHALE

The Antrim Shale is an Upper Devonian formation in the Michigan Basin. The Antrim play also includes parts of the Ellsworth Shale in western Michigan and Bedford Shale in Eastern Michigan. The Michigan basin is a circular sedimentary basin centered on an area near Midland, Michigan. Sedimentary layers, including the Antrim Shale, are near the surface along the margins of the basin (around the edges of the Lower Peninsula) and are found at progressively deeper levels toward the center of the basin. The Antrim play collectively covers approximately 39,000 square miles mostly in the northern part of the Lower Peninsula.[23] Production is generally at depths between 1,200 and 2,000 feet or deeper and requires natural or induced fractures to allow adequate flow to support production.[24]

The Antrim Shale has been producing natural gas since the 1940s, however activity increased dramatically in the 1980s, peaking in 1998.[25] Over the last 50 years, approximately 12,000 wells in Michigan, mostly in the Antrim, have employed fracking techniques.[26] However a typical Antrim Shale well is short and vertical, and treatments are at a much smaller scale than those of deep, horizontal, large volume fracking operations in other formations. In fact, as interest in the Antrim Shale has waned in the past few years, the Utica Shale, which is also present in the Michigan Basin has become a more attractive target nearby in eastern Ohio, has continued to receive increased attention. As of December 20, 2012, permits for 53 high-volume, hydraulically fractured wells have been granted in Michigan by the Michigan Department of Environmental Quality, of which four are producing.[27]

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[20] U.S. Energy Information Administration, State Ranking 3. Natural Gas Marketed Production, 2010 (million cubic feet) (Washington, D.C.: EIA, n.d.); http://www.eia.gov/beta/state/rankings/?sid=US#/series/47.

[21] Earthjustice, Fracking Across the United States, http://www. http://earthjustice.org/features/campaigns/fracking-across-the-united-states.

[22] Koppelaar, Rembrandt. Shale oil: The latest insights. Energy Bulletin. The Oil Drum, October 24, 2012. Website: http://www.energybulletin.net/stories/2012-10-26/shale-oil-the-latest-insights.

[23] Dolton, G.L., 1996, An Initial Resource Assessment of the Upper Devonian Antrim Shale in the Michigan basin, U.S. Geological Survey, Open-File Report 95-75K.

[24] Dolton, G.L., 1995, Michigan Basin Province (063), in Gautier, D.L., Dolton, G.L., Takahashi, K.J., and Varnes, K.L., eds., 1995 National Assessment of United States oil and gas resources—Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series 30, one CD-ROM

[25] Goodman, W.R. & Maness, T.R., Michigan's Antrim Gas Shale Play – A Two Decade Template for Successful Devonian Gas Shale Development, Search and Discovery, 2008.

[26] Questions and answers about hydraulic fracturing in Michigan. Michigan Department of Environmental Quality. website: http://www.michigan.gov/documents/deq/deq-FINAL-frack-QA_384089_7.pdf.

[27] List of high volume Hydraulic Fracturing active permits and applications, Michigan Department of Environmental Quality, available for download on DEQ website: http://www.michigan.gov/deq/0,1607,7-135-3306_57064-87386--,00.html.

THE UTICA SHALE

The Utica Shale is an Upper Ordovician formation between 200 and 400 feet thick, underlying parts of Canada, Michigan, New York, Pennsylvania, Ohio, West Virginia, and Kentucky at a depth of 4,000 to 10,000 feet, deepening from NW to SE.[28] The Utica in part underlies the Marcellus shale, and is found 2,000 to 6,000 feet beneath it. The Utica can be divided into wet gas producing zones and dry gas producing zones along a curve that is generally parallel to the wet/dry division in the Marcellus. However, unlike the Marcellus, continuing west past the wet gas zone, the Utica also hosts oil-bearing zones in Ohio. As the formation becomes shallower to the west, the hydrocarbon rich zones give way to immature zones that did not achieve sufficient depth to allow temperatures to release hydrocarbons from the shale.

As of January 5, 2013, permits for 493 horizontal wells have been granted in the Utica-Point Pleasant play in eastern Ohio by the Ohio Department of Natural Resources, of which 205 have been drilled, and, as of December 29, 2012, there are 46 wells producing.[29]

THE RISKS

Concerns about fracking focus on both known and suspected, though often unconfirmed, threats to public health and to the environment. Policy makers must balance the appeal of domestic energy independence and increased economic activity for local industries and communities against a raft of human and natural environmental concerns, including protection of surface water quality and subsurface sources of drinking water, impacts of large volume water withdrawals, air quality concerns from exploration, production and longer term general air quality concerns related to continued hydrocarbon energy reliance, direct impacts of exploration and production on surrounding habitats and wildlife, concerns about triggering seismic activity, and disposal of waste fluids.

Perhaps the most common public concern regarding fracking is the risk of contamination of drinking water sources. For the purposes of this paper, the perceived avenues for contamination are grouped into the following four categories that include fluid released by:

1. simple spills from operations at the surface;
2. leaks in the pipe that lines the wells (casing) that would allow fluids to migrate from the wellbore to the surface or into adjacent formations at depth;
3. fracturing of rocks during the actual fracking process, which would allow fluids to flow from the reservoir to the surface or, more likely, into overlying formations; and
4. operations having to do with disposal of waste fluids.

[28] Yost, A. "Research Plan for Utica Shale Characterization and Development." Presentation to Petroleum Technology Transfer Council Workshop: Taking A Deeper Look At Shales: Geology And Potential Of The Upper Ordovician Utica Shale In The Appalachian Basin. June, 21, 2011.

[29] Well list of Utica shale activity from Division of Oil and Gas Resources Management, available for download on ODNR website: http://www.dnr.state.oh.us/tabid/23014/default.aspx; Map of Horizontal Utica-Point Pleasant Well Activity In Ohio, Marcellus and Utica Shales Data, Ohio Department of Natural Resources, http://www.dnr.state.oh.us/tabid/23014/default.aspx.

While the primary interest of this paper is the fourth category, disposal of waste into its final resting place, the question of disposal and treatment touches each of these avenues for contamination. Familiarity with each of the following categories provides context for examination of the issues surrounding disposal. Each of the above four categories is briefly discussed below, and relevant state regulatory structures are mentioned.

SURFACE SPILLS AND RELEASES

This category of release can occur at a drill site, a disposal site, or during transportation of waste from one place to the other. Construction and trucks moving large volumes of fluids in and out of an area present ample opportunity for spills, and require much care and attention with regard to regulation of permitted practices. Surface spills and releases are protected against and expressly prohibited under Ohio oil and gas regulations. Strictly speaking, if releases occur, they are the result of negligence or an illegal action by either the operator or a third party. Even a small volume release can be damaging, depending on what substances are spilled and the proximity to sources of drinking water. Above ground spills are the most visible, and likely the most common. In many ways they are also the simplest to regulate because they demand practically no technical knowledge of the drilling process, geochemistry, geology, or hydrology to understand and therefore to anticipate. Ultimate disposal in pits or dikes of brine or any liquid waste substances is banned outright in Ohio and Michigan.[30] In Ohio, maximum duration of temporary storage in lined pits is limited by specific timetables for restoration of the drill site upon completion and also upon plugging of the well.[31] In any event, the brine, saltwater, or other wastewater shall be drained, removed, or disposed of at least every 180 days, the pits must be lined or otherwise “liquid tight and constructed to prevent escape” and the surface level of the waste can at no time rise above the surrounding ground level.[32] If tanks are used instead, they must be above ground unless there is written permission from the Chief of the Ohio Division of Minerals Resources Management, in which case the tanks must be steel (unless express permission indicating otherwise is granted by the Chief) and burial witnessed by an inspector.[33] With regard to fracking fluid or “frac-water” as it called in the Ohio Administrative Code, only temporary storage is permitted, lasting only until the termination of the fracturing process, at which time pits or tanks must be emptied, contents disposed of, and pits filled in.[34] In Michigan, lined pits are forbidden outright for well completion fluids, and earthen pits cannot be used to contain fluids produced from a well.[35]

CASING LEAKS

This second avenue for potential contamination occurs either during drilling or is the result of faulty casing of the well hole. Casings are the concrete and steel linings within the well hole that serve as a barrier between the well and surrounding formations. Specific regulations for

[30] Ohio Rev. Code Ann. § 1509.22; Mich. Admin. Code r. 324.702
[31] Ohio Rev. Code Ann. § 1509.072(A)&(B)
[32] Ohio Admin. Code § 1501:9-3-08(A)
[33] Ohio Admin. Code § 1501:9-3-08(B)
[34] Ohio Admin. Code § 1501:9-3-08(C)
[35] Mich. Admin. Code r. 324.408(7)(d); Mich. Admin. Code r. 324.503(1)

casings vary state to state, and most call for redundancy. The Ohio Revised Code calls for steel production casing and "sufficient" cement to "protect and isolate all underground sources of drinking water as defined by the SDWA" and in accordance with "industry standards for the type and depth of the well and the anticipated fluid pressures that are associated with the well."[36] For the purposes of fracking, which requires holes, or perforations, in the casing where the fracturing is intended, the perforations cannot be in any part of the casing that "protects underground sources of drinking water" unless there is written authorization from the Chief.[37] There is an exemption to the Ohio casing rules if the zone that will not be cased is isolated and there is a minimum of five hundred feet between the shallowest perforation and the deepest underground drinking water above.[38]

Annular disposal is the only aspect of this category directly relevant to the regulation of disposal. Annular disposal is the disposal of waste in the annular space of a wellhole. This is a strange place to dispose of fluids, however it remains on the books as an possible option in Ohio. The term Annular Disposal is used in regulations, however it is not given a formal legal definition. According to industry custom, annular space is the space between the casing and the tubing of a wellhole. Annular disposal would consist of injection of waste fluids into that space. In Ohio there is a general outright prohibition of this disposal method, however it is allowed subject to approval by the Chief on a case-by-case basis.[39] This subject is discussed further in the **RECOMMENDATIONS** section, below.

CONTAMINATION VIA INDUCED FRACTURES

The third avenue for potential contamination is perhaps the most challenging for people unfamiliar with the fracking process to conceptualize. The concern at this stage is that the fracturing procedure discussed above will induce fractures that not only free trapped natural gas, but go beyond the target formation and connect to formations that contain underground sources of drinking water. These induced fractures could then serve as conduits for fracking fluid, natural gas, or natural brines in a manner that would contaminate sources of drinking water. The risk of this type of contamination hinges on several related factors, among them the proximity of the point of fracking to nearest underground sources of drinking water, the depth and the pressure. Currently, public concern over this avenue for contamination has been less voiced in the media. Unless a fracking permit is improperly issued for a shallow well near an underground water source, it is extremely unlikely that the hydraulic pressure in the wellbore could be sufficient to overcome the pressure of the lithostatic overburden and extend to an overlying formation containing groundwater.

DISPOSAL OF WASTE

In all three of the potential mechanisms for contamination of water sources discussed above, if there is any loss of fluid, then a mistake has been made. Disposal is different. With

[36] Ohio Rev. Code Ann. § 1509.17(A)
[37] Ohio Rev. Code Ann. § 1509.17(A)
[38] Ohio Rev. Code Ann. § 1509.17(C)
[39] Ohio Admin. Code § 1501:9-3-11(A)(1)

disposal the goal is to be rid of the substance, however it must be done in a manner that will sequester any potentially harmful materials. Prior to the advent of environmental regulations, a popular liquid waste disposal method was to dump the waste into the nearest river. While this is no longer an acceptable or legal disposal method, as we will see, the specific requirements for the disposal of fracking flowback often rely on or mirror the local requirements for disposal of traditional oil and gas wastes. Fracking flowback from modern high volume fracking operations is a relatively new substance, the characteristics of which must be considered as to the most prudent method of disposal. As discussed below, the disposal of fracking flowback is not completely without regulation. Below, we will see how the federal categorization of fracking flowback into the same classification as traditional oil and gas waste in large part places the burden of prudent regulation of disposal on the states. For the purposes of this section, the threat of contamination resulting from irresponsible disposal is simple; if waste is improperly disposed of, harmful components might migrate into and contaminate sources of drinking water.

THE REGULATIONS

Treatment and disposal of flowback is subject to federal and state laws that are intended to protect water resources. The Clean Water Act (CWA) governs treatment and discharge of wastewater into surface waters. The Safe Drinking Water Act (SDWA) regulates disposal of fracking flowback and saltwater brines to ensure the protection of underground sources of drinking water.[40] The fracking waste disposal process necessarily begins when waste is first created. The moment flowback emerges from the wellbore it should be considered waste. Flowback is collected and can either be treated to a sufficient quality for reuse as a component of fracking fluid in a new treatment (referred to as "recycling" in the industry), or transported untreated to an injection site for disposal. Whether an operator will decide to inject or recycle is generally based on the economics that are in turn a function of the regulatory structure. In the Midwest the overwhelming preference is for injection. For example, in Ohio 98% of produced brine and fracking flowback is disposed of via injection.[41]

UNDERGROUND DISPOSAL

Idealized underground geology consists of discrete horizontal layers of rock. Each layer is a separate formation with slightly different characteristics. Some formations are more permeable than others; some are not permeable at all. An impermeable formation serves as a

[40] "Underground source of drinking water (USDW) means an aquifer or its portion:(a)(1) Which supplies any public water system; or (2) Which contains a sufficient quantity of ground water to supply a public water system; and (i) Currently supplies drinking water for human consumption; or (ii) Contains fewer than 10,000 mg/l total dissolved solids; and (b) Which is not an exempted aquifer. (40 CFR §144.3, Definitions); An aquifer can be exempted if it currently does not, could not currently, and will not at any time in the future serve as a source of drinking water because it is too deep, to contaminated, to dangerous, or too valuable for another use. Specific rubric for exemption is found at 40 CFR §146.4.

[41] http://www.ohiodnr.com/mineral/injection/tabid/10374/Default.aspx; The other 2% is used to control dust and ice on roads via surface application, however only brine from traditional wells is used, fluids from fracking and other well treatments are specifically prohibited from this use. (ORC 1509.226 (B)(10)

barrier that keeps the fluids in one formation from mixing with the fluids in another formation. Water in a deeper formation cannot mix with water in a more shallow formation if there is an impermeable layer separating the two saturated formations. Based on these concepts, disposal wells inject waste into formations calculated to be isolated from sources of drinking water in order to avoid contamination.

To facilitate underground disposal for all manner of waste, the Safe Drinking Water Act (SDWA) and, with regard to hazardous wastes the Resource Conservation and Recovery Act (RCRA), establish the requirements for the federal Underground Injection Control (UIC) program.[42] The SDWA prohibits an operator of an injection well from endangering underground sources of drinking water by contaminating groundwater "which supplies or can reasonably be expected to supply any public water system."[43] Underground injection has a broad definition that covers all “subsurface emplacement of fluids by well injection.”[44] States that meet the minimum requirements for underground injection or that can demonstrate that their program is effective in preventing endangerment of drinking water sources, can obtain primary authority over their state UIC program (“primacy”).[45] Primacy states manage their own permitting process, often using the federal UIC for guidance. In 1983, the EPA gave Ohio primacy over Class II wells in that state.[46] In Ohio, all underground injection activities must be permitted by the state.[47] Michigan does not have primacy. In Michigan, the U.S. EPA[48] and the Supervisor of Wells within the Michigan Department of Environmental Quality both manage disposal separately.

Under the UIC there are six classes of injection wells, covering hazardous waste, fluids relating to the oil and gas industry, solution mining, carbon sequestration, and any and all other uses. For the purposes of this review, only Class I and Class II wells are relevant.

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[42] 40 CFR 144.1(b)(1)

[43] 42 U.S.C. §§ 300h , 300h-1 (2006). S*ee also* 40 C.F.R. §144.3 (defining an "underground source of drinking water (USDW)" as "an aquifer or its portion: (a)(1) Which supplies any public water system; or (2) Which contains a sufficient quantity of ground water to supply a public water system; and (i) Currently supplies drinking water for human consumption; or (ii) Contains fewer than 10,000 mg/l total dissolved solids; and (b) Which is not an exempted aquifer").

[44] 40 CFR 144.3 “Well injection”; Note: A literal application of this definition to the entire hydraulic fracturing process would suggest that from the time that the fracking fluid is mixed to the time when it is disposed of, fracking fluid physically is injected into the ground two times; the first during the fracking treatment into the production well, followed by partial flowback and collection, and the second during disposal into the final resting place, the disposal well. However, in 2005 a federal level carve out from the federal UIC was enacted to exclude fracking operations from the UIC definition of underground injection. (“excludes … the underground injection of fluids or propping agents … pursuant to hydraulic fracturing operations to oil, gas, or geothermal production activities.” 42 USCA 300h (d)(1)(B)(ii)) This carve out only excludes fracking treatments and does not exclude the disposal of flowback fluids. While UIC classifications still explicitly cover all non-fracking “wells which inject fluids for enhanced recovery of oil or natural gas” as Class II injection wells ((OAC 3745-34-04 (B)), enhanced recovery is a general term for a variety of processes designed to increase the life and yield of a field. A typical process includes injection of gas or fluids into a traditional oil field to increase pressure in the reservoir allowing a greater percentage of the oil to be produced. Injected substances are not used to induce fractures, but merely to increase the pressure or otherwise alter reservoir conditions. Fracking treatments themselves are definitively outside the scope of the UIC.

[45] 40 CFR 145; 42 U.S.C. § 300h-4(a) (2006).

[46] Ohio Department of Natural Resources Underground Injection Control; Program Approval, 48 Fed. Reg. 38238 (1983); 40 CFR 147

[47] Ohio Admin. Code § 3745-34-12 (A) (1)

[48] 40 CFR 144.1800; 40 CFR 144.1151; States that meet the minimum requirements for underground injection specified in Part 145 of Title 40 can obtain primary authority over their state UIC program and manage their own permitting process using the UIC for guidance; 40 CFR 147

- Class I wells are used for injection of municipal and industrial waste, as well as hazardous or radioactive waste, *beneath* the lowermost formation containing, within ¼ mile of the well bore, an underground source of water.[49]
- Class II wells are used for fluids that return to the surface with gas or oil storage or production, for enhanced recovery of oil or gas production, or for liquid hydrocarbon storage, unless the fluids are classified as hazardous at the time of injection.[50]

Part of the reason that controversy over fracking has been so prolonged is that, despite the federal UIC, government oversight of fracking still falls mainly on the states, rather than the federal government. Wastewater from all oil and gas wells is exempted from the federal "cradle to grave" provisions governing generation, transportation, treatment, storage, and disposal of hazardous waste in the RCRA.[51] This categorical exemption includes flowback from hydraulically fractured wells, regardless of whether they contain potentially hazardous characteristics.[52] Under this RCRA exclusion, there is a carve out for fluids and produced waters associated with the production of oil and natural gas; by statute fracking fluid and flowback are categorically nonhazardous wastes and therefore exempt from regulation under the more rigorous RCRA Subtitle C waste regulation requirements.[53] Despite the toxic or sometimes undetermined nature of many of the chemical additives, rather than requiring disposal in Class I wells, the federal level RCRA exclusion places fracking flowback waters outside the federally mandated scope of Class I injection wells. Instead, fracking flowback waters are included within the same category as produced salt water from traditional oil and gas production. They are disposed of in Class II injection wells, a category of injection well with less stringent statutory requirements. Due to this federal level exemption from RCRA, tailoring of disposal regulation for fracking flowback falls on state level rules and regulations regarding acceptable class of disposal well and level of stringency.[54]

With the recent increase and forecasted continued use of fracking as a production method, and in light of each state's unique geological and hydrological setting, clear state-level guidance on disposal mechanisms for produced waters is necessary in order to the maintain and

[49] 40 CFR 144.6(a); 3745-34-04 (A)
[50] 40 CFR 144.6(b) ; 3745-34-04 (B)
[51] One of the amendments to the Solid Waste Disposal Act in 1980 was the Bentsen Amendment (§3001(b)(2)(A)) that exempted drilling fluids, produced waters, and other wastes associated with the exploration, development, and production of crude oil or natural gas or geothermal energy. Eight years later, in 1988, the EPA issued a regulatory determination that the regulation of oil and gas production wastes under the RCRA Subtitle C regulations for hazardous waste was not warranted. The exemption is now codified and can be found within RCRA. 40 C.F.R. § 261.4(b)(5) . *See also* 42 U.S.C. §§ 6921(b)(2), 6982(m) (2006).
[52] Confusingly, liquid wastes that demonstrate hazardous characteristics are regulated under RCRA's broad definition of solid waste. 40 CFR 261.2 If not excluded, wastes that are not specifically listed may still be considered hazardous if they exhibit hazardous waste characteristics which are defined as characteristics that "cause, or significantly contribute to, an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness; or pose a substantial present or potential hazard to human health or the environment when it is improperly treated, stored, transported, disposed of or otherwise managed." 40 CFR 261.10(a)(1)(i)-(ii) There are four hazardous waste characteristics, each with specific guidance with regard to qualifying thresholds: ignitability, corrosivity, reactivity, and toxicity. 40 CFR 261.21-24.
[53] "Drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy" are classified as solid wastes that are not hazardous wastes, and are therefore exempt from regulation under the RCRA, the federal hazardous waste regulatory program. 40 CFR 261.4(b)(5)
[54] As fracking has become increasingly prevalent, the state regulations state level regulations have taken on increased importance.

protect underground sources of drinking water.[55] States with primacy over their UIC programs can tailor their programs to explicitly address disposal of fracking fluids, and states not in primacy have the option to put in place separate regulations that would be enforced by the state in addition to and independent of the existing federal UIC program. States not in primacy can independently regulate fracking through their own administrative systems separate from and in addition to the federally mandated regulation enforced by the U.S. EPA.

At the time U.S. EPA made its determination to exempt such wastewater in 1988, the majority of such wastewater was from traditional or enhanced oil recovery and not fracking flowback. Still, the agency estimated that 10-70% of drilling fluids and produced water "could potentially exhibit RCRA hazardous waste characteristics."[56] The EPA concluded, however, that the risk of exposure to toxic substances in the wastewater was small and the costs of compliance were large, and that the existing state regulatory programs were generally adequate to control the management of oil and gas wastes. If disposal of fracking wastes is to be regulated in a way different from other oil and gas fluid wastes, either the federal RCRA exclusions would need to be appealed, or state legislatures must take up the issues directly. State level consideration of the need for rules and regulations regarding disposal of flowback from fracking operations and regarding the regulation of Class II wells is important.

Under the Clean Water Act, oil and gas well operators are prohibited from discharging wastewater, including flowback, into navigable waters of the United States.[57] Although the CWA allows operators to discharge flowback through treatment facilities if certain requirements are met, discharge of flowback into surface waters is prohibited under Michigan and Ohio state laws.[58] Land application of flowback is also forbidden in both states.[59] Thus, oil and gas well operators who wish to dispose of flowback in Michigan and Ohio must use underground injection wells. The federal SDWA, discussed *infra*, governs underground injection of fluids.[60] In Michigan, the EPA regulates disposal wells through its Underground Injection Control (UIC) program; the state of Michigan also has separate permitting requirements under Part 615 of NREPA. As mentioned above, Ohio has primacy to administer its own UIC program.

[55] The U.S. Energy Information Administration estimates that by 2035 almost half of the nation's natural gas will be produced from shale formations, doubling the percentage produced in 2010; The percentage of crude oil obtained from "tight oil" sources, including shale, is estimated to more than double during the same time period, from 12% of onshore production to 31%. (U.S. Energy Information Administration, Annual Energy Outlook 2012 Early Release Overview (2012), *available at* http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf).
[56] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. 25447 (1988).
[57] 40 C.F.R. §§ 435.30, 435.32 . There is an exception for so-called "stripper wells," wells at the end of their useful life that produce 10 barrels of crude oil or less per day. 40 C.F.R. § 435.60 .
[58] Ohio Rev. Code Ann. §1509.22(C)(1) . While this provision allows disposal by other methods approved by the chief for testing or implementing a new technology or method of disposal, treatment and discharge is not considered such a method by the state. *See* Letter from Scott J. Nally, Ohio Department of Environmental Quality, to David Mustine, Director, Ohio Department of Natural Resources (May 6, 2011), available at http://www.epa.ohio.gov/portals/35/pretreatment/marcellus_shale/POTW_Brine_Disposal_Letter_may11.pdf. The revised permit for this facility prohibits flowback as of April 1, 2012.
[59] Mich. Admin. Code r. 324.705(2) (allowing use for ice and dust control only upon approval of MDEQ); Ohio Rev. Code Ann. §§1509.22(C)(1), Ohio Rev. Code Ann. § 1509.226(B)(10) .
[60] *See* "Regulation of Well Activities" section.

Below is a discussion of how fracking waste is disposed of in two states, one with and one without primacy, Ohio and Michigan. Both of these states support established oil and gas industries, and, as mentioned above, both host fracking targets.

MICHIGAN

In Michigan, the U.S. EPA regulates both Class I and Class II wells. In addition, Class II wells used for disposal of oil or gas field waste fluid waste are also regulated on the state level by the Michigan Department of Environmental Quality, Supervisor of Wells.[61] As mentioned above, Michigan has not applied for primacy of the federal UIC program. Well operators wishing to receive a permit to inject produced salt waters from oil or gas production must apply separately to the US EPA and to the state for permits, whereas in Ohio permit applicants to the state can satisfy both state and federal requirements in one application process regulated by the state. In addition to a permit from the US EPA for a Class II well as defined above, the Michigan Supervisor of Wells requires any person who wishes to drill or operate a well to "inject for the disposal of brine, oil or gas field waste, or other fluids incidental to the drilling, producing, or treating of wells of oil or gas, or both…" to apply through them for a permit from the State as well.[62] The Michigan Administrative Rules indicate a strong preference for disposal via injection, though the supervisor may approve another manner of disposal, the default method is injection into an "approved underground formation in a manner that prevents waste." [63]

Each disposal well that accepts flowback fluid must have a Class II well permit from the EPA.[64] Several wells in the same area and operated by the same entity may be permitted under a single area permit.[65] A disposal well owner or operator may not "construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water" if the contamination violates drinking water standards or adversely affects public health.[66] Applying for a permit, the operator has the burden of demonstrating that a proposed well will not contaminate drinking water sources.[67] For a Class II well accepting only waste from oil and gas production, a permit may be issued for the life of the well; however, the EPA must review the permit every five years.[68]

A disposal well that accepts flowback fluid must also have a permit from the MDEQ under Part 615 of NREPA.[69] The MDEQ considers flowback a form of brine, which is defined in Part 615 as "all nonpotable water resulting, obtained, or produced from the exploration, drilling, or production of oil or gas, or both."[70] A permit is for the life of the well. Storage, transportation, or disposal of brine that results in, or may result in, pollution is prohibited.[71] Part 615

[61] 40 CFR 144.1151; Mich. Admin. R 324.201(1)(c)
[62] Mich. Admin. R 324.201(1)(c)
[63] Mich. Admin. R 324.705(3); Mich. Admin. R 324.702
[64] 40 C.F.R. §§ 144.11, 144.31 .
[65] 40 C.F.R. § 144.33 .
[66] 40 C.F.R. § 144.12(a) .
[67] 40 C.F.R. § 144.12(a) .
[68] 40 C.F.R. § 144.36 .
[69] Mich. Admin. Code r. 324.201(1)(c) .
[70] Mich. Admin. Code r. 324.102(f) .
[71] Mich. Admin. Code r. 324.701 .

requirements also include secondary containment for surface facilities to protect against spills.[72]

A disposal well that accepts flowback fluid must be sited so that the wastewater will not migrate up into aquifers through natural or manmade conduits. New Class II wells must inject into a formation separated from any underground source of drinking water "by a confining zone that is free of known open faults or fractures within the area of review."[73] The "area of review" is a fixed radius of ¼ mile around the wellbore or a zone of endangering influence calculated using a mathematical model.[74] Under Michigan's program, brine wells must inject into a formation that is isolated from freshwater strata by an impervious confining formation.[75] In addition, both programs require a disposal well operator to submit a corrective action plan for nearby wells that may act as conduits because they are improperly sealed, completed, or abandoned.[76]

A disposal well that accepts flowback fluid must also be constructed to prevent migration of wastewater. All Class II wells must "be cased and cemented to prevent movement of fluids into or between underground sources of drinking water."[77] In addition, the "casing and cement used in the construction of each newly drilled well shall be designed for the life expectancy of the well." In determining how a well is to be constructed, the EPA must consider certain factors, such as depth to the injection zone and drinking water sources, and estimated injection pressures. Under Michigan's program, a disposal well must meet specific construction requirements applicable to all wells.[78] These include casing that extends from the surface to 100 feet below freshwater strata. In addition, fluid must be injected through "adequate" tubing inside the casing and through a "packer" that seals the bottom of the well.[79]

Before a well operator may begin injecting flowback, the disposal well must be approved by the EPA and the MDEQ.[80] The operator must also demonstrate to both agencies that the well has mechanical integrity.[81] Under the federal UIC program, the operator is required to show both internal mechanical integrity, defined as no significant leaks in the casing and other well components, as well as external mechanical integrity, defined as no significant fluid movement outside of the casing along the contact between wellbore and the rock.[82] Under Michigan's program, the operator need only demonstrate internal mechanical integrity by conducting a pressure test.[83] Both programs also require that the operator continue to demonstrate mechanical integrity every five years.[84] During operations, the operator may not exceed the maximum injection pressure set by both the federal and state permits.[85]

A disposal well operator must submit information to both the EPA and the MDEQ on the

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[72] Mich. Admin. Code r. 324.301(1) .
[73] 40 C.F.R. § 146.22(a) .
[74] 40 C.F.R. § 146.6 .
[75] Mich. Admin. Code r. 324.703, 324.705(3) .
[76] 40 C.F.R. §§ 146.24(a)(2)-(3), 144.55 ; Mich. Admin. Code r. 324.201(j) .
[77] 40 C.F.R. § 146.22(b) .
[78] *See* Mich. Admin. Code r. 324.408, 324.410-11 .
[79] Mich. Admin. Code r. 324.801 ; *see* Ground Water Protection Council, Injection Wells: An Introduction to Their Use, Operation, and Regulation 10, *available at* http://www.gwpc.org/sites/default/files/injection_wells-_an_introduction_to_their_use_operation_and_regulation.pdf (last visited June 13, 2012).
[80] 40 C.F.R. § 144.51(m) ; Mich. Admin. Code r. 803 .
[81] 40 C.F.R. §§ 144.51(q), 146.8(a) ; Mich. Admin. Code r. 803 .
[82] 40 C.F.R. § 146.8(b)-(c) .
[83] Mich. Admin. Code r. 803 .
[84] 40 C.F.R. § 146.23(b)(3) ; Mich. Admin. Code r. 805 .
[85] 40 C.F.R. §§ 144.52(a)(3), 146.23(a) ; Mich. Admin. Code r. 324.804 .

source and chemical and physical characteristics of the flowback.[86] For commercial Class II disposal wells, a permit applicant is required to submit a chemical analysis of the normal brine constituents for each source.[87] Michigan's program requires an applicant to submit a chemical analysis for a representative sample of each type of injected fluid. In addition, both programs require the well operator to monitor the injection pressure, flow rate, and cumulative volume of the flowback on a weekly basis.[88] A Class II operator of a disposal well must also monitor the nature of the flowback "at time intervals sufficiently frequent to yield data representative of their characteristics" and annually submit information on any major changes in characteristics or sources of the wastewater.[89] For commercial Class II disposal wells, the EPA requires a quarterly chemical analysis of each source and approval of all new sources.[90] If there is evidence that a disposal well is leaking or other data indicates a malfunction, the operator must contact both agencies within 24 hours of discovery and submit a written report within five days.[91]

When a disposal well has reached the end of its life, both programs require the operator to plug the well with cement and abandon it in accordance with a plan submitted at the time of the permit application.[92] Under the federal UIC program, a well must be plugged using one of several methods and in a manner that will prevent the movement of flowback into underground sources of drinking water.[93] In contrast, Michigan's plugging requirements, which apply to both production and disposal wells, detail the specific method and material to be used.[94] Neither program requires continued monitoring of nearby aquifers. A well operator must provide the EPA and the MDEQ with evidence of sufficient financial means to plug the well.[95] Both programs require the operator to submit a financial instrument, such as a bond, or a statement of financial responsibility.

OHIO

In Ohio, Class I wells are regulated by the Ohio EPA and Class II wells are regulated by the Ohio Division of Oil and Gas.[96] While the UIC program is part of SDWA, the implementation of which generally falls under the purview of the Ohio EPA, the disposal of “any and all nonpotable water resulting, obtained, or produced from the exploration, drilling, or production of oil or gas” is permitted by the Ohio Division of Oil and Gas. Disposal of these fluids occurs in Class II wells under the provisions for Saltwater Operations.[97] The Ohio EPA’s UIC defers to Chapter 1509 on Oil & Gas with regard to permits for Class II wells by accepting Division of Oil and Gas permits for Class II wells in lieu of EPA enforced permit requirements found under the UIC.[98] Though Chapter 1509 does not use the UIC well classification language,

[86] 40 C.F.R. § 146.24(a)(4) ; Mich. Admin. Code r. 324.201(j) .
[87] *Requirements for Commercial Underground Injection Control Class II Wells*, *supra* note 273.
[88] 40 C.F.R. § 146.23(b) ; Mich. Admin. Code r. 806 .
[89] 40 C.F.R. § 146.23(b)-(c) .
[90] *Requirements for Commercial Underground Injection Control Class II Wells*, *supra* note 273.
[91] 40 C.F.R. § 144.51(l)(6) ; Mich. Admin. Code r. 807 .
[92] 40 C.F.R. §§ 144.31(e)(10), 144.52(a)(6) ; Mich. Admin. Code r. 201(j), 903 .
[93] 40 C.F.R. § 146.10(a) .
[94] Mich. Admin. Code r. 902 .
[95] 40 C.F.R. § 144.52(a)(7) ; Mich. Admin. Code r. 324.210 .
[96] 40 CFR §147.1800; 40 CFR §147.1801
[97] Ohio Admin. Code § 1501:9-3-01 (E)
[98] Ohio Admin. Code § 3745-34-12(A)(3); 40 CFR §147.1800(a)

relying on the UIC well definitions, all non-fracking wells used for injection that are covered in Chapter 1509 fall under the definition of Class II wells.

In the Ohio Revised Code, the Division of Oil and Gas requires any injection to be permitted or expressly authorized by the Chief of the Division of Oil and Gas Resources Management.[99] The Chief is responsible for promulgating rules to ensure monitoring, compliance, and the implementation of the goals of the Safe Drinking Water Act. As in Michigan, this includes placing the burden on the applicant to show that injection will not result in contamination of underground sources of drinking water.[100] While the Ohio rule lacks the same level of specificity regarding the type of information that must be submitted with a permit application that the UIC requires for permitting Class I wells, the rules still place the burden of proving the environmental viability of the injection plan squarely on the applicant. The applicant can submit as detailed a report as needed to make his case. Regarding fracking flowback, the Division of Oil and Gas uses the term "saltwater" to refer to "any and all non-potable water resulting, obtained, or produced from the exploration, drilling, or production of oil or gas."[101] Flowback from fracking, a mix of brine and fracking fluid as discussed above, fits within this definition. However the fracking fluid component, the focus of concern with regard to disposal practices, is not specifically referenced and the explicit list of exceptions does not exclude fracking flowback from this chapter and this term.[102]

As a primacy state, Ohio was not required to adopt the federal minimum standards in the UIC program. The SDWA allows a state to regulate Class II wells if the program is effective in preventing endangerment of drinking water sources and includes inspection, monitoring, recordkeeping, and reporting requirements.[103] Ohio's requirements, however, mirror many of the federal standards, in some cases exceeding them. In addition to the requirements applicable to disposal well operators, an applicant for an oil or gas well permit must submit a plan for disposal of water and other waste substances, including identification of the disposal well or wells to be used.[104]

Under Ohio's law, all well operators that inject "brine or other waste substances resulting from, obtained from, or produced in connection with oil or gas drilling, exploration, or production" must obtain a permit from the ODNR.[105] This includes well operators that accept fracking flowback.[106] A permit is for the life of a well, expiring if the operator fails to drill the well within twelve months.[107] As in the federal UIC program, an applicant must demonstrate that injection will not result in contamination of "groundwater that supplies or can reasonably be expected to supply any public water system" and the contamination violates drinking water

[99] Ohio Rev. Code Ann. § 1509.22(D)
[100] Ohio Rev. Code Ann. § 1509.22(D)
[101] Ohio Admin. Code § 1501:9-3-01 (E)
[102] Ohio Admin. Code § 1501:9-3-02
[103] 42 U.S.C. § 300h-4(a) (2006).
[104] Ohio Admin. Code § 1501:9-1-02(A)(3) .
[105] Ohio Rev. Code Ann. § 1509.22(D)
[106] The statute defines "brine" to mean "saline geological formation water." Ohio Rev. Code Ann. § 1509.01(U) . The ODNR's regulations in some cases reference "saltwater," defined as "nonpotable water," and in other cases reference "brine." *See* Ohio Admin. Code § 1501:9-3-01(E) . For purposes of this report, "brine" is assumed to include flowback.
[107] Ohio Admin. Code § 1501:9-3-06(I) . Under rules drafted by the ODNR in response to concerns about seismic activity, an operator in a non-urban area would have 24 months to drill the well. Draft Rule Ohio. Rev. Code. 1501:9-3-06, Ohio Department of Natural Resources (June 6, 2012) *available at* http://www.ohiodnr.com/portals/11/oil/pdf/uic_1501_9-3-06_5-year-rule_review_CSI.pdf.

standards or adversely affects public health.[108] An operator is also generally prohibited from conducting well operations in a manner that will contaminate or pollute land, surface waters, or groundwater.[109]

Like the federal UIC and Michigan programs, Ohio's program is designed to prevent flowback from migrating up into aquifers through natural or manmade conduits. But there is no specific requirement that disposal wells inject into a formation separated from underground sources of drinking water. The operator is prohibited, however, from injecting flowback in a manner that will allow movement of fluid into groundwater and flowback must be injected into an underground formation in a manner approved by the ODNR.[110]

In a permit application, the disposal well operator must submit a casing and cementing program to construct the well.[111] There are also specific construction requirements for disposal wells. For wells permitted after 1982, surface casing must extend to at least 50 feet below the deepest underground source of drinking water and the casing must be cemented to the surface.[112] Cemented casing must also extend to at least 300 feet above the top of the injection zone.[113] Flowback must be injected through tubing and a packer[114] set no more than 100 feet above the injection zone and installed under the supervision of the ODNR.[115] The ODNR may grant a variance from these requirements for wells injecting less than 25 barrels a day at minimal pressures or if the proposed construction will protect underground sources of drinking water in an equivalent manner.[116] In addition, all storage facilities must be generally constructed so as to "prevent pollution to surrounding surface and subsurface soils and waters."[117]

Prior to first injecting fluids, a disposal well operator is required to give reasonable notice to the ODNR and to test the internal mechanical integrity of the well through a pressure test supervised by the ODNR.[118] The results of the pressure test must be reported to the ODNR 30 days after completion of the injection well.[119] During operations, the well pressure must be monitored at least monthly at a pressure sufficient to detect leaks, and the data must be annually reported to the ODNR.[120] If such monitoring is not feasible, the operator is required to demonstrate mechanical integrity every five years by conducting a pressure test or other tests of internal or external integrity.[121] An operator may not exceed the maximum injection pressure calculated for the well.[122]

An applicant for a disposal well permit must identify the composition of the liquid to be

[108] Ohio Rev. Code Ann. § 1509.22(D) .
[109] Ohio Admin. Code § 1501:9-3-04(A) .
[110] Ohio Admin. Code § 1501:9-3-12 .
[111] Ohio Admin. Code § 1501:9-3-06(C)(8) .
[112] Ohio Admin. Code § 1501:9-3-05(A)(1) .
[113] Ohio Admin. Code § 1501:9-3-05(A)(2) .
[114] A piece of downhole equipment that serves to seal the inside of the well but leaves an inside passage for fluids so that fluids can be injected, but preventing movement back up the wellbore.
[115] Ohio Admin. Code § 1501:9-3-05(A)(3) .
[116] Ohio Admin. Code § 1501:9-3-05(A)(7) .
[117] Ohio Admin. Code § 1501:9-3-05(A)(6) .
[118] Ohio Admin. Code §§ 1501:9-3-05(A)(5), 1501:9-3-05(C), 1501:9-3-07(B) .
[119] Ohio Admin. Code § 1501:9-3-07(A) .
[120] Ohio Admin. Code § 1501:9-3-07(F) . Under rules drafted by the ODNR in response to concerns about seismic activity, continuous monitoring would be required for all new wells. Draft Rule Ohio. Rev. Code. 1501:9-3-07, Ohio Department of Natural Resources (June 6, 2012), *available at* http://www.ohiodnr.com/portals/11/oil/pdf/uic_1501_9-3-07_5-year-rule_review_CSI.pdf.
[121] Ohio Admin. Code § 1501:9-3-07(G) .
[122] Ohio Admin. Code § 1501:9-3-07(D) .

injected; unlike the federal UIC and Michigan programs, however, the ODNR does not require applicants to submit a chemical or physical analysis.[123] During operations, the well operator must monitor injection pressures and volumes on a daily basis, and file an annual report with the ODNR.[124] In addition, under the new legislation, the ODNR is directed to issue rules requiring a disposal well operator and transporters of brine to submit quarterly information concerning shipments of brine or other waste substances to a well.[125] Unlike the federal UIC program, a well operator is not required to regularly test the characteristics of injected fluids, however the ODNR may test injected fluids at any time.[126] If an operator discovers that a well was not adequately constructed, the operator must notify the ODNR within 24 hours of the discovery and immediately repair the well.[127] An injection well owner must cease operations immediately when "mechanical failures or downhole problems" cause contamination.[128]

Once a disposal well becomes incapable of receiving injected fluids, it must be plugged in accordance with a permit from the ODNR.[129] The well operator is required to notify the ODNR a minimum of 24 hours prior to commencement of plugging operations, and an inspector must be present during plugging.[130] Like Michigan's program, Ohio's program specifies the method, depth, and cement to be used.[131] There is no requirement to monitor nearby aquifers.

ARE CLASS II INJECTION WELLS SUFFICIENT FOR DISPOSING OF FRACKING FLOWBACK?

Now that we have considered in detail how the federal and state regulation of Class II wells is actually put into use, the important question is whether it is the appropriate type of regulation for fracking flowback. Fracking flowback contains chemical additives that traditional produced waters do not, and the concern is that a “new” waste stream that is more dangerous than Class II, but might not be as dangerous as to warrant full Class I consideration, will slip through the regulatory system by being shoehorned into an existing classification that is not stringent enough to provide adaquate protections. The UIC generally prohibits injection disposal that could cause contamination of sources of drinking water across all classes of wells.[132] Class I wells for injecting hazardous waste carry the most stringent requirements and are the most protective of drinking water because they are the *per se* disposal sites of hazardous waste. The term “hazardous waste” refers to a wide variety of substances. A determination is based on four characteristics: ignitability, corrosively, reactivity, and toxicity, however there is a large body of guidance determining what is and is not hazardous.[133] It is important for this discussion to remember that Class I wells are designed to isolate a wide variety of extremely dangerous

[123] S.B. 315, 129th Leg., Ohio Rev. Code Ann. § 1509.06(A)(6)(b) (Ohio 2012).
[124] Ohio Admin. Code § 1501:9-3-07(E) .
[125] S.B. 315, 129th Leg., **§** 1509.22(D)(1)(c)-(d) (Ohio 2012).
[126] Ohio Admin. Code § 1501:9-3-07(I) .
[127] Ohio Rev. Code Ann. § 1509.12(A) .
[128] Ohio Admin. Code § 1501:9-3-07(H) .
[129] Ohio Admin. Code § 1501:9-3-07(J); Ohio Rev. Code Ann. § 1509.13(A) .
[130] Ohio Rev. Code Ann. § 1509.13(C) ; Ohio Admin. Code § 1501:9-11-04 .
[131] *See* Ohio Admin. Code §§ 1501:9-11-07 to -08 .
[132] “No … injection activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water” if the presence of that contaminant would violate any primary drinking water regulation or adversely affect the health of persons. 40 CFR 144.12(a); 3745-34-07(A)
[133] See OAC 3745-51-20 and 40 C.F.R. § 261 for more detailed guidance on what qualifies as a hazardous waste.

wastes. To avoid contamination, Class I wells require waste to be injected into a formation *beneath* the lowermost formation containing drinking water within a quarter mile radius of the wellbore.[134] With regard to Class I wells for hazardous waste, injection must be into a layer that is separated from the lowest underground source of drinking water by at least one sequence of permeable and less permeable strata.[135] For these Class I hazardous waste disposal wells, the area of review for permitting is a two mile radius from the well bore.[136] Because Class II well fluids have not traditionally been considered as dangerous as Class I well wastes, they have not been subject to as stringent requirements.[137] The federal UIC requirements for Class II wells require that injection must be into a formation that is separated from any underground sources of drinking water by a confining zone that is free of known open faults or fractures within an area of review to be determined based on the site characteristics, or one quarter mile radius from the well bore.[138] Ohio's Administrative Code Chapter 1501 does not specify a specific layer of injection for Class II liquid wastes relative to the nearest source of drinking water, only that the injection zone must be a minimum of 50 feet below the deepest underground source of drinking water.[139]

Still, both Class I and Class II wells must inject in a manner that prevents contamination of underground sources of drinking water.[140] The Ohio EPA and the US EPA have detailed guidance and requirements for Class I wells. While Ohio requires even more information from a permit applicant for a Class I hazardous waste disposal well than the federal UIC program does, both schemes require more information for Class I permit applicants than for Class II permit applicants. This is in part due to the range of substances that a Class I disposal well might handle. To help identify the type of waste intended for a given facility, for example industry identification codes, and other permits or approvals needed for the facility are required. [141] In addition, information regarding the physical and chemical nature of the waste to be injected and its compatibility with the construction materials and fluids naturally found in the injection zone or some variation of this type of information is required.[142] In addition to information about the chemical composition and physical properties of the substances that will be injected, a statement of expertise of the permit applicant along with his own track record with disposal wells is also required.[143] There is also a wide variety of information required to support geologic, hydrologic, and seismic acceptability of the proposed site, in addition to data on existing wells within the surrounding area of review.[144] Further, the applicant for any injection well permit is required to determine the condition of all active and non-active wells within their zone of review, and if

[134] 40 C.F.R. § 146.62(a); 40 C.F.R. § 146.12(a); OAC 3745-34-37(A)
[135] 40 C.F.R. § 146.62(d)(1); OAC 3745-34-51(D)(1)
[136] Ohio Admin. Code § 3745-34-52
[137] The Class I well category includes hazardous, radioactive, municipal and industrial liquid wastes. Though municipal and industrial wastes are not always categorized legally as "hazardous wastes", they still might be dangerous to human health and must be disposed of in a manner that will isolate them from sources of drinking water. In this respect the Class I well category acts as an all purpose disposal mechanism for a broad range of wastes that might potentially contaminate drinking water.
[138] 40 C.F.R. § 146.22(a); 40 C.F.R. § 146.6
[139] Ohio Admin. Code § 1501:9-3-05(A)(1)
[140] Ohio Admin. Code § 3745-34-07(C); Ohio Admin. Code § 1501:9-3-12(A); Mich. Admin. Code r. 324.701; 40 C.F.R. § 144.12
[141] Ohio Admin. Code § 3745-34-36
[142] Ohio Admin. Code § 3745-34-59; 3745-34-12; 40 CFR § 146.31(e)(1)-(10);
[143] Ohio Admin. Code § 3745-34-13
[144] Ohio Admin. Code § 3745-34-13

needed, determine and execute any necessary corrective action to prevent movement of fluid into USDWs, including plugging, as a condition of their permit.[145] For Class I hazardous waste disposal wells, detailed information on the proposed operating schedule, including daily maximum rates of pressure and volumes to be injected, the stimulation procedure, injection procedure, contingency plans to cope with failures, construction procedures, financial ability to eventually plug the well are also required, as well as other supporting information regarding the expected compatibility of the injected substance with the construction materials as and the fluids and materials that are in the injection zone.[146]

Permitting application requirements for Class II wells are not as detailed as those of Class I wells; these wells are not technically designed for a broad variety of "hazardous" wastes, but for a specific type of waste, produced waters from traditional oil and gas production. They are not expected to cope with a diverse variety of substances, but rather with a single specific and relatively known substance. While crucial that produced saltwater is kept from comingling with sources of drinking water in order to preserve the use of aquifers, produced waters from traditional oil and gas production do not pose the same level threat as hazardous wastes. This variance in threat level is reflected in the two permitting processes. As discussed above, disposal requirements for traditional produced saltwaters in Class II wells do not approach the same level of stringency as those of Class I wells.

The requirements for disposal of produced fluids via injection in Ohio's Class II requirement equivalent specify standards as to the casing and the method of injection, as well as the requirement that the wellbore be set at least 50 feet below the deepest underground source of water.[147] In Michigan, the injection formation must be isolated from fresh water strata by an impervious confining formation.[148] In Ohio, the applicant is required to submit a detailed application to the Division, which will be approved if it is determined to be not in violation of law, if it meets all of the Chapter 1501-3 requirements, and if it "will not jeopardize public health or safety or the conservation of natural resources."[149] In Michigan, the Class II disposal applicant submits an application to the Supervisor of Wells and an application to Region 5 of the US EPA. With regard to disposal of fracking flowback, though regulated through different mechanisms, there is no reason why Class II well requirements designed for oil and gas production wastes should be any less protective than Class I requirements designed for hazardous wastes. The level of stringency and numerosity of specific requirements is determined by the Division in Ohio, or in Michigan by the Supervisor and the regional EPA Administrator, who have some discretion to determine what is and is not adequate based on the site-specific characteristics.

The bottom line is that under both Class I and Class II disposal guidelines, practices that risk contamination of drinking water are strictly prohibited. In practice, the prevention of contamination cannot be ensured simply by having more demanding information gathering prior to permitting. When considering the application of a single standard, it is reasonable to expect that a waste stream with a known composition could be disposed of safely by a less burdensome process than would be required for a single standard to dispose of a wide variety of wastes with unknown and varying compositions in an equally safe manner. The disposal requirements for

[145] Ohio Admin. Code § 3745-34-53; Ohio Admin. Code § 1501:9-3-06(C)(9); 40 C.F.R. § 144.55
[146] Ohio Admin. Code § 3745-34-59; Ohio Admin. Code § 3745-34-54; Ohio Admin. Code § 3745-55-47(F); Ohio Admin. Code § 3745-55-43; Ohio Admin. Code § 3745-55-45; 40 CFR § 144.63(f)
[147] Ohio Admin. Code § 1501:9-3-05
[148] Mich. Admin. Code r. 324.703
[149] Ohio Admin. Code § 1501:9-3-06 (E)(2)(d)

fracking flowback should be determined by review of the composition of the particular waste. Fracking flowback is not the same as produced water from traditional oil and gas production and therefore Class II disposal requirements might not be adequate for every waste currently covered by that class. However fracking flowback is a known waste, with determinable characteristics and composition, and therefore Class I catch-all hazardous waste disposal requirements may be unnecessarily burdensome.

IDEAS ON THE TABLE: A LOOK AT ONE PROPOSED BILL

On March 14, 2012, a Bill (HB 474) aimed at implementing a new approach to brine disposal was introduced to the Ohio House.[150] As of April 2013, this bill does not appear to have gained any momentum, however it does provide a look at the sort of legislation that is being considered. The proposed Bill does not differentiate between those flowback waters produced from fracking activities and those produced from traditional oil and gas production; it would require the Division of Oil and Gas to treat applications for disposal of both types of waste stream with the same heightened level of scrutiny. For brines and waste associated with fracking activities, this is the sort of closer look that has been missing from the rules. Studies conducted on the state or national level to determine if fracking flowback would satisfy the RCRA definition of hazardous, if not for the RCRA exclusion,[151] would serve as a useful indicator of the level of care states should take in regulating their disposal. However, mandating that produced waters from traditional oil and gas production not associated with fracking activities be included in this higher level of scrutiny may be overly protective and needlessly burdensome.

HB 474 contains a number of clauses that mirror parts of the Ohio EPA requirements for Class I well applicants, and would effectively upgrade all oil and gas wastes uniformly. One such requirement of HB 474 is that each permittee develop and submit a comprehensive waste analysis plan for all produced waters from oil and gas activities. This requirement is similar to the waste analysis plan requirement that the Ohio EPA has for Class I injection wells.[152] Flowback from fracking operations contains chemical additives that distinguish it from other produced waters. In light of the varied combinations of chemical additives that constitute fracking fluid, waste monitoring and analysis prior to injection makes sense. But produced waters from traditional non-fracking oil and gas activities do not contain these additives and have been disposed of in large part without complaint in Ohio under the oversight of the Division of Oil and Gas since the RCRA exemption was took effect in 1980. HB 474 is a great step towards tailoring disposal rules for fracking, however it appears to drag traditional oil and gas wastes along as well.

One of the largest steps forward proposed in HB 474 is the shift from disposal via injection as the state disposal method of choice to recycling as the mandated method.[153] Key to the debate over recycling of wastewater and flowback is the level to which the waters can and should be treated. "Treatment" under current industry usage, as mentioned above, is not to drinking standards, but to the point that it can be reused for injection during fracking. Due to the availability of injection sites in states such as Ohio and Michigan, there has been little economic

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[150] H.B. 474, 129th Gen. Assem., Reg. Sess. (Ohio 2012)
[151] Do to the characteristics of the majority of the additives and do to the level of dilution this finding is unlikely. Results would be useful informing policy decisions regardless of the finding.
[152] H.B. 474, 129th Gen. Assem., Reg. Sess. (Ohio 2012), Sec. 1509.22(D)(2); OAC 3745-34-57(A)
[153] H.B. 474, 129th Gen. Assem., Reg. Sess. (Ohio 2012), Sec. 1509.074

pressure to explore alternatives such as recycling. Until HB 474, there has been no serious legislative emphasis in Ohio on "treatment" for reuse in future production that employs fracking. Such reuse would reduce the amount of freshwater consumed, and on-site treatment, as is common in Pennsylvania, would reduce or eliminate risks of spills during transport to injection sites. Reuse of "saltwater from oil and gas operations" is allowed for use in enhanced recovery projects.[154] Other methods of disposal are not precluded, and are provided for in Ohio Admin. Code § 1501:9-1-02(3) wherein the chief must simply approve them of. Adoption of HB 474 would require the Division of Oil and Gas to develop and regulate a more detailed recycling program.

HB 474 also provides for seismic testing, a more detailed notice, hearing, and comment period, a more in depth assessment of the applicant's prior and current record with disposal wells, as well as providing for the establishment of an injection well ground water monitoring fund and the monitoring of groundwater using purpose-drilled wells.[155]

CONCLUSION & RECOMMENDATIONS

As with all large-scale natural resource industries, there is a need for oversight and regulation. Though opposites, advocating for an absolute ban is as extreme a position as advocating for zero regulation, a position that not only is without any support, but it is completely impossible under current regulatory requirements anyway. The questions are not "if" but rather "how" fracking should be regulated and what adequate level of protection is required to protect people, drinking water of the U.S., and the environment in general. Under federal regulation, fracking flowback is classified as a type of produced water resulting from oil and gas development and production. Under federal regulations, fracking waste is treated the same as waste fluids from traditional oil and gas production. By default, federal requirements provide for fracking flowback disposal in Class II injection wells. More specific regulations targeting the disposal of fracking waste can be and are enforced by the state. Many of the state regulations are more stringent than federal regulations, however many still do not specifically address fracking. One source of concern over fracking is that injection well classifications pre-date the large-scale emergence of modern fracking.[156] As modern fracking was not taken into account when injection well classifications were created, health and environmental concerns have arisen regarding the unknown impacts of chemical additives in flowback fluids. Due to the large increase in wastewater generated by fracking and based on the assumption that fracking is a production technique that is here to stay, it is appropriate at this time, to reexamine the preexisting state regulations for disposal of waste water in order to ensure that they continue to effectively protect sources of drinking water from contamination. More stringent requirements for disposal of flowback may or may not be warranted, however a reexamination of the relevance of preexisting regulations that control disposal of fracking waste is justified.

[154] Ohio Admin. Code § 1501:9-5-10(C)

[155] H.B. 474, 129th Gen. Assem., Reg. Sess. (Ohio 2012), Sec. 1509.22(D)(4); Sec. 1509.22(D)(3); Sec. 1509.228; Sec. 1509.227

[156] For the purposes of this paper modern fracking is distinguished from earlier fracking by the increased use of chemical additives in fracking fluid and the application of horizontal drilling technologies the processes described previously in this paper.

RECOMMENDATIONS

Based on this review of laws governing the disposal of waste and produced waters resulting from hydraulic fracturing, the regulatory framework could be improved in the following ways:

First Steps in Writing Effective Regulation

State statues and code concerning oil and gas should contain a specific subsection or a completely separate section to specifically address disposal of fracking flowback, including tailored guidance for disposal of flowback from fracking. Such a section would call for either heightened scrutiny for the initial permitting of the site or require a supplementary permit for upgrading a standard Class II injection well for disposal of fracking flowback. In either case explicit language is needed to acknowledge the difference between these two wastes.

To inform state requirements for disposal of fracking flowback, studies should be undertaken to investigate the differences between the nature of fracking flowback and traditional produced salt water. Particular attention might be turned towards determining if fracking flowback, at its normal level of dilution, exhibits characteristics of hazardous substances. This knowledge would help indicate the correct level of stringency for fracking specific rules concerning disposal of waste. Despite RCRA exclusions, such studies conducted either on an individual state level or on a federal level, will either give weight to arguments for stricter regulation or give comfort to concerned parties. If the current permitting practices can be shown to sufficiently safeguard USDW, then all that is required is that they are crystallized in detail in rule form. Due to the varied combinations of chemical additives that can constitute a given fracking fluid, waste monitoring and analysis designed to have a clear understanding of what is being injected for disposal prior to injection makes sense and should be a standard procedure for any nonhomogeneous waste stream. In addition to any requirements the state might have, a minimum requirement for a disposal permit should be a study that demonstrates to the same standard as the UIC requires for Class I well permit applications: that there is no comingling of injected substances and USDW.

For example, in Ohio, while OAC 1501 appears to be the chapter that regulates the permitting of disposal of flowback, it does not treat fracking flowback any differently from traditional produced waters. Here is a case where it would be prudent to have tailored guidance for disposal of flowback from fracking. Currently regulated under the same rule as disposal of brine produced from traditional oil and gas production, much confusion could be eliminated if flowback from fracking operations had its own dedicated section in Chapter 1501:9 of the Ohio Administrative Code. Flowback from fracking operations contains chemical additives that might differentiate it from other produced waters. As mentioned above, though they need not necessarily be as stringent as Class I well guidelines, now that this method of production is becoming more common, the combination of the increased need to dispose of fracking flowback with the possibility of heightened risk suggests that it is time to unpack fracking wastes from the standard Class II disposal standards, or at least study the differences. The Division of Oil and Gas Resources Management should also be more explicit regarding the standards used to determine the suitability of an application for a permit to dispose of flowback from fracking operations. This is not a call for piling on extra unneeded regulation; again, as mentioned above, if the current Division permitting practices are sufficient to safeguard underground sources of water, then all that is required is that existing practices are crystallized in detail into a rule. This sort of clarity would comfort concerned parties and provide guidance for the industry.

Miscellaneous Specific Recommendations

- Michigan and Ohio should examine the current bonding requirements in order to ensure that they reflect the true costs of plugging the wells. On a case-by-case basis, the EPA and the states should also consider increasing the amount of any financial instrument to include post-closure monitoring for contamination around production wells and around disposal wells.
- Given the risks of improper treatment of flowback, both Michigan and Ohio should continue to prohibit treatment and discharge of flowback to surface waters unless it can be shown that treated water to be released is of a quality acceptable to sustain the designated uses of surface waters in accordance with the water quality standards in that jurisdiction, and in any event, that the risks of such disposal are at a similar level or lower than the risks of underground injection.
- If fracking flowback from a given formation or well is found to exhibit any of the four hazardous waste characteristics under RCRA, flowback produced from said location should be treated like other potentially hazardous substances and be placed in Class I hazardous wells. The first time fracking flowback from a given formation is produced, EPA, Michigan, and Ohio should require that flowback to be tested for these characteristics prior to injection in a disposal well. The disposal requirements for that waste and further waste from the same site would be determined based off of those tests.
- The maximum injection pressure for Class II wells that accept flowback should be calculated to ensure that no fractures occur in the injection zone or the confining zone, and that the differential underground pressures in, around, and above the disposal zone, considering density effects, injection pressures, and any significant pumping in the overlying formations promote a stable disposal zone that reduces the chance of migration.
- With the reexamination of the standards for disposal of fracking fluid, a more comprehensive program for monitoring migration of injected waste into Class II wells that accept flowback should be developed to monitor lateral movement within target disposal formations as well as movement between formations.
- Surface applications of fracking flowback and other produced waters from wells that have been fracked, such as dust control and ice prevention, should not be permitted under any circumstance.
- A comprehensive regulation would contain specific guidance for temporary storage of fracking flowback prior to disposal and should require some level of redundancy, as well as cushion or surplus storage in the event of unexpected return volume. This might achieved either with tanks, lined pits, or some sort compromise that allows the use of lined pits as a temporary storage solution in the event of unanticipated volume. If such a compromise is made then there should be a cap on the length of time waste can remain in lined pits prior to disposal.
- There should be redundancy in the safeguards around the well site such as berms, linings, and checking of valves. Requirements currently vary dramatically from state to state. Limits on number of times a waste can be transported prior to treatment would cause a reduction in transfers which would in turn cut down on opportunities for exposure or

spills. This would also encourage on-site treatment and recycling.

- Most or all states hosting oil and gas production require operators or owners to submit a bond and carry insurance. There is concern that high volume hydraulic fracturing could carry with it a risk of larger impacts. The proper adjustment of bond or insurance to reflect a given well would be a topic for its own paper.[157] However, some examination of the insurance and bonds paid by disposal well operators dealing with this new waste form is warranted.
- Annular Disposal should be banned outright for fracking wastes. It is currently on an as-approved basis in Ohio. If approved, the Ohio Administrative Code requires demonstration of "mechanical integrity" as defined as "no significant leak in the surface casing" and "no significant fluid movement into an underground source of drinking water through channels adjacent to the well bore".[158] This "no significant movement" standard is in sharp contrast to the more stringent "zonal isolation" standard for casing[159] and the requirement that applicants for permits must perform secondary recovery operations to demonstrate that "injection will not result in the presence of *any* contaminant in the underground water that supplies or can be reasonably expected to supply any public water system."[160] It does not follow that the requirements for annular disposal, if it is in fact merely disposal of waste via injection into the space between casing layers, would have a less stringent standard for isolation than the standard required for casings of wells to begin with. Regardless of the isolation standard, this method of disposal accommodates a relatively small volume of waste while it carries all of the surface spill risks in order to place the waste in a final resting place within a layer that might be contiguous with drinking water sources, relying on solely the casing, and not the surrounding geology, to prevent contamination. If permitted to continue, use of this method should be informed by data on how many wells are permitted for annular disposal per year. It may be the case that this is a legacy clause in the Code that references an industry practice that was once common, has fallen out of mainstream use, but has remained in the Code.
- Seismic testing, detailed notice, hearing and comment periods, closer inspection of would-be operators track records, detailed groundwater monitoring, and creation of injection well monitoring funds, as included in HB 474 are all worthwhile practices that should be considered for fracking flowback injection programs in line with the findings and rules resulting from recommendations in the *Macro* section above.

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[157] Market forces and strict liability, who is at risk and what happens if a source is contaminated? The larger companies have sufficient funds that allow them to be responsible because they can afford to avoid cutting corners with regard to the safety of the environment. They also have a larger incentive to have a clean track record, because one mistake on one lease could impact their ability to aquire permits on a different lease. A heavily invested entity would also be more concerned with the public image as they have more skin in the game. When corners are cut, then damage occurs. A study of the safety record, and spill record of the companies active and that have been active in shale oil fracking might reveal an interesting result. If it turns out that market forces and pressures do in fact keep larger companies more responsible, then one could advocate for a minimum valuation, or some other standard mandating that the corporate operator must be of a certain size that would align market forces and environmental concerns.

[158] Ohio Admin. Code § 1501:9-3-11(C)(1)(a)&(b)

[159] Ohio Rev. Code Ann. § 1509.17(C)

[160] Ohio Rev. Code Ann. § 1509.21

- Looking beyond injection, the cultural shift to a preference for recycling as the standard method for waste management is important. The reuse of flowback helps mitigate two large concerns — disposal of a toxic flowback and reduction of consumptive freshwater use — and should be required as a minimum standard for dealing with flowback. Treatment to a level of quality suitable for reinjection is a productive use that also reduces the volume of fluid waste that must be transported to a disposal site and then disposed of via injection into a Class II well. Administrators should consider promulgating rules requiring a minimum volume or percentage of flowback treated onsite and recycled in future fracking treatments. Alternatively, administrators could promulgate rules making injection more expensive either by limiting the number of injection permits or raising the fees. This would incentivize the development of economically viable recycling technology. Such a requirement could be staged to eventually phase out all non treatment to a certain standard. The technology is there, it is just expensive, however this could be made a cost of doing business and it would not only encourage improved treatment technology, but also encourage development of safer, less toxic fracking fluids.[161] At a minimum, as proposed in HB 474, states should require an operator to give an explanation for why they are not treating and recycling fracking flowback.

[161] Forcing development of better treatment tech is generally good. In a world facing shortages of drinking water, the benefits of new treatment techniques to deal with heavily toxic/radioactive waters as well as saline brines would be applicable outside of the oil & gas industry.

APPENDIX: TABLE OF REQUIREMENTS FOR DISPOSAL WELLS

Subject of Regulation	Disposal Well Requirement	EPA Class I Hazardous Well	EPA Class I Non-Hazardous Well	EPA Class II Well	Michigan Part 615	Ohio Class II Well
Well Location	*Injection zone depth in relation to an underground source of drinking water (USDW)*	Formation beneath the lowermost formation containing, within 1/4 mile of the wellbore, an USDW Confining zone separated from the base of the lowermost USDW by at least one sequence of permeable and less permeable strata	Formation beneath the lowermost formation containing, within 1/4 mile of the wellbore, an USDW	Formation separated from a USDW by a confining zone that is free of known open faults or fractures within area of review	Formation that is isolated from freshwater strata by an impervious confining formation	No provision
Permit Review	*Area of review for possible conduits*	Minimum 2 miles; Demonstration that no migration out of injection zone as long as remain hazardous	Minimum ¼ of a mile; 2 miles in EPA Region 5	Usually ¼ of a mile	¼ of a mile	¼ to ½ of a mile depending on injected volume
	Injected fluid information	Source Representative waste analysis, hazardous characteristics	Source Chemical, physical, radiological and biological characteristics	Source and physical and chemical characteristics	Chemical analysis for a representative sample of each type of injected fluid	Source of shipment Composition of liquid injected, but no analysis
	Permit term	10 years	10 years	Operating life	Operating life	Operating life
Construction	*Casing*	At least two layers of casing, inner casing cemented to surface Tubing and packer	At least two layers of casing, surface casing cemented to surface Tubing and packer	Varies	At least two layers of casing, surface casing cemented to surface Tubing and packer	Surface casing cemented to surface Tubing and packer
	Mechanical integrity testing	Continuous monitoring Internal testing every year, external testing every 5 years	Continuous monitoring and testing every 5 years	Testing prior to injection and every 5 years	Pressure test prior to injection and every five years	Pressure test prior to injection Monthly monitoring
Operation	*Monitoring wells*	May be installed in first aquifer immediately above injection zone	May be installed	May be installed	No provision	No provision
	Testing of fluid	Waste analysis plan, detailed chemical and physical analysis of a representative sample	Waste analysis plan, detailed chemical and physical analysis of a representative sample	Representative sample	No provision	No provision
	Maximum injection pressure	Does not fracture the injection zone or confining zone	Does not fracture the injection zone or confining zone	Does not fracture the confining zone	Calculated by formula	Calculated by formula
Plugging	*Financial responsibility*	Amount determined for each well and for post-closure; statement if net worth > $10 million	Amount determined for each well; for statement, may require net worth > $10 million	Amount determined for each well; statement if net worth > $1 million	Up to $30,000 single bond; statement if net worth > $2 million	$5,000 single bond; statement if net worth > $10,000; liability insurance