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Hydraulic Fracturing and Safe Drinking Water Act Regulatory Issues

Mary Tiemann
Specialist in Environmental Policy

Adam Vann
Legislative Attorney

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Summary

Hydraulic fracturing is a technique developed initially to stimulate oil production from wells in declining oil reservoirs. With technological advances, hydraulic fracturing is now widely used to initiate oil and gas production in unconventional (low-permeability) oil and gas formations that were previously uneconomical to produce. Nationwide, this process is now used in more than 90% of new oil and gas wells and in many existing wells to stimulate production. Hydraulic fracturing is done after a well is drilled and involves injecting large volumes of water, sand (or other propping agent), and specialized chemicals under enough pressure to fracture formations holding the oil or gas. The sand or other proppant holds the fractures open to allow the oil or gas to flow freely out of the formation and into a production well. In combination with directional drilling, its application for production of natural gas (methane) from unconventional shale formations, tight sands, and coal beds has resulted in the marked expansion of estimated U.S. natural gas reserves in recent years. Similarly, hydraulic fracturing is enabling the development of tight oil resources, such as the Bakken and Eagle Ford formations. The rapid growth in the use of fracturing has raised concerns over its potential impacts on groundwater and drinking water resources and has led to calls for more state and/or federal oversight of this activity.

The principal federal law regulating underground injection activities is the Safe Drinking Water Act (SDWA), administered by the Environmental Protection Agency (EPA). Historically, EPA had regulated injection of fluids for disposal and enhanced oil recovery but had not regulated the underground injection of fluids for hydraulic fracturing of oil or gas production wells. In 1997, the U.S. Court of Appeals for the 11th Circuit ruled that fracturing for coalbed methane (CBM) production in Alabama constituted underground injection and must be regulated under the SDWA. This ruling led EPA to study the risk that hydraulic fracturing for CBM production might pose to drinking water sources. In 2004, EPA reported that the risk was small, except where diesel fuel was used, and that national regulation was not needed. However, to address the regulatory uncertainty the ruling created, the Energy Policy Act of 2005 (EPAct 2005) revised the SDWA term "underground injection" to explicitly exclude the injection of fluids and propping agents (except diesel fuels) used for hydraulic fracturing purposes. Thus, EPA lacks authority under the SDWA to regulate hydraulic fracturing except where diesel fuels are used. In February 2014, EPA issued final permitting guidance for hydraulic fracturing operations using diesel fuels.

As the use of the process has grown, some in Congress would like to revisit the 2005 statutory exclusion. Legislation to revise the act's definition of underground injection to explicitly include hydraulic fracturing has been offered in recent years but not enacted. A variety of hydraulic fracturing bills that would amend the SDWA are pending in the 114th Congress. In EPA's FY2010 appropriations act, Congress urged the agency to study the relationship between hydraulic fracturing and drinking water. On June 4, 2015, the agency released the draft hydraulic fracturing report for peer review by the EPA's Science Advisory Board and for public comment. EPA expects to issue a final report in 2016.

This report reviews past and proposed treatment of hydraulic fracturing under the SDWA, which authorizes regulation of the underground injection of fluids to protect groundwater sources of drinking water. It reviews current SDWA provisions for regulating underground injection activities and discusses some possible implications of the enactment of legislation authorizing EPA to regulate hydraulic fracturing (beyond diesel) under this statute. The report also reviews legislative proposals concerning the regulation of hydraulic fracturing under the SDWA.

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Introduction

Hydraulic Fracturing in Oil and Gas Production

The process of hydraulic fracturing was developed initially in the 1940s to stimulate production from oil reservoirs with declining productivity.[1] More recent technological advances in hydraulic fracturing, along with horizontal drilling, have allowed this practice to be used to initiate oil and gas production in unconventional (low-permeability) oil and gas formations.[2] Its application in the extraction of natural gas from coal beds, tight gas sands,[3] and unconventional shale formations has resulted in the marked expansion of estimated U.S. natural gas reserves and production in recent years. Similarly, hydraulic fracturing has enabled the development of domestic tight oil resources, such as the Bakken formation in North Dakota and Montana and the Eagle Ford formation in Texas. However, the rapidly increasing and geographically expanding use of this well stimulation process has raised concerns over its potential impacts on groundwater and drinking water and has led to calls for greater state and/or federal oversight of hydraulic fracturing and more research on its potential risks to water resources.

Hydraulic fracturing involves injecting into production wells large volumes of water, sand or other proppant,[4] and specialized chemicals under enough pressure to fracture low-permeability geologic formations containing oil and/or natural gas.[5] The sand or other proppant holds the new fractures open to allow the oil or gas to flow freely out of the formation and into a production well. Fracturing fluid and water remaining in the fracture zone can inhibit oil and gas production and must be pumped back to the surface. The fracturing fluid—"flowback"—along with any naturally occurring formation water pumped to the surface (together called produced water) has typically been disposed of through deep well injection and less frequently has been treated and discharged into surface waters.[6] According to industry estimates for various geographic areas, the volume of flowback water can range from less than 30% to more than 70% of the original fracture fluid volume.[7] Increasingly, efforts are being made to treat and reuse flowback.

[1] Hydraulic fracturing is also used for other purposes, such as developing water supply wells and geothermal production wells. This report focuses only on its use for oil and gas development.

[2] For a brief history of technological developments that have enabled unconventional gas and oil production, see U.S. Department of Energy, National Energy Technology Laboratory, *Shale Gas: Applying Technology to Solve America's Energy Challenges*, March 2011, http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/Shale_Gas_March_2011.pdf.

[3] Tight gas sands are sandstone formations with very low permeability that must be fractured to release the gas.

[4] According to the Schlumberger *Oilfield Glossary*, propping agents (or proppants) are "sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used." The glossary is available at http://www.glossary.oilfield.slb.com/default.cfm.

[5] This process is distinct from enhanced oil and gas recovery and other secondary and tertiary hydrocarbon recovery techniques that involve separate wells. Injections for hydraulic fracturing are done through the production wells.

[6] The Schlumberger glossary notes that "produced fluid is a generic term used in a number of contexts but most commonly to describe any fluid produced from a wellbore that is not a treatment fluid. The characteristics and phase composition of a produced fluid vary and use of the term often implies an inexact or unknown composition." *Flowback* refers to "the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production."

[7] U.S. Department of Energy, Office of Fossil Energy and National Energy Technology Laboratory, *Modern Shale Gas Development in the United States: A Primer*, April 2009, p. 66, http://fossil.energy.gov/programs/oilgas/publications/
(continued...)

Reliance on the use of hydraulic fracturing continues to increase as more easily accessible oil and gas reservoirs have declined and companies move to develop unconventional oil and gas formations. The Interstate Oil and Gas Compact Commission reported that 90% of oil and gas wells in the United States have undergone hydraulic fracturing to stimulate production.[8] According to the American Petroleum Institute, hydraulic fracturing has been applied to more than 1 million wells nationwide—and typically multiple times per well.[9] The U.S. Energy Information Administration reports that natural gas from tight sand formations was the largest source of unconventional production but in recent years has been surpassed by production from shale formations.[10] **Figure 1** illustrates different types of natural gas reservoirs.

Production of shale gas and shale oil (often called "tight" oil) involves drilling a well vertically and then drilling horizontally out from the wellbore. Because of the low permeability of these formations, more wells must be drilled into a reservoir than into more permeable, conventional reservoirs to retrieve the same amount of oil or gas. A benefit of horizontal drilling through a producing shale layer is that one well pad utilizing horizontal drilling can replace numerous individual well pads and reduce the surface density of wells in an area. Six to eight horizontal wells, and potentially more, can be drilled from a single well pad and access the same reservoir. According to a report prepared for the Department of Energy:

> The spacing interval for *vertical* wells in the gas shale plays averages 40 acres per well for initial development. The spacing interval for *horizontal* wells is likely to be approximately 160 acres per well. Therefore, a 640-acre section of land could be developed with a total of 16 vertical wells, each on its own individual well pad, or by as few as 4 horizontal wells all drilled from a single multi-well drilling pad.[11]

A single production well may be fractured multiple times, using from 500,000 gallons of water to more than 10 million gallons, with compounds and proppants of various amounts added to the water. Slickwater fracturing, which involves adding conditioning chemicals to water to increase fluid flow, is a more recent development that has improved production of unconventional shale gas.[12]

(...continued)

naturalgas_general/Shale_Gas_Primer_2009.pdf.

[8] Independent Petroleum Association of America, "Hydraulic Fracturing: Effects on Energy Supply, the Economy, and the Environment," April 2008, http://energyindepth.org/docs/pdf/Hydraulic-Fracturing-3-E%27s.pdf.

[9] American Petroleum Institute, "Hydraulic Fracturing," http://www.api.org/oil-and-natural-gas-overview/exploration-and-production/hydraulic-fracturing.aspx.

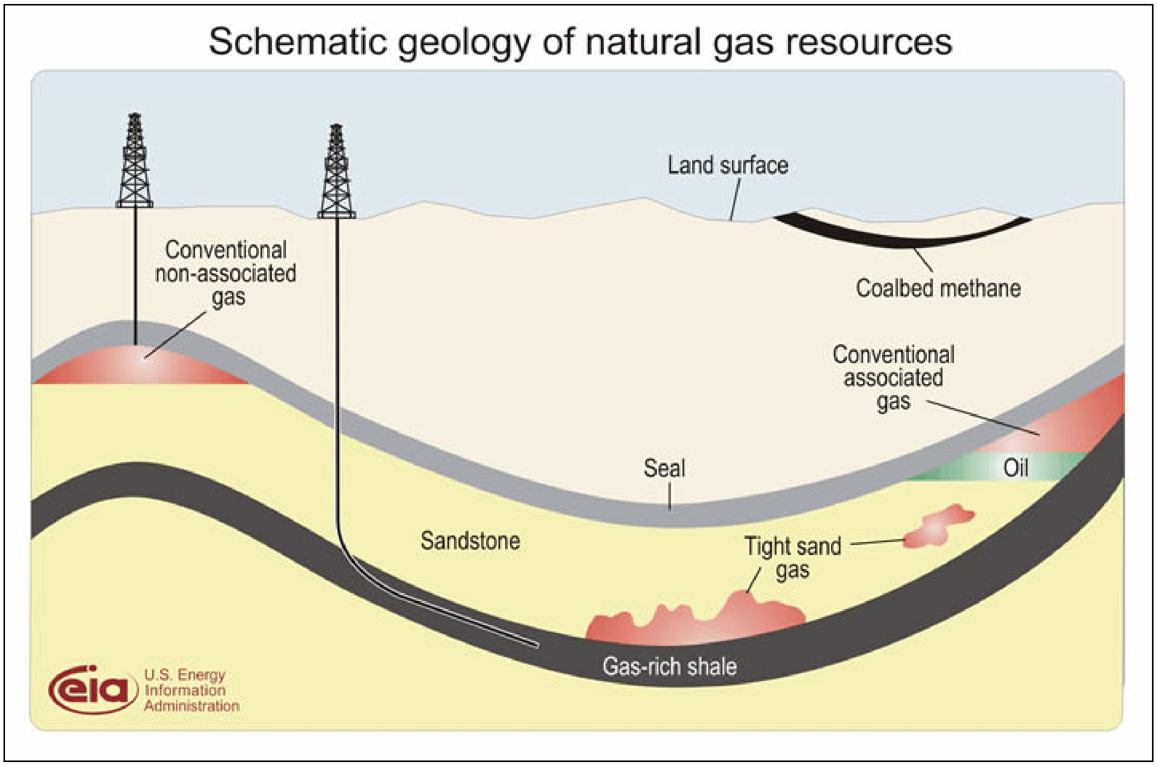
[10] U.S. Energy Information Administration, *Annual Energy Outlook 2014*, May 7, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=16171.

The U.S. Geological Survey's National Assessment of Oil and Gas Resources Update (2013) is available at http://energy.usgs.gov/OilGas/AssessmentsData/NationalOilGasAssessment/AssessmentUpdates.aspx.

[11] U.S. Department of Energy, National Energy Technology Laboratory, *Modern Shale Gas Development in the United States: An Update*, September 2013, http://www.netl.doe.gov/research/oil-and-gas/natural-gas-resources.

[12] Using slickwater fracturing increases the rate at which fluid can be pumped down the wellbore to fracture the shale. The process may involve the use of friction reducers, biocides, surfactants, and scale inhibitors. Biocides prevent bacteria from clogging wells; surfactants help keep the sand or other proppant suspended. Slickwater fracturing was first used in the Barnett Shale formation in Texas.

Figure 1. Geologic Nature of Major Sources of Natural Gas in the United States



Source: U.S. Energy Information Administration, October 2008, http://www.eia.gov/oil_gas/natural_gas/special/ngresources/ngresources.html. [Not to scale.]

Notes: The diagram shows schematically the geologic nature of most major U.S. sources of natural gas:

- Gas-rich shale is the source rock for many natural gas resources but, until recently, was not a focus for production. Horizontal drilling and hydraulic fracturing have made shale gas an economically viable alternative to conventional gas resources.
- Conventional gas accumulations occur when gas migrates from gas-rich shale into an overlying sandstone formation and then becomes trapped by an overlying impermeable formation, called the seal. Associated gas accumulates in conjunction with oil, while non-associated gas does not accumulate with oil.
- Tight sand gas accumulations occur in a variety of geologic settings where gas migrates from a source rock into a sandstone formation but is limited in its ability to migrate upward due to reduced permeability in the sandstone.
- Coalbed methane does not migrate from shale but is generated during the transformation of organic material to coal.

Hydraulic Fracturing and Drinking Water Issues

While the use of high-volume hydraulic fracturing has enabled the oil and gas industry to markedly increase domestic production, questions have emerged regarding the potential impacts this process may have on groundwater quality, particularly on private wells and drinking water supplies. During hydraulic fracturing, new fractures are induced into a shale or other tight formation, and existing fractures may be lengthened. As production activities have increased and expanded into more populated areas, so has concern that the fracturing process might introduce chemicals, methane, and other contaminants into aquifers.

A particularly contentious issue concerns whether the fracturing process could create or extend fractures linking the producing zone to an overlying aquifer and thus provide a pathway for gas or fracturing fluids to migrate. In shale formations, the vertical distance separating the target zone from usable aquifers is generally much greater than the length of the fractures induced during hydraulic fracturing. Thousands of feet of rock layers typically overlay the produced portion of the shale, and these layers serve as barriers to flow. In these circumstances, geologists and state regulators generally view as remote the possibility of creating a fracture that could reach a potable aquifer. If the shallow portions of shale formations were developed, then the thickness of the overlying rocks would be less and the distance from the shale to potable aquifers would be shorter, posing more of a risk to groundwater. In contrast to shale, coalbed methane (CBM) basins often qualify as underground sources of drinking water. Injection of fracturing fluids directly into or adjacent to such formations would be more likely to present a risk of contamination, and this is where initial regulatory attention and study was focused.[13] (See discussion under "EPA's 2002-2004 Review of Hydraulic Fracturing for CBM Production.")

Complaints of impacts to well water have emerged with unconventional oil and gas development and the use of hydraulic fracturing. Water contamination incidents have been associated with the development of shale gas and tight oil more broadly;[14] however, state investigations have not reported a direct connection between hydraulic fracturing of shale formations and groundwater contamination. In 2009, the Ground Water Protection Council (GWPC)[15] reported that several citizen complaints of well water contamination attributed to hydraulic fracturing appeared to be related to hydraulic fracturing of CBM zones that were in relatively close proximity to underground sources of drinking water.[16]

Regulators have expressed more concern about the potential groundwater contamination risk that is associated with developing a natural gas or oil well (drilling through an overlying aquifer and casing, cementing, and completing the well). The challenges of sealing off the groundwater and isolating it from possible contamination are common to the development of any oil or gas well and are not unique to hydraulic fracturing. However, some states have revised cementing and other well construction requirements specifically to address the injection pressures and fluid volumes associated with many hydraulic fracturing operations. Also, industry best practices for well construction and integrity have been developed for hydraulic fracturing.[17]

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[13] The Environmental Protection Agency (EPA) reviewed 11 major CBM formations to determine whether coal seams lay within underground sources of drinking water (USDWs). EPA determined that 10 of the 11 producing coal basins "definitely or likely lie entirely or partially within USDWs." EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoir*s, Washington, DC, June 2004, p. 4-1.

[14] For a review of the scientific literature on potential environmental impacts associated with unconventional oil and gas production and hydraulic fracturing and related state and federal measures, see U.S. Department of Energy, National Energy Technology Laboratory, *Environmental Impacts of Unconventional Natural Gas Development and Production*, May 29, 2014, http://www.netl.doe.gov/File%20Library/Research/Oil-Gas/publications/NG_Literature_Review3_Post.pdf.

[15] The GWPC is a national association representing state groundwater and underground injection control (UIC) agencies whose mission is to promote protection and conservation of groundwater resources for beneficial uses. See http://www.gwpc.org.

[16] GWPC and U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, *State Oil and Natural Gas Regulations Designed to Protect Water Resources*, May 2009, p. 24, http://www.gwpc.org/sites/default/files/state_oil_and_gas_regulations_designed_to_protect_water_resources_0.pdf.

[17] American Petroleum Institute, *Hydraulic Fracturing Operations-Well Construction and Integrity Guidelines*, October 2009, http://www.api.org/policy-and-issues/policy-items/hf/api_hf1_hydraulic_fracturing_operations.aspx.

Another potential source of groundwater contamination comes from surface activities. Leaky surface impoundments, accidental spills of hydraulic fracturing fluids or drilling fluids at the production site, and inadequate wastewater management practices (including the storage, treatment, and disposal of flowback and produced water) could all increase the risk of contamination of water resources.[18] A more recent concern is that the deep-well disposal of wastewater from oil and gas extraction appears to be associated with increased rates of seismic activity in certain areas. Deep-well injection has long been the environmentally preferred method for managing produced brine (salt water) and other wastewater associated with oil and gas production. In recent years, the use of high-volume hydraulic fracturing has significantly increased the volume of wastewater requiring disposal and has created demand for disposal wells in new locations.[19]

Identifying the source or cause of groundwater contamination can be difficult for various reasons, including the complexity of hydrogeological processes and investigations, a lack of baseline testing of nearby water wells prior to drilling and fracturing, and the confidential business information status traditionally provided for certain fracturing compounds.[20] In cases that have been investigated, regulators have typically determined that groundwater contamination was caused by failure of well-bore casing and cementing, well operation problems, or surface activities rather than the hydraulic fracturing process.

Although regulators have not identified hydraulic fracturing of shale formations as the direct cause of groundwater contamination, water quality problems attributed to other production activities have raised concerns regarding the adequacy and/or enforcement of state well construction and wastewater management regulations for purposes of managing oil and gas development that is increasingly dependent on high-volume hydraulic fracturing. In the past several years, major producing states have revised their oil and gas laws and regulations to address hydraulic fracturing more explicitly and comprehensively, and some states have increased the number of inspectors to oversee increased production activities. A few states have imposed moratoria on hydraulic fracturing while evaluating potential impacts and developing new rules, and on June 29, 2015, New York State officially banned high-volume hydraulic fracturing.[21]

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[18] The discharge of oil and gas extraction wastewater to surface waters is regulated pursuant to the Clean Water Act. For a discussion of Clean Water Act requirements governing discharges of pollutants, see EPA, *Natural Gas Drilling in the Marcellus Shale: NPDES Program Frequently Asked Questions*, March 16, 2011, http://www.epa.gov/npdes/pubs/hydrofracturing_faq.pdf.

[19] Although the Safe Drinking Water Act (SDWA) underground injection control provisions do not address seismicity, EPA rules for certain injection well classes require evaluation of seismic risk. Such requirements do not apply to Class II wells; however, EPA has developed a framework for evaluating seismic risk when reviewing Class II permit applications in states where EPA administers this program. EPA has also developed a document outlining best practices for minimizing and managing such risks. EPA, *Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches*, Underground Injection Control National Technical Workgroup, November 12, 2014 (released February 2015), http://www.epa.gov/r5water/uic/techdocs.htm#ntwg. For a discussion of this issue, see CRS Report R43836, *Human-Induced Earthquakes from Deep-Well Injection: A Brief Overview*, by Peter Folger and Mary Tiemann.

[20] See, for example, Garth T. Llewellyn et al., "Evaluating a Groundwater Supply Contamination Incident Attributed to Marcellus Shale Gas Development," *Proceedings of the National Academy of Sciences*, vol. 112, no. 20 (May 19, 2015).

[21] California, Colorado, Idaho, Michigan, Montana, New Mexico, North Dakota, Ohio, Pennsylvania, Texas, West Virginia, Wyoming, and other states have revised or are revising their oil and gas production rules. Common changes include new requirements for well construction and operation (cementing, casing, pressure testing), wastewater management, and chemical disclosure. Colorado and North Dakota further require baseline testing of nearby wells before drilling begins. Maryland law prohibits the issuance of drilling permits until October 2017. New York State (continued...)

The debate over the groundwater contamination risks associated with hydraulic fracturing has been fueled in part by the lack of definitive scientific studies that assess the practice and related complaints, and in 2009, Congress urged EPA to conduct a study on the relationship between hydraulic fracturing and drinking water.[22] On June 4, 2015, EPA released the draft study on the potential impacts of hydraulic fracturing on drinking water resources. (See "EPA Hydraulic Fracturing Study.")

The "hydraulic fracturing" debate has also been complicated by terminology. Many who express concern over the potential environmental issues associated with hydraulic fracturing do not differentiate the well stimulation process of "fracing" (or "fracking") from the broader range of activities associated with unconventional oil and gas extraction. The American Water Works Association, representing drinking water utilities and professionals, noted this issue:

> Because other activities [in the life cycle of an oil or gas well] are often mistakenly associated with fracking in the media and elsewhere, there can be significant confusion on the entire subject. This in turn often leads to difficulty in communicating information about risks, benefits, scientific research, regulatory systems, and policies.[23]

Currently, EPA lacks authority under the SDWA to regulate hydraulic fracturing operations except where diesel fuels are used in the fracturing fluids.[24] Some have called for broader federal regulation of hydraulic fracturing through the SDWA, and legislation has been offered in recent Congresses to give EPA this authority. Such proposals have prompted debate over the possibility of broad new federal involvement in regulating oil and gas development—an area long managed by the states. In addition to a lack of consensus regarding the federal role, there is uncertainty over what kind of regulatory framework might be developed to address hydraulic fracturing activities under the SDWA. At issue is whether further federal regulation is needed, and if so, does the current EPA underground injection control (UIC) program under the SDWA fit? EPA developed this program primarily to regulate wells that received fluids injected for long-term disposal or for enhanced recovery operations but excluded oil and gas *production* wells. This distinction could raise regulatory challenges and the possibility that the agency may need to develop an essentially new framework to address hydraulic fracturing of production wells. In February 2014, EPA issued final guidance for fracturing operations that involve diesel fuels.[25] This guidance may indicate how the agency might approach the broader regulation of hydraulic

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spent several years evaluating potential environmental and health risks associated with high-volume hydraulic fracturing (HVHF), and in December 2014, the state's health commissioner announced plans to issue a findings statement in 2015, recommending that the state not go forward with HVHF. The state officially banned HVHF on June 29, 2015. For a comparison of major elements of state oil and gas rules, see, for example, Resources for the Future, "A Review of Shale Gas Regulations by State," http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx. The FracFocus website (www.fracfocus.org) contains links to each state's oil and gas regulations.

[22] The Department of the Interior, Environment, and Related Agencies Appropriations Act, 2010. P.L. 111-88, H.Rept. 111-316.

[23] American Water Works Association, "Water and Hydraulic Fracturing: A White Paper from the American Water Works Association," 2013, p. 3, http://www.awwa.org/fracking.

[24] In the Energy Policy Act of 2005 (EPAct 2005, P.L. 109-58, §322), Congress amended the definition of "underground injection" in the SDWA to specifically exclude the injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities.

[25] EPA, Office of Water, *Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels: Underground Injection Control Program Guidance #84*, EPA 816-R-14-001 (February 2014).

fracturing if so directed by Congress. (See discussion under "EPA Guidance for Permitting Hydraulic Fracturing Using Diesel Fuels.")

This report reviews past and proposed treatment of hydraulic fracturing under the SDWA, the principal federal statute for regulating the underground injection of fluids to protect underground sources of drinking water (USDWs). It reviews current SDWA provisions for regulating underground injection activities and discusses some possible implications of, and issues associated with, enactment of legislation authorizing EPA to fully regulate hydraulic fracturing under this statute. This report also discusses recent developments among the states to address the growing use of high-volume hydraulic fracturing, which may add insight to the possible implications of federal legislation and any subsequent regulations.

The Safe Drinking Water Act and Regulation of Underground Injection

Relevant SDWA Provisions

To evaluate any potential federal action to regulate hydraulic fracturing under the SDWA, it may be helpful to understand the existing statutory and regulatory framework.

Most public water systems and nearly all rural residents rely on groundwater as a source of drinking water. Because of the nationwide importance of USDWs, Congress included groundwater protection provisions in the 1974 SDWA. The SDWA, among other things, directs EPA to regulate the underground injection of fluids (including solids, liquids, and gases) to protect USDWs.[26]

Part C of the SDWA establishes the national regulatory program for the protection of USDWs through the establishment of UIC regulations. Key UIC requirements and exceptions contained in Part C include the following:

- Section 1421 of the SDWA directs the EPA Administrator to promulgate regulations for state UIC programs and mandates that the EPA regulations "contain minimum requirements for programs to prevent underground injection that endangers drinking water sources." Section 1421(b)(2) specifies that EPA

> may not prescribe requirements for state UIC programs which interfere with or impede—(A) the underground injection of brine or other fluids which are brought to the surface in connection with oil or natural gas production or natural gas storage operations, or (B) any underground injection for the secondary or tertiary recovery of oil or natural gas, *unless such requirements are essential to assure that underground sources of drinking water will not be endangered by such injection*.[27] [Emphasis added.]

[26] The SDWA (P.L. 93-523) authorized the UIC program at EPA. UIC provisions are contained in SDWA Part C, §§1421-1426; 42 U.S.C. §§300h-300h-5.

[27] 42 U.S.C. §300h(b)(2).

- Section 1421(d), as amended by the Energy Policy Act of 2005 (EPAct 2005),[28] specifies that the phrase "underground injection" as it is used in the SDWA means the subsurface emplacement of fluids by well injection and specifically excludes the underground injection of fluids or propping agents associated with hydraulic fracturing operations related to oil, gas, or geothermal production activities.[29] The use of diesel fuels in hydraulic fracturing, however, forfeits eligibility for this exclusion from the definition of "underground injection."[30]
- Section 1422 authorizes EPA to delegate primary enforcement authority (primacy) for UIC programs to the states, provided that the state program meets EPA requirements promulgated under Section 1421 and prohibits any underground injection that is not authorized by a state permit or rule.[31] If a state's UIC program plan is not approved or the state has chosen not to assume program responsibility, then EPA must implement the UIC program in that state.
- Section 1425 authorizes EPA to approve the portion of a state's UIC program that relates to "any underground injection for the secondary or tertiary recovery of oil or natural gas" if the state program meets certain requirements of Section 1421 and represents an effective program to prevent underground injection that endangers drinking water sources.[32] Under this provision, states may demonstrate to EPA that their existing programs for oil and gas injection wells are effective in preventing endangerment of underground sources of drinking water. This provides states with an alternative to meeting the specific requirements contained in EPA regulations promulgated under Section 1421.[33]
- Section 1423 authorizes EPA enforcement actions for UIC regulatory violations.
- Section 1431 applies broadly to the SDWA and grants the EPA Administrator emergency powers to issue orders and commence civil actions to protect public water systems or USDWs.[34]

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[28] P.L. 109-58, §322.

[29] 42 U.S.C. §300h(d).

[30] Ibid.

[31] 42 U.S.C. §300h-1. The minimum requirements for a state UIC program can be found at 40 C.F.R. Part 145.

[32] 42 U.S.C. §300h-4. SDWA §1425 was added by the Safe Drinking Water Act Amendments of 1980, P.L. 96-502. The House committee report accompanying the legislation that added §1425 noted:

> Most of the 32 states that regulate underground injection related to the recovery or production of oil or natural gas (or both) believe they have programs already in place that meet the minimum requirements of the Act including the prevention of underground injection which endangers drinking water sources. This is especially true of the major producing states where underground injection control programs have been underway for years. It is the Committee's intent that states should be able to continue these programs unencumbered with additional Federal requirements if they demonstrate that they meet the requirements of the Act. (U.S. House of Representatives, Committee on Interstate and Foreign Commerce, *Safe Drinking Water Act Amendments*, H. Rept. 96-1348 to accompany H.R. 8117, 96th Congress, 2d Session, September 19, 1980, p. 5.)

[33] SDWA §1425 requires a state to demonstrate that its UIC program meets the requirements of §1421(b)(1)(A)-(D) and represents an effective program (including adequate record keeping and reporting) to prevent underground injection that endangers USDWs. To receive approval under §1425's optional demonstration provisions, a state program must include permitting, inspection, monitoring, and record-keeping and reporting requirements.

[34] 42 U.S.C. §300i. The Administrator may take action when information is received that (1) a contaminant is present in or is likely to enter a public drinking water supply system or USDW that "may present an imminent and substantial endangerment to the health of persons," and (2) the appropriate state or local officials have not taken adequate action to (continued...)

- Section 1449, another broadly applicable SDWA provision, authorizes citizen civil actions against persons allegedly in violation of the act's enforceable requirements or against EPA for allegedly failing to perform a duty. State-administered oil and gas programs may not have such provisions, so this could represent an expansion in the ability of citizens to challenge administration of statutes and regulations related to hydraulic fracturing and drinking water were the hydraulic fracturing exemption provision to be repealed.

The "Endangerment" Standard

As noted, the SDWA states that UIC regulations must "contain minimum requirements for effective programs to prevent underground injection which endangers drinking water sources."[35] Known as the "endangerment standard," this statutory standard is a major driving force in EPA regulation of underground injection.

The endangerment language focuses on protecting groundwater that is used or may be used to supply public water systems. This focus parallels the general scope of the statute, which addresses the quality of water provided by public water systems and does not address private residential wells. The endangerment language has raised questions as to whether EPA regulations can reach underground injection activities to protect groundwater that is not used by public water systems.

The SDWA directs EPA to protect against endangerment of a USDW. The statute defines a USDW to mean an aquifer or part of an aquifer that does either of the following:

- Supplies a public water system,
- Contains a sufficient quantity of groundwater to supply a public water system[36] and either currently supplies drinking water for human consumption or contains fewer than 10,000 milligrams per liter (mg/L or parts per million) total dissolved solids, and
- Is not an "exempted aquifer."[37]

In a 2004 report on hydraulic fracturing of coalbed methane reservoirs, the agency further noted that "EPA also assumes that all aquifers contain sufficient quantity of groundwater to supply a

(...continued)

protect such persons.

[35] 42 U.S.C. §300h(b)(1).

[36] EPA further explained this requirement in a 1993 memorandum that provided that "any aquifer yielding more than 1 gallon per minute can be expected to provide sufficient quantity of water to serve a public water system and therefore falls under the definition of a USDW." James R. Elder, Director, Office of Ground Water and Drinking Water, *Assistance on Compliance of 40 CFR Part 191 with Ground Water Protection Standards* , memorandum to Margo T. Oge, Director, Office of Radiation and Indoor Air, June 4, 1993.

[37] §40 C.F.R. 144.3. According to EPA regulations, an exempted aquifer is an aquifer or a portion of an aquifer that meets the criteria for a USDW for which protection has been waived under the UIC program. Under 40 C.F.R. Part 146.4, an aquifer may be exempted if it is not currently being used—and will not be used in the future—as a drinking water source, or it is not reasonably expected to supply a public water system due to a high total dissolved solids content. The SDWA does not mention aquifer exemption, but EPA explains that without aquifer exemptions, certain types of energy production, mining, or waste disposal into USDWs would be prohibited. EPA, typically at the region level, makes the final determination on granting all exemptions.

public water system, unless proven otherwise through empirical data."[38] However, because these expanded agency characterizations of what constitutes a USDW are not included in SDWA or related regulation—and, therefore, are not binding on the agency—it is uncertain how they might be applied in future situations. Notably, the SDWA does not prohibit states from establishing requirements that are stricter than federal requirements, and many states have their own definitions and classifications for groundwater resources.

UIC Regulatory Program Overview

The UIC program governs more than 800,000 injection wells. To implement the UIC program as mandated by the provisions of the SDWA described above, EPA has established six classes of underground injection wells based on categories of materials that are injected into the ground by each class. In addition to the similarity of fluids injected in each class of wells, each class shares similar construction, injection depth, design, and operating techniques. The wells within a class are required to meet a set of appropriate performance criteria for protecting USDWs. The six well categories are briefly described below, including the estimated number of wells nationwide.[39]

- Class I wells inject hazardous wastes, industrial non-hazardous liquids, or municipal wastewater beneath the lowermost USDW. (There are 680 such wells regulated as Class I wells in the United States.) The most stringent UIC regulations apply to these wells.
- Class II wells inject brines and other fluids associated with oil and gas production and hydrocarbons for storage. The wells inject fluids beneath the lowermost USDW (172,068 wells). Section 1425, which allows states to apply their own regulations in lieu of EPA regulations, applies to Class II wells.[40]
- Class III wells inject fluids associated with solution mining of minerals (e.g., salt and uranium) beneath the lowermost USDW (22,131 wells).
- Class IV wells inject hazardous or radioactive wastes into or above USDWs. These wells are banned unless authorized under a federal or state groundwater remediation project (33 wells).
- Class V includes all injection wells not included in Classes I-IV, including experimental wells. Class V wells frequently inject non-hazardous fluids into or above USDWs and are typically shallow, on-site disposal systems. However, some deep Class V wells inject below USDWs (400,000-650,000 wells).[41]
- Class VI wells—established in 2010—are to be used for the geologic sequestration of carbon dioxide (two permitted wells).

[38] EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, EPA 816-R-04-003, June 2004, pp. 1-5.

[39] Regulatory requirements for state UIC programs are established in 40 C.F.R. §§144-147.

[40] EPA notes that state requirements "can be, and often are, more stringent than minimum federal standards." EPA, "Underground Injection Control 101: Permitting Guidance for Hydraulic Fracturing Using Diesel Fuels," Technical Webinars, May 9-16, 2011.

[41] EPA, "Underground Injection Control Program: Classes of Wells," http://water.epa.gov/type/groundwater/uic/wells.cfm. The inventory of Class V wells is incomplete.

The UIC regulatory program includes the following broad elements: site characterization, area of review, well construction, well operation, site monitoring, well plugging and post-injection site care, public participation, and financial responsibility. While the six classes broadly share similar regulatory requirements, those for Class I wells are the most comprehensive and stringent. **Table 1** outlines the shared minimum technical requirements for Class I, II, and III wells. **Table 2** outlines basic regulatory requirements for Class II wells.

Table 1. Minimum Federal Technical Requirements for Class I, II, and III Wells

Permitting Requirements Common to Class I, II, and III Wells
Demonstration that casing and cementing are adequate to prevent movement of fluid into or between USDWs. Cement bond logs are often needed to evaluate/verify the adequacy of the cementing records.
Financial assurances (bond, letter of credit, or other adequate assurance) that the owner or operator will maintain financial responsibility to properly plug and abandon the wells.
A maximum operating pressure calculated to avoid initiating and/or propagating fractures that would allow fluid movement into a USDW.
Monitoring and reporting requirements.
Requirement that all permitted (and rule authorized) wells that fail mechanical integrity be shut in immediately. A well may not resume injection until mechanical integrity has been demonstrated.
Schedule for demonstrating mechanical integrity (at least every five years for Class I nonhazardous, Class II, and Class III salt recovery wells).[a]
All permitted injection wells that have had the tubing disturbed must have a pressure test to demonstrate mechanical integrity.
Plans for plugging and abandonment. All Class I, II, and III wells must be plugged with cement.

Source: U.S. Environmental Protection Agency, "Technical Program Overview: Underground Injection Control Regulations," EPA 816-R-02-025, December 2002, p. 65.

a. Class I hazardous wells must demonstrate mechanical integrity once a year.

Table 2. Minimum EPA Regulatory Requirements for Class II Wells

Requirement	Explanation
Permit Required	Yes, except for existing Enhanced Oil Recovery wells authorized by rule.
Life of Permit	Specific period, may be for life of well.
Area of Review	New wells—¼ mile fixed radius or radius of endangerment.
Mechanical Integrity Test (MIT) Required	Internal MIT: prior to operation and pressure test or alternative at least once every five years for internal well integrity. External MIT: cement records may be used in lieu of logs.
Other Tests	Annual fluid chemistry and other tests as needed/required by permit.
Monitoring	Injection pressure, flow rate, and cumulative volume observed weekly for disposal and monthly for enhanced recovery.
Reporting	Annual.

Source: U.S. Environmental Protection Agency, "Technical Program Overview: Underground Injection Control Regulations," EPA 816-R-02-025, December 2002, pp. 11, 67, and Appendix E.

Class II Wells

Because this discussion of hydraulic fracturing is related to oil and gas production, this report focuses primarily on regulatory requirements for Class II wells rather than other categories of injection wells in EPA's UIC program. If authorized or mandated to regulate hydraulic fracturing broadly under SDWA, EPA might regulate hydraulic fracturing as a Class II activity, which would parallel its proposed approach for regulating the injection of diesel for fracturing purposes.[42] However, it is possible that EPA could classify oil and gas production wells that are hydraulically fractured under a different class or develop an entirely new regulatory structure or subclass of wells.[43]

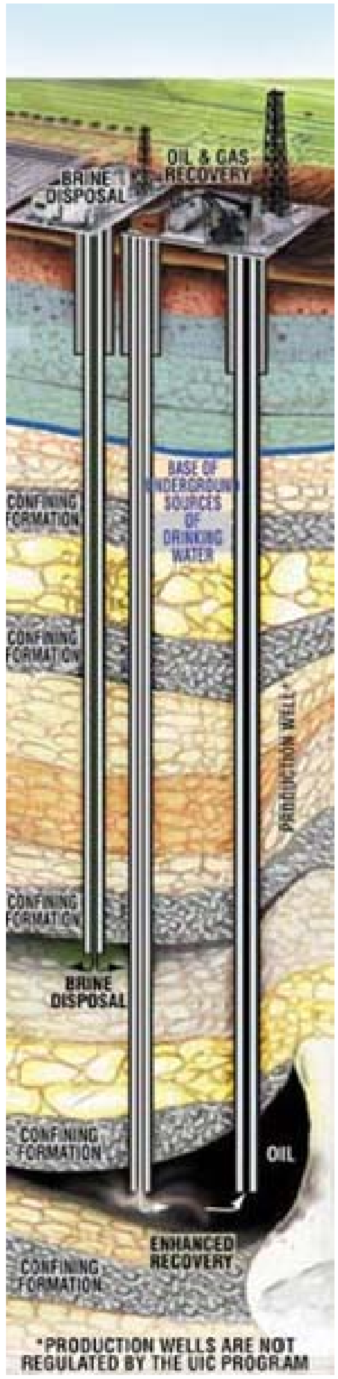
Class II wells may be used to dispose of brines and other fluids associated with oil and gas production or storage, to store natural gas, or to inject fluids for enhanced oil and gas recovery. Enhanced recovery (ER) wells inject brine, water, steam, polymers, or carbon dioxide primarily into oil-bearing formations (also called secondary or tertiary recovery). ER injection wells are separate from, and typically surrounded by, production wells.[44] EPA estimates that approximately 80% of Class II wells are ER wells. (For example, Pennsylvania has roughly 1,850 Class II wells. Almost all are ER wells, and fewer than 10 are wastewater disposal wells.) **Figure 2** illustrates the various types of Class II wells.

[42] This approach would also parallel the agency's response to a court ruling on hydraulic fracturing (discussed below under "The LEAF Challenge to the Alabama UIC Program and EPA's Interpretation of the SDWA").

[43] Regulations for Class II wells (used for disposal of wastewater related to oil and gas production and for enhanced recovery) are located at 40 C.F.R. Parts 144 and 146.

[44] EPA has historically differentiated Class II wells from production wells.

Figure 2. Class II Wells



Source: U.S. Environmental Protection Agency, Underground Injection Control Program.

Note: An oil or gas production well would require a Class II UIC permit if the hydraulic fracturing fluid to be used contains diesel fuels.

State Primacy for UIC Program Administration

SDWA Section 1422 authorizes states to assume primary enforcement authority for the UIC program for any or all classes of injection wells. EPA must delegate this authority—provided that the state program meets EPA requirements promulgated under Section 1421 and prohibits underground injection that is not authorized by permit or rule. Otherwise, EPA must implement the UIC program in that state. Thirty-three states have assumed primacy for the entire UIC program (injection well Classes I-V), EPA has lead implementation authority in 10 states, and authority is shared in the remaining states.[45] EPA directly implements the entire UIC program in several oil and gas producing states, including Kentucky, Michigan, New York, Pennsylvania, and Virginia.[46] **Figure 3** identifies state primacy status for the UIC program.

As noted, for Class II oil- and gas-related injection operations, under Section 1425, a state may be delegated primary enforcement authority without meeting EPA regulatory requirements for state UIC programs promulgated under Section 1421 provided the state demonstrates that it has an effective program that prevents underground injection that endangers drinking water sources. EPA has issued guidance for approval of state programs under Section 1425.[47] If directed by Congress to regulate hydraulic fracturing as underground injection, this regulatory approach could give states significant flexibility and thus might reduce potential regulatory costs, redundancy, and other possible impacts to the industry and the states.[48] EPA's draft guidance on the use of diesel fuels in fracturing fluids does not require revision or review of state UIC programs.

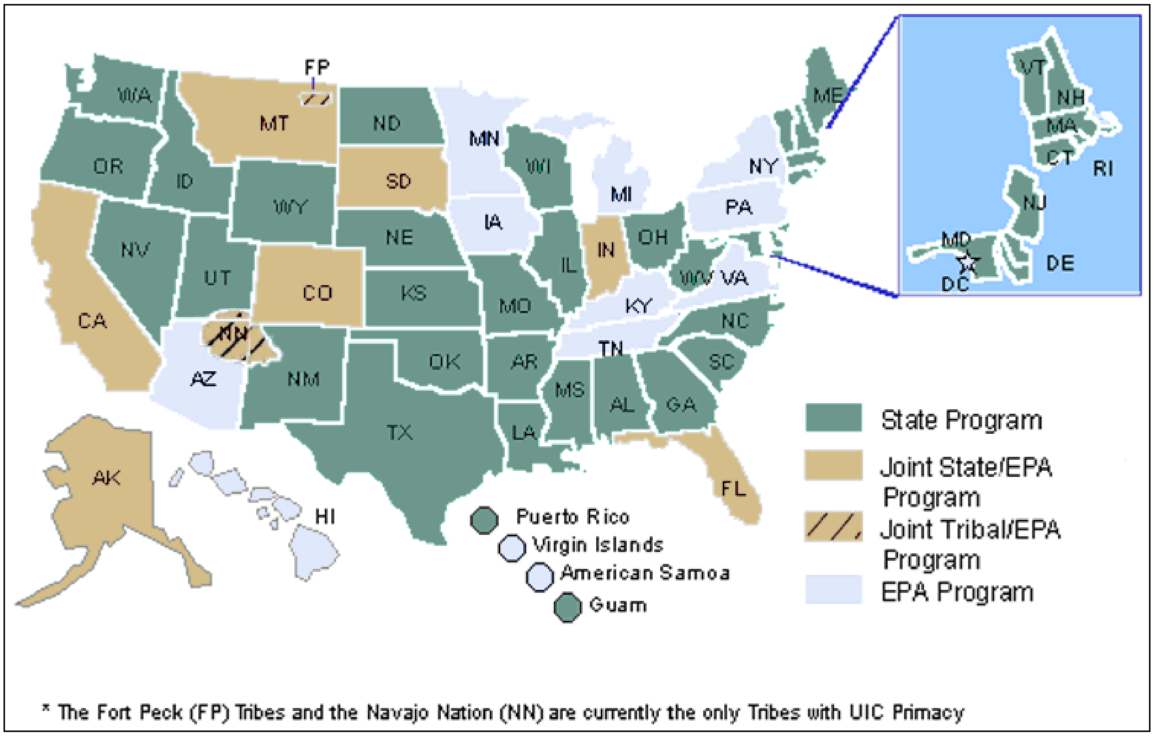
[45] This discussion excludes EPA's new Class VI well category for geologic sequestration of carbon dioxide.

[46] To receive primacy, a state, territory, or Indian tribe must demonstrate to EPA that its UIC program is at least as stringent as the federal standards. The state, territory, or tribal UIC requirements may be more stringent than the federal requirements. For Class II wells, states must demonstrate that their programs are effective in preventing endangerment of USDWs. Requirements for state UIC programs are established in 40 C.F.R. §§144-147.

[47] EPA, *Guidance for State Submissions under Section 1425 of the Safe Drinking Water Act*, p. 20, http://www.epa.gov/safewater/uic/pdfs/guidance/guide_uic_guidance-19_primacy_app.pdf.

[48] The House report for the 1980 Safe Drinking Water Act Amendments, H.R. 8117, which established §1425, states, "So long as the statutory requirements are met, the states are not obligated to show that their programs mirror either procedurally or substantively the Administrator's regulations." H. Report to accompany H.R. 8117, No. 96-1348, September 19, 1980, p. 5.

Figure 3. Primacy Status for EPA's UIC Program



Source: U.S. Environmental Protection Agency, "UIC Program Primacy," http://www.epa.gov/safewater/uic/primacy.html.

Most oil and gas producing states exercise primary enforcement authority for injection wells associated with oil and gas production (Class II wells) under SDWA Section 1425. Among these states, Alaska, California, Colorado, Indiana, Montana, and South Dakota have received primacy for only Class II wells, while EPA administers the remainder of the UIC program (Class I, III, IV, and V wells) for these states. **Table 3** lists states that regulate Class II wells under Section 1425.

Table 3. States and Tribes Regulating Oil and Gas (Class II) UIC Wells Under SDWA Section 1425

Alabama	Louisiana	Oklahoma
Alaska	Mississippi	Oregon
Arkansas	Missouri	South Dakota
California	Montana	Texas
Colorado	Nebraska	Utah
Illinois	New Mexico	West Virginia
Indiana	North Dakota	Wyoming
Kansas	Ohio	Navajo Nation
		Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation

Source: Adapted from information provided by U.S. Environmental Protection Agency.

Note: With primacy granted under Section 1425, states and tribes regulate Class II wells using their own program requirements rather than following EPA regulations, providing significant regulatory flexibility to the states.

Table 4. States Where EPA Implements the UIC Class II Program

Shale-Gas-Producing States	Others
Pennsylvania	Arizona
New York	District of Columbia
Michigan	Florida
Kentucky	Hawaii
Tennessee[a]	Iowa
Virginia	Minnesota
	Multiple tribes, few territories

Source: U.S. Environmental Protection Agency, "UIC Program Primacy," http://water.epa.gov/type/groundwater/uic/Primacy.cfm.

Notes: Eighteen states or territories (e.g., Arizona, Maryland, New Jersey, and North Carolina) have no Class II wells. The states with the most Class II wells are Texas (52,501), California (47, 624), Kansas (15,919), and Oklahoma (10,854).

a. In April 2015, EPA proposed to approve the Tennessee UIC program, for wells in Classes 1-V, for state primacy under SDWA §1422. EPA, "State of Tennessee Underground Injection Control (UIC) Program; Primacy Approval: Proposed Rule," 80 *Federal Register* 18326, April 6, 2015.

The Debate over Regulation of Hydraulic Fracturing Under the SDWA

From the date of the enactment of the SDWA in 1974 until the late 1990s, hydraulic fracturing was not regulated under the act by EPA or the states tasked with administration of the SDWA. However, in the last 15 years a number of developments have called into question the extent to which hydraulic fracturing should be considered an "underground injection" to be regulated under the SDWA. A key trigger for this debate was a challenge to the Alabama UIC program brought by the Legal Environmental Assistance Foundation (LEAF).

The LEAF Challenge to the Alabama UIC Program and EPA's Interpretation of the SDWA

In 1994, LEAF petitioned EPA to initiate proceedings to have the agency withdraw its approval of the Alabama UIC program because the program did not regulate hydraulic fracturing operations in the state associated with production of methane gas from coalbed formations.[49] EPA had previously authorized Alabama to administer a UIC program pursuant to the terms of the

[49] *Legal Environmental Assistance Foundation, Inc. v. U.S. Environmental Protection Agency*, 118F.3d 1467, 1471 (11th Cir. 1997) ("*LEAF I*").

SDWA.[50] EPA denied the LEAF petition in 1995 based on a finding that hydraulic fracturing did not fall within the definition of "underground injection" as the term was used in the SDWA and the EPA regulations promulgated under that act.[51] According to EPA, that term applied only to wells whose "principal function" was the placement of fluids underground.[52] LEAF challenged EPA's denial of its petition in the U.S. Court of Appeals for the Eleventh Circuit, arguing that EPA's interpretation of the terms in question was inconsistent with the language of the SDWA.[53]

The court rejected EPA's claim that the language of the SDWA allowed it to regulate only those wells whose "principal function" was the injection of fluids into the ground. EPA based this claim on what it perceived as "ambiguity" in the SDWA regarding the definition of "underground injection" as well as a perceived congressional intent to exclude wells with primarily non-injection functions.[54] The court held that there was no ambiguity in the SDWA's definition of "underground injection" as "the subsurface emplacement of fluids by well injection," noting that the words have a clear meaning. The court continued:

> The process of hydraulic fracturing obviously falls within this definition, as it involves the subsurface emplacement of fluids by forcing them into cracks in the ground through a well. Nothing in the statutory definition suggests that EPA has the authority to exclude from the reach of the regulations an activity (i.e. hydraulic fracturing) which unquestionably falls within the plain meaning of the definition, on the basis that the well that is used to achieve that activity is also used—even primarily used—for another activity (i.e. methane gas production) that does not constitute underground injection.[55]

The court therefore remanded the decision to EPA for reconsideration of LEAF's petition for withdrawal of Alabama's UIC program approval.[56]

Alabama's Regulation of Hydraulic Fracturing in CBM Production

Consideration of Alabama's UIC program after the court's decision (known as *LEAF I*) was issued in 1997 is a helpful case study. It is useful in assessing exactly how EPA authorized a state to regulate hydraulic fracturing under the SDWA "class" well system, understanding the regulatory options available to EPA and the states authorized to enforce SDWA programs, and evaluating the industry impact resulting from the requirement that hydraulic fracturing be regulated under a UIC program.

Following the *LEAF I* decision and EPA's initiation of proceedings to withdraw its approval of Alabama's Class II UIC program, in 1999 Alabama submitted a revised UIC program to EPA.[57] The revised program sought approval under Section 1425 of the SDWA rather than Section 1422(b). As discussed above, Section 1425 differs from Section 1422(b) in that approval under Section 1425 is based on a showing by the state that the program meets the generic requirements

[50] Ibid., 1470.

[51] Ibid., 1471.

[52] Ibid.

[53] Ibid., 1472.

[54] Ibid., 1473-1474.

[55] Ibid., 1474-1475.

[56] Ibid., 1478.

[57] See 64 *Federal Register* 56986, October 22, 1999.

found in Section 1421(b)(1)(A)-(D) of the SDWA and that the program "represents an effective program (including adequate recordkeeping and reporting) to prevent underground injection which endangers drinking water sources."[58] In contrast, approval of a state program under Section 1422(b) requires a showing that the state's program satisfies the requirements of the UIC regulations promulgated by EPA.[59] As discussed, the key difference between the two options for program approval is that the requirements for programs approved under Section 1425 are more flexible than the requirements for those programs approved under Section 1422(b).

EPA approved Alabama's revised UIC program under Section 1425 in 2000.[60] LEAF appealed EPA's decision to the Eleventh Circuit in what came to be known as *LEAF II*.

LEAF made three arguments. First, LEAF claimed that EPA should not have approved state regulation of hydraulic fracturing under Section 1425 because it does not relate to "underground injection for the secondary or tertiary recovery of oil or natural gas," one of the requirements for approval under Section 1425.[61] The court rejected this argument, finding that the phrase "relates to" was broad and ambiguous enough to include regulation of hydraulic fracturing as being related to secondary or tertiary recovery of oil or natural gas.[62]

Second, LEAF challenged the Alabama program's regulation of hydraulic fracturing as "Class II-like" wells not subject to the same regulatory requirements as Class II wells.[63] The court agreed with LEAF on this point, noting that in its decision in *LEAF I*, it had held that methane gas production wells used for hydraulic fracturing are "wells" within the meaning of the statute.[64] As a result, the court found that wells used for hydraulic fracturing must fall under one of the five classes set forth in the EPA regulations at 40 C.F.R. Section 144.6.[65] Specifically, the court found that the injection of hydraulic fracturing fluids for recovery of coalbed methane "fit squarely within the definition of Class II wells," and as a result the court remanded the matter to EPA for a determination of whether Alabama's updated UIC program complied with the requirements for Class II wells.[66]

Finally, LEAF alleged that even if Alabama's revised UIC program was eligible for approval under Section 1425 of the SDWA, EPA's decision to approve it was "arbitrary and capricious" and therefore a violation of the Administrative Procedure Act.[67] The court rejected this argument.[68]

Among other provisions added in response to the Eleventh Circuit's decisions, the Alabama regulations prohibited fracturing "in a manner that would allow the movement of fluid containing

[58] 42 U.S.C. §300h-4(a).

[59] Ibid., §300h-1(b)(1)(A).

[60] 65 *Federal Register* 2889, October 2000.

[61] *Legal Environmental Assistance Foundation, Inc. v. U.S. Environmental Protection Agency*, 276 F.3d 1256 (11th Cir. 2001) ("*LEAF II*").

[62] Ibid., 1259-1261.

[63] Ibid., 1256.

[64] Ibid., 1262.

[65] Ibid., 1263.

[66] Ibid., 1263-1264.

[67] Ibid., 1256 (referring to 5 U.S.C. §706(2)(A).

[68] Ibid., 1265.

any contaminant into a USDW, if the presence of the contaminant may (a) cause a violation of any applicable primary drinking water standard; or (b) otherwise adversely affect the health of persons."[69] The state regulations further required state approvals (but not permits) prior to individual fracturing jobs. Specifically, well operators were required to certify in writing, with supporting evidence, that a proposed hydraulic fracturing operation would not occur in a USDW or that the mixture of fracturing fluids would meet EPA drinking water standards. Regulations also prohibited fracturing at depths shallower than 399 feet (most drinking water wells rely on aquifers shallower than that) and prohibited the use of diesel oil or fuel in any fracturing fluid mixture. The requirements regarding minimum depths and the diesel ban remain in place, but the rules no longer require that injection fluids meet drinking water standards. Instead, "each coal bed shall be hydraulically fractured so as not to cause irreparable damage to the coalbed methane (CBM) well, or to adversely impact any fresh water supply well or any fresh water resources."[70]

With hydraulic fracturing regulations in place, CBM development in Alabama continued. In 2009, a member of the State Oil and Gas Board of Alabama noted, "Since Alabama adopted its hydraulic fracturing regulations, coalbed operators have submitted thousands of hydraulic fracturing proposals and engaged in thousands of hydraulic fracturing operations."[71]

The number of CBM well permits increased in the years following the adoption of revised regulations.[72] However, it is not clear whether, or by how much, the number of wells, the production costs, or the time required by operators may have been different without the revisions.[73] One of the requirements of the Alabama regulations in response to *LEAF I* was that fracturing fluids had to meet tap water standards to protect USDWs. To ensure compliance, operators purchased water from municipal water supplies that were in compliance with federal drinking water standards to use for fracturing wells. Industry representatives have noted that if this approach were adopted for hydraulic fracturing nationwide, it would not only raise costs but potentially put companies in competition with communities for drinking water supplies.

EPA's 2002-2004 Review of Hydraulic Fracturing for CBM Production

In response to the *LEAF I* decision, citizen reports of water well contamination attributed to hydraulic fracturing of coal beds, and the rapid growth in CBM development, EPA undertook a study to evaluate the environmental risks to USDWs from hydraulic fracturing practices associated with CBM production. EPA issued a draft report in August 2002 that identified water quality and quantity problems that individuals had attributed to hydraulic fracturing of coal beds in Alabama, New Mexico, Colorado, Wyoming, Montana, Virginia, and West Virginia.[74] Based on

[69] *Ala Admin. Code*, r. 400-3-8-.03(4), (2002). Responding to EPAct 2005 (see below), the state made some revisions to its regulations for hydraulic fracturing of coal beds in 2007. Ala. Admin. Code r. 400-3-8-.03(1).

[70] Ala. Admin. Code r. 400-3-8-.03(1).

[71] S. Marvin Rogers, State Oil and Gas Board of Alabama and Chairman, IOGCC Legal and Regulatory Affairs Committee, *History of Litigation Concerning Hydraulic Fracturing to Produce Coalbed Methane*, January 2009, p. 5.

[72] Ala. Admin. Code r. 400-3-8-.03(6)(a), 2002. To mitigate its increased administrative costs associated with implementation of the added regulations, operators pay a fee of $175 for each coalbed group fractured.

[73] A representative of the Alabama Coalbed Methane Association noted that the costs of hydraulic fracturing are site specific and vary with operators as well as geology.

[74] EPA, *Draft Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, August 2002, pp. 6-20-6-21.

the preliminary results of the study, EPA tentatively concluded that the potential threats to public health posed by hydraulic fracturing of CBM wells appeared to be small and did not justify additional study or regulation.

EPA also reviewed whether direct injection of fracturing fluids into USDWs posed any threat. EPA reviewed 11 major CBM formations to determine whether coal seams lay within USDWs. EPA determined that 10 of the 11 producing coal basins "definitely or likely lie entirely or partially within USDWs." The draft report identified the use of diesel fuels in hydraulic fracturing as a potential risk to USDWs.

In 2002, the GWPC board of directors passed a resolution calling for a ban on the use of diesel fuel in hydraulic fracturing of CBM wells where drinking water sources were present.[75] In 2003, EPA entered into an agreement with three companies that provided roughly 95% of hydraulic fracturing services (BJ Services, Halliburton Energy Services, and Schlumberger Technology Corporation). Under this agreement, the firms agreed to remove diesel fuel from CBM fluids injected directly into drinking water sources if cost-effective alternatives were available.[76]

In January 2003, EPA's National Drinking Water Advisory Council submitted to the EPA Administrator a report on hydraulic fracturing, underground injection control, and CBM production and its impacts on water quality and water resources. The council noted concerns regarding (1) the lack of resources to implement the UIC program, (2) the use of diesel fuel and potentially toxic additives in the hydraulic fracturing process, (3) the potential impact of CBM development on local underground water resources and the quality of surface waters, and (4) the maintenance of EPA regulatory authority within the UIC program.[77]

In 2004, EPA issued a final version of the 2002 draft report, based primarily on an assessment of the available literature and extensive interviews. EPA found no confirmed cases of contamination from hydraulic fracturing of CBM formations and concluded that the injection of hydraulic fracturing fluids into CBM wells posed little threat to USDWs and required no further study. However, EPA found that very little documented research had been done on the environmental impacts of injecting fracturing fluids.[78] EPA concluded in the final report that "the use of diesel fuel in fracturing fluids poses the greatest potential threat to USDWs because the BTEX constituents in diesel fuel exceed the MCLs [maximum contaminant levels] at the point-of-

[75] GWPC and U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, *State Oil and Natural Gas Regulations Designed to Protect Water Resources*, May 2009, p. 22.

[76] *Memorandum of Agreement Between the United States Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation*, December 12, 2003.

[77] National Drinking Water Advisory Council, Report on Hydraulic Fracturing and Underground Injection Control and Coalbed Methane Resulting from a Conference Call Meeting Held December 12, 2002, http://www.epa.gov/ogwdw000/ndwac/pdfs/summaries/ndwac_full_121202.pdf.

[78] EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoir*s, Final Report, EPA-816-04-003, June 2004, p. 4-1. The EPA study focused specifically on CBM wells and did not review the use of hydraulic fracturing in other geologic formations, such as the Marcellus Shale or other tight oil and gas formations.

injection."[79] EPA noted that estimating the concentration of diesel fuel components and other fracturing fluids beyond the point of injection was beyond the scope of its study.[80]

EPAct 2005: A Legislative Exemption for Hydraulic Fracturing

The *LEAF I* decision highlighted a debate over whether the SDWA, as it read at the time, required EPA to regulate hydraulic fracturing. Although the Eleventh Circuit's decision applied only to hydraulic fracturing for CBM production in Alabama, the court's reasoning—in particular, its finding that hydraulic fracturing "unquestionably falls within the plain meaning of the definition" of underground injection[81]—raised the issue of whether EPA could be required to regulate under the SDWA all hydraulic fracturing operations used for oil and gas production.

Before this question was resolved through agency action or litigation, Congress passed an amendment to the SDWA as a part of EPAct 2005 (P.L. 109-58) that addressed this issue. Section 322 of EPAct 2005 amended the definition of "underground injection" in the SDWA as follows:

> The term "underground injection"—(A) means the subsurface emplacement of fluids by well injection; and (B) excludes—(i) the underground injection of natural gas for purposes of storage; and (ii) the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities.

This amendment clarified that the UIC requirements found in the SDWA do not apply to hydraulic fracturing, although the exclusion does not extend to the use of diesel fuels in hydraulic fracturing operations. This amended language is the definition of "underground injection" found in the SDWA as of the date of this report.

EPA Guidance for Permitting Hydraulic Fracturing Using Diesel Fuels

As noted above, the EPAct 2005 amendment to the definition of "underground injection" in the SDWA excluded injections as part of hydraulic fracturing operations, but such injections involving the use of diesel fuels were not made part of the exclusion, meaning that injections for purposes of hydraulic fracturing involving the use of diesel fuel might still be made subject to regulation under the SDWA. It was not clear to states or the regulated community how EPA would address the EPAct 2005 amendment, and for several years EPA took no official position regarding the regulation of hydraulic fracturing using diesel fuels under the SDWA.[82] In 2010,

[79] Ibid., p. 4-19. BTEX is the acronym for benzene, toluene, ethylbenzene, and xylene, which are compounds typically found in petroleum products such as gasoline and diesel fuel. These compounds are common indicators of gasoline, diesel, or other petroleum product contamination. MCLs are enforceable drinking water standards under the SDWA.

[80] Ibid., p. 4-12.

[81] *LEAF I*, 118 F.3d at 1475.

[82] In January 2011, an investigation led by Representatives Henry Waxman, Edward Markey, and Diana DeGette of the House Committee on Energy and Commerce found that "oil and gas service companies have injected over 32 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states between 2005 and 2009." (continued...)

EPA specified on its website that hydraulic fracturing operations using diesel fuels are subject to Class II permit requirements under the SDWA. However, the agency did not issue regulations or guidance to accompany this determination, which resulted in implementation and compliance uncertainty and concern among state regulators and within the regulated industry.

In February 2014, EPA issued diesel permitting guidance, which states that "under the 2005 amendments to the SDWA, a UIC Class II permit must be obtained prior to conducting the underground injection of diesel fuels for hydraulic fracturing."[83] As described earlier in this report, injections subject to UIC Class II requirements must comply with a number of regulatory requirements. These include permitting requirements and testing and monitoring obligations with respect to the well.[84] The guidance is intended for EPA permit writers and is relevant where EPA directly implements the UIC Class II program. EPA notes, "To the extent that states may choose to follow some aspects of EPA guidance in implementing their own programs, it may also be relevant in areas where EPA is not the permitting authority."[85]

There had been considerable debate regarding how EPA would define "diesel fuels" in the final guidance. The draft guidance recommended using six Chemical Abstracts Service Registry Numbers (CASRNs) for determining whether diesel fuels are used in hydraulic fracturing operations.[86] These six CASRNs collectively include various types of diesel fuels, home heating oils, kerosene, crude oil, and a range of other petroleum compounds.[87] Also at issue was whether the final guidance would specify a de minimis amount of diesel fuel content for hydraulic fracturing fluids; the draft guidance did not do so. The final document covers five of the six proposed CASRNs (no longer including crude oil) and does not establish a de minimis concentration of "diesel" in fracturing fluid that would be exempt from permitting requirements. EPA has not received permit applications for hydraulic fracturing activities using diesel fuels.

(...continued)

House Energy and Commerce Committee Democrats, "Waxman, Markey, and DeGette Investigation Finds Continued Use of Diesel in Hydraulic Fracturing Fluids," press release, January 31, 2011, http://democrats.energycommerce.house.gov/index.php?q=news/waxman-markey-and-degette-investigation-finds-continued-use-of-diesel-in-hydraulic-fracturing-f/.

[83] EPA, *Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels: Underground Injection Control Program Guidance #84*, February 2014, p. 1, http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/hydraulic-fracturing.cfm.

[84] 40 C.F.R. §124 and §§144-147.

[85] "Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels—Draft," 77 *Federal Register* 27542.

[86] EPA explains that "diesel fuels may be used in hydraulic fracturing operations as a primary base (or carrier) fluid, or added to hydraulic fracturing fluids as a component of a chemical additive to adjust fluid properties (e.g., viscosity and lubricity) or act as a solvent to aid in the delivery of gelling agents. Some chemicals of concern often occur in diesel fuels as impurities or additives. Benzene, toluene, ethylbenzene, and xylene compounds (BTEX) are highly mobile in ground water and are regulated under national primary drinking water regulations because of the risks they pose to human health." EPA, *FACT SHEET: Underground Injection Control (UIC) Program Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels, UIC Program Guidance #84—Draft*, EPA 816-K-12-001.

[87] 77 *Federal Register* 27453. EPA explains that these CASRNs were selected "because either their primary name, or their common synonyms contained the term 'diesel fuel' and they meet the chemical and physical properties 'diesel fuel' as provided in the Toxic Substances Control Act (TSCA) Inventory."

Legislative Proposals in the 114th Congress

In the 114th Congress, as in recent Congresses, several bills have been introduced to expand federal regulation of hydraulic fracturing activities, while others would limit federal involvement. The Fracturing Responsibility and Awareness of Chemicals Act of 2015 (FRAC Act) has been introduced in the House (H.R. 1482) and the Senate (S. 785). The bills would amend the SDWA to (1) require disclosure of the chemicals used in the fracturing process, (2) repeal the hydraulic fracturing exemption established in EPAct 2005, and (3) amend the term "underground injection" to include the injection of fluids used in hydraulic fracturing operations, thus authorizing EPA to regulate this process under the SDWA. Additionally, the Senate bill would authorize states to seek primary enforcement responsibility for hydraulically fractured wells separately from other underground injection wells.

Legislation has also been introduced to require baseline and follow-up testing of potable groundwater in the vicinity of hydraulic fracturing operations. H.R. 1515, the Safe Hydration is an American Right in Energy Development (SHARED) Act of 2015, would amend the SDWA to prohibit hydraulic fracturing unless the entity proposing to conduct the fracturing operations agreed to testing and reporting requirements regarding USDWs. Similar to H.R. 2983 in the 113th Congress, H.R. 1515 would require testing prior to, during, and after hydraulic fracturing operations. Testing would be required for any substance EPA determines would indicate damage associated with hydraulic fracturing operations. The bill would also require EPA to post all test results on its website.

Potential Implications of Hydraulic Fracturing Regulation Under the SDWA

The full regulation of hydraulic fracturing under the SDWA (i.e., beyond injections involving diesel) could have benefits and costs. The benefits might include increased protection of aquifers and drinking water wells and nationally consistent requirements for disclosing information on chemicals used in fracturing operations. Costs could include duplicative permitting requirements, more time-consuming permitting processes for oil and natural gas producers, and increased (and possibly redundant) resource and staff needs for regulators. Resulting groundwater protection and public health benefits would likely be experienced most significantly in any states that might have relatively weaker groundwater protection provisions compared to provisions that EPA might adopt (such as weaker requirements for cementing and casing or injection of fracturing fluids into aquifers that would be protected under the SDWA).

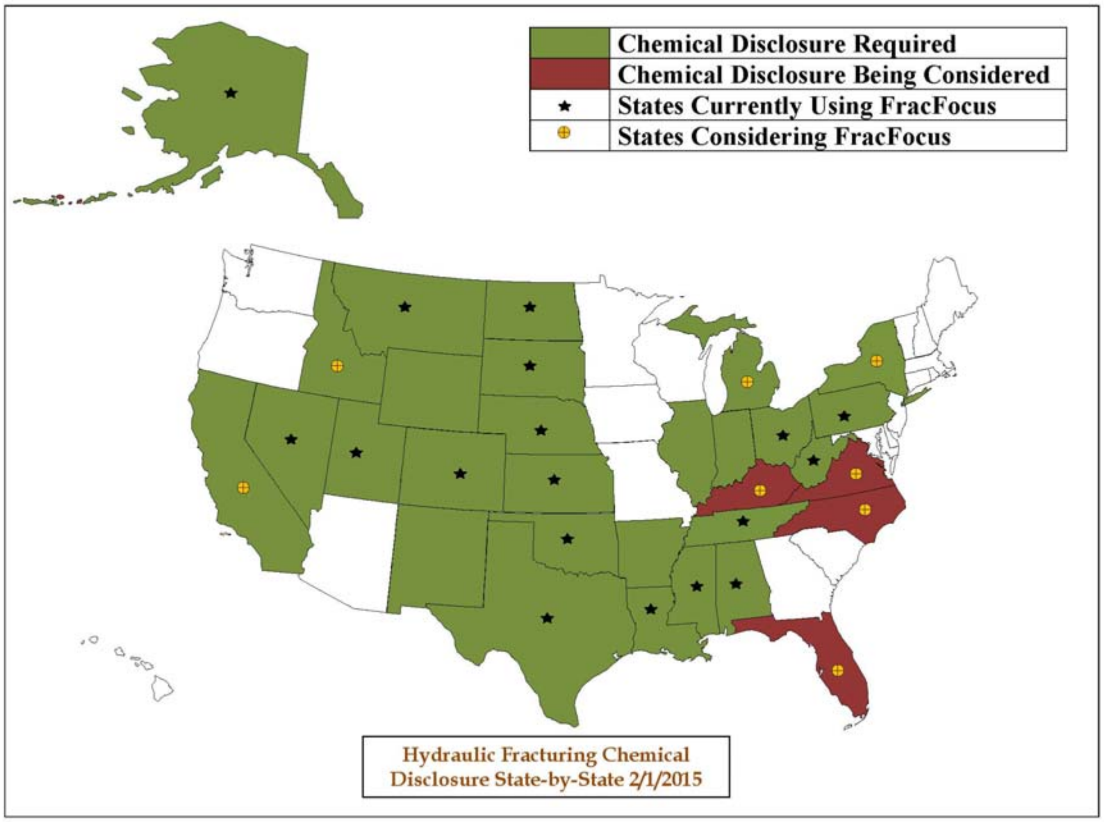
Alternatively, the possible benefits of federal regulation may be reduced to the degree that states have effective groundwater protection requirements or respond to increased development of unconventional gas and oil resources with their own revised requirements (and numerous states have done so). The regulation of the injection of fluids for hydraulic fracturing purposes would not address surface management of chemicals or drilling wastes or the treatment and disposal of produced water. If such surface activities were determined to be the sources of most water contamination incidents associated with unconventional oil and gas development, then regulation of hydraulic fracturing under the SDWA may have limited water quality protection benefits.

Requirements for chemical disclosure are widely viewed as beneficial. The lack of information regarding chemicals used in hydraulic fracturing has made investigations of groundwater contamination difficult in some cases, because well owners and state regulators have typically not known which chemicals to test for to determine whether a fracturing compound has migrated into a water well. The debate has involved who should regulate (the states or federal government) and what should be disclosed and when. Some have called for public disclosure of chemicals in frac fluids before well stimulation so that property owners would be able to test well water for the presence of specific compounds and establish a baseline of well water quality before oil or gas development occurs. The FRAC Act would not require chemical disclosure prior to hydraulic fracturing; however, some states (e.g., Wyoming and California) do require public disclosure prior to commencement of fracing operations.

Many states have adopted a variety of disclosure requirements since the FRAC Act was first introduced in 2009. In 2011, the GWPC and Interstate Oil and Gas Compact Commission established FracFocus (http://www.fracfocus.org), a public registry where companies may voluntarily identify chemicals used in hydraulic fracturing in specific wells. According to the GWPC, as of February 2015, 27 states had adopted chemical disclosure requirements (with various trade secret protections), and at least 18 of these states required public disclosure using FracFocus.[88] **Figure 4** identifies the states that have adopted chemical disclosure requirements and the states that use, or are considering using, FracFocus.

[88] Some have argued that trade secret protections in some states are overly broad, precluding disclosure of information that may be needed to investigate causes of water quality changes should they occur following fracing operations. For a review of disclosure requirements for selected states and BLM (as proposed), see CRS Report R42461, *Hydraulic Fracturing: Chemical Disclosure Requirements*, by Brandon J. Murrill and Adam Vann.

Figure 4. Hydraulic Fracturing Chemical Disclosure by State



Source: Ground Water Protection Council, http://fracfocus.org/welcome.

Notes: FracFocus was established in 2011 by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. FracFocus is a publicly available registry where oil and gas companies may voluntarily identify chemicals used in hydraulic fracturing operations at specific wells. Many states allow or require operators to meet state disclosure requirements by posting information on the FracFocus website. Similarly, new Bureau of Land Management hydraulic fracturing regulations require oil and gas operators on federal lands to disclose chemicals through the FracFocus website. In June 2015, New York banned high-volume hydraulic fracturing.

Additionally, in March 2015, the Bureau of Land Management within the Department of the Interior issued a final hydraulic fracturing rule applicable to oil and gas operations on federal and Indian lands, effective June 24, 2015.[89] The rule requires companies to disclose information on each additive used in the hydraulic fracturing fluids (chemicals and proppants) with exceptions and requirements for trade secrets. Operators must provide this information to BLM by posting it on the FracFocus website within 30 days of completing fracturing operations.

[89] U.S. Department of the Interior, Bureau of Land Management, "Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands: Final Rule," 80 *Federal Register* 16131, March 26, 2015. The final rule revises existing BLM well completion regulations at 43 C.F.R. §316.3-2 and adds a new §3162.3-3. The rule is available at http://www.blm.gov/wo/st/en/info/newsroom/2015/march/nr_03_20_2015.html. BLM oil and gas rules related to hydraulic fracturing were promulgated in 1982 and last revised in 1988—before the widespread use of hydraulic fracturing and horizontal drilling.

If the SDWA were amended to authorize (but not mandate) EPA to regulate hydraulic fracturing, EPA might undertake further study to assess the potential risks of hydraulic fracturing to USDWs. (The agency has been conducting such studies, as discussed below.) Subsequently, EPA might determine the need for, and potential scope of, any new regulations and decide whether to adapt the existing regulatory framework or to develop a new approach under the UIC program. The rulemaking process typically takes several years. A 2009 presentation by EPA's Region 8 UIC program explained that if legislative change occurs,

> additional study may take place, regulations may be written by EPA, some combination of these may happen, [and] there may be a phased-in approach. If regulations are developed, they typically include: establishing a regulation development workgroup which can include the public; a proposed regulation, including opportunity for public comment (and one or more hearings if needed); a final regulation, including opportunity for judicial appeals; and an effective date for the regulation.[90]

One implication of regulating hydraulic fracturing under SDWA relates to the SDWA's citizen suit provisions. As noted, Section 1449 provides for citizen civil actions against any person or agency allegedly in violation of provisions of SDWA or against the EPA Administrator for alleged failure to perform any action or duty that is not discretionary.[91] This provision could represent an expansion in the ability of citizens to challenge state administration of oil and gas programs related to hydraulic fracturing and drinking water if the hydraulic fracturing exemption provision were repealed.

As discussed, the SDWA currently includes two options for approving state UIC programs related to oil and gas recovery.[92] Under the less federally prescriptive approach authorized in Section 1425, EPA may be able to implement new requirements primarily through guidance and review and approval of state programs revised to address hydraulic fracturing. EPA used this approach when ordered to require Alabama to regulate hydraulic fracturing of coal beds, and a federal district court approved this approach. For regulating the use of diesel fuels in hydraulic fracturing, EPA has issued guidance for EPA permit writers but has not established any new requirements, nor has the agency proposed to review state programs.

If EPA approached state regulation of hydraulic fracturing under Section 1425, the agency might also write new hydraulic fracturing regulations under Section 1421 for states that exercise primacy under Section 1422 (i.e., following the EPA regulations)—such as Idaho, Maryland, and North Carolina—and for EPA to use in states where EPA directly implements the UIC program (e.g., Kentucky, Michigan, New York, Pennsylvania, and Virginia). Regardless of the regulatory approach, new requirements could require substantially more resources for UIC program administration and enforcement by the states and EPA.

The possible impacts of enacting legislation directing EPA to regulate hydraulic fracturing feasibly could vary for different oil and gas formations. The SDWA directs EPA, when

[90] EPA, Region 8, *Hydraulic Fracturing*, presentation at the Underground Injection Control Program Meeting, Glenwood Springs, CO, August 8, 2009.

[91] §1449; 42 U.S.C. 300j-8.

[92] In the case concerning Alabama, the Eleventh Circuit Court of Appeals ruled that "EPA's decision to subject hydraulic fracturing to approval under § 1425 rests upon a permissible construction of the Safe Drinking Water Act." *Legal Environmental Assistance Fund v. Environmental Protection Agency, State Oil and Gas Board of Alabama*, 276 F.3d 1253 (11th Cir. 2001).

developing UIC regulations, to take into consideration "varying geologic, hydrological, or historical conditions in different States and in different areas within a State."[93] Thus, if EPA were to regulate hydraulic fracturing broadly under the SDWA, the agency could conceivably establish different requirements to address such differences among states or regions. If practical and applicable, EPA might find this statutory flexibility helpful, as the USDW contamination risks of hydraulic fracturing could vary widely among different formations and settings. For example, fracturing a coal bed that may qualify as a USDW poses very different groundwater contamination risks than fracturing a shale formation that is widely separated from any USDW.[94] Thus the possible application and impact of federal regulations might vary for different formations, and the impacts and potential environmental benefits would likely be greatest in formations that qualify as USDWs or are near USDWs.[95] However, the agency has not used the flexibility in the past and might broadly apply new requirements—such as those related to well construction and cementing and mechanical integrity testing—to protect USDWs through which wells may pass, among other purposes.

For the oil and gas industry, regulation of hydraulic fracturing under the UIC program could have a range of impacts. In some states, oil and gas operations are subject to regulation by a state oil and gas agency or commission as well as an environmental or public health agency. States and industry representatives have expressed concern over the potential for some duplication of requirements from state oil and gas regulations and UIC regulations. Delays in issuing permits and commensurate delays in well stimulation and gas marketing are among the concerns. The citizen suit provision of the SDWA may also be an issue. One analysis attempting to measure the economic and energy effects of potential regulation noted:

> Experience suggests that there will be a reduction in the number of wells completed each year due to increased regulation and its impact on the additional time needed to file permits, push-back of drilling schedules due to higher costs, increased chance of litigation, injunction or other delay tactics used by opposing groups and availability of fracturing monitoring services.[96]

The GWPC, representing state agencies, has opposed reclassification of hydraulic fracturing as a permitted activity under the UIC programs, stating that (1) a risk has not been identified, and thus there is no evidence that UIC regulation is necessary; and (2) UIC regulation would divert resources from higher risk activities.[97] The legislatures of major oil and gas producing states—including Alabama, Alaska, Montana, North Dakota, Wyoming, and Texas—passed and sent to

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[93] §1421(b)(3)(A); 42 U.S.C. 300h(b)(3)(A).

[94] Because coal beds are frequently sources of drinking water, the Alabama State Oil and Gas Board requires well operators to certify that a proposed hydraulic fracturing operation would not occur in a USDW or that the mixture of fracturing fluids would meet EPA drinking water standards. State rules also prohibit fracturing at depths shallower than 399 feet, as most drinking water wells rely on aquifers shallower than that. Under the federal UIC program, injections that endanger USDWs are prohibited, unless the aquifer (or portion thereof) is exempted. (See footnote 37.)

[95] U.S. Department of Energy, Office of Fossil Energy and National Energy Technology Laboratory, *Modern Shale Gas Development in the United States: A Primer*, April 2009, http://fossil.energy.gov/programs/oilgas/publications/naturalgas_general/Shale_Gas_Primer_2009.pdf.

[96] IHS Global Insight, *Measuring the Economic and Energy Impacts of Proposals to Regulate Hydraulic Fracturing*, Task 1 Report, prepared for the American Petroleum Institute, 2009, p. 7.

[97] Statement of Scott Kell, for the Ground Water Protection Council, in U.S. Congress, House Committee on Natural Resources, Subcommittee on Energy and Mineral Resources, oversight hearing on "Unconventional Fuels, Part I: Shale Gas Potential," June 4, 2009.

Congress resolutions asking Congress not to extend SDWA jurisdiction over hydraulic fracturing activities.

The American Water Works Association (AWWA) has called for effective and adequately funded regulation of hydraulic fracturing at the federal, state, and local levels to reduce risks to water supplies to the greatest extent possible.[98] The AWWA supports pre-drilling water quality monitoring to establish baseline conditions and periodic monitoring during oil or gas development to assess and respond to any changes in water quality. One pending bill, H.R. 1515, would amend the SDWA to prohibit hydraulic fracturing unless the company proposing to conduct the fracturing operations agreed to groundwater testing and reporting before, during, and following hydraulic fracturing operations (see "Legislative Proposals in the 114th Congress").

If authorized, EPA regulation of hydraulic fracturing under the SDWA UIC program could increase protection of groundwater resources if state rules were less stringent. It would not address many significant public concerns often associated with the development of unconventional oil and gas resources. These concerns involve land surface disturbances associated with the development of roads, well pads, and natural gas gathering pipelines; potential impacts of water withdrawal and consumption; direct or indirect discharge of produced water to surface waters; air quality impacts; wildlife habitat impacts, noise; etc. Some of these activities are subject to other federal laws, such as Clean Water Act requirements covering the treatment and discharge of produced water into surface waters[99] and new Clean Air Act regulations.[100] The state and federal regulatory requirements for management, treatment, and discharge of produced water may have a more significant impact on the industry than possible UIC-related requirements.[101] Other impacts related to development of unconventional oil and gas resources are highly visible and may raise more concern than the specific process of deep underground fracturing of oil and gas formations. Some of these issues (particularly land use and facility siting issues) are beyond the reach of federal regulation and thus are left to state and local governments to address. Issues related to well construction, operation, monitoring, and closure could be addressed through the UIC program.

UIC Program Resource Issues

The funding and staffing resource implications of including hydraulic fracturing under the UIC program could be significant for regulatory agencies. Considering only the number of wells added to the program, the workload under Class II UIC programs could more than double. Currently, there are some 172,000 Class II wells nationwide.[102] By comparison, the DOE Energy

[98] American Water Works Association, "Water and Hydraulic Fracturing: A White Paper from the American Water Works Association," 2013, p. 14.

[99] On April 7, 2015, EPA proposed to establish a "zero discharge" pretreatment standard to prohibit discharges of wastewater from unconventional oil and gas extraction to municipal wastewater treatment plants. (EPA is not aware of any such discharges. The rule excludes wastewater from the extraction of CBM.) EPA, *Effluent Limitations Guidelines and Standards for the Oil and Gas Extraction Point Source Category, Proposed Rule*, 80 *Federal Register* 18,557, April 7, 2015. See also EPA, "Natural Gas Extraction—Hydraulic Fracturing," http://www2.epa.gov/hydraulicfracturing#swdischarges.

[100] In August 2012, EPA issued emission standards for air pollutants from oil and gas wells and related production systems and activities. See CRS Report R42833, *Air Quality Issues in Natural Gas Systems*, by Richard K. Lattanzio.

[101] U.S. Department of Energy, Office of Fossil Energy and National Technology Laboratory, *Modern Shale Gas Development in the United States: A Primer*, pp. 29-42.

[102] EPA, "Underground Injection Control Program: Classes of Wells," http://water.epa.gov/type/groundwater/uic/ (continued...)

Information Administration reports that the number of producing natural gas wells in the United States increased from 302,421 in 1999 to 482,286 in 2013 and that most new wells—conventional and unconventional—are fractured.[103]

EPA's annual appropriation includes funds for state grants to support state administration of many EPA programs. For the past 30 years, the annual appropriations to support state UIC programs have remained essentially flat (not adjusted for inflation) at roughly $10.5 million.[104] Ten EPA regional offices and 42 states share this amount annually to administer the full UIC program, which covers more than 700,000 wells. The GWPC has estimated that annual UIC program funding would need to increase to $56 million to fully meet the needs of the existing UIC program.[105] The GWPC further estimated that EPA would need to provide funding at a level of $100 million annually to meet the needs for the full UIC program. Given the large number of wells that are fractured, UIC program oversight and enforcement costs for state agencies could be considerably higher if this process is subjected to federal UIC regulations in addition to state oil and gas rules. If authorized or directed to regulate hydraulic fracturing under the SDWA, EPA and states would need to develop new requirements for these wells and increase staff to review applications and make permitting decisions, and more integration with state oil and gas agencies would likely be needed. States and industry representatives have expressed concern that failure to provide sufficient resources would likely create permitting backlogs. For example, under UIC regulations, EPA or the primacy state must provide for a public hearing for each permit issuance.[106] Some states impose permit fees or use other revenue-generating mechanisms to fund their oil and gas regulatory programs. The SDWA has no comparable provisions.

Because of the sheer number of potentially newly regulated wells, EPA (given current resource levels) would necessarily need to rely heavily upon the states to implement such a program. In 2007, the GWPC noted that states are already struggling to fully implement their UIC programs, and new requirements for hydraulic fracturing would be problematic. The GWPC cautioned that without substantial increases in funding for the UIC program,

- more states would decide to return primacy to EPA (which would also require additional funds to implement the program);
- the overall effectiveness of UIC programs would suffer as more wells and well types are added without a concurrent addition of resources to manage them;

(...continued)

wells.cfm.

[103] EIA, *Natural Gas Navigator: Number of Producing Gas Wells*, 2015, http://tonto.eia.doe.gov/dnav/ng/ng_prod_wells_s1_a.htm. The number of producing wells has declined since reaching 514,637 wells in 2011.

[104] For state UIC grants, Congress provided $10.50 million for each of FY2014 and FY2015, the same amount as requested for FY2016. SDWA §1443(b) authorized appropriations for state UIC program grants at $15 million annually for FY1992-FY2003.

[105] GWPC, *Ground Water Report to the Nation: A Call to Action*, ch. 9, 2007, http://www.gwpc.org. This estimate preceded EPA's promulgation of new UIC regulations establishing Class VI wells for geologic sequestration of carbon dioxide and EPA's determination that production wells that use diesel must receive a Class II permit.

[106] See, for example, requirements at 40 C.F.R. § 144.51(m), *Requirements prior to commencing injection*. Also, 40 C.F.R. §124.11 provides for public comments and requests for public hearings for UIC permits. The UIC program director is required to hold a public hearing whenever he or she finds a significant degree of public interest in a draft permit (40 C.F.R. §124.12(a)). Section 124.13 states that a comment period may need to be longer than 30 days to allow commenters time to prepare and submit comments.

- decisions regarding which parts of the program to fund with limited dollars could result in actual damage to USDWs if higher risk/higher cost portions of the program are put "on the back burner"; and
- negative impacts on the economy could occur as permitting times lengthen due to increased program workloads.[107]

EPA Hydraulic Fracturing Study

The use of hydraulic fracturing for oil and gas development has expanded rapidly over the past decade, and much concern has been expressed regarding the potential for this well-stimulation practice to contaminate aquifers and drinking water supplies. Although hydraulic fracturing has been applied to wells more than 1 million times in the United States[108] with little documented harm to groundwater quality, few scientific studies have been conducted to examine processes and pathways between hydraulic fracturing operations and groundwater supplies and whether and to what extent groundwater quality may be affected. A 2013 journal article noted the debate and uncertainty regarding the relationship between hydraulic fracturing and potable aquifers:

> Indeed many articles in newspapers, journals, and the electronic news media regarding pollution of groundwater by the hydraulic fracturing industry (e.g., Zoback et al. 2010; Molofsky et al. 2011; Osborn et al. 2011; Myers 2012; Schnoor 2012; Warner et al. 2012) convey widely differing views regarding risks of groundwater contamination by the development of unconventional gas plays. Unfortunately, little peer-reviewed scientific information is available on the hydrogeological conditions—shallow groundwater quality in particular—associated with unconventional gas production or, for that matter, with conventional oil and gas production.[109]

In EPA's FY2010 appropriations act, Congress urged EPA to carry out a study on the relationship between hydraulic fracturing and drinking water using a credible approach that relies on the best available science as well as independent sources of information.[110] In 2011, EPA issued a Hydraulic Fracturing Study Plan, noting that the agency designed the study to examine conditions that may be associated with potential contamination of drinking water sources and to identify factors that may lead to human exposure and risks.[111]

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[107] Mike Nickolaus, GWPC, UIC Funding Presentation, January 23, 2007.

[108] George E. King, "Hydraulic Fracturing 101: What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells," Society of Petroleum Engineers, p. 2, http://www.kgs.ku.edu/PRS/Fracturing/Frac_Paper_SPE_152596.pdf.

[109] R. E. Jackson et al., "Groundwater Protection and Unconventional Gas Extraction: The Critical Need for Field-Based Hydrogeological Research," *Groundwater*, vol. 51, no. 4 (July/August 2013), p. 489.

[110] P.L. 111-88, H.Rept. 111-316:

> Hydraulic Fracturing Study.—The conferees urge the Agency to carry out a study on the relationship between hydraulic fracturing and drinking water, using a credible approach that relies on the best available science, as well as independent sources of information. The conferees expect the study to be conducted through a transparent, peer-reviewed process that will ensure the validity and accuracy of the data. The Agency shall consult with other Federal agencies as well as appropriate State and interstate regulatory agencies in carrying out the study, which should be prepared in accordance with the Agency's quality assurance principles.

[111] EPA, Office of Research and Development, *Plan to Study the Potential Impacts of Hydraulic Fracturing on*
(continued...)

On June 4, 2015, the agency released the draft report, *Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources (External Review Draft)*, for public comment and submitted it to the EPA Science Advisory Board for peer review.[112] A final report is expected in 2016.[113]

As illustrated in **Figure 5**, the study broadly assesses five stages of the water cycle associated with hydraulic fracturing activities: (1) water acquisition, (2) chemical mixing, (3) well injection, (4) wastewater (flowback and produced water) collection and transport, and (5) wastewater treatment and waste disposal. It identifies potential drinking water issues associated with each stage. EPA research activities included analyzing hydraulic fracturing data collected from the oil and gas industry and states, modeling several scenarios to identify conditions that may lead to impacts on drinking water resources, conducting laboratory studies to identify impacts of discharging inadequately treated wastewater to rivers and to assess how well wastewater treatment processes remove contaminants, compiling toxicity information of chemicals, and conducting case studies. Additionally, EPA investigated reported incidents of drinking water contamination at five sites where hydraulic fracturing has occurred. These five retrospective case studies were conducted to determine the potential relationship, if any, between reported impacts and hydraulic fracturing activities.[114]

(...continued)

Drinking Water Sources, November 2011, http://www.epa.gov/hfstudy/HF_Study__Plan_110211_FINAL_508.pdf. The hydraulic fracturing study plan stated that "EPA has designated the report of results as a 'Highly Influential Scientific Assessment,' which will undergo peer review by the EPA's Science Advisory Board, an independent and external federal advisory committee that conducts peer reviews of significant EPA research products and activities.... Ultimately, the results of this study are expected to inform the public and provide decision-makers at all levels with high-quality scientific knowledge that can be used in decision-making processes." EPA, *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Sources*, p. 4. In December 2012, EPA released a progress report describing the status and scope of research being conducted for the study. EPA, Office of Research and Development, *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources: Progress Report*, December 2012, http://www.epa.gov/hfstudy.

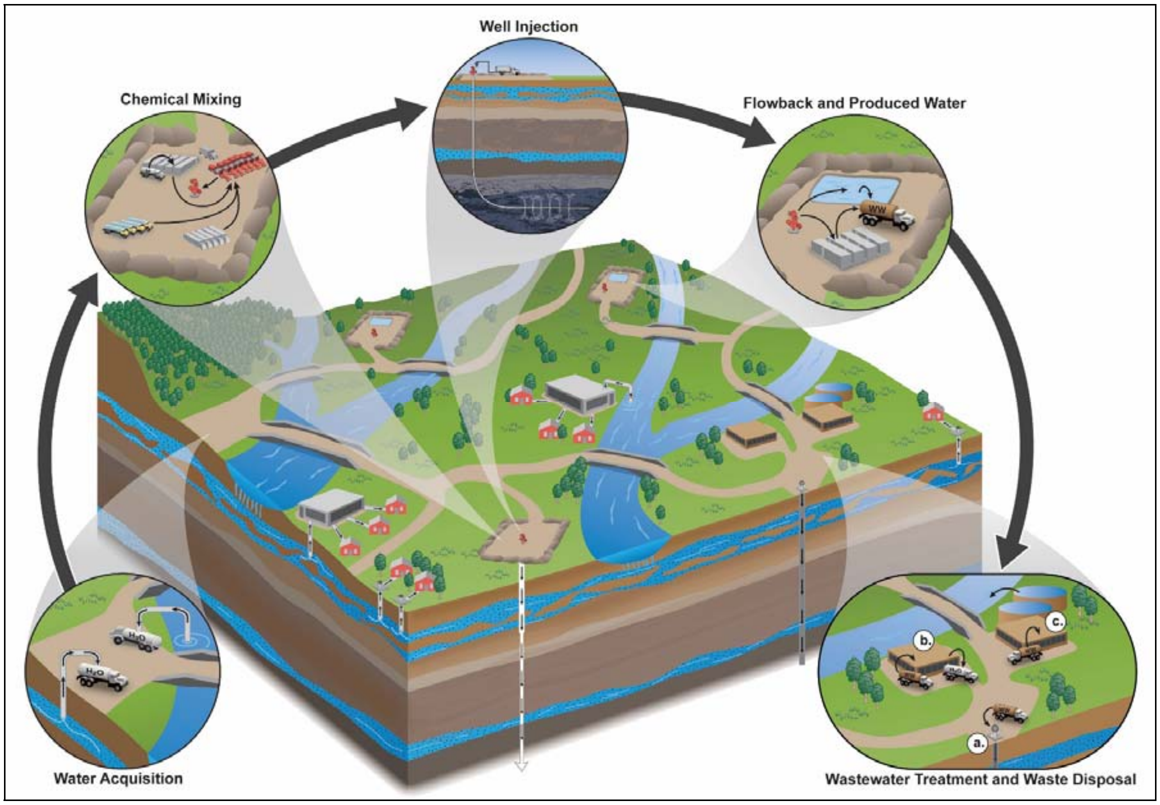
[112] EPA, *Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources (External Review Draft)*, June 2015, http://www2.epa.gov/hfstudy/hydraulic-fracturing-study-draft-assessment-2015.

[113] In the 113th Congress, H.R. 2850 (H.Rept. 113-252), the EPA Hydraulic Fracturing Study Improvement Act, would have required EPA to follow certain procedures governing peer review and data presentation in conducting its study on the relationship between hydraulic fracturing and drinking water. As reported by the House Committee on Science, Space and Technology, the bill would have required EPA to release the final report by September 30, 2016. H.R. 2850 was placed on the Union Calendar on October 23, 2013, but no further action was taken.

[114] EPA conducted retrospective case studies at five sites to develop information about the potential impacts of hydraulic fracturing on drinking water resources under different circumstances. The case studies involve the investigation of reported drinking water contamination attributed to hydraulic fracturing operations at oil or gas production sites (the Bakken Shale in Kildeer, Dunn County, ND; the Barnett Shale in Wise County, TX; the Marcellus Shale in Northeastern PA and in Southwestern PA; and coalbed methane in the Raton Basin, CO). EPA has posted on its website a report and factsheet for each of the case studies.

Figure 5. Scope of Activities Addressed in EPA Draft Hydraulic Fracturing Study

Conceptualized Stages of the Hydraulic Fracturing Water Cycle



Source: EPA, *Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources (External Review Draft)*, June 2015, p. 1-3.

Notes: EPA developed this generalized landscape to illustrate the activities associated with hydraulic fracturing and their relationship to drinking water resources. [Not to scale.]

In the draft assessment, EPA concluded that several mechanisms, above and below ground, have the potential to impact drinking water resources:

- Water withdrawals in times of, or in areas with, low water availability;
- Spills of hydraulic fracturing fluids and produced water;
- Fracturing directly into underground drinking water resources;
- Below ground migration of liquids and gases; and
- Inadequate treatment and discharge of wastewater.[115]

Among the major findings in the draft assessment, EPA notes the following:

> We did not find evidence that these mechanisms have led to widespread, systemic impacts on drinking water resources in the United States. Of the potential mechanisms identified in this report we found specific instances where one or more mechanisms led to impacts on

[115] EPA, *Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources (External Review Draft)*, June 2015.

> drinking water resources, including contamination of drinking water wells. The number of identified cases, however, was small compared to the number of hydraulically fractured wells.
>
> This finding could reflect a rarity of effects on drinking water resources, but may also be due to other limiting factors. These factors include: insufficient pre-and post-fracturing data on the quality of drinking water sources; the paucity of long-term systematic studies; the presence of other sources on contamination precluding a definitive link between hydraulic fracturing activities and an impact; and the inaccessibility of some information on hydraulic fracturing activities and potential impacts.[116]

The study's breadth and associated costs and timetable have drawn attention. The House Appropriations Committee report for the Department of the Interior, Environment, and Related Agencies Appropriation Bill, 2013, directed EPA to narrow the scope of the study and did not include the requested $4.25 million increase for additional hydraulic fracturing research.[117]

For each of FY2012, FY2013, and FY2014, Congress provided $6.1 million for the study. EPA requested the same amount for FY2015, and Congress provided $4.6 million. For FY2016, EPA has requested $4 million to complete the study. This would be the seventh year of funding and would bring total funding provided for the study to $33.1 million since FY2010.

Concluding Observations

Hydraulic fracturing bills introduced in the 114th Congress and previously have generated considerable debate. Many state agencies have argued against regulation of hydraulic fracturing under the SDWA groundwater protection provisions and note a long history of the successful use of this practice in developing oil and gas resources and of state regulation of the industry. Various states and industry representatives argue that additional federal regulation would be redundant vis-à-vis state rules and would likely slow domestic oil and gas development. At the same time, drilling and fracturing methods and technologies have changed significantly over time as they have been applied to more challenging formations, greatly increasing the amount of water, fracturing fluids, and well pressures involved in many oil and gas production operations. In recent years, numerous major oil and gas producing states have revised their regulations in response to changes in the industry, while other states are currently developing or considering new laws and regulations. A few states have imposed moratoria on hydraulic fracturing while evaluating potential impacts and developing regulations, and on June 29, 2015, New York State officially banned high-volume hydraulic fracturing.[118]

Despite state actions, the increasing density of wells and geographic expansion of unconventional oil and gas extraction activities, along with citizen complaints of groundwater contamination in areas where hydraulic fracturing is used, have led to calls for greater federal oversight of this well

[116] Ibid., ES-6.

[117] U.S. Congress, House Appropriations, *Department of the Interior, Environment, and Related Agencies Appropriation Bill, 2013*, H.Rept. 112-589, to accompany H.R. 6091, 112th Cong., 2nd sess., July 10, 2012, p. 48. Specifically, EPA had incorporated a review of environmental justice impacts that the committee found to be outside the scope of the study.

[118] New York State Department of Environmental Conservation, "New York State Officially Prohibits High-Volume Hydraulic Fracturing," press release, June 29, 2015, http://www.dec.ny.gov/press/102337.html.

stimulation technique—and of oil and gas extraction activities more broadly. Proponents of federal regulation assert the need for a consistent, minimum level of regulation and water quality protection nationwide.

Central issues in the debate concern the need for, and potential benefits of, regulation of hydraulic fracturing under the SDWA. Pollution prevention generally—and groundwater protection in particular—is much less costly than cleanup, and where groundwater supplies are not readily replaceable, protection becomes a high priority. Federal environmental regulations are generally used to address activities found to have widespread public health and/or environmental risks, particularly where significant regulatory gaps and unevenness exist among the states. If Congress directed EPA to regulate fracturing broadly under the SDWA, the environmental benefits could be significant if the risks of contamination were significant and states were not addressing those risks effectively. Alternatively, the benefits may be small if states were addressing risks and/or most pollution incidents were found to be related to other oil and gas production activities, such as poor management of produced water or surface spills. Such issues are not subject to SDWA authority and would not be addressed through regulation under this act. Issues related to well construction, operation, monitoring, and closure could be addressed through the UIC program.

Thus far, the data suggest that hydraulic fracturing—particularly in deep zones—presents a low risk of contamination to underground sources of drinking water, and most reports of contamination have been associated with surface activities or well construction and operation problems, not hydraulic fracturing per se. However, while regulators and industry practitioners define hydraulic fracturing as a specific well stimulation operation, the term is frequently used to refer broadly to the full range of activities associated with unconventional oil and gas production. The answer to the question of whether hydraulic fracturing is contaminating drinking water supplies may depend on how broadly one defines *hydraulic fracturing*.

While state oil and gas and groundwater protection agencies widely support keeping responsibility for regulating hydraulic fracturing with the states, public water suppliers have called for effective and adequately funded regulation of hydraulic fracturing at the federal, state, and local levels to reduce risks to water supplies as much as possible. Whether state or federal, regulations require adequate resources to be administered effectively. The sheer number of wells that rely on fracturing suggests that state and federal regulators might need significant new staffing and other resources to implement and enforce any new EPA requirements on top of existing state requirements.

Debate continues over the risks that hydraulic fracturing operations may pose to drinking water resources, and Congress directed EPA to study this matter. On June 4, 2015, EPA released its draft study of hydraulic fracturing and drinking water, and the final report is scheduled for 2016. The results of this and other studies are expected to provide a better assessment of potential risks and particular circumstances that may be associated with such risks and may help inform the need for, and focus of, additional regulation—whether at the state level through oil and gas laws and regulations or at the federal level through the SDWA UIC program.

Author Contact Information

Mary Tiemann
Specialist in Environmental Policy
mtiemann@crs.loc.gov, 7-5937

Adam Vann
Legislative Attorney
avann@crs.loc.gov, 7-6978