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Earthworks' Oil and Gas Accountability Project (OGAP) appreciates the opportunity to provide written comments the Environmental Protection Agency (EPA) on the UIC Class II permitting guidance being developed for hydraulic fracturing activities that use diesel fuels in fracturing fluids.

HISTORY OF OGAP INVOLVEMENT WITH THIS ISSUE

In 2004, after EPA came out with the final draft of its report *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs,* OGAP conducted a review of the EPA study. In our report, *Our Drinking Water at Risk*, we outlined numerous concerns related to information contained in the EPA study. Some of the major findings of our review: [1]

- Numerous fracturing fluid chemicals may be injected directly into USDWs at concentrations that pose a threat to human health.
- At least one oil and gas service company recommends that some of its fracturing fluids should be disposed of at hazardous waste facilities.
- In the draft version of EPA's report, the agency calculated that at least nine chemicals (including benzene that is present in diesel) used in hydraulic fracturing fluids may be injected at concentrations that exceed water quality standards at the point of injection.
- There is a lack of data on the recovery of injected fracturing fluids
- There is no evidence to prove that concentrations of hydraulic fracturing fluid chemicals stranded in USDWs are safe
- EPA does not know what effect groundwater recharge will have on the mobilization of fracturing fluids that have accumulated in dewatered coal formations
- Studies show that hydraulic fracturing fluids follow natural fracture systems in coal, and that the fluids are able to move out of coal beds into adjacent formations.

As a result of our review OGAP developed several recommendations, which still hold true today:

1. Further study of the effects of hydraulic fracturing on underground sources of drinking water should be conducted.
2. Hydraulic fracturing should not be exempt from the *Safe Drinking Water Act* (SDWA).
3. EPA should develop hydraulic fracturing regulations under the *SDWA.*
4. Until proven safe, all potentially toxic substances should be eliminated from fracturing fluids.

[1] Sumi, L. April 2005. *Our Drinking Water at Risk: What EPA and the Oil and Gas Industry Don't Want Us to Know About hydraulic Fracturing*. Earthworks' Oil and Gas Accountability Project. http://www.earthworksaction.org/pubs/DrinkingWaterAtRisk.pdf

5. Public accountability mechanisms related to hydraulic fracturing should be put into place (e.g., public disclosure of all chemicals used, volumes of chemicals injected, and tracking of flowback volumes for hydraulic fracturing operations).

WHY IS REGULATION OF DIESEL UNDER THE SAFE DRINKING WATER ACT NECESSARY?

1) Hydraulic fracturing fluids are allowed to be injected into Underground Sources of Drinking Water (USDW).

In EPA's 2004 *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, the agency reported that ten out of eleven coalbed methane basins in the U.S. are located, at least in part, within USDWs.[2] The co-location of coalbeds and USDWs is known to occur in Alabama, Arkansas, Colorado, Kansas, Montana, New Mexico, Virginia, Washington, West Virginia and Wyoming, and possibly occurs in Nebraska, Pennsylvania and Kentucky.[3]

In the conclusion section of the report EPA stated that:

> *Although the largest portion of fracturing fluid constituents is nontoxic (>95% by volume), **direct fluid injection into USDWs of some potentially toxic chemicals does take place.*** [emphasis added]
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> *For example, potentially hazardous chemicals are introduced into USDWs when diesel fuel is used in fracturing fluids in operations targeting coal seams that lie within USDWs. Diesel fuel contains constituents of potential concern regulated under SDWA – benzene, toluene, ethylbenzene, and xylenes (i.e., BTEX compounds).*[4]

In 1974 the *Safe Drinking Water Act* authorized EPA to regulate underground injection wells in order to protect drinking water sources. Recognizing that cleanup was not always possible, Part C of the SDWA stressed prevention of contamination to ensure safe drinking water supplies.[5]

The prevention of contamination was further emphasized in 1984, when legislation was passed that banned injection well disposal of hazardous waste unless operators could demonstrate that the waste would not migrate for as long as it remained hazardous. The legislators who required EPA to strengthen the Underground Injection Control (UIC) program did so despite the fact that there were "few confirmed cases of drinking water contamination from hazardous waste

[2] U.S. EPA. June, 2004. Page ES-13.

[3] U.S. EPA. June, 2004. Chapter 5. "Summary of Coalbed Methane Basin Descriptions."

[4] U.S. Environmental Protection Agency (EPA). June, 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*. EPA Document# 816-R-04-003. pp. 7-3. http://www.epa.gov/safewater/uic/cbmstudy.html (**Hereafter referred to as U.S. EPA. June, 2004**.)

[5] U.S. General Accounting Office. August 1989. *Drinking Water – Safeguards Are Not Preventing Contamination from Oil and Gas Wastes.* Report to the Chairman, Environment, Energy and Natural Resources Subcommittee, House of Representatives. GAO/RCED-89-97. p. 11. http://archive.gao.gov/d26t7/139245.pdf

injection wells."[6] Those legislators had enough wisdom to recognize that without adequate safeguards over the disposal of hazardous wastes, USDWs could become contaminated.[7]

EPA developed UIC regulations to prevent hazardous and nonhazardous wastes from contacting USDWs. For example, regulations for Class I UIC wells (which allow the disposal of hazardous and nonhazardous substances) state that injection must occur beneath the lowermost USDWs, and operators must demonstrate that there is a confining layer between the injection zone and any USDW to prevent upward movement of injected materials.[8] These safeguards are not in place for hydraulic fracturing operations that inject diesel or other toxic chemicals directly into USDWs.

2) When diesel is used, benzene is injected at concentrations that exceed water quality standards.

In the executive summary of EPA's 2004 study on hydraulic fracturing, EPA states that:

> *Underground injection endangers drinking water sources if the presence of such a contaminant may result in such system's noncompliance with any national primary drinking water regulation (i.e., maximum contaminant levels).*[9]

In the final version of the EPA study, the agency calculated that the maximum concentration of benzene at the point-of-injection could be 880 times the acceptable level of benzene in drinking water (the maximum contaminant level or MCL is 5.0 µg/l in drinking water).[10] Even using the minimum value for benzene in diesel, and injecting the smallest quantity of diesel reported by oil and gas service companies, EPA calculated that benzene at the point-of-injection would be nine times the acceptable concentration of benzene in drinking water.

[It must be noted that while we recognize that EPA is focusing on permitting guidance related to diesel in hydraulic fracturing operations, diesel is not the only fracturing fluid that is injected at concentrations that exceed MCLs.[11]]

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[6] U.S. General Accounting Office. August 1987. *Hazardous Waste – Controls Over Inject Well Disposal Operations Protect Drinking Water.* Report to the Chairman, Environment, Energy and Natural Resources Subcommittee, Committee on Government Operations, House of Representatives. GAO/RCED-87-170. p.4.

[7] U.S. General Accounting Office. August 1987. *Hazardous Waste – Controls Over Inject Well Disposal Operations Protect Drinking Water.* Report to the Chairman, Environment, Energy and Natural Resources Subcommittee, Committee on Government Operations, House of Representatives. GAO/RCED-87-170. p.2.

[8] U.S. Environmental Protection Agency. 2001. *Class I Underground Injection Control Program: Study of the Risks Associated with Class I Underground Injection Wells*. EPA 8160-R-01-007. http://www.epa.gov/ogwdw/uic/pdfs/study_uic-class1_study_risks_class1.pdf

[9] U.S. EPA. June, 2004. p. ES-7.

[10] "EPA has revised the fraction of BTEX compounds in diesel used to estimate the point-of-injection concentrations from a single value to a documented broader range of values for the fraction of BTEX in diesel fuel. For example, the fraction of benzene in diesel was revised from 0.00006 g benzene/g diesel to a range with a minimum value of 0.000026 g benzene/g diesel and a maximum value of 0.001 g benzene/g diesel." (**Source:** U.S. EPA. June, 2004. p. 4-11.)

[11] In the final EPA report, diesel was singled out in the EPA study as one of the most harmful fracturing fluid additives, but other chemicals are also injected above MCLs. For some reason, this information was in the draft EPA report but was removed from the final version of the study). The information from the draft EPA study indicated that in addition to benzene at least eight chemicals might be injected at concentrations that pose a threat to human health (concentrations that are anywhere from 4 to almost 13,000 times the acceptable concentration in drinking water).

3) There is potential for movement of diesel-bearing fracturing fluids into USDWs.

As mentioned above, in some cases hydraulic fracturing fluids are directly injected into USDWs. While injection of toxic chemicals directly into coalbed methane formations that are also USDWs is a primary concern, OGAP also has concerns associated with fracturing deeper formations (such as gas-bearing shales).

Increasingly, there is information that shows that communication can and does occur between hydraulic fracturing operations conducted in shale formations. Not only does this increase the potential for issues such as blowouts, it also presents the potential for movement of fracturing fluids up uncemented or poorly cemented wells and into aquifers.

The best example of this comes from shale gas wells in British Columbia (BC), Canada. While BC is outside the jurisdiction of EPA, the example is provided to illustrate that fracture stimulation of horizontal wells in shale formations can lead to communication between wells.

In May 2010 the British Columbia Oil and Gas Commission (BCOGC) released a Safety Advisory entitled "Communication During Fracture Stimulation."[12] This advisory mentioned a number of incidents where fluids and substances from hydraulic fracturing operations migrated into other gas wells, and in some cases, resulted in the migration of fracturing fluids back to the surface.

The advisory described a recent case where a horizontal well being drilled in the Montney Shale formation experienced a large "kick," which is an unintended entry of water, gas, oil or other fluids from the formation. The kick was caused by a fracturing operation located 670 metres (or 2,200 feet) away, and resulted in fracture sand being circulated from the drilling wellbore.

In the advisory the BCOGC acknowledged 18 similar fracture communication incidents in BC and one in western Alberta. Some of the incidents involved communication between a hydraulic fracturing operation and a well being drilled nearby, while others were fracture stimulations that impacted adjacent producing wells. The distances between the affected horizontal wells ranged from 50 m [164 feet] to 715 m [2,145 feet]. The advisory goes on to say that "large kicks resulted in volumes of up to 80 m^3 (more than 21,000 gallons) of fluids **produced to the surface**." [emphasis added]

No contamination of groundwater was mentioned in the advisory, but the fact that the injected fluids were able to migrate back to the surface suggests the potential for groundwater

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EPA does not include any data in the draft or final study to show that these eight chemicals (naphthalene, 1-methylnaphthalene, 2-methylnaphthalene, fluorenes, phenanthrenes, aromatics, ethylene glycol or methanol) will undergo physical or chemical transformations to significantly minimize their concentrations in USDWs. Consequently, EPA is knowingly permitting companies to inject hydraulic fracturing fluid chemicals at concentrations known to endanger drinking water quality and human health. (**For more information, see:** Sumi, L. April 2005. *Our Drinking Water at Risk: What EPA and the Oil and Gas Industry Don't Want Us to Know About hydraulic Fracturing*. Earthworks' Oil and Gas Accountability Project. pp. 5-8. http://www.earthworksaction.org/pubs/DrinkingWaterAtRisk.pdf

[12] British Columbia Oil and Gas Commission. May 20, 2010. "Communication During Fracture Stimulation," Safety Advisory. http://www.ogc.gov.bc.ca/documents/safetyadvisory/SA%202010-03%20Communication%20During%20Fracture%20Stimulation.pdf

contamination.

According to the BCOGC "Fracture propagation via large scale hydraulic fracturing operations has proven difficult to predict. Existing planes of weakness in target formations may result in fracture lengths that exceed initial design expectations."

There has been some concern expressed in U.S. shale basins as well. For example, in a May 2011 letter to the editor in the *Oil and Gas Journal*, a geologist from Arkansas wrote that, "In the 80 or so declines I ran last year there was clear evidence in several areas that wells were communicating. Each well drilled had a lower EUR than its neighbor. This suggests the wells were perhaps sharing a single fracture system and feeding off each others' fractures. As each well is drilled it finds part of the unit has already surrendered some part of the reserves."[13]

While there was no suggestion that the fractures had actually impacted adjacent wells, the fact that fractures from adjacent wells are intersecting one another is cause for concern. If high-pressure hydraulic fracturing operations hit weaknesses in target formations in U.S. shales, the fractures may be able to contact adjacent wells as they have done in BC. Can cement jobs hold up to the pressures exerted by adjacent hydraulic fracturing operations? Or will the communication between fracturing jobs weaken cement and casing of adjacent wells, and form conduits for gas and fracturing fluids to migrate up the well bore into overlying USDWs?

The Ground Water Protection Council has stated that it believes the greatest risk of contamination of ground water by fracture fluids comes from the potential for fluids to migrate upward within the casing/ formation annulus during the fracturing process.[14]

Given the potential for communication between wells and the movement of fluids into USDWs, stringent safeguards should be included in any permit issued for hydraulic fracturing operations that use diesel. These safeguards are discussed in OGAP's recommendations below.

4) Voluntary agreements don't provide adequate protection of USDWs

In its 2004 report on hydraulic fracturing in coalbed methane formations, EPA wrote that:

> *Because of the potential for diesel fuel to be introduced into USDWs, EPA requested, and the three major service companies agreed, to eliminate diesel fuel from hydraulic fracturing fluids that are injected directly into USDWs for coalbed methane production.*[15]

In a February 2010 memorandum to the members of the Subcommittee on Energy and Environment, it was disclosed that energy companies Halliburton and BJ Services had used

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[13] ***Cited in:*** Urbina, I. June 25, 2011. "Insiders Sound an Alarm Amid a Natural Gas Rush." *New York Times*. http://www.nytimes.com/2011/06/26/us/26gas.html?pagewanted=1&_r=1&partner=rss&emc=rss
Documents: Leaked Industry E-Mails and Reports. p. 14. http://www.nytimes.com/interactive/us/natural-gas-drilling-down-documents-4.html#document/p11/a22740

[14] Nickolaus, M., Bryson, W. and Jehn, P. (Ground Water Protection Council). May 2009. *State Oil and Natural Gas Regulations Designed to Protect Water Resources.* Report prepared for the U.S. Department of Energy –National Energy Technology Lab. p. 23. http://www.gwpc.org/e-library/documents/general/State%20Oil%20and%20Gas%20Regulations%20Designed%20to%20Protect%20Water%20Resources.pdf

[15] U.S. EPA. June, 2004. pp. 7-3.

diesel and other known toxic chemicals in hydraulic fracturing operations in at least 15 states in 2005, 2006 and 2007. BJ Services reported using 1,700 gallons of two diesel-based fluids in several fracturing jobs in Arkansas and Oklahoma. In a letter to the House Oversight Committee, BJ Services acknowledged that these events were "in violation of the MOA [Memorandum of agreement with EPA]."[16] A spokesperson for BJ Services corroborated that the company had violated the MOA in 2007.[17]

The voluntary nature of this "ban" on the use of diesel in coalbed methane formations that are USDWs, the fact that only three companies signed the MOA, and the fact that the MOA did not require companies to report their use of diesel to EPA created a situation whereby government agencies and citizens were left in the dark regarding whether or not the use of diesel in fracturing might be endangering underground sources of drinking water. It was only a congressional inquiry that finally unearthed the information, and even then, the answers were not completely enlightening:

> *None of the oil and gas service companies could provide data on whether they performed hydraulic fracturing in or near underground sources of drinking water, telling us that the well operators, not the service companies, track that information. We also asked about diesel fuel use in coalbed methane formations, which tend to be shallower and closer to drinking water sources. The three largest companies-Halliburton, BJ Services, and Schlumberger-told us they have stopped using diesel fuel in coal bed methane formations located in underground sources of drinking water. Three smaller companies reported using a limited volume of products containing diesel in coal bed methane wells but did not provide information on the proximity of these wells to drinking water sources.*[18]

Because operators and service companies are not required to report diesel use or the location of the closest USDWs to their hydraulic fracturing operations, no reliable information was provided to the congressional committee that was seeking answers as to whether or not there had been endangerment or contamination of any USDWs. This information must be required, not voluntarily provided.

5) Current regulation of diesel in fracturing fluid is not working

In 2005 Congress passed the *Energy Policy Act*, in which the definition of "underground injection" was amended to exclude "the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or

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[16] Waxman, H. and Markey, E. February 19, 2010. *Memorandum to Members of the Subcommittee on Energy and Environment Re: Examining the Potential Impact of Hydraulic Fracturing.* http://democrats.energycommerce.house.gov/Press_111/20100218/hydraulic_fracturing_memo.pdf

[17] Jeff Smith, a spokesman for BJ Services, corroborated that the company did inadvertently violate the MOA in 2007. (**Source:** April, 2010. "New Congressional Inquiries On Hydraulic Fracturing; EPA Delays Compression Station Rule; GHG Limits Face New Hurdle," *Pipeline and Gas Journal.* Volume 237 No. 4. http://www.pipelineandgasjournal.com/new-congressional-inquiries-hydraulic-fracturing-epa-delays-compression-station-rule-ghg-limits-face

[18] Waxman, H., Markey, E. and DeGette, D. January 31, 2011. "Letter to the Environmental Protection Agency Administrator Lisa Jackson regarding the results of an investigation into the use of diesel fuel in hydraulic fracturing fluids." p. 2. http://democrats.energycommerce.house.gov/index.php?q=news/waxman-markey-and-degette-investigation-finds-continued-use-of-diesel-in-hydraulic-fracturing-f

geothermal production activities." In other words, hydraulic fracturing operations were exempted from regulation under the SDWA unless the fracturing fluids contained diesel fuels.

According to the EPA web site, when hydraulic fracturing fluids contain diesel, companies are supposed to receive "prior authorization from the UIC program."[19]

In a 2011 letter from Representatives Waxman, Markey and DeGette to EPA Administrator Lisa Jackson, it was reported that in the 19 states where companies reported using diesel fuel in hydraulic fracturing operations no permit for the use of diesel fuel had ever been sought by a company or granted by EPA or state agencies.[20] This widespread lack of adherence to the SDWA suggests that clarification of the permitting requirements for diesel used in hydraulic fracturing operations is necessary.

OGAP's PERMIT GUIDANCE RECOMMENDATIONS

The *Energy Policy Act* of 2005 exempted hydraulic fracturing from the *Safe Drinking Water Act*, but allowed for the regulation of diesel fuels used during hydraulic fracturing. If done correctly, the regulation of diesel during hydraulic fracturing may help to alleviate some citizen concerns related to the contamination of underground sources of drinking water by diesel fuel. But as the Ground Water Protection Council recognized, "the best way to eliminate concern would be to use additives that are not associated with human health effects."[21]

We recognize that elimination of all toxic additives is beyond the scope of this permitting guidance initiative. Given the narrow scope of this permit guidance effort, OGAP has the following recommendations for how EPA can reduce the risks created by using diesel in hydraulic fracturing fluids:

I. EPA should require reporting of chemicals used during hydraulic fracturing operations.
II. Permits should not be issued for operations that inject diesel-bearing fluids directly into USDWs.
III. Where hydraulic fracturing occurs in non-USDWs, permits should not be issued unless companies can demonstrate that the concentrations of benzene, toluene, ethylbenzene and xylenes, which are present in diesel fuels, do not exceed MCLs.

[19] "*While the SDWA specifically excludes hydraulic fracturing from UIC regulation under SDWA § 1421 (d)(I), the use of diesel fuel during hydraulic fracturing is still regulated by the UIC program. Any service company that performs hydraulic fracturing using diesel fuel must receive prior authorization from the UIC program. Injection wells receiving diesel fuel as a hydraulic fracturing additive will be considered Class II wells by the UIC program.*" (**Source:** U.S. Environmental Protection Agency web site: Regulation of Hydraulic Fracturing by the Office of Water. "Safe Drinking Water Act." http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydroreg.cfm)

[20] Waxman, H., Markey, E. and DeGette, D. January 31, 2011. "Letter to the Environmental Protection Agency Administrator Lisa Jackson regarding the results of an investigation into the use of diesel fuel in hydraulic fracturing fluids." p. 6. http://democrats.energycommerce.house.gov/index.php?q=news/waxman-markey-and-degette-investigation-finds-continued-use-of-diesel-in-hydraulic-fracturing-f

[21] Nickolaus, M., Bryson, W. and Jehn, P. (Ground Water Protection Council). May 2009. *State Oil and Natural Gas Regulations Designed to Protect Water Resources.* Report prepared for the U.S. Department of Energy –National Energy Technology Lab. pp. 22, 23. http://www.gwpc.org/e-library/documents/general/State%20Oil%20and%20Gas%20Regulations%20Designed%20to%20Protect%20Water%20Resources.pdf

IV. Additionally, for wells that use diesel, apply permit requirements similar to those used for Class I UIC wells.

I. EPA should require reporting of chemicals used during hydraulic fracturing operations.

In the past, energy companies, industry groups and others have not been completely honest about the use of diesel in hydraulic fracturing operations. In a January 2011 letter to Lisa Jackson (EPA Administrator), Reps. Waxman, Markey and DeGette reported that:

> *At a hearing on hydraulic fracturing in the Committee on Oversight and Government Reform in 2007, Rep. Darrell Issa asserted, "this practice does not include the use of diesel fuel."*[22] *In January 2010, Energy In Depth, a group representing most of America's oil and gas producers, wrote that "diesel fuel is simply not used in fracturing operations."*[23]

In the same letter to Lisa Jackson, Reps. Waxman et al. also reported that 12 out of 14 oil and gas service companies surveyed by the House Committee on Energy and Commerce revealed that between 2005 and 2009 they used 32.2 million gallons of diesel fuel in hydraulic fracturing operations. Clearly, Rep. Darrell Issa misspoke during the 2007 Committee on Oversight and Government Report hearing. And while it is possible that the use of diesel in hydraulic fracturing operations ceased at the end of 2009, as suggested by Energy In Depth, it seems highly unlikely.

The first issue that must be addressed is "how is the EPA to know whether or not operators or service companies are using diesel in their hydraulic fracturing operations?"

There is currently no federal requirement to report all of the constituents being injected during hydraulic fracturing operations. While some states do require some level of disclosure (e.g., Wyoming, Colorado, Texas) other states have voluntary disclosure programs (e.g., Pennsylvania), and still others have no disclosure requirements.[24]

We strongly suggest that there be federal oversight of the disclosure of chemicals used during hydraulic fracturing operations so that operators in all states are required to report their use of diesel. Otherwise, it will be very difficult for EPA to ensure that companies obtain the required

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[22] House Committee on Oversight and Government Reform, Opening Statement of Rep. Darrell Issa, *Oil and Gas Exemptions in Federal Environmental Protections*, 110th Cong. (Oct. 31, 2007). ***Cited in:*** Waxman, H., Markey, E. and DeGette, D. January 31, 2011. "Letter to the Environmental Protection Agency Administrator Lisa Jackson regarding the results of an investigation into the use of diesel fuel in hydraulic fracturing fluids." p. 4. http://democrats.energycommerce.house.gov/index.php?q=news/waxman-markey-and-degette-investigation-finds-continued-use-of-diesel-in-hydraulic-fracturing-f

[23] Jan. 20, 2010. "When Gummy Bears Attack." Energy in Depth. http://www.energyindepth.org/2010/01/when-gummy-bears-attack ***Cited in:*** Waxman, H., Markey, E. and DeGette, D. January 31, 2011. "Letter to the Environmental Protection Agency Administrator Lisa Jackson regarding the results of an investigation into the use of diesel fuel in hydraulic fracturing fluids." p. 4. http://democrats.energycommerce.house.gov/index.php?q=news/waxman-markey-and-degette-investigation-finds-continued-use-of-diesel-in-hydraulic-fracturing-f

[24] Soraghan, M. May 4, 2011. "Well Blowout Tests Natural Gas Industry on Voluntary Fracking Disclosure," *New York Times.* http://www.nytimes.com/gwire/2011/05/04/04greenwire-pa-well-blowout-tests-natural-gas-industry-on-36297.html

authorization before they use diesel in their operations. Information collected by EPA should be housed in a publicly accessible database.

There also need to be meaningful penalties for failure to report the use of diesel. Because of the weak or non-existent disclosure requirements currently in place, there is no incentive to disclose this information. Strong penalties, such as a nationwide restriction on all permits to drill until the companies meet the permit requirements for injecting diesel, in addition to fines for failure to report, would help to ensure that operators report their use of diesel and go through the proper permitting channels.

II. Permits should not be issued for operations that inject diesel-bearing fluids directly into USDWs.

As mentioned previously, the three largest oil service companies –Halliburton, BJ Services, and Schlumberger– told the House Committee on Energy and Commerce that they have stopped using diesel fuel in coal bed methane formations located in underground sources of drinking water.[25] Since it is possible to replace diesel with other fluids, EPA should simply ban the use of diesel into USDWs, and ensure that any replacement products for diesel are less toxic than the chemicals in diesel to ensure that USDWs are not threatened by the diesel substitutes.

III. Where hydraulic fracturing occurs in non-USDWs, permits should not be issued unless companies can demonstrate that the concentrations of benzene, toluene, ethylbenzene and xylenes, which are present in diesel fuels, do not exceed MCLs.

The concern about diesel in hydraulic fracturing fluids was raised by EPA in their 2004 study of the *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs.* In the study, EPA stated that:

> *. . .potentially hazardous chemicals are introduced into USDWs when diesel fuel is used in fracturing fluids in operations targeting coal seams that lie within USDWs. Diesel fuel contains constituents of potential concern regulated under SDWA – benzene, toluene, ethylbenzene, and xylenes (i.e., BTEX compounds). . . Because of the potential for diesel fuel to be introduced into USDWs, EPA requested, and the three major service companies agreed, to eliminate diesel fuel from hydraulic fracturing fluids that are injected directly into USDWs for coalbed methane production*.[26]

At that time, EPA clearly expressed concern about the injection of diesel into coalbed methane formations. The concern was specific to diesel in coal seams because that was the only type of geological formation that EPA was studying at the time.

The 2004 EPA study reveals that the agency was concerned about diesel primarily because of the presence of BTEX compounds:

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[25] Waxman, H., Markey, E. and DeGette, D. January 31, 2011. "Letter to the Environmental Protection Agency Administrator Lisa Jackson regarding the results of an investigation into the use of diesel fuel in hydraulic fracturing fluids." p. 2. http://democrats.energycommerce.house.gov/index.php?q=news/waxman-markey-and-degette-investigation-finds-continued-use-of-diesel-in-hydraulic-fracturing-f

[26] U.S. Environmental Protection Agency. June 2004. E*valuation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*. p. 7-3.

The use of diesel fuel in fracturing fluids poses the greatest threat to USDWs ***because BTEX compounds in diesel fuel exceed the MCL at the point-of-injection*** *(i.e. the subsurface location where fracturing fluids are initially injected).*[27]

There are other hydraulic fracturing chemicals that contain BTEX. For example, according to the Environmental Working Group petroleum distillates are likely to contain all of the so-called BTEX chemicals – benzene, toluene, ethylbenzene and xylene.[28]

OGAP recommends that EPA restricts the use of diesel (and any chemicals that are substituted for diesel) in fracturing fluids unless companies can prove that the injected fracturing fluids do not exceed MCLs for BTEX at the point of injection. This type of restriction is used in Georgia for all of its UIC permits. According to the Georgia Environmental Protection Division, "no UIC permit will be issued for the injection of fluids which exceed maximum contaminant levels (MCLs) for any constituent regulated under Georgia's Drinking Water standards."[29]

To obtain the permit, companies should be required to provide calculations showing the concentrations of BTEX at the point-of-injection. But EPA should also require a water quality sample of the actual diesel-bearing hydraulic fracturing fluid to prove that the companies' calculations were accurate.

If companies cannot meet the MCLs for the BTEX chemicals (or other hazardous chemicals in the diesel-bearing fracturing fluid), they should be required to either alter their hydraulic fracturing fluid formula to meet the MCLs or close down their operation. This requirement is laid out in a 2002 EPA Technical Program Overview document, which outlines the minimum regulations that are the basis of the U.S. Environmental Protection Agency's (EPA) Underground Injection Control regulations:

Exceeding an MCL at the point injected fluids enter a USDW would be cause for the Director to determine if the prohibition of fluid movement has been violated. This is an especially critical issue for injection wells disposing of nonhazardous waste directly into a USDW. Operators of such wells could be required to obtain an injection well permit, modify the injection procedure to reduce contaminant levels or cease injection and close the well.[30]

IV. Additionally, for wells that use diesel, apply permits requirements similar to those used for Class I UIC wells

[27] U.S. Environmental Protection Agency. June 2004. E*valuation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*. p. 7-3.

[28] Statement of Dusty Horwitt, Environmental Working Group. Before the New York City Council Committee on Environmental Protection Friday, October 23, 2009. *Oversight Hearing on the Draft Supplemental Generic Environmental Impact Statement Relating to Drilling for Natural Gas in New York State Using Horizontal Drilling and Hydraulic Fracturing.* http://www.ewg.org/book/export/html/28285

[29] Environmental Protection Division, Georgia Department of Natural Resources. "Underground Injection Control Permit Application for Underground Injection." http://www.gaepd.org/Documents/uiccovlt.html

[30] U.S. EPA. December, 2002. *Technical Program Overview: Underground Injection Control Regulations.* Office of Water. 4606 EPA 816-R-02-025. p. 6. http://water.epa.gov/type/groundwater/uic/upload/2004_5_3_uicv_techguide_uic_tech_overview_uic_regs.pdf

We strongly recommend that wells using diesel (or other toxic chemicals) during hydraulic fracturing be required to follow regulations required for Class I UIC wells. We recognize that unlike Class I UIC wells hydraulic fracturing is not intended to be the permanent disposal of hazardous (or nonhazardous) fluids, but data suggest that some fracturing fluids permanently remain in the target formation. For example, in the draft version of the EPA study, the attachment on the San Juan Basin said that, "A few water samples from the Fruitland aquifer show possible evidence of residual contamination from previous fracturing treatments, suggesting that fracturing fluids might not always be fully recovered.[31]

Estimates of the amount of fluid that remains underground have been made. For example, the 2004 EPA study reported that 61% of injected fluids would flow back initially, with possibly as much as 82% of the fluids eventually returning to the surface. These numbers are based on data from one study, which reported results from one well in one coal seam in one CBM basin, so these figures are not universally applicable to fracturing fluid recovery from all coalbed methane wells. Literature cited by EPA in the draft version of its study indicated that in non-CBM basins 25 to 61% of certain hydraulic fracturing fluids might be recovered over time,[32] leaving 39 to 75% of the injected fluids in the formation.

More recently, in a 2010 presentation to the Quebec government, ALL Consulting stated that 15 to 30 % of fracturing fluid is recovered as flowback from high volume hydraulic fracturing (HVHF) operations.[33] This means that 70 – 85% of the injected fluids are at least initially left in the formation. Over time, more of the injected fluids are expected to return to the surface via produced water from the formation, but the final recovery of fluids is not known because companies are not required to report either the volume of fluid that flows back to the surface or the estimated volume of fluid that remains in the formation following a hydraulic fracturing treatment.[34]

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[31] U.S. Environmental Protection Agency (EPA). August, 2002. *DRAFT Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*. p. A1-8.

[32] "Palmer and others (1991a) found that only **61 percent** of fracturing fluids were recovered during a 19-day production sampling of a coalbed well in the Black Warrior basin, Alabama. Samuel et al. (1997) report that several studies relating to guar-based polymer gels document flow-back recovery rates of approximately **30-45%.** The paper did not discuss the duration over which flow-back recovery rates were measured. Willberg et al. (1997) report that polymer recovery rates during flowback averaged **29-41%** of the amount pumped into the fracture. The results from this study were derived from tests performed on 10 wells over periods of four or five days (Willberg et al., 1997). Willberg et al. (1998) report that polymer returns at conservative flow back rates averaged **25-37%** of the amount pumped into the fracture, while returns at aggressive flow back rates averaged **37-55%.** The results from this study were derived from tests performed on 15 wells over periods of two days at aggressive flow back rates and five days at conservative flow back rates." (**Source:** U.S. Environmental Protection Agency (EPA). August, 2002. *DRAFT Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*. p. 3-10). Also, in a study by Mukherjee and co-workers (cited on p. A-18 of the draft EPA study), the authors observed that between **35% and 45%** of fracturing fluids were recovered from layered formations (i.e., 55-65% remained in the ground. This study is not mentioned in the final EPA study's discussion of flowback (Chapter 3), nor is it listed in the Master Reference List for the EPA final study. The only Mukhergee study listed was one from 1993. (Reference for the deleted study is: Mukhergee, H., Paoli, B.F., McDonald, T. and Cartaya, H. 1995. "Successful control of fracture height growth by placement of an artificial barrier." *SPE Production and Facilities*, 10(2):89-95.)

[33] Bohm, B.K. and Arthur, J.D. (ALL Consulting). Oct. 13 and 14, 2010. "Horizontal Drilling and Hydrualic Fracturing Considerations for Shale Gas". Presentation to the Bureau d'audiences publiques sur l'environement (BAPE) Saint-Hyacinthe, Québec. Slide 14. http://www.bape.gouv.qc.ca/sections/mandats/Gaz_de_schiste/documents/DB61.pdf

[34] Nickolaus, M., Bryson, W. and Jehn, P. (Ground Water Protection Council). May 2009. *State Oil and Natural Gas Regulations Designed to Protect Water Resources.* Report prepared for the U.S. Department of Energy –National

Furthermore, we believe that the requirements for Class I wells are appropriate for the injection of hydraulic fracturing fluids containing diesel because as described above constituents like benzene may exceed MCLs at the point of injection. Also, MSDSs for some unused hydraulic fracturing chemicals suggest that they should be disposed of as hazardous wastes. For example, the Material Safety Data Sheets submitted by Schlumberger to EPA recommended that many fracturing fluid chemicals be disposed of at hazardous waste facilities.[35] Yet these same fluids (in diluted form) are allowed to be injected directly into or adjacent to USDWs. Under the *Safe Drinking Water Act*, hazardous wastes may not be injected into USDWs.[36] Moreover, even if hazardous wastes are diluted with water so that the hazardous characteristics of the fluids are removed, the wastes are still subject to Class I nonhazardous well requirements, i.e., they cannot be injected into USDWs.[37]

Since hydraulic fracturing may occur within or adjacent to USDWs, it is imperative that the stringent requirements such as those developed for Class I UIC wells be followed to provide at least some safeguards to prevent the injection of diesel-bearing fluids from threatening underground sources of drinking water.

In 2003, the General Accounting Office conducted a review of Class I deep injection wells. The following summary of requirements comes from the GAO report:

> *Class I deep injection wells are built to contain hazardous waste – from the pharmaceutical, chemical manufacturing, and metalworking industries, among others – below the lowest underground source of drinking water. . . In order to operate a commercial well that accepts hazardous waste, well owners need to obtain several different permits that establish conditions, including requirements under EPA regulations. First, under the Underground Injection Control (UIC) program, owners must*

Energy Technology Lab. p. 25. http://www.gwpc.org/e-library/documents/general/State%20Oil%20and%20Gas%20Regulations%20Designed%20to%20Protect%20Water%20Resources.pdf

[35] In October of 2004, OGAP filed a *Freedom of Information Act* request with EPA to obtain the Material Safety Data Sheets (MSDS) supplied to the agency by hydraulic fracturing companies. (*Freedom of Information Act*, 5 U.S.C. 552, Request Number HQ-RIN-00044-05).

[36] According to EPA's *Underground Injection Control Regulations:* **Class I wells,** "shall be sited in such a fashion that they inject into a formation which is beneath the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water," (40 CFR Ch. 1 §146.12) and, "in no case shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water." (40 CFR Ch. 1 §146.13) For both **Class II and III wells**, "In no case, shall injection pressure initiate fractures in the confining zone or cause the migration of injection or formation fluids into an underground source of drinking water." (40 CFR Ch. 1 §146.23 and §146.33). **Class V wells,** "inject non-hazardous fluids into or above formations that contain underground sources of drinking water." [emphasis added] (40 CFR Ch. 1 §146.51) **Class IV wells** allow for the injection of hazardous waste directly into USDWs, BUT these wells have been banned. (**Source:** EPA. 2002. *Protecting Drinking Water through Underground Injection Control.* Drinking Water Pocket Guide #2. EPA 816-K-02-001. p.7. http://yosemite.epa.gov/water/owrccatalog.nsf/065ca07e299b464685256ce50075c11a/496beae5658a8d1f85256d83004fdb47!OpenDocument)

[37] U.S. Environmental Protection Agency. 2001. *Class I Underground Injection Control Program: Study of the Risks Associated with Class I Underground Injection Wells.* EPA 8160-R-01-007. pp. 17-18 **AND** 40 CFR Ch. I. §146.11. *Criteria and Standards Applicable to Class I Nonhazardous Wells.* http://www.access.gpo.gov/nara/cfr/waisidx_02/40cfr146_02.html

obtain a construction permit, which, among other things, specifies how the well is to be constructed to prevent the injected waste from migrating to sources of drinking water. The wells must also be located in geologically suitable areas--areas that are not susceptible to earthquakes--to ensure that the waste will not migrate. Second, under the Resource Conservation and Recovery Act (RCRA), owners must obtain a permit to ensure that any above-ground treatment and storage facilities can be operated safely; owners frequently treat and store the waste on the surface before injecting it below ground. Under RCRA, they must also demonstrate that injected waste will be contained within a defined underground area. Finally, owners must have a UIC operating permit from EPA or the state before injecting any waste. Both UIC and RCRA regulations require EPA or the state to obtain public comments before they issue permits.[38]

We suggest that all of the above requirements be placed on wells used for hydraulic fracturing operations that use diesel in their fracturing fluids.

Additionally, the following Class I UIC well requirements should be imposed – with some amendments due to the differences between Class I wells and wells used for hydraulic fracturing (amendments are suggested in column three).

	Class I Wells[39]	**Hydraulic fracturing wells that use diesel**
Permit required	Yes	Yes. This permit should include construction standards, a geological suitability analysis, and should include a period for public comments before issuance of the permit.
Life of permit	Up to 10 years	Up to 10 years
Area of Review (AOR)	2 mile minimum for hazardous waste wells	2 mile minimum if point-of-injection concentrations of BTEX exceed MCLs
Internal Mechanical Integrity Test (MIT)	Pressure test annually and after each workover	Initial pressure test prior to hydraulic fracturing, and additional pressure tests prior to refracturing wells with diesel-bearing fracturing fluids
External MIT	A temperature, noise or other approved log at least every five years	A temperature, noise or other approved log at least every five years. Definitely prior to any refracturing opration. (Ideally, abandoned and producing wells within the AOR should also have external external MITs in case there is communication between the well being fractured and an adjacent well)
Other tests	Yearly radioactive tracer survey, yearly fall-off test, casing inspection log after each workover, continuous corrosion testing	Perhaps not necessary to do all of the tests in Column 2 on a yearly basis, but they should be done prior to any refracturing of the well. In addition to the tests mentioned, operators should be required to determine the concentration of BTEX and other potentially toxic substances in fracturing fluids prior to injection.

[38] U.S. General Accounting Office (GAO). July 14, 2003. *Deep Injection Wells: EPA Needs to Involve Communities Earlier and Ensure That Financial Assurance Requirements Are Adequate*. Report number GAO-03-761. http://www.gao.gov/htext/d03761.html

[39] U.S. EPA. December, 2002. *Technical Program Overview: Underground Injection Control Regulations.* Office of Water. 4606 EPA 816-R-02-025. p. 11. http://water.epa.gov/type/groundwater/uic/upload/2004_5_3_uicv_techguide_uic_tech_overview_uic_regs.pdf

Monitoring	Continuous injection pressure, flow rate, volume, temperature, and annulus pressure + fluid chemistry + groundwater monitoring as needed.	During the hydraulic fracturing operation, operators should conduct continuous injection pressure, flow rate, volume, temperature and annulus pressure and fluid chemistry. Groundwater monitoring in the AOR should be conducted prior to the fracturing event (to establish baseline) and following the fracturing operation, and prior to and following any refracturing operations. Operators should also be required to monitor hydraulic fracturing fluids flowback volumes.
Reporting	Quarterly	Because injection is not continuous, reporting need not occur on a quarterly basis. It should be required within a specified period of time after every hydraulic fracturing or refracturing operation, test or monitoring event (e.g., within 14 days of each event).

Implementation of the recommendations listed above will help to prevent the contamination of underground sources of drinking water when diesel is used during hydraulic fracturing operations.

In closing, while we acknowledge that EPA is currently working on a permit guidance document for diesel in particular, and that this is a guidance document, not regulations, we encourage the agency to continue to work toward strengthening regulations related to ALL toxic constituents in fracturing fluids.

Sincerely,

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