EPA Science Advisory Board
Hydraulic Fracturing Research Advisory Panel
Public Teleconference February 1, 2016
Oral Statement of Barbara Arrindell

From: B.Arrindell
Sent: Thursday, January 28, 2016 5:28 PM
To: Docket OEI <Docket_OEI@epa.gov>; Hanlon, Edward <Hanlon.Edward@epa.gov>; Frithsen, Jeff <Frithsen.Jeff@epa.gov>;
Subject: EPA - Comments to SAB HF Study Panel 2-1-2016 teleconference meeting

Dear Mssrs. Hanlon and Frithsen, and Dr. Dzombak;

Attached are my oral comments to be presented to the Advisory Panel during Feb 1, 2016 conference call, a written version of same and 7 supporting documents.

I ask that my comments and all supporting documents be posted to the Panel's website and specifically sent to each member of the Panel.

One attachment for the Panel's consideration is not included within this posting, due to copyright protection requirements. This attachment is noted below:

FREELY available on the web

1) Hannah Wiseman entitled "Untested Waters: The Rise of Hydraulic Fracturing in Oil and Gas. Production and the Need to Revisit Regulation" http://law.uh.edu/faculty/thester/courses/Emerging%20Tech%202011/Wiseman%20on%20Fracking.pdf

Thank you, and apologies for the delay in sending this.
B. Arrindell

B. Arrindell
Director
Damascus Citizens for Sustainability

The American Petroleum Institute has asked for 'science' to support the SAB panel's draft recommendations to among other things, remove the 'no widespread, systemic impacts' headline. That science is supplied by gas/oil industry's own publications through Society of Petroleum Engineers and research by industry companies; see link to previous submissions by DCS. It is exactly that science that led to industry recognition of the environmental and public health damage they would cause and therefore the liabilities under environmental laws they would face. The industry then spurred its lobbists into action to get the exemptions they now hold to major protective environmental laws and even worker protective laws.

The federal court of appeals 2000 ruling in the Alabama 'LEAF' case ordered the EPA to evaluate the impacts of drilling as underground injection. So the EPA started a look at impacts in 2000 - withdrawn in 2002, eventually became the flawed 2004 report that EPA scientist, Weston Wilson, invoked whistleblower status to complain about - cherry picked data, politically vetted chapter and executive summaries and conclusions…see Wilson's statement filed with this comment. The industry's army of lobbyists worked for decades and were successful in 2005 (as a result in part of that flawed EPA study) to get exemptions for the gas oil industry from major provisions of the Safe Drinking Water Act, Clean Air Act, Clean Water Act, Community Right to Know Act, RCRA, Superfund law and parts of the National Environmental Policy Act for any sort of drilling though that report was on coal bed methane mining not even looking at deep shale drilling. Also the wastes from gas and oil were declared 'special' via the Bentsen Amendment to the RCRA law (in 1980) so that material toxic by any other definition, is not tracked, manifested, analyzed or mandated to be disposed of properly. The companies do not have liability for much pollution as a result of these exemptions so mostly the pollution is hidden. These exemptions are a huge subsidy as a result, paid for by the health of communities near drilling and infrastructure and by the global population as a result of facilitated climate change.

The EPA was complicit in the distortion of science that hydraulic fracking is safe for drinking water sources with that 2004 report. This SAB panel has the chance to speak clearly about the science and be true to their ethical and moral obligations to act on truth and not political lobbying wishes. The removal of Dimock PA, Pavillion WY and Parker County TX from the report is also a parallel to the 2004 report that should not be repeated.

Please see the back up material for these statements. Thank you.

LINK to EPA Hydraulic Fracturing Study References from DCS
in a dropbox folder https://www.dropbox.com/sh/vfk5vbgovezgn9k/I1EUZ4QZnY
and submitted previously to the SAB panel.
and comments and documents below are in this folder
https://www.dropbox.com/sh/9h8eno7k6f6pexx/AADzq0k8j155uCO0JjecC2swa?dl=0

ATTACHED to this email to Mr. Ed Hanlon and at link
https://www.dropbox.com/sh/9h8eno7k6f6pexx/AADzq0k8j155uCO0JjecC2swa?dl=0

1- one page intro to DCS 2014 SAB submissions

2 - Summary of LEAF case in this http://www.fas.org/sgp/crs/misc/R41760.pdf
Congressional Research Service
Hydraulic Fracturing and Safe Drinking Water Act Regulatory Issues

3, 4 - Hannah Wiseman's summary/history of the gas/oil exemptions and another of her pieces on this subject

5 - Earthworks 2 page exemptions summary
https://www.earthworksaction.org/files/publications/FS_LoopholesForPollutersNEW.pdf

6 - Weston Wilson's 2004 complaint

7 - Soraghan's worker exemption piece in eenews **Drilling's safety exemptions and how they got there** **Mike Soraghan, E&E reporter** *EnergyWire: Tuesday, November 4, 2014* Link is http://www.eenews.net/stories/1060008302

8 - these comments - two versions - oral and written

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The American Petroleum Institute has asked for 'science' to support the SAB panel's draft recommendations to among other things, remove the 'no widespread, systemic impacts' headline. That science is supplied by gas/oil industry's own publications through organizations such as the Society of Petroleum Engineers and research by companies in the industry; see link to previous submissions by DCS. It is exactly that science that led to recognition by the industry of the environmental and public health damage they would cause and therefore the liabilities under environmental laws they would face. The industry's response was not to change its oil and gas production methods but rather to obtain exemptions from the requirements of each of the major protective environmental laws and even worker protective laws. These exemptions apply to the Safe Drinking Water Act, Clean Air Act, Clean Water Act, Community Right to Know Act, Resource Conservation and Recovery Act (RCRA), Superfund law and important parts of the National Environmental Policy Act. Also the wastes from gas and oil were declared 'special' via the Bentsen Amendment to the RCRA law (in 1980) so that material toxic by any other definition, is not tracked, manifested, analyzed or mandated to be disposed of properly. The companies do not have liability for much pollution as a result of these exemptions so mostly the pollution is hidden. These exemptions are a huge subsidy as a result, paid for by the health of communities near drilling and infrastructure and by the global population as a result of facilitated climate change.

A review of events relating to these exemptions demonstrates the importance of the recommendation by this panel that EPA remove the statement about 'no widespread systemic impacts" from its current draft report. In 2000, as a result of a lawsuit filed by the environmental group LEAF, the federal court of appeals ordered EPA to review and revise its approval of Alabama's underground injection control program under the Safe Drinking Water Act as applied to oil and gas production using hydraulic fracturing (aka, "fracking").

While EPA responded to the court's remand related to oil and gas fracking, it started a nationwide study in 2000 looking at the impacts on drinking water sources of fracking to produce methane from coal beds. This report, withdrawn in 2002 and then restarted to be finally published in 2004, concluding in the executive summary that "the injection of hydraulic fracturing fluids into coal bed methane wells poses little or no threat to underground sources of drinking water." This caused a long term EPA scientist, Weston Wilson, to invoke whistle blower protection to challenge this conclusion as inconsistent with the studies and analysis presented in the body of the report and to have been politically vetted by the White House. Wilson accused the EPA of cherry picking data as well as the interference in the wording of the summaries and conclusions.

Also remember that this 2004 report which looked at impacts to drinking water sources of fracking to produce methane from coal beds not deep drilling or deep drilling into

shale with horizontal drilling and high volume hydraulic fracturing was, however, used to persuade congress to pass the 2005 Energy Policy Act (link to searchable pdf..http://www.gpo.gov/fdsys/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf) that exempted all gas and oil 'exploration and production' regardless of methodology from that list of protective legislations above.

In the 2004 report, EPA was complicit in the distortion of science to conclude that hydraulic fracking is safe for drinking water sources. In the current draft report, EPA is attempting once again to ignore the science and their own data. This SAB panel has the chance to speak clearly about the science and be true to their ethical and moral obligations to act on truth and not political lobbying wishes. The removal of Dimock PA, Pavillion WY and Parker County TX from the report is also a parallel to the 2004 report that should not be repeated.

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Hydraulic Fracturing and Safe Drinking Water Act Regulatory Issues

Mary Tiemann
Specialist in Environmental Policy

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July 13, 2015

Congressional Research Service
7-5700
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R41760

CRS REPORT
Prepared for Members and
Committees of Congress

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.

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[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.

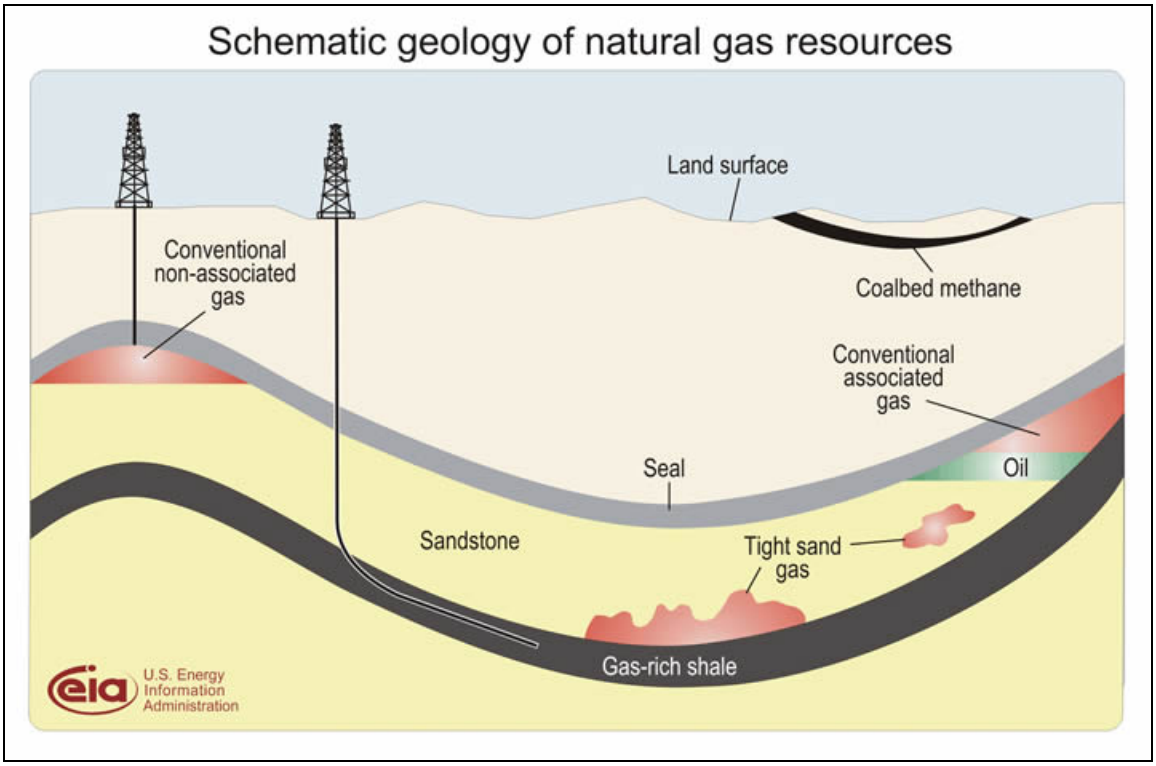
[10] U.S. Energy Information Administration, *Annual Energy Outlook 2014*, May 7, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=16171.

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

(...continued)

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]

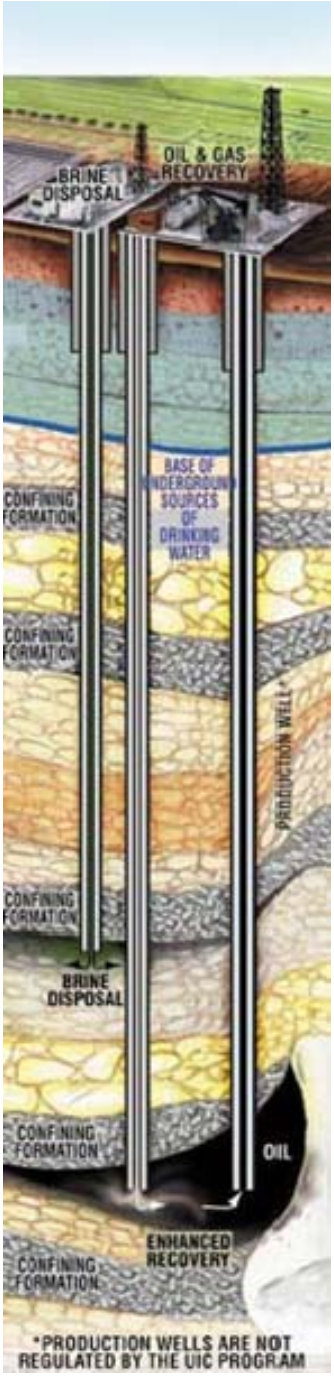
Class II wells may be used to dispose of brines and other fluids associated with oil and gas production or storage, to store natural gas, or to inject fluids for enhanced oil and gas recovery. Enhanced recovery (ER) wells inject brine, water, steam, polymers, or carbon dioxide primarily into oil-bearing 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.

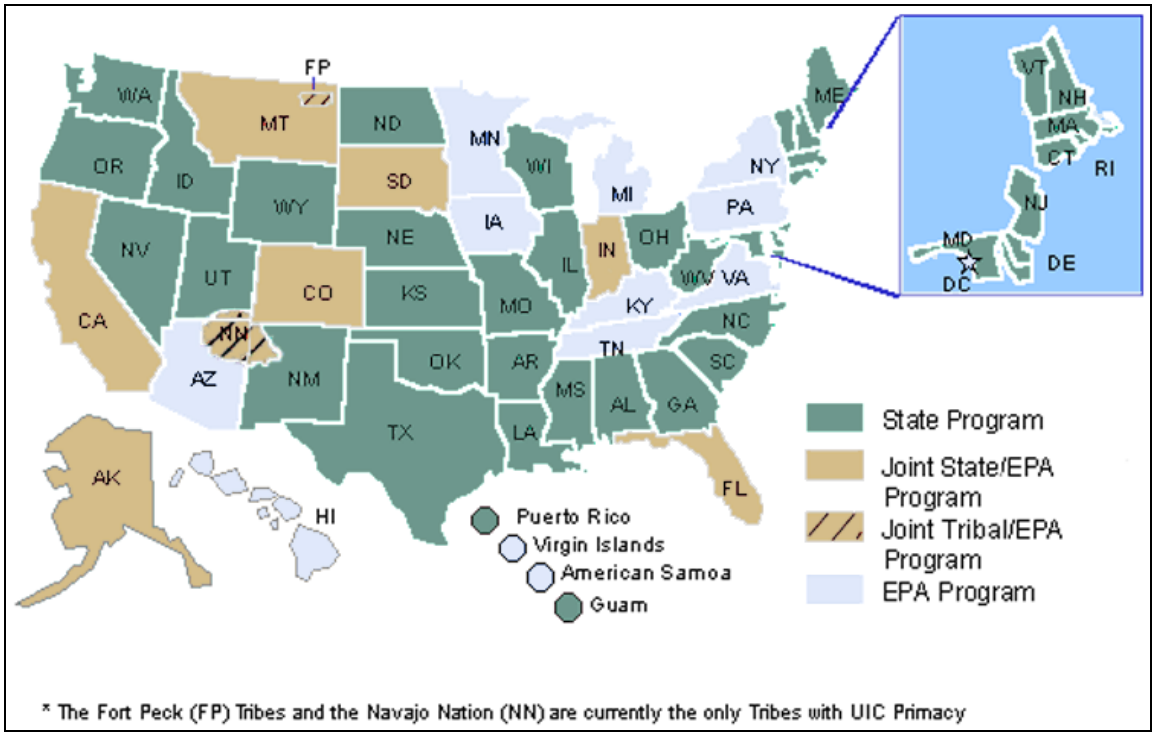
[45] This discussion excludes EPA's new Class VI well category for geologic sequestration of carbon dioxide.

[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,

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[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.

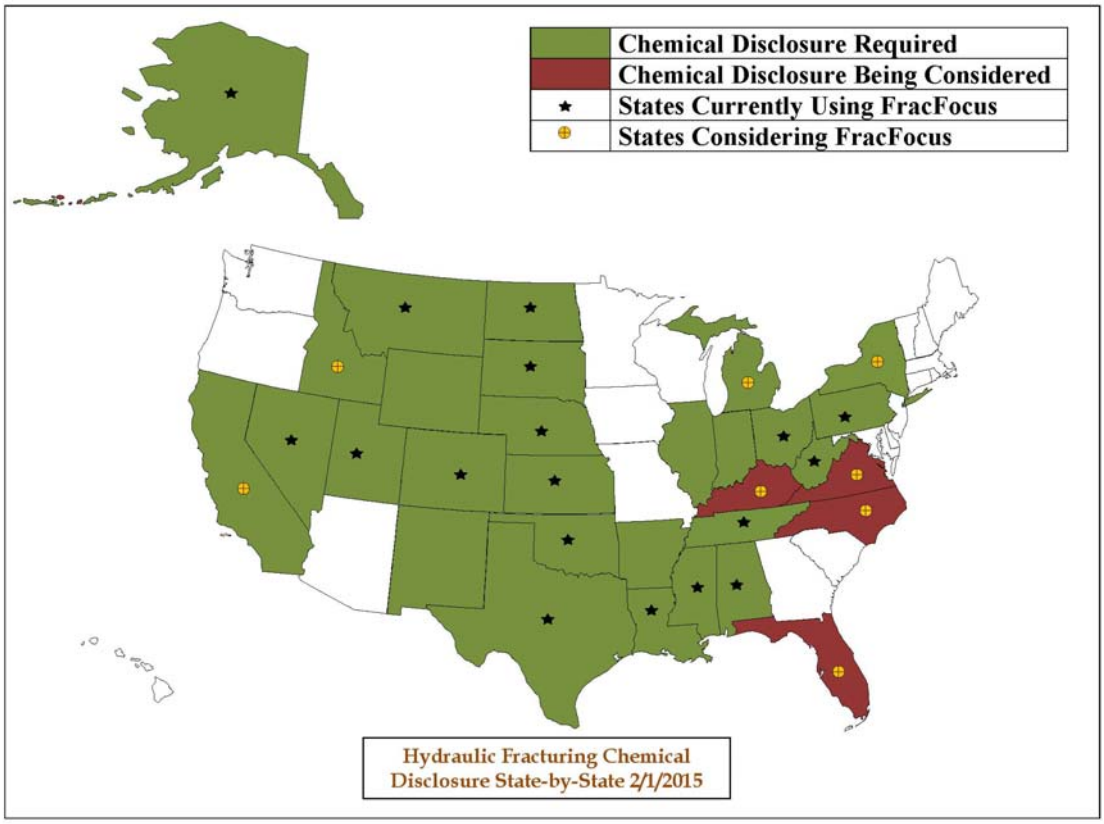
Requirements for chemical disclosure are widely viewed as beneficial. The lack of information regarding chemicals used in hydraulic fracturing has made investigations of groundwater

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

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[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

[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.

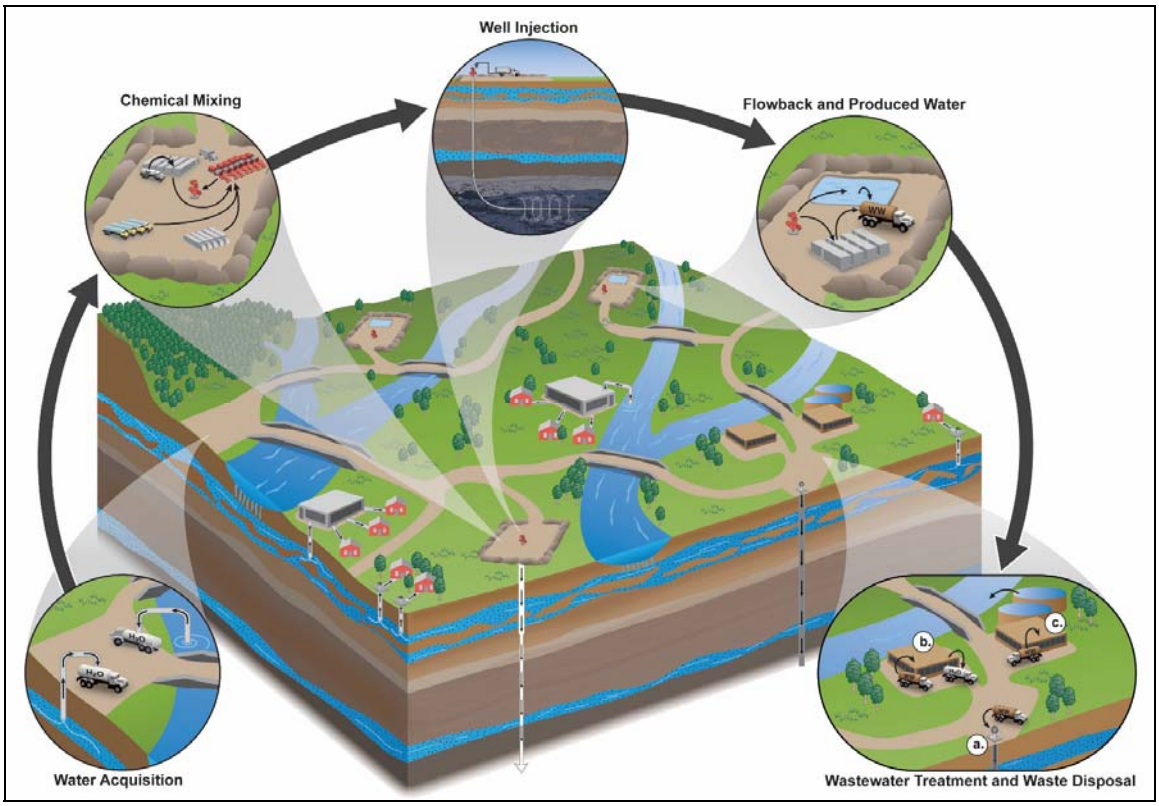
[112] EPA, *Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources (External Review Draft)*, June 2015, http://www2.epa.gov/hfstudy/hydraulic-fracturing-study-draft-assessment-2015.

[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.

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LOOPHOLES FOR POLLUTERS –
The oil and gas industry's exemptions to major environmental laws

Loopholes: The oil and gas industry is exempt from key provisions of seven major federal environmental laws — allowing practices that would otherwise be illegal. Some exemptions date back decades. Others were adopted as recently as 2005.

While states and tribes have tried to fill the gaps with their own rules and regulations, they vary widely in effectiveness and enforcement. Federal laws provide consistent standards that equally protect all Americans. That's why it's essential to reverse these federal loopholes.

1. The Safe Drinking Water Act – SDWA

The Safe Drinking Water Act[1] (SDWA) of 1974 was established to protect America's drinking water. It covers waters actually or potentially designated for drinking, whether from above ground or underground sources.

The Energy Policy Act of 2005 exempted hydraulic fracturing (fracking) from SDWA[2] oversight, leaving drinking water sources in the 34 oil and gas producing unprotected from the host of toxic chemicals used during fracking. Congress qualified this exemption to regulate diesel fuel additives used during fracking, which requires industry to apply for a SDWA permit if they are using diesel fuel to hydraulically fracture a well.

2. The Clean Air Act – CAA

The Clean Air Act[3] (CAA), adopted in 1970, is the comprehensive federal law that regulates air emissions from area, stationary, and mobile pollution sources. The CAA established limits for major pollution sources called the National Emission Standards for Hazardous Air Pollutants (NEHAPS)[4]. NEHAPS must be met by installing the Maximum Achievable Control Technology (MACT) for each source.

Smaller sources of pollutants that are under common control by a single operator, are located in close proximity to each other, and perform similar functions are considered as one source of emissions. This aggregation allows for the CAA oversight of smaller sources that, when concentrated, may actually be as harmful as larger sources.

Unfortunately, the CAA exempts oil and gas wells, and in some instances pipeline compressors and pump stations, from aggregation. This exemption to the aggregation requirement allows the oil and gas industry—which often operates many small facilities in one area—to pollute the air while being largely unregulated under the CAA.

In addition, in 1991 hydrogen sulfide was removed from the list of Hazardous Air Pollutants under the CAA. This elimination has remained despite a 1993 EPA study, *Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas,* which clearly concludes that accidental releases of hydrogen sulfide during oil and gas development are a serious air quality concern and pose a great risk to public health. Common symptoms of exposure to low levels of hydrogen sulfide can include headache, skin complications, respiratory problems and system damage, confusion, verbal impairment, and memory loss.

3. Clean Water Act – CWA

Enacted in 1972 , the Federal Water Pollution Control Act[5], commonly known as the Clean Water Act (CWA), establishes the basic structure for regulating discharges of pollutants into the waters of the United States.

In 1987, Congress amended the CWA to require EPA to develop a permitting program for storm-water runoff — but exempted oil and gas production[6].

The 2005 Energy Policy Act amended the CWA to redefine sediment as a nonpollutant. This redefinition broadened the existing exemption for storm-water discharges to oil and gas construction. These exemptions leave streams and rivers in high oil and gas areas unprotected from sediment run-off caused by the construction and operation of well pads, pipelines, drill rigs,

The oil and gas industry is exempt from key provisions of seven major federal environmental laws — allowing practices that would otherwise be illegal.

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LOOPHOLES FOR POLLUTERS –
The oil and gas industry's exemptions to major environmental laws

4. Resource Conservation and Recovery Act – RCRA

Adopted in 1976, the Resource Conservation and Recovery Act[7] (RCRA) is the principal federal law that governs the disposal of solid and hazardous wastes. The law takes a "cradle to grave" approach to ensure that wastes are handled properly from the point of creation to transport to disposal.

In 1980, Congress exempted oil field wastes (which includes waste from natural gas production) from RCRA[8] until EPA proved they were a danger to human health and the environment. Rather than do so, EPA eventually ceded authority to regulate these wastes to the states.

This exemption leaves produced water, drilling fluids, and hydraulic fracturing fluids from oil and gas production unregulated under the nation's premier hazardous waste law. This allows unsafe handling of toxic substances, including their conventional transport on roads and treatment in municipal rather than specialized facilities.

5. Comprehensive Environmental Response, Compensation, and Liability Act – CERCLA

Commonly known as the "Superfund" law, the Comprehensive Environmental Response, Compensation, and Liability Act[9] (CERCLA) of 1980 makes liable those responsible for a spill or release of a hazardous substance into the environment.

Included in the list of hazardous substances under CERCLA are benzene, toluene, ethylbenzene, and xylene (Btex)– chemicals found in crude oil and petroleum.

Yet CERCLA exempts these substances from liability requirements if they are found in crude oil and petroleum[10] (which are used in natural gas production). Thus, hazardous chemicals that would otherwise be regulated under CERCLA are immune from the statute. The definition of hazardous substance also excludes natural gas, natural gas liquids, liquefied natural gas, and synthetic gas usable for fuel.

In addition, Superfund allows "Potentially Responsible Parties" to be held liable for clean-up costs for a release or threatened release of a "hazardous substance." But CERCLA defines this term to exclude oil and natural gas. Consequently, industry has little incentive to clean up its hazardous waste, or to minimize leaks and spills, in part because the exemption allows companies to escape liability when these problems occur.

6. National Environmental Policy Act – NEPA

The National Environmental Policy Act[11] (NEPA) of 1970 establishes the broad national framework for protecting our environment. NEPA's ensures the federal government gives proper consideration to the environment before undertaking any major federal action (including involvement in industrial projects) that significantly affects the environment.

The Energy Policy Act of 2005 stripped NEPA's strong requirements for public involvement and environmental review when it comes to several oil and gas related activities[12]. It stipulated that they should be analyzed and processed by the Interior and Agricultural Departments under a much narrower and weaker process known as a "categorical exclusion[13]" (CE), as opposed to the more comprehensive and stringent Environmental Assessment[14] (EA) or Environmental Impact Statement[15] (EIS) required under NEPA. In addition, a CE does not allow for any public comment. In 2006 and 2007, the BLM granted this exemption to about 25 percent of all oil and gas wells approved on public land[16] in the West.

7. The Toxic Release Inventory of EPCRA

The Toxic Release Inventory[17] (TRI) was created by section 313 of the Emergency Planning and Community Right-to-Know Act[18] (EPCRA) of 1986. It requires most industries to report significant of toxic substances to the EPA, which then aggregates and disseminates the information to the public.

The information on chemical use and release includes point and fugitive onsite air releases, water releases, on and off-site land releases, underground injection, transfers to a Publicly Owned Treatment Works (POTW) or waste management facility (including the name and address of the facility), and the use of specific on-site waste treatment and management practices.

But despite their use of toxic chemicals throughout production, oil and gas facilities are not required to report to the TRI[19]. This exemption leaves communities in oil and gas producing areas in the dark about what chemicals are being released—making it difficult to attribute responsibility and seek remedy for resulting health and environmental problems.

Sources

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Introduction to Submissions by Damascus Citizens for Sustainability to the EPA ORD Team Conducting the Study of the Impacts of Hydraulic Fracturing on Drinking Water Resources and to the SAB Panel Providing Oversight to the Study Team

Damascus Citizens for Sustainability (DCS) has participated in this study by the Office of Research and Development and the Science Advisory Board oversight panel since the inception of the study. In response to the document request to the public, DCS submitted copies of many scientific papers, articles, and other written materials to the ORD docket for this study and to the SAB panel in November 2013. After further discussions with members of the study team, the docket office and the SAB staff, DCS has organized the documents submitted into eight different folders that group the submitted documents into topic categories. DCS has also submitted a few additional documents that are relevant to the study and only became available after the November submission date.

As you review these documents, please keep in mind that the various documents were initially submitted as attachments to email messages. In many instances there were two or more documents attached to a single email. We have attempted to place each email and its attachments in the most appropriate topic folder, but in a few instances the attachments are relevant to more than one folder. In these cases, we have included such emails and attachments in each relevant folder at the risk that there will be duplications. As you review the contents of each folder, it is fairly easy to determine which attachments are relevant to the topic folder you are considering. Another thing to keep in mind during your review is that the folder topics are interrelated so that a particular document may be relevant to multiple topics. For example, a paper about groundwater contamination may be connected to the toxicity of chemicals and constituents of fracturing and produced fluids and to public health impacts while also relating to well construction and operation issues. These relationships among the various topics are essential to understanding the overall drinking water resources risk picture related to high volume hydraulic fracturing gas development.

Finally, we have attempted to keep our commentary about how to interpret these materials to a minimum. Instead, we believe it will be most useful to this study to let the materials speak for themselves. We will continue to update our submissions to you as new relevant materials become available. As you review these materials we suggest that you expand the "Name" section of the display by dragging the double arrow link between the "Name" and "Date" columns so that the display shows the full file name. This helps considerably in selecting the document of interest to you.

The Dropbox folder is accessible from this link:
https://www.dropbox.com/sh/vfk5vbgovezgn9k/I1EUZ4QZnY

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OIL AND GAS:

Drilling's safety exemptions and how they got there

Mike Soraghan, E&E reporter

EnergyWire: Tuesday, November 4, 2014

In 1983, troubled by the high death rate in the oil field, the Occupational Safety and Health Administration set out to impose a set of worker safety rules on drilling companies.

The effort backfired. As OSHA officials ushered the proposal through the process, they agreed to exempt drilling from other new rules on noise protection, machine safety and preventing explosions. Those topics, they said, would be covered in the pending oil and gas rulebook.

But when that proposal died, drilling companies wound up exempt from a suite of basic worker protections.

"It's mind-boggling to me how many safety standards they're exempt from," said Dennis Schmitz, a trainer who leads the MonDaks Safety Network, a group of safety officials from companies in the Bakken Shale region. "What's the culture that creates?"

In the 30 years since the drilling regulations were proposed, the industry's death rate regularly has been among the highest in the United States. Current and former OSHA officials say the exemptions and the absence of the drilling regulations left safety inspectors with fewer tools to police an industry heavy with "unique hazards."

SPECIAL SERIES

An investigation of the drilling industry's worker safety record and what it means for those living amid the boom. **Click here** to read the series.

And as petroleum production pushes into more populated areas, public health experts say the risks for those who live and work nearby remain poorly understood.

Industry leaders, though, say oil companies take safety seriously.

"We welcome strong regulation," American Petroleum Institute President Jack Gerard said last year after a speech on industry standards. "We resist duplicative, contradictory, confusing regulation. There's an important difference between the two in terms of our ability to operate."

That ability to operate was under threat in late 1983, according to industry leaders at the time.

OSHA, created in 1970, had originally tried to regulate oil and gas under its construction standards. But industry challenged that, and OSHA gave up on the idea after it lost a series of enforcement cases.

Still, fatalities were mounting. Records show there were at least 459 deaths at drilling work sites from 1977 to 1981, an average of 92 a year.

In the early '80s, OSHA began work on a new, separate set of rules, called a "standard," for oil and gas drilling. The rule was formally proposed in late 1983, during President Reagan's administration. In the *Federal Register* on Dec. 28, 1983, the agency laid out a stark rationale linking lack of regulation to worker deaths.

"OSHA believes that the current general industry standards inadequately address the unique hazards encountered during drilling," agency officials wrote. "OSHA believes this lack of adequate regulatory protection has contributed to the high number of deaths and injuries in this industry."

The drilling standard was to cover a wide variety of topics, from blowout preventers to hydraulic fracturing to how many employees had to be trained in first aid.

OSHA said at the time that some oil companies supported the proposal because they wanted a clear and consistent set of rules.

But industry lobby groups in Washington showed no such interest. They fought the rule hard even before it was formally proposed. They said it was too expensive. They preferred their own voluntary programs.

Federal Register / Vol. 48, No. 250 / Wednesday, December 28, 1983 / Proposed Rules 57283

California, Kentucky, and the United General Insurance Company. OSHA found this input helpful in developing this proposal.

OSHA believes that the current general industry standards inadequately address the unique hazards encountered during drilling, servicing and the performance of special services operations on oil and gas wells. OHSA believes this lack of adequate regulatory protection has contributed to the high number of deaths and injuries in this industry. Additionally, the frequent issuance of general duty citations by OSHA compliance officers is further evidence of the inadequacy of current regulations.

The Occupational Safety and Health Administration set out to impose a set of worker safety rules on drilling companies in 1983. To see the original *Federal Register* notice, click **here**.

"It would require a number of major modifications to all rigs at a cost of millions of dollars for no real safety benefit," Roy Carlson, production director at the American Petroleum Institute, wrote to OSHA in February 1983. "We see little likelihood that the current draft would improve safety beyond voluntary programs already developed in the industry."

Some executives conceded that injuries had gone up during a drilling boom that started in 1979. But they said the industry was improving safety on its own.

"We agree that accident rates are high with respect to general industry, but it has not been established that rates are disproportionately high for the kind of work involved," H.B. Barton, regulatory affairs manager for Exxon Co. USA, wrote in May 1984. "Continual progress is being made toward reducing accident frequency as a direct result of efforts within the industry."

The industry resistance was effective. OSHA announced in 1985 that it would start over and rewrite the proposed rules. Officials in the Reagan White House said OSHA had understated the costs and said "extensive changes" were needed. After that, interest dwindled. But the proposal remained on the books through the administrations of Presidents George H.W. Bush and Clinton.

OSHA finally pulled the plug in 2001, in the early days of the George W. Bush administration.

Bush and then-Vice President Dick Cheney, both oilmen, led a drive to free domestic energy production from regulatory restraints. That drive led to, among other things, a ramp-up in drilling on federal lands in the Rocky Mountain West.

What's a safe speed?

Not every industry has its own specific OSHA standard. The ones that do are construction, maritime and agriculture.

Without an industry-specific standard, OSHA continued to monitor oil and gas work sites using "general industry standards," purposely vague enough to cover everything from routine office work to climbing a rig tower in the middle of the night. Inspectors enforce the "general duty" of oil and gas companies to provide a safe workplace.

OSHA officials said in 1983 that regulating oil and gas under general industry standards worked badly. Current and former OSHA officials say it's still not a good fit.

One former OSHA official compared it to a police officer patrolling a highway without a set speed limit.

"The general duty clause is like saying, 'You should drive at a safe speed,'" said R. Dean Wingo, a former assistant regional administrator. "The duty shifts to the officer to show what you were doing was unsafe."

Wingo retired last year as assistant administrator for the Dallas-based region that includes the country's top oil-producing states. However unpopular they might be with management, he said, the agency's standards save lives and keep workers from getting hurt.

"If you look at OSHA's history, where they developed standards for an industry, it has impacted that industry to improve safety and health," he said.

A 'powerful lobby'

There are OSHA standards that do cover work at well sites. Oil and gas crews, for example, must follow the standard covering electrical work. But industry is exempt from several standards other industries must follow. Most of those exemptions trace back to accommodations made while the drilling-specific standard was pending.

The first exemption was from "hearing conservation" rules that protect workers' hearing at loud sites.

"A combination of factors, including tremendous variation in working conditions, high mobility of operations, extremely high employee turnover rate, and limited accessibility of many worksites convinced OSHA that employees would be better served by developing a standard more specifically tailored to the needs of this industry," the agency wrote at the time.

There were noise protection provisions in the drilling-specific rules, but they fizzled along with the broader proposal.

The same decision was made on machine safety rules called "lockout-tagout" or "LOTO." The rules require machines to be turned off when being serviced so that people, or their limbs, don't get caught in them.

Inspectors can still cite oil and gas companies that don't employ lockout-tagout procedures. The American Petroleum Institute has a standard they're expected to follow.

In practice, though, Schmitz says the exemption creates a Catch-22. The oil companies that own the wells don't develop LOTO procedures for their equipment, because they're exempt. But most of the work is done by contractors. They're supposed to follow lockout-tagout, but frequently there are no procedures for the operators' equipment.

"The folks that are dying out there are contractors," said Schmitz, chairman of the MonDaks safety group of companies operating in Montana and North Dakota, and a regional manager and safety trainer for PEC Safety.

Explosions cause an unusually high number of deaths in the oil field (***EnergyWire***, Oct. 20). OSHA's standard for preventing industrial explosions is called "Process Safety Management." The standard was enacted in the early 1990s after a series of deadly disasters at refineries and chemical plants. "PSM," as it's called, requires employers to put systems in place for dealing with highly hazardous chemicals.

In the realm of oil and gas, it requires increased scrutiny of hydrogen sulfide, one of the best-known killers in the oil field (***EnergyWire***, Oct. 21). It also requires employees to follow set procedures before lighting a blowtorch and welding, the cause of many explosions in the oil and gas field.

As with the noise rules and lockout-tagout, drilling was exempted from PSM in anticipation of the industry-specific standard.

After wells are drilled and start flowing with oil or gas, they become production sites that fall under the PSM rules. But OSHA exempted most well sites because companies don't keep employees there, and they're considered "remote."

But remote means separate from a company's other operations, not distant from people. They can be close to subdivisions, houses and businesses and still be exempt.

"Urban drilling, I think, should require the regulatory agencies to take a hard look at public safety," Wingo said. "It really isn't [OSHA's] jurisdiction to address this issue, but no other government agency has stepped up to address these concerns."

Oil and gas is also exempt from OSHA's general standard on exposure to benzene, which can cause cancer. Under that standard, the limit for workers' exposure is 1 part per million. For oil and gas drilling, it is set at 10 ppm.

Federal safety exemptions for oil and gas drilling

Oil and gas drilling sites are exempt from the following federal safety provisions:

OSHA

• Process safety management of highly hazardous and explosive chemicals.

• Includes provisions on welding and hydrogen sulfide.

• Benzene general exposure limit -- 1 ppm. The limit is 10 ppm at well sites.

• Noise rules -- oil and gas is exempt from monitoring and testing requirements.

• Lockout-tagout (requires that the power be cut to machines being serviced).

EPA

• Clean Air Act rules requiring a risk-management plan for sites with "extremely hazardous substances."

• Clean Water Act spill control provisions requiring chemical storage tank facilities to be fenced and locked.

DOT

• Drivers of vehicles used exclusively to service oil and gas wells are not required to count waiting time at the well site toward their on-duty hours for hours-of-service regulations.

-- Mike Soraghan

Oil and gas was exempted because exposure to the chemical was considered more likely to be a problem at refineries, Wingo said, not because of the planned drilling rules.

Some workers at well sites are getting exposed to troubling levels of benzene, according to the National Institute for Occupational Safety and Health. The agency reported last summer its researchers found that well site workers who measure tanks get exposed to levels of benzene higher than NIOSH-recommended limits, and high amounts of volatile organic

compounds (VOCs). And there are indications that several Bakken Shale workers might have been killed by VOCs at well sites (***EnergyWire***, Oct. 27).

"The petroleum people have a very powerful lobby," said Mark Kaszniak, senior recommendation specialist with the U.S. Chemical Safety Board, an independent agency that has investigated numerous oil and gas accidents. "And they are particularly powerful in making sure the regulators give them exemptions in 'upstream' areas where they're getting the oil and gas directly out of the ground."

The oil and gas industry ranks sixth among industries for the amount it spends lobbying the federal government, according to OpenSecrets.org. Since 1998, companies have spent more than $1.6 billion to lobby the federal government.

'You have a higher burden to prove'

Eric Brooks navigates this maze of rules and exemptions every day.

From his neatly organized desk in downtown Bismarck, N.D., adorned in front with the Labor Department seal, he oversees workplace safety in one of the most dangerous places in the country for workers: the Bakken Shale.

Once an inspector here, he is now OSHA's area director for North and South Dakota. He has watched the shale drilling boom transform rural North Dakota into a major oil producer, boost employment and double the state's rate of worker deaths.

North Dakota had the highest fatality rate in the nation in 2012 (17.7 per 100,000 workers), according to an AFL-CIO report. That was five times the national average. The death rate for North Dakota's oil and gas production sector was 104 per 100,000 workers, more than 30 times the country's average fatality rate.

As the deaths mounted, OSHA's presence in the Dakotas shrank. In 2008, OSHA had seven inspectors in the Dakotas. Retirements, a federal pay freeze and soaring housing costs across the state combined to erode manpower. In 2012, Brooks said, there were four full-time inspectors and a trainee.

"That 2011 and 2012 was a trying time for everyone," Brooks said. "I think we're past that. I hope we're past that."

The number of inspectors has since risen to nine, and the agency is bringing in rotating teams for special enforcement sweeps. Fatalities declined in North Dakota last year.

But with the exemptions and the lack of a specialized standard for drilling, the inspectors Brooks does have face a host of hurdles.

Using the general duty clause, he said, makes it "exponentially" harder to bring a case.

Inspectors can't cite minor violations under general duty. Citations must be for "serious" hazards that would likely result in death or serious physical harm. In some cases, an inspector must get a Labor Department attorney to sign off before issuing a general duty citation. And for that attorney, general duty cases are more difficult to resolve, because the "serious" violations can't be bargained down in a settlement.

"It does take a lot more," Brooks said. "You have a higher burden to prove."

Still, in a safety sweep across the Bakken in the spring of 2013, inspectors cited violations in 50 percent of the wells they visited. Another group of inspectors, called a "health response team," is in the Bakken this week, Brooks said, "conducting focused inspections" at oil and gas sites.

But he said the heavy use of "general duty" violations is an indication the rules aren't keeping up, and haven't been for a long time.

Brooks keeps a yellowing copy of the *Federal Register* from Dec. 28, 1983, on the corner of his desk. He picks it up and reads the assessment of the drilling industry and OSHA's role in regulating it.

"OSHA believes that the current general industry standards inadequately address the unique hazards encountered during drilling," he says. "OSHA believes this lack of adequate regulatory protection has contributed to the high number of deaths and injuries in this industry." And he pauses.

"That's a great quote," Brooks says, "that still rings true today."

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October 8, 2004

Weston Wilson
EPA Employee
Denver, Colorado

Honorable Wayne Allard
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Englewood, Colorado 80111

Honorable Ben Nighthorse Campbell
6950 E. Belleview Avenue, Suite 200
Greenwood Village, Colorado 80111

Honorable Diana DeGette
600 Grant Street, Suite 202
Denver, Colorado 80203

Dear Senators Allard and Campbell and Representative DeGette,

Recent events at EPA have caused me and several of my peers at EPA great concern. In June of this year, EPA produced a final report pursuant to the Safe Drinking Water Act that I believe is scientifically unsound and contrary to the purposes of the law. In this report, EPA was to have studied the environmental effects that might result from the injection of toxic fluids used to hydraulically fracture coal beds to produce natural gas. In Colorado, coal beds that produce natural gas occur within aquifers that are used for drinking water supplies. While EPA's report concludes this practice poses little or no threat to underground sources of drinking water, based on the available science and literature, EPA's conclusions are unsupportable. EPA has conducted limited research reaching the unsupported conclusion that this industry practice needs no further study at this time. EPA decisions were supported by a Peer Review Panel; however five of the seven members of this panel appear to have conflicts-of-interest and may benefit from EPA's decision not to conduct further investigation or impose regulatory conditions.

As these matters are complex, I enclose a technical analysis to further inform you and other members of Congress. I invoke the protections under the First Amendment of the Constitution and the Whistleblowers Protection Act should EPA retaliate against me as a result of speaking with you or other members of Congress or speaking to the press or the public regarding this matter.

I am a resident of Denver in the first Congressional District of Colorado and I am employed by the Environmental Protection Agency in Denver. I have been employed by the EPA's Regional Office in Denver, since 1974. I am currently assigned to the Office of Ecosystems Protection and Remediation, National Environmental Policy Act (NEPA) Team. I am an environmental engineer assigned to assist EPA with its responsibilities under Section 309 of the Clean Air Act to independently review federal agency's compliance with NEPA. Currently I analyze the environmental impacts of coal mining, gold mining, and oil and gas development on public lands. I serve as the Legislative Advocate for the American Federation of Government Employees Local 3607 representing professional and non-professional employees in EPA Region 8. I have also served as the President of Local 3607 in the past.

EPA's failure to regulate the injection of fluids for hydraulic fracturing of coal bed methane reservoirs appears to be improper under the Safe Drinking Water Act and may result in danger to public health and safety. I respectfully request that you investigate this matter and respond as you and other members of Congress deem appropriate.

Sincerely,

Weston Wilson

Enclosure: EPA Allows Hazardous Fluids to be Injected into Ground Water, A report on EPA's failure to protect America's ground water from the impacts of oil and gas production, Weston Wilson, October 7, 2004, 18 pages.

cc: Representative Bob Beauprez
Representative Joel Hefley
Representative Marilyn Musgrave
Representative Scott McInnis
Representative Thomas Tancredo
Representative Mark Udall
EPA Office of the Inspector General

EPA Allows Hazardous Fluids to be Injected into Ground Water

A report on EPA's failure to protect America's ground water
from the impacts of oil and gas production

A technical analysis by Weston Wilson, an employee of the U.S. Environmental Protection Agency

October 8, 2004

Abstract

EPA has established that: 1) coal bed methane hydraulic fracturing occurs within underground sources of drinking water, 2) hydraulic fracturing fluids contain toxic components that are not entirely removed during methane gas production, and 3) this fracturing process can create pathways which allow methane to migrate into high quality ground water. The industry's practice of hydraulically fracturing coal bed reservoirs could endanger underground sources of drinking water and render these aquifers unusable as a future drinking water supply. Therefore, the industry practice of hydraulic fracturing of coal beds should be investigated further by EPA and, if found harmful, or potentially harmful, to ground water and other resources, should be regulated by EPA throughout the United States.

Disclaimer

The views and opinions contained in this report are not those of EPA. I am solely responsible for all information contained in this report. I was not involved in either the preparation or review of EPA's report on the hydraulic fracturing of coal bed methane reservoirs.

I request the rights granted under the first amendment to the United States Constitution and assert protection under the Whistleblowers Protection Act should the Environmental Protection Agency retaliate against me for speaking to members of Congress or speaking to the press or speaking to the public about the matters contained herein.

Weston Wilson, October 8, 2004

A. Author's conclusions about EPA's failure to protect ground water

In June 2004, EPA's Office of Water in Washington, D.C., completed a study on the potential effects to underground sources of drinking water resulting from the industrial practice of hydraulically fracturing coal bed reservoirs to produce methane. EPA concluded this practice poses little or no threat to underground sources of drinking water and does not warrant additional site-specific investigations. As a result of this conclusion, EPA will not regulate this activity anywhere except in the State of Alabama where a federal court ordered that EPA must do so.

Despite EPA's conclusions that this practice poses little or no threat to underground sources of drinking water, EPA obtained a national agreement from three oil and gas industry service companies indicating that these companies would stop injecting hydraulic fracturing fluids containing diesel fuel into coal bed reservoirs with good quality water. EPA has not sought to restrict other entities or any of the other toxic components of the fracturing fluids.

Some formulations of the hydraulic fluids used to fracture coal bed reservoirs are considered proprietary information by the oil and gas industry service companies. Because this information has been kept confidential as proprietary information, the public does not have access to information to determine whether these materials could endanger underground sources of drinking water.

Coal bed hydraulic fracturing, a method used to produce natural gas, may introduce toxic materials such as acids, benzene, toluene, ethyl benzene, xylene, formaldehyde, polyacrylamides, chromates, and other toxic components into underground sources of drinking water. Because it 'fractures' coal beds, hydraulic fracturing can also create new pathways for methane migration into aquifers containing good quality ground water, and thus into privately-owned water wells and community water supplies.

Except in Alabama, neither EPA nor the States regulate the type or quantity of toxic fluids used to fracture coal beds to produce methane. The toxic components of these fracturing fluids are not reported to any regulatory authority or to the public.

B. Hydraulic fracturing of coal bed reservoirs improves natural gas production

Natural gas, or methane, is adsorbed within coal beds. Natural gas can be produced after overlying ground water has been pumped out reducing the fluid pressure that holds the natural gas in place. Hydraulic fracturing in coal beds is the process of pumping thickened fluids into a well at a rate that exceeds the capacity of the coal bed to accept them. A large capacity pump is used to increase the pressure of the injected fluid which results in cracks or fractures, allowing a path to move the injected fluids along these newly formed fractures. The hydraulic fluid often contains propping agents, usually silica sand particles, which hold the fractures open after the pressure is released. While hydraulic fracturing of oil and gas found in conventional geologic traps is well established, hydraulic fracturing of coal beds is relatively new.

According to the Gas Technology Institute, natural gas from coal beds produced approximately 1.3 trillion cubic feet of natural gas in 2000. The Department of Energy estimates that approximately six percent of the U.S. total natural gas production in 2000 was obtained from coal beds and predicts this percentage will increase in the future.[1]

Natural gas is produced from nine coal basins in the United States, from Alabama to Montana, and is being explored in Alaska. Oil and gas service companies inject fluids for hydraulic fracturing of coal beds in Colorado, New Mexico, Utah, Wyoming, Montana, West Virginia, Virginia, Kentucky, Arkansas, Oklahoma, and Alabama. Approximately seventy percent of the total U.S. coal bed methane production is derived from the San Juan Basin in Colorado and New Mexico.

Unlike natural gas developed from conventional oil and gas deposits, geologic formations which contain coal bed methane can be near the surface where ground water may used as a source of drinking water supplies. Conventional oil and gas occurs in geologic traps that are usually associated with deep (generally over 1000 feet deep) and typically highly saline ground water that is unsuitable for drinking water. Enhanced recovery techniques used to develop conventional natural gas and oil in deep geologic structural traps, including fracturing the rock

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[1] Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, Appendix A, Department of Energy – Hydraulic Fracturing White Paper, EPA Drinking Water Protection Division, Final Report, June 2004, page App. A-1. http://www.epa.gov/safewater/uic/cbmstudy.html

to allow more oil and gas to flow, are thus less likely to risk damage to usable ground water supplies. Although the practice of hydraulic fracturing has been used in the recovery of conventional oil and gas since the 1950s, this practice has been applied for recovery of coal bed methane only since the mid-1990s. And only in the last few years has the industry begun the injection of fluids to conduct hydraulic fracturing in aquifers that supply, or could supply, community and individually-owned drinking water wells.

C. EPA decisions are not consistent with the findings of its study nor have EPA decisions complied with the purposes of the SDWA

In EPA's June 2004 final report and court-directed decisions, EPA has acknowledged the following.

* Hydraulic fracturing fluids are injected into underground sources of drinking water and these fluids contain substances that are toxic and carcinogenic. (EPA apparently takes the position that the composition of these fluids may be propriety information and EPA was unable to find complete chemical analyses of these hydraulic fracturing fluids in the literature.)

* The primary function of these wells is to produce methane from coal beds; therefore, and not to inject fluids underground. Therefore, in EPA's opinion, these wells are not subject to the regulatory provisions of the Safe Drinking Water Act. (A federal appeals court has rejected that position as inconsistent with the Safe Drinking Water Act.)

* There is no further need for EPA to investigate the practice of hydraulic fracturing in coal bed methane reservoirs. (But EPA recognizes there is a lack of field water quality data regarding the fate of the substances in the hydraulic fracturing fluids within these sources of drinking water.)

* In the San Juan Basin of Colorado following coal bed methane production, unwanted methane gas has migrated into underground sources of drinking water from unplugged oil and gas wells. (But EPA did not investigate whether pathways created by hydraulic fracturing may contribute to methane contamination or contamination associated with fracturing fluids in underground sources of drinking water.)

Further, EPA actions do not appear to be based on objective and impartial information.

* EPA relied upon an external peer review panel that supported EPA's findings and conclusions. (However, five of EPA's seven-member Peer Review Panel appear to have conflicts-of-interest.)

* EPA utilized a seven-member Peer Review Panel composed only of external experts. (EPA's Peer Review Panel members did not achieve the needed balance of interests by including EPA professional staff with knowledge and expertise on these matters. Further, EPA did not include its most experienced professional staff to participate and prepare EPA's study of the impacts of this industry practice.)

* EPA obtained a national agreement from three oil and gas service companies to cease the use of diesel fuel in hydraulic fracturing fluids in coal bed methane reservoirs. (However this agreement is voluntary and non-enforceable. EPA has no oversight of these companies to assure that diesel fuel is no longer used in hydraulic fracturing fluids in coal bed methane reservoirs.)

The following information addresses each of the above claims of improper conduct by EPA which may result in danger to public heath and safety. This information was obtained from publicly-available sources including Congress, EPA, Department of Energy, Occupational Safety and Health Administration, or from the scientific literature as noted.

1. Hydraulic fracturing fluids may contain toxic components

Hydraulic fracturing fluids consist of water, foamed liquids, thickening gels, and propping agents. Fracturing fluids used in the northern San Juan Basin, for example, include: 1) hydrochloric acid, 12% to 28% HCl with pH less than 1 to 3, 2) water mixed with hydrocarbon-based solvents such as diesel fuel, 3) gels containing guar-gum or a polymer such as polyacrylamide, and 4) cross-linked gels with 'breaker' chemicals.[2]

[2] Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, EPA June. 2004, Attachment 1 – San Juan Basin, page A1-7.

In addition to diesel fuel, which contains benzene, toluene, ethyl benzene and xylene, fluids used in coal bed methane hydraulic fracturing may also contain acids, formaldehyde, polyacrylamides[3], chromates, and other potentially toxic or carcinogenic substances.[4] These compounds can reduce viscosity after fracturing so that the gels can be pumped back to the well after treatment, impart corrosion protection for metal casings in the well, reduce bacterial growth, and have other production benefits. Because thickening gels dissolve more readily in diesel fuel than in water, using diesel fuel increases the transport of the sand propping agent in the fracturing fluids. According to EPA's findings: "Many of the compounds listed in Table A1-1 are quite hazardous in their undiluted form. However, these compounds are substantially diluted prior to injection."

Oil and gas production wells, including all coalbed methane production wells in the San Juan Basin, are permitted by either the Colorado Oil and Gas Board or by the New Mexico Oil and Gas Board. Both agencies regulate the underground disposal of coal bed methane produced water as Class II wells under the SDWA. However, based on EPA's analysis of current regulations, "neither agency regulates the type or amount of fluids used for (coal bed methane hydraulic) fracturing."[5]

Oilfield service companies, including Halliburton, Schlumberger, and JB Services Company, supply the fracturing fluids used to fracture the coalbeds as part of their service contracts. Again, according to EPA's findings: "The chemical composition of many fracturing fluids used by these service companies may be proprietary, *and EPA was unable to find complete chemical analyses of any fracturing fluids in the literature.*"[6] (Emphasis added.)

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[3] Polyacrylamide may be contaminated with acrylamide, which is a toxic substance. Polyacrylamide may also degrade in the environment to acrylamide. EPA established a limit of 500 ppm acrylamide contamination in polyacrylamide products to be acceptable for use in water treatment systems. 40 C.F.R. 141.61 See also Smith, et.al. 1996, Environmental degradation of polyacrylamides, Toxicological Sciences 35(2):121-135 and Khan, et.al. 1999, Changes in thyroid gland morphology after acute acrylamide exposure. Toxicological Sciences 47(2):151-157.

[4] Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, EPA June, 2004, Attachment 1 - San Juan Basin, Table A1-1.

[5] Ibid. Attachment 1- San Juan Basin, page A1-7 which cites the Colorado State Oil and Gas Board Rules and Regulations 400-3, 2001; and New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division Regulations, Title 19, Chapter 15, 2001.

[6] Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, EPA, June 2004, page A1-7.

2. EPA's legal position has been rejected by the only court that has considered this matter

The Safe Drinking Water Act (SDWA) is designed to protect underground sources of drinking water from contamination caused by underground injection of fluids. (See 42 U.S.C. Sections 300h to 300h-8.) The law requires EPA to promulgate regulations for states to administer these provisions of the law in order to protect underground sources of drinking water. According to EPA regulations an underground source of drinking water is an aquifer used for drinking water supply or one that is capable of being used in the future, because it contains less than 10,000 parts per million total dissolved solids and has sufficient water yield to serve as a drinking water supply.[7]

The SDWA provides the authority to EPA to regulate underground injection practices. In approving this Act, Congress directed that EPA should not prescribe unnecessary regulation on oil- and gas-related injection.

EPA determined in 2001 it would conduct a nationwide study to assess the potential of hydraulic fracturing of methane bearing coal beds to endanger underground sources of drinking water. Prior to 1997, EPA had not regulated hydraulic fracturing because it determined this process did not fall under the Underground Injection Control Program's authority under the SDWA.[8] EPA at that time believed that methane gas production wells that employed hydraulic fracturing need not be regulated pursuant to the SDWA because the principal function of these wells is methane gas production and not the underground injection of fluids.

In 1994, the Legal Environmental Assistance Foundation (LEAF) petitioned EPA to regulate this practice in Alabama under the SDWA. EPA denied LEAF's petition and LEAF litigated the matter. The Eleventh Circuit Court of Appeals ruled EPA's interpretation was inappropriate. The court stated: "[We] conclude that hydraulic fracturing activities constitute underground injection under Part C of the SDWA. Since EPA's contrary interpretation could not be squared with the plain language of the statute, we granted LEAF's petition and remanded for further proceedings." Further, the court stated that "... as LEAF correctly notes, wells used for the injection of hydraulic fracturing fluids fit squarely within the

[7] 40 C.F.R. part 144.3. http://www.epa.gov/safewater/uic/classes.html
[8] Federal Register, Volume 66, Number 146, pages 39396-39397.

definition of Class II wells. Accordingly, they must be regulated as such."[9] In 1999, Alabama amended its Underground Injection Program to include the regulation of injection of fluids for coal bed reservoir hydraulic fracturing as Class II wells under the SDWA and EPA approved.[10] The court's 1997 decision held that the injection of fluids for hydraulic fracturing is underground injection and in 2001 the court decision held that methane production wells doing hydraulic fracturing were Class II wells. Class II wells under EPA's Underground Injection Control Program regulations include wells which inject fluids for enhanced recovery of oil or natural gas.[11]

The court ordered EPA to require hydraulic fracturing for coal bed methane production to be regulated in Alabama pursuant to the SDWA. EPA has not applied the court's reasoning and interpretation of the law in any other part of the nation, nor did EPA appeal the decision by the 11th Circuit Court. EPA's decision is contrary to the only reported court decision that considered this matter. EPA appears determined to confine the 11th Circuit Court decision to only within the jurisdiction of the 11th Circuit.[12]

In 2001, in response to the 11th Circuit Court's decision and based on concerns by citizens in several states who claimed they may be affected by coal bed methane production practices, EPA proposed a three-phase study design. EPA focused its study on the impacts of the toxic substances contained in fluids used to fracture coalbeds. EPA formed a Peer Review Panel of professional reviewers to evaluate its findings. EPA did not form a federal advisory panel of citizens and other interested parties as appropriate for significant national decisions pursuant to the Federal Advisory Committee Act.

3. EPA should have conducted further investigation based on its findings

EPA proposed a study to be conducted in three phases. In its first phase, EPA conducted a fact-finding effort based on the existing literature. The intent of phase one was to identify and assess the potential threat to underground

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[9] Legal Environmental Assistance Foundation vs. United States Environmental Protection Agency, United States Court of Appeals for the Eleventh Circuit, No. 00-10381, EPA No. 65-02889-Fed. Reg., December 21, 2001. http://www.epa.gov/safewater/uic/leaf2.pdf
[10] Federal Register, Volume 64, Number 204, October 22, 1999, pages 56986-56991. http://www.epa.gov/safewater/uic/alc2.html.
[11] 40 C.F.R. part 144.6(b). www.epa.gov/safewater/contaminants/dw_contamfs/acrylami.html
[12] The 11th Circuit Court of Appeals includes Alabama, Georgia, and Florida. Coal resources are not present in either Georgia or Florida.

sources of drinking water posed by injection of hydraulic fracturing fluids into coal bed reservoirs. In the second phase, EPA planned to conduct field investigations to obtain water quality data near wells that were hydraulically fractured within or near underground sources of drinking water to determine the extent of potential risks. If the second phase of study resulted in identifying potential risks to underground sources of drinking water, EPA planned to conduct a third phase. This third study phase would have considered and analyzed various regulatory mechanisms pursuant to the SDWA to control or minimize any potential risk that EPA had determined existed based on results obtained from the second phase of study.

In phase one EPA defined two mechanisms whereby hydraulic fracturing could potentially impact underground sources of drinking water: 1) direct injection or injection where there is already a hydraulic communication with an underground source of drinking water, and 2) creation of hydraulic connections with an adjacent underground source of drinking water through fracturing mechanisms.[13] EPA should have also investigated whether this practice resulted in unwanted migration of methane because EPA had received complaints from citizens regarding methane in drinking water wells.

In phase one, EPA also investigated citizen-reported incidents of water quality degradation potentially associated with these mechanisms. Since the hydraulic fracturing practice is not regulated by either EPA or the States, this meant that the data would have to be obtained from the industry itself in order to demonstrate water quality degradation. There was no such water quality data from industry monitoring programs available in the literature.

Based on the existing literature and field visits, EPA identified seven coal basins where the industry was injecting hydraulic fracturing fluids either into, or adjacent to, an underground source of drinking water. Table A presents a summary of the water quality conditions in coal bed methane production areas.

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[13] Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, EPA, June 2004, Appendix B, Quality Assurance Plan, page App. B-5.

Table A – U.S. coal basins where hydraulic fracturing may take place into, or adjacent to, an underground source of drinking water

Coal Basin	Location by State	Coal bed reservoir used, or adjacent to, drinking water supply	Water Quality total dissolved solids (ppm)
San Juan Basin, northern and eastern edge	Colorado	Yes	180 - 3015[14]
Black Warrior Basin – western edge of basin	Alabama	Yes	50 to less than 10,000[15]
Powder River Basin	Wyoming and Montana	Yes, but hydraulic fracturing is seldom utilized	850[16]
Central Appalachian Coal Basin	Virginia, West Virginia, and Kentucky	Yes	less than 1000[17]
Northern Appalachian Coal Basin	Pennsylvania, West Virginia, Ohio, Kentucky, and Maryland	Yes	2000-5000[18]
Western Interior Basin (Arkoma Basin)	Arkansas and Oklahoma	Yes	55-534[19]
Raton Basin	Colorado	Yes	1000-2500[20]
Sand Wash Basin	Colorado and Wyoming	No	less than 10,000[21]

[14] Ibid, at page A1-4. See Table A1-1. Hydraulic fracturing fluids contain acids, formaldehyde, chromates, polyacrylamides, and diesel which contain benzene, ethyl benzene, toluene, and xylene.
[15] Ibid. at page A2-3 through A2-5. Fracturing fluids contain water and gels and may contain chromates, formaldehyde, and polyacrylamides. See Table A2-1. According to service companies there, diesel fuel is no longer used in Alabama.
[16] Ibid. page A5-8, A5-9. Hydraulic fracturing is rarely used in the Powder River Basin because it would increase groundwater flow into the coal bed methane production wells.
[17] Ibid. page A6-4, A6-5.
[18] Ibid, at page A7-3.
[19] Ibid. at page A8-3 and A8-9. Hydraulic fracturing fluids contain acids, benzene, xylene, toluene, gasoline, diesel, solvents, bleach, and surfactants.
[20] Ibid. at page A9-3. Hydraulic fracturing fluids are typically gels and water with sand propping agents.
[21] Ibid. at page A10-3. There is limited development in this basin by one company using hydraulic fracturing fluids containing gels and water with sand propping agents.

EPA received several citizen reports of cloudy water and objectionable odors in their well water after a service company had conducted hydraulic fracturing services in their neighborhood. Based on the available literature and field data in the San Juan Basin, EPA attributed citizen-reported incidents to causes other than hydraulic fracturing, including the possibility of methane migration associated with nearby abandoned unplugged oil and gas wells.

Most citizens lack the resources needed to obtain reliable water quality data for trace concentrations of hydrocarbons such as benzene which may be associated with hydraulic fracturing fluids. Citizens are also unlikely to have sampled their water supply before and after a service company conducts hydraulic fracturing in order to establish baseline conditions and causality. The industry has not reported water quality data in nearby water wells before or after hydraulic fracturing services in the existing literature.

EPA should have initiated phase two of its study because it concluded that toxic and carcinogenic substances are injected directly into underground sources of drinking water by hydraulic fracturing practices. Conducting phase two of its study would have been consistent with EPA's scientifically-valid principle established in its phase one study design. Therefore, based upon EPA's own findings, EPA should begin phase two of its intended study and conduct site-specific field analysis and independent water quality data investigations wherever hydraulic fracturing is being conducted in underground sources of drinking water.

4. <u>EPA did not investigate pathways for unwanted methane migration</u>

EPA's report acknowledges that methane has migrated into domestic wells used to supply drinking water associated with coal bed methane production, specifically in the San Juan Basin in Colorado. Methane is a highly flammable and asphyxiating gas. In confined spaces, methane at sufficient concentrations can induce unsafe conditions due to the risk of combustion or simple asphyxiation. Methane can saturate soils resulting in reduced plant growth, even killing plants and trees by depleting oxygen supply to plant roots. In the San Juan Basin of Colorado, the U.S. Department of the Interior's Bureau of Land Management provided a history of gas seeps and methane contamination of drinking water wells following citizen reports of methane in wells.[22] The composition of the gas in samples from shallow, private drinking water well was

[22] Ibid. page 6-6. See also, Bureau of Land Management, Draft Environmental Impact Statement, Southern Ute Gas Development, 1999.

analyzed to confirm the well owners' observations. The data obtained showed that the methane in approximately half of the samples appeared to have originated in the Fruitland Formation coal beds, the source of coal bed methane in the basin.[23] Methane migrated into soils near the Fruitland Formation outcrop in the northern edge of the basin resulting in dead grasses and trees. Amoco operates coal bed methane production in the San Juan Basin and decided to buy three ranches after La Plata county officials tested indoor air and found extremely high levels of methane.[24]

The1999 Bureau of Land Management report regarding the San Juan Basin attributed the following possible pathways for methane to move from a deep source to a shallow aquifer: 1) natural fractures, 2) hydraulically-induced fractures, 3) disposal of produced water from coal bed methane wells, 4) poorly constructed, sealed, or cemented conventional gas wells, 5) coal bed methane wells, 6) shallow drinking water wells, and 7) cathodic protection wells installed to protect oil and gas pipelines from corrosion.[25]

EPA's study failed to investigate that methane could travel along the pathways created by the hydraulic fracturing process. This is an especially important contamination pathway that is more likely to result from hydraulic fracturing in shallow, near-surface, coal beds. Hydraulically-induced fractures break at right angles to the least stress. In deep formations, generally greater than 1000 feet, fractures are more likely to be break vertically due to the intense overburden pressure which restrains fracturing horizontally. In shallow hydraulic fracturing locations, generally less than 1000 feet, fracturing can occur horizontally at significant distances from the well.[26] Shallow locations are most likely to include underground sources of drinking water. EPA made no attempt in its study to investigate the movement of unwanted methane as a result of hydraulic fracturing inducing such new pathways.

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[23] Ibid. page 6-7.

[24] Ibid. page 6-3. Methane threshold limit values are established by the Occupation Safety and Health Administration. See http://www.osha.gov/dts/chemicalsampling/data/CH_250700.html.

[25] Ibid. page 6-8. See also, Bureau of Land Management, Draft Environmental Impact Statement, Southern Ute Gas Development, 1999.

[26] Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, EPA, June 2004, Appendix A, Department of Energy - Hydraulic Fracturing White Paper, pages A6-A11.

5. Five members of EPA's Peer Review Team appear to have conflicts-of-interest

EPA's peer review process uses one of two forms. The review team may consist primarily of relevant experts from within EPA who have no other involvement with respect to the work product that is to be evaluated, known as the "internal peer review" process. A peer review team may also consist primarily of independent experts from outside EPA, known as the "external peer review" process. Peer review teams may also be formed with representatives of both internal and external experts.[27] For this study, EPA selected an external peer review team that did not include any EPA expert.

According to EPA's policy, external peer reviewers should be chosen to ensure an independent and objective evaluation. The affiliations of peer reviewers should be identified on the public record, so as to avoid undercutting the credibility of the peer-review process by conflicts-of-interest. EPA's policy states that peer reviewers should be free of real or perceived conflicts-of-interest or there should be a balancing of interests among peer reviewers. EPA's policy states that the matter of obtaining a fair and credible peer review, as well as maintaining the credibility of the Agency and the Agency's scientific products, is of paramount importance. EPA's managers are encouraged to assure peer reviewers do not have a legal or perceived conflict of interest that creates the appearance that the peer reviewer lacks impartiality or objectivity. According to EPA's policies, conflicts-of-interest could occur if reviewers are affected by their private interests or when the reviewers and their associates would derive economic or other benefit from incorporation of their point of view in an Agency product.[28]

Five of the seven members of EPA's Peer Review Panel formed to evaluate the impacts of hydraulic fracturing of coalbed methane reservoirs appear to have a conflict of interest. The Peer Review Panel includes three individuals employed by the oil and gas industry. These individuals may benefit from incorporation of their point of view if EPA and the States do not regulate the practice of hydraulic fracturing. Peer Review Team members with a possible financial conflict of

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[27] Peer Review and Peer Involvement at the U.S. Environmental Protection Agency, 1 EPA/600/9-91/050, March 1992.

[28] Science Policy Handbook, Office of Science Policy, U.S. Environmental Protection Agency, Office of Research and Development, December 2000, EPA 100-B-00-001, Sections 3.4.5-6. http://epa.gov/osa/spc/htm/prhandbk.pdf

interest include Ian Palmer, a petroleum engineer with BP Amoco, Buddy McDaniel, a technical advisor for Halliburton Energy Services, Inc, and David Hill, an engineer with the Gas Technology Institute. Two other members have an appearance of potential conflict of interest as a result of previous employment in the oil and gas industry including Morris Bell, an engineer with the Colorado Oil and Gas Conservation Commission who was formerly an employee of BP Amoco, and Jon Olson, an assistant professor at the University of Texas, formerly employed by Mobil Exploration. The other peer review panel members are Peter E. Clark, an associate professor at the University of Alabama, and Norm Warpinski, from Sandia Laboratories.

6. <u>EPA did not include in its Peer Review Panel any EPA expert nor did EPA include its most experienced professional staff to participate in its study of hydraulic fracturing of coal bed methane reservoirs</u>

EPA did not include on its Peer Review Team any qualified, experienced professional employed by EPA that is knowledgeable with: 1) the industries' hydraulic fracturing practices in each coal basin, 2) human and animal toxicological effects with regard to the toxic and carcinogenic components of the injected fluids, or 3) groundwater flow in these coal basins regarding the fate and transport of these fluids in these specific underground conditions. Had EPA included on its Peer Review Panel key experienced EPA staff, not directly involved in the preparation of EPA's study, it may have provided a balancing of interests among peer reviewers to achieve the goals cited in EPA's science policy.

Utilizing a Peer Review Panel composed largely of the members of the regulated industry with real or perceived conflicts-of-interest and failing to assign EPA's most experienced and independent professionals has contributed to EPA producing a decision that lacks impartiality and objectivity.

Further, EPA did not include its most experienced professional staff to prepare and review EPA's study of the impacts of this industry practice. EPA should have included as part of its team of experts preparing this study experienced professional staff including toxicologists and hydrogeologists knowledgeable about the fate and transport of trace substances associated with the ground water flow conditions unique to each coal basin.

7. Three service companies have agreed not to inject diesel fuel in hydraulic fluids used for hydraulic fracturing of coal bed methane reservoirs

In the study, EPA acknowledges that potentially hazardous substances may be introduced into underground sources of drinking water when fracturing fluids are injected into coal bed reservoirs. In particular, EPA notes that diesel fuel, if used in hydraulic fracturing fluids, could introduce toxic substances because diesel fuel contains benzene, toluene, ethyl benzene, and xylene which are toxic at low concentrations.[29] EPA has established the maximum concentration limit for benzene in drinking water at five parts per billion. Benzene is a carcinogen and therefore harmful to those who drink it.[30] EPA established goal for benzene concentrations in drinking water is not to exceed the level of analytical detection which is less than one part per billion.[31]

Based on its June 2004 study, EPA concludes that the practice of hydraulic fracturing in coal bed reservoirs is safe, poses little of no threat to underground sources of drinking water, and does not need to be further studied or regulated. EPA supports this conclusion based on an action that EPA believes will reduce the risks of endangerment to underground sources of drinking associated with injecting diesel fuel into coal bed methane reservoirs. EPA obtained an agreement from three oil and gas industry service companies to *voluntarily* eliminate diesel fuel injection into underground sources of drinking water for coalbed methane production.[32]

These companies did not agree with EPA's concerns. The agreement states: "While the companies do not necessarily agree that hydraulic fracturing fluids using diesel fuel endanger USDWs (underground sources of drinking water) when they are injected into CBM (coal bed methane) production wells, the companies are prepared to enter into this agreement in response to EPA's concerns and to reduce potential risks to the environment."[33]

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[29] Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coaled Methane Reservoirs, EPA, June 2004, at page ES-16.
[30] 40 C.F.R. 141.61 http://www.epa.gov/safewater/contaminants/dw_contamfs/benzene.html
[31] 40 C.F.R. 141.50
[32] Memorandum of Agreement Between the United States Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc. and Schlumberger Technology Corporations, Elimination of Diesel Fuel in Hydraulic Fracturing Fluids Injected into Underground Sources of Drinking Water During Hydraulic Fracturing of Coalbed Methane Wells, signed by G. Tracy Mehan, III; EPA Office of Water and representatives of the above companies, December 12, 2003.
[33] See Memorandum of Agreement, ibid. page 2.

Because the agreement is voluntary, the public and regulators cannot determine whether these service companies will comply with the conditions established in the agreement.

The agreement does not appear to be enforceable by EPA or any party and EPA has no oversight to assure that the conditions established in the agreement are achieved. The agreement states: "Any company or EPA may terminate its participation in this MOA (memorandum of agreement) by providing written notice to the other signatories."[34]

This agreement also does not refer to any other toxic or carcinogenic substance that could be contained in hydraulic fracturing such as acids, formaldehyde, polyacrylamides, chromium, and other substances. As some hydraulic fracturing fluids remain proprietary, it is not known if other toxic substances are contained in hydraulic fracturing fluids.

This agreement does not refer to the potential of hydraulic fracturing creating new pathways for methane migration to endanger underground sources of drinking water.

This agreement does not apply to any other service company or any owner of a well that may inject diesel fuel to hydraulic fracturing coal beds for methane recovery.

D. EPA should conduct additional analysis and consider regulatory options

Congress is considering exempting the practice of hydraulic fracturing by the oil and gas industry perhaps before EPA can conduct further investigations. The public should be wary of exempting this practice from regulatory oversight by EPA. EPA should correct is faulty analysis. This can be accomplished if EPA reverses its decisions and begins anew its proposed three-phase study of the impacts of injection of fluids for hydraulic fracturing of coal bed reservoirs, provided it is conducted, this time, in compliance with EPA's science policies.

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[34] Memorandum of Agreement, ibid. page 5.

1. The oil and gas industry is now seeking to exempt the practice of hydraulic fracturing from the requirements of the SDWA

Congress has a legislative amendment under consideration that would exempt the practice of hydraulic fracturing from compliance with the SDWA with support based, in part, on EPA's flawed analysis. Section 327 of the proposed Energy Bill (H.R. 6)[35] would amend sections 1421(d) of the Safe Drinking Water Act (42 U.S.C. 300h(d)) to exclude the underground injection of fluids or propping agents pursuant to hydraulic fracturing operations related to oil and gas production activities.

This legislative change, if approved by Congress, would exempt this practice for both coal bed methane production and for conventional oil and gas production. EPA has not applied its authority under the SDWA to investigate the risks of endangerment to underground sources of drinking water that might result from hydraulic fracturing in underground sources of drinking water associated with conventional oil and gas production.

The oil and gas service companies that are parties to the Memorandum of Agreement could withdraw from the conditions set forth in the agreement as soon as legislation is in place with little or no recourse by EPA or affected citizens. These service companies could recommence the practice of injecting fluids containing diesel fuel into coal bed methane reservoirs which could risk public health or the safety of the environment.

2. The public should be wary of exempting this practice from compliance with the Safe Drinking Water Act

The reasons that exemption of this industry practice from the regulatory provisions of the SDWA may not be warranted at this time include: 1) the risks of endangering underground sources of drinking water from hydraulic fracturing practices are poorly understood due to a lack of field monitoring data; 2) these risks deserve extensive additional study; 3) the injection practices introduce toxic and carcinogenic materials that are not likely to be fully recovered during production; 4) the content of these hydraulic fracturing fluids is unknown; 5) the majority of EPA's external peer review panel, whose review supports the decision, appear to have conflicts-of-interest, and; 6) the only national precedent

[35] H.R 6 PP. http://thomas.loc.gov/cgi-bin/query/D?c108:5:./temp/~c108BCiRdc::

established to control impacts to underground sources of drinking water from hydraulic fracturing is an unenforceable voluntary agreement.

3. Recommendations to EPA to correct its faulty analysis

a) EPA should revise and amend EPA's June 2004 study conclusions. EPA should begin anew its three-phase study of the risks to underground sources of drinking water from the hydraulic fracturing of coal bed methane reservoirs. This revised study should also investigate migration of unwanted methane associated with the practice of hydraulic fracturing in coal bed methane reservoirs.

b) EPA should form a federal advisory panel including interested citizens to provide oversight of EPA's study efforts consistent with the Federal Advisory Committee Act.

c) EPA should form a new Peer Review Panel and include a balance of interests among peer reviewers by assigning internal and external peer reviewers. This panel must be comprised to avoid reviewers with real or perceived conflicts-of-interest.

d) If the data and analytical results of phase two indicate that an underground source of drinking has or may become endangered as a result of hydraulic fracturing in coal bed reservoirs, EPA should conduct phase three of its study to investigate regulatory program options consistent with the Safe Drinking Water Act and the Toxic Substances Control Act. This effort should identify the benefits and costs of Alabama's application of that state's SDWA Underground Injection Control Program which regulates hydraulic fracturing in coal bed methane reservoirs.

Professional qualifications of the author

Wilson received a Bachelors of Science degree in Geological Engineering in 1969 and a Masters of Science degree in Water Resources Administration in 1973 from the University of Arizona. He has received numerous honors and awards for his professional accomplishments at the EPA during his 30-year career with the federal government. In 2003, Wilson received the "Four C's Award" from Kathleen Clark, Director of the Bureau of Land Management, for his analysis of the surface water quality impacts associated with coal bed methane development in Montana and Wyoming. The 'Four C's Award' is awarded to federal employees for their "consultation, cooperation, communication, (for) conservation."

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A Review of Some Oil and Gas Exemptions from Environmental Regulation

By Environmental Law Prof

As hydraulic fracturing for natural gas continues to attract media attention, I thought that this would be a good time to review several of the major statutory exemptions enjoyed by oil and gas companies. The most substantial exemption, in my view, is the EPA's determination in 1988 that oil and gas exploration and production or "E&P" wastes should not be regulated under Subtitle C of the Resource Conservation and Recovery Act. When Congress enacted RCRA in 1976, the Act contained no oil and gas exemption. Congress eventually directed the EPA to study, though, whether certain oil and gas wastes should be regulated under Subtitle C or not, and after some foot-dragging and a lawsuit, the agency determined that the wastes--although some of them were hazardous--should be exempted. Specifically, the EPA's 1988 study, located at 53 Fed. Reg. 25,446, concluded that "23 percent of the statistically weighted sample sites generating produced water contain one or more of the toxic constituents of concern at levels greater than 100 times the health-based standards." More generally, the EPA found that between ten and seventy percent of the oil and gas wastes sampled (the percentages varied by type of waste) "could potentially exhibit RCRA hazardous waste characteristics." The EPA concluded, though, that imposing corrective action requirements, including on-site management of the wastes under RCRA, would result in "significant costs to the industry" and that "most existing State regulations are generally adequate for protecting human health and the environment."

The EPA conducted its RCRA exemption study before high-volume "slickwater" hydraulic fracturing in shales had fully emerged. Gas operators in the Barnett Shale did not perfect the slickwater technique, which uses large quantities of water mixed with smaller quantities of chemicals, until the late 1990s, so the EPA has never directly studied whether the several million gallons of fracture solution injected into a well--some of which flow back up and must be disposed of--have hazardous characteristics and might merit a reconsideration of the RCRA Subtitle C exemption. In light of this concern, the Natural Resources Defense Council submitted a rulemaking petition to the EPA in 2010, requesting that the EPA reconsider the 1988 RCRA exemption for oil and gas exploration and production wastes.

Another interesting aspect of the RCRA exemption is its reliance, to some extent, on non-mandatory guidelines that are intended to improve state regulations. Because the EPA recognized that some oil and gas exploration and production wastes were hazardous when it exempted them from RCRA Subtitle C regulation, the agency noted that some gaps in state regulation needed to be filled. As a solution, the agency gave money to the Interstate Oil and Gas Compact Commission to review state regulations, and the IOGCC formed something called the State Review of Oil & Natural Gas Environmental Regulations, Inc., or "STRONGER." STRONGER brings together representatives from industry, state environmental agencies, and environmental groups to review the efficacy of state oil and gas regulations, but STRONGER is of course not a regulatory agency. After reviewing the adequacy of regulations--including recent reviews specific to hydraulic fracturing--STRONGER develops non-mandatory "guidelines" for better state laws. In evaluating whether the RCRA exemption is a good idea, we should therefore look both to the data and assumptions behind the EPA's 1988 exemption decision and to its assumption about how states would improve their laws by, for example, following STRONGER recommendations.

A second important oil and gas exemption in federal environmental law is the exemption of uncontaminated sediments from oil and gas construction sites from National Pollutant Discharge Elimination System stormwater permitting requirements. The EPA has a useful website that summarizes several aspects of this exemption, including: its original text; Congress's attempt to expand the exemption to most oil and gas construction, exploration, and production activities in the Energy Policy Act of 2005; and subsequent litigation that has somewhat narrowed this attempted expansion.

Third, oil and gas operators do not need to prepare annual toxic chemical release forms under the Emergency Planning and Community Right-to-Know Act. (42 U.S.C. 11023 describes the Standard Industrial Classification codes to which the reporting requirement applies, and oil and gas drilling do not appear to fall within the SIC codes covered.) Oil and gas operators must keep material safety data sheets on site under Section 311 of EPCRA, however, and must provide the MSDS to local emergency planning committees upon request. EPCRA specifically allows the operators to claim trade secret status for chemicals when providing MSDS to local emergency planning committees.

Finally, the process of fracturing itself is not regulated under the Safe Drinking Water Act. The EPA had long maintained that hydraulic fracturing did not count as "underground injection" under the Safe Drinking Water Act--a position that the Legal Environmental Assistance Foundation successfully challenged in Alabama--and Congress formally affirmed the EPA's position in the Energy Policy of Act of 2005, in which Congress declared that hydraulic fracturing (unless the fracturing used diesel fuel) did not fall under the SDWA definition of underground injection. This exemption means that oil and gas operators need not obtain a permit for an underground injection control (UIC) well prior to fracturing. Interestingly, a report recently released by Representatives Waxman, Markey, and DeGette concludes that some of the major fracturing companies injected approximately thirty million gallons of diesel fuel "or hydraulic fracturing fluids containing diesel fuel" into fractured wells between 2005 and 2009. It is not clear whether these companies obtained a UIC permit for this fracturing. The report that reveals the use of diesel fuel is also interesting because several of the major fracturing companies signed a memorandum of agreement with the EPA in 2003 stating that they would not use diesel fuel in fracturing. (The memorandum is no longer available online, but the EPA's press release about the memo is still available.)

In sum, oil and gas companies operate under several substantial exemptions from federal environmental laws. As the Ground Water Protection Council likes to point out, many other federal laws still apply. A company wanting to discharge wastes into a river, for example, must obtain an NPDES permit under the Clean Water Act. Oil and gas companies also must comply with the Endangered Species Act and OSHA regulations, among many other federal laws. But the exemptions should not be ignored, particularly as states, and groups of state regulators such as the Ground Water Protection Council, argue that state regulations adequately control hydraulic fracturing risks. If we continue to rely substantially on states to control the risks, we should ensure that state regulations are sufficiently robust.

-Hannah Wiseman

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