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OGAP EARTHWORKS™

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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

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[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] <u>These safeguards are not in place for hydraulic fracturing operations that inject diesel or other toxic chemicals directly into USDWs.</u>

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.

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[19] *"While the SDWA specifically excludes hydraulic fracturing from UIC regulation under SDWA § 1421 (d)(l), 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 <u>all states</u> 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. *Evaluation 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. *Evaluation 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 Hydraulic 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,

Gwen Lachelt

Gwen Lachelt, Director
Earthworks' Oil & Gas Accountability Project

June 29, 2011

Office of Groundwater and Drinking Water
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Comments on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels

Dear Sir or Madam:

Thank you for the opportunity to provide comments on the Environmental Protection Agency's ("EPA") development of UIC Class II permitting guidance for hydraulic fracturing activities that use diesel fuels in fracturing fluids.

The Natural Resources Defense Council ("NRDC") is a national, non-profit legal and scientific organization with 1.3 million members and activists worldwide. Since its founding in 1970, NRDC has been active on a wide range of environmental issues, including fossil fuel extraction and drinking water protection. NRDC is actively engaged in issues surrounding oil and gas development and hydraulic fracturing, particularly in the Rocky Mountain West and Marcellus Shale regions.

Earthjustice is a non-profit public interest law firm originally founded in 1971. Earthjustice works to protect natural resources and the environment, and to defend the right of all people to a healthy environment. Earthjustice is actively addressing threats to air, water, public health and wildlife from oil and gas development and hydraulic fracturing in the Marcellus Shale and Rocky Mountain regions.

Founded in 1892, the Sierra Club works to protect communities, wild places, and the planet itself. With 1.4 million members and activists worldwide, the Club works to provide healthy communities in which to live, smart energy solutions to combat global warming, and an enduring legacy of for America's wild places. The Sierra club is actively addressing the environmental threats to our land, water, air from natural gas extraction across the United States.

General Comments

We appreciate EPA's decision to issue permitting guidance for hydraulic fracturing using diesel fuel. While this practice is regulated under the currently existing UIC Class II regulations, hydraulic fracturing also poses unique risks to USDWs. For that reason, we believe that EPA must promulgate new regulations in addition to permitting guidance. The issuance of permitting guidance under Class II is an important stopgap, but only through regulation that specifically address hydraulic fracturing using diesel can USDWs be adequately protected.

UNPERMITTED INJECTION OF DIESEL FUELS THROUGH HYDRAULIC FRACTURING IS A VIOLATION OF THE SAFE DRINKING WATER ACT

As an initial matter, EPA should use its proposed guidance to reemphasize an important point: the use of diesel fuel injection for hydraulic fracturing is already subject to the requirements of the Safe Drinking Water Act ("SDWA"), whether or not it is specifically addressed by EPA guidance or state UIC programs.

The statutory definition of "underground injection" as "the subsurface emplacement of fluids by well injection" plainly encompasses hydraulic fracturing. 42 U.S.C. § 300h(d)(1); see, e.g., Legal Environmental Assistance Found. v. EPA, 118 F.3d 1467, 1475 (11th Cir. 1997) (holding that the statute requires EPA to regulate hydraulic fracturing operations). SDWA underscores this point by excluding hydraulic fracturing from the definition of "underground injection," except where diesel fuel is used. 42 U.S.C. § 300h(d)(1)(B)(ii). Such an exclusion would be unnecessary if hydraulic fracturing were not otherwise a form of SDWA-regulated underground injection.

Because it represents a form of underground injection, all hydraulic fracturing with diesel fuel violates SDWA unless a permit has been issued. 42 U.S.C. § 300h(b)(1)(A); 40 C.F.R. §§ 144.1(d)(6), (g), 144.11.

Because diesel fuel contains carcinogenic benzene, toluene, ethylene, and xlyene ("BTEX") compounds it poses a major concern.[1] Therefore, when Congress exempted some hydraulic fracturing injections from the Act, it explicitly limited that exemption to wells where fluids "other than diesel fuels" are used. 42 U.S.C. § 300h(d)(1)(B)(ii).[2] For those hydraulic fracturing injections using diesel fuel, the SDWA Class II well program applies. See 40 C.F.R. § 144.6(b).

Nevertheless, many companies have continued to use diesel fuel without obtaining a permit. The minority staff of the House Committee on Energy and Commerce determined that between 2005 and 2009 "oil and gas service companies injected 32.2 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states."[3] The investigators determined that "no oil and gas service companies have sought – and no state and federal regulators have issued – permits for diesel fuel use in hydraulic fracturing."[4]

In light of this noncompliance (and assertions of confusion on the part of hydraulic fracturing service companies), EPA should reaffirm that these injections were illegal, and future injections without a permit are also illegal.

EPA should further clarify that these injections were barred under SDWA whether or not they occurred in a state with primacy to enforce SDWA, and whether or not such states had rules on the books. This is so because the SDWA requires each state to prohibit unpermitted injections. 42 U.S.C. § 300h(b)(1)(A).

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[1] For example, EPA described diesel as the "additive of greatest concern" in hydraulic fracturing operations.US EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* (June 2004) at ES-12.

[2] Of course, "[n]otwithstanding any other provision of [the SDWA]," including the hydraulic fracturing exemption, EPA retains its power to act against injection practices which "may present an imminent and substantial endangerment to the health of persons." 42 U.S.C. § 300i(a). EPA could also use this authority to address diesel injection.

[3] Letter from Reps. Waxman, Markey, and DeGette to EPA Administrator Lisa Jackson (Jan. 31, 2001) at 1.

[4] *Id.; see also* Dusty Horwitt, Environmental Working Group, *Drilling Around the Law* (2009) at 12-13 (documenting state and federal agency officials' failure to regulate these injections).

The statute leaves no room for states to simply ignore illegal injections to which the Act applies. Moreover, the SDWA regulations provide that each state program "must be administered in accordance" with various federal regulations, including 40 C.F.R. § 144.11, which prohibits "[a]ny underground injection, except into a well authorized by rule or except as authorized by permit." 40 C.F.R. § 145.11(a)(5). Thus, even if a state's rules do not explicitly address hydraulic fracturing injections with diesel fuel, the Class II permitting rules remain in place and govern all such injections.[5]

As the Congressional investigation demonstrates, oil and gas companies ignored these clear requirements.[6] In light of this apparently common failure to comply with the law, EPA would be well within its authority to ban diesel injection entirely. Diesel fuel injection is an inherent threat to safe drinking water. Cf. 42 U.S.C. § 300h(b)(1)(B) (applicants for permits must satisfactorily demonstrate that "the underground injection will not endanger drinking water sources"). Companies can and should be required to avoid using diesel fuel in their operations. But if EPA does not do so, it should at a minimum limit the threats it poses by issuing strong guidance and requiring permits to control injection practices.

Responses to EPA's Discussion Questions

<u>WHAT SHOULD BE CONSIDERED AS "DIESEL FUELS?</u>

The injection of any quantity of diesel fuels for hydraulic fracturing should be covered under EPA's UIC Class II regulations. This includes products derived from, containing, or mixed with diesel fuels or any fuel which could be used in a diesel engine.

At 40 CFR §80.2(x), "diesel fuel" is defined as:

Diesel fuel means any fuel sold in any State or Territory of the United States and suitable for use in diesel engines, and that is—

(1) A distillate fuel commonly or commercially known or sold as No. 1 diesel fuel or No. 2 diesel fuel;

(2) A non-distillate fuel other than residual fuel with comparable physical and chemical properties (e.g., , biodiesel fuel); or

(3) A mixture of fuels meeting the criteria of paragraphs (1) and (2) of this definition.

<u>WHAT WELL CONSTRUCTION REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?</u>

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[5] States which do not enforce against scofflaw injectors risk their primacy, as EPA should make clear. *See* 42 U.S.C. § 300h(c) (providing that if EPA determines that "a state no longer meetings the requirements" of the SDWA, then EPA shall implement a federal program).

[6] Indeed, even diesel injection into wells permitted by rule is barred if the operator did not comply with the Class II regulations. These applicable rules include EPA's inventory requirements at 40 C.F.R. § 144.26, which trigger reporting of well location and operating status, and, for EPA-administered programs, reports on the "nature of injected fluids" and on the mechanical integrity of the well. *See* 40 C.F.R. § 144.22(prohibiting injection without inventory reporting). If operators inject into permitted-by-rule wells without complying with these and other applicable requirements, they further violate the SDWA.

Casing and Cement

Proper well construction is crucial to ensuring protection of USDWs. The first step to ensuring good well construction is ensuring proper well drilling techniques are used. This includes appropriate drilling fluid selection, to ensure that the wellbore will be properly conditioned and to minimize borehole breakouts and rugosity that may complicate casing and cementing operations. Geologic, engineering, and drilling data can provide indications of potential complications to achieving good well construction, such as highly porous or fractured intervals, lost circulation events, abnormally pressured zones, or drilling "kicks" or "shows." These must be accounted for in designing and implementing the casing and cementing program. Reviewing data from offset wellbores can be helpful in anticipating and mitigating potential drilling and construction problems. Additionally, proper wellbore cleaning and conditioning techniques must be used to remove drilling mud and ensure good cement placement.

Hydraulic fracturing requires fluid to be injected into the well at high pressure and therefore wells must be appropriately designed and constructed to withstand this pressure. The casing and cementing program must:

- Properly control formation pressures and fluids
- Prevent the direct or indirect release of fluids from any stratum to the surface
- Prevent communication between separate hydrocarbon-bearing strata
- Protect freshwater aquifers/useable water from contamination
- Support unconsolidated sediments
- Protect and/or isolate lost circulation zones, abnormally pressured zones, and any prospectively valuable mineral deposits

Casing must be designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; corrosion; erosion; and hydraulic fracturing pressure. The casing design must include safety measures that ensure well control during drilling and completion and safe operations during the life of the well.

UIC Class II rules require that injection wells be cased and cemented to prevent movement of fluids into or between underground sources of drinking water and that the casing and cement be designed for the life of the well [40 CFR §146.22(b)(1)]. Achieving and maintaining mechanical integrity are crucial to ensuring these requirements. Operators must demonstrate that wells will be designed and constructed to ensure both internal and external mechanical integrity. Internal mechanical integrity refers to the absence of leakage pathways through the casing; external mechanical integrity refers to the absence of leakage pathways outside the casing, primarily through the cement.

The components of a well that ensure the protection and isolation of USDWs are steel casing and cement. Multiple strings of casing are used in the construction of oil and gas wells, including: conductor casing, surface casing, production casing, and potentially intermediate casing. For all casing strings, the design and construction should be based on Good Engineering Practices (GEP), Best Available Technology (BAT), and local and regional engineering and geologic data. All well construction materials must be compatible with fluids with which they may come into contact and be resistant to corrosion, erosion, swelling, or degradation that may result from such contact.

Conductor Casing:

Conductor casing is typically the first piece of casing installed and provides structural integrity and a conduit for fluids to drill the next section of the well. Setting depth is based on local geologic and engineering factors but is generally relatively shallow, typically down to bedrock. Depending on local conditions, conductor casing can either be driven into the ground or a hole drilled and the casing lowered into the hole. In the case where a hole is excavated, the space between the casing and the wellbore – the annulus – should be fully cemented from the base, or "shoe," of the casing to the ground surface, a practice referred to as "cementing to surface." A cement pad should also be constructed around the conductor casing to prevent the downward migration of fluids and contaminants.

Surface Casing:

Surface casing is used to: isolate and protect groundwater from drilling fluids, hydrocarbons, formation fluids, and other contaminants; provide a stable foundation for blowout prevention equipment; and provide a conduit for drilling fluids to drill the next section of the well.

Surface casing setting depth must be based on relevant engineering and geologic factors, but generally should be:

1. Shallower than any pressurized hydrocarbon-bearing zones
2. 100 feet below the deepest USDW

Surface casing must be fully cemented to surface by the pump and plug method. If cement returns are not observed at the surface, remedial cementing must be performed to cement the casing from the top of cement to the ground surface. If shallow hydrocarbon-bearing zones are encountered when drilling the surface casing portion of the hole, operators must notify regulators and take appropriate steps to ensure protection of USDWs.

Intermediate Casing:

Depending on local geologic and engineering factors, one or more strings of intermediate casing may be required. This will depend on factors including but not limited to the depth of the well, the presence of hydrocarbon-or fluid-bearing formations, abnormally pressured zones, lost circulation zones, or other drilling hazards. When used, intermediate casing should be fully cemented from the shoe to the surface by the pump and plug method. Where this is not possible or practical, the cement must extend from the casing shoe to 600 feet above the top of the shallowest zone to be isolated (e.g. productive zone, abnormally pressured zone, etc). Where the distance between the casing shoe and shallowest zone to be isolated makes this technically infeasible, multi-stage cementing must be used to isolate any hydrocarbon- or fluid-bearing formations or abnormally pressured zones and prevent the movement of fluids.

Production Casing:

To be most protective, one long-string production casing (i.e. casing that extends from the total depth of the well to the surface) should be used. This is preferable to the use of a production liner – in which the casing does not extend to surface but is instead "hung" off an intermediate string of casing – as it provides an additional barrier to protect groundwater. The cementing requirements are the same as for intermediate casing.

Production Liner:
If production liner is used instead of long-string casing, the top of the liner must be hung at least 200 feet above previous casing shoe. The cementing requirements for production liners should be the same as for intermediate and production casing.

General:
For surface, intermediate, and production casing, a sufficient number of casing centralizers must be used to ensure that the casing is centered in the hole and in accordance with API Spec 10D (Specification for Bow-Spring Casing Centralizers) and API RP 10D-2 (Recommended Practice for Centralizer Placement and Stop Collar Testing). This is necessary to ensure that the cement is distributed evenly around the casing and is particularly important for directional and horizontal wells. In deviated wells, the casing will rest on the low side of the wellbore if not properly centralized, resulting in gaps in the cement sheath where the casing makes direct contact with the rock. Casing collars should have a minimum clearance of 0.5 inch on all sides to ensure a uniformly concentric cement sheath.

For any section of the well drilled through fresh water-bearing formations, drilling fluids must be limited to air, fresh water, or fresh water based mud and exclude the use of synthetic or oil-based mud or other chemicals. This typically applies to the surface casing and possibly conductor casing portions of the hole.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, all surface, intermediate, and production casing strings should be pressure tested. Drilling may not be resumed until a satisfactory pressure test is obtained. Casing must be pressure tested to a minimum of 0.22 psi/foot of casing string length or 1500 psi, whichever is greater, but not to exceed 70% of the minimum internal yield. If the pressure declines more than 10% in a 30-minute test or if there are other indications of a leak, corrective action must be taken.

Cement compressive strength tests must be performed on all surface, intermediate, and production casing strings. Casing must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi. The cement mixture must have a 72-hour compressive strength of at least 1200 psi. Additionally, the API free water separation must average no more than six milliliters per 250 milliliters of cement, tested in accordance with API RP 10B-2.

For cement mixtures without published compressive strength tests, the operator or service company must perform such tests in accordance with the current API RP 10B-6 and provide the results of these tests to regulators prior to the cementing operation. The test temperature must be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of cement. A better quality of cement may be required where local conditions make it necessary to prevent pollution or provide safer operating conditions.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, casing shoe tests should be performed immediately after drilling out of the surface or intermediate casing. These may include Formation Integrity Tests (FIT), Leak-Off Tests (LOT or XLOT), and pressure fall-off or pump tests. Casing shoe tests are used to ensure casing and cement integrity, determine whether the formations below the casing shoe can withstand the pressure to which they will be subjected while drilling the next section of the well, and gather data on rock mechanical properties. If any of the casing shoe tests fail, remedial action must be taken to ensure that no migrations pathways exist. Alternatively, the casing and cementing plan may need to be revised to include additional casing strings in order to properly manage pressure.

UIC Class II rules require that cement bond, temperature, or density logs be run after installing surface, intermediate, and production casing and cement [40 CFR §146.22(f)(2)(i)(B)]. Ideally, all three types of logs should be run. The term "cement bond log" refers to out-dated technology and the terms "cement evaluation logs," "cement integrity logs" or "cement mapping logs" are preferable. Cement integrity and location must be verified using cement evaluation tools that can detect channeling in 360 degrees. A poor cement job, in which the cement contains air pockets or otherwise does not form a complete bond between the rock and casing or between casing strings, can allow fluids to move behind casing from the reservoir into USDWs. Verifying the integrity of the cement job is crucial to ensure no unintended migration of fluids. Traditional bond logs cannot detect the fine scale channeling which may allow fluids to slowly migrate over years or decades and therefore the use of more advanced cement evaluation logs is crucial. (For further reading see, e.g., Lockyear et. al, 1990; Frisch et. al, 2005)

When well construction is completed, the operator should certify, in writing, that the casing and cementing requirements were met for each casing string.

In addition, it may be useful to review the casing and cementing regulations of states with long histories of oil and gas production such as Texas, Alaska, California, and Pennsylvania. Specific examples include:

- Requirements for casing and cementing record keeping for casing and cementing operations in the California Code of Regulations (CCR) at 14 CCR §1724
- Requirements for casing and cementing program application content in the Alaska Administrative Code (AAC) at 20 AAC §25.030(a)
- Cement chemical and physical degradation standard in the Pennsylvania Code (Pa. Code) at 25 Pa. Code §78.85(a)
- Requirement to report and repair defective casing or take the well out of service in the Pennsylvania Code at 25 Pa. Code §78.86
- Casing standard in gas storage areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with gas storage
- Casing standard in coal development areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with sufficient coal seams
- Casing testing and minimum overlap length standards in the California Code of Regulations at 14 CCR §1722

- Cement quality, testing, and remedial repair standard in the Alaska Administrative Code at 20 AAC §25.030
- Casing quality and amount standard in the Pennsylvania Code at 25 Pa. Code §78.84 and §78.71

Well Logs

After drilling the well but prior to casing and cementing operations, operators must obtain well logs to aid in the geologic, hydrologic, and engineer characterization of the subsurface. Open hole logs, i.e. logs run prior to installing casing and cement, should at a minimum include:

Gamma Ray Logs:

Gamma ray logs detect naturally occurring radiation. These logs are commonly used to determine generic lithology and to correlate subsurface formations. Shale formations have higher proportions of naturally radioactive isotopes than sandstone and carbonate formations. Thus, these formations can be distinguished in the subsurface using gamma ray logs.

Density/Porosity Logs:

Two types of density logs are commonly used: bulk density logs, which are in turn used to calculate density porosity, and neutron porosity logs. While not a direct measure of porosity, these logs can be used to calculate porosity when the formation lithology is known. These logs can be used to determine whether the pore space in the rock is filled with gas or with water.

Resistivity Logs:

These logs are used to measure the electric resistivity, or conversely conductivity, of the formation. Hydrocarbon- and fresh water-bearing formations are resistive, i.e. they cannot carry an electric current. Brine-bearing formations have a low resistivity, i.e. they can carry an electric current. Resistivity logs can therefore be used to help distinguish brine-bearing from hydrocarbon-bearing formations. In combination with Darcy's Law, resistivity logs can be used to calculate water saturation.

Caliper Logs:

Caliper logs are used to determine the diameter and shape of the wellbore. These are crucial in determining the volume of cement that must be used to ensure proper cement placement.

These four logs, run in combination, make up one of the most commonly used logging suites. Additional logs may be desirable to further characterize the formation, including but not limited to Photoelectric Effect, Sonic, Temperature, Spontaneous Potential, Formation Micro-Imaging (FMI), Borehole Seismic, and Nuclear Magnetic Resonance (NMR). The use of these and other logs should be tailored to site-specific needs. (For further reading see, e.g., Asquith and Krygowski, 2004)

UIC Class II rules have specific logging requirements "(f)or surface casing intended to protect underground sources of drinking water in areas where the lithology has not been determined" [40 CFR §146.22(f)(2)(i)]. For such wells, electric and caliper logs must be run before surface casing is installed [40 CFR §146.22(f)(2)(i)(A)]. Such logs should be run on all wells, not just those where lithology has not been determined, and the electric logs suite should include, at a minimum, caliper, resistivity and gamma ray or spontaneous potential logs. For intermediate and long string casing "intended to facilitate injection," UIC Class II rules require that electric porosity, gamma ray, and fracture finder logs be run before casing is installed [40 CFR §146.22(f)(2)(ii)(A) and (B)]. Hydraulic fracturing should be included in the definition of "injection." Operators should also run caliper and resistivity logs. The term "fracture finder logs" refers to out-dated technology. More advanced tools for locating fractures should be used, such as borehole imaging logs (e.g. FMI logs) and borehole seismic.

Core and Fluid Sampling

While not specifically required by current UIC Class II regulations, operators of wells that will be hydraulically fractured using diesel should also obtain whole or sidewall cores of the producing and confining zone(s) and formation fluid samples from the producing zone(s). At a minimum, routine core analysis should be performed on core samples representative of the range of lithology and facies present in the producing and confining zone(s). Special Core Analysis (SCAL) should also be considered, particularly for samples of the confining zone, where detailed knowledge of rock mechanical properties is necessary to determine whether the confining zone can prevent or arrest the propagation of fractures. Operators should also record the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the producing and confining zone(s). Operators should prepare and submit a detailed report on the physical and chemical characteristics of the producing and confining zone(s) and formation fluids that integrates data obtained from well logs, cores, and fluid samples. This must include the fracture pressure of both the producing and confining zone(s).

WHAT WELL OPERATION, MECHANICAL INTEGRITY, MONITORING, AND REPORTING REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?

Mechanical Integrity

Operators must maintain mechanical integrity of wells at all times. Mechanical integrity should be periodically tested by means of a pressure test with liquid or gas, a tracer survey such as oxygen activation logging or radioactive tracers, a temperature or noise log, and a casing inspection log. The frequency of such testing should be based on site and operation specific requirements and be delineated in a testing and monitoring plan prepared, submitted, and implemented by the operator.

Mechanical integrity and annular pressure should be monitored over the life of the well. Instances of sustained casing pressure can indicate potential mechanical integrity issues. The annulus between the production casing and tubing (if used) should be continually monitored. Continuous monitoring allows problems to be identified quickly so repairs may be made in a timely manner, reducing the risk that a wellbore problem will result in contamination of USDWs.

Operations and Monitoring

Each hydraulic fracturing treatment must be modeled using a 3D geologic and reservoir model, as described in the Area of Review requirements, prior to operation to ensure that the treatment will not endanger USDWs. Prior to performing a hydraulic fracturing treatment, operators should perform a pressure fall-off or pump test, injectivity tests, and/or a mini-frac. Data obtained from such tests can be used to refine the hydraulic fracture model, design, and implementation.

The hydraulic fracturing operation must be carefully and continuously monitored. In API Guidance Document HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines, the

America Petroleum Institute recommends continuous monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate.

If at any point during the hydraulic fracturing operation the monitored parameters indicate a loss of mechanical integrity or if injection pressure exceeds the fracture pressure of the confining zone(s), the operation must immediately cease. If either occurs, the operator must notify the regulator within 24 hours and must take all necessary steps to determine the presence or absence of a leak or migration pathways to USDWs. Prior to any further operations, mechanical integrity must be restored and demonstrated to the satisfaction of the regulator and the operator must demonstrate that the ability of the confining zone(s) to prevent the movement of fluids to USDWs has not been compromised. If a loss of mechanical integrity is discovered or if the integrity of the confining zone has been compromised, operators must take all necessary steps to evaluate whether injected fluids or formation fluids may have contaminated or have the potential to contaminate any unauthorized zones. If such an assessment indicates that fluids may have been released into a USDW or any unauthorized zone, operators must notify the regulator within 24 hours, take all necessary steps to characterize the nature and extent of the release, and comply with and implement a remediation plan approved by the regulator. If such contamination occurs in a USDW that serves as a water supply, a notification must be placed in a newspaper available to the potentially affected population and on a publically accessible website and all known users of the water supply must be individually notified immediately by mail and by phone.

Techniques to measure actual fracture growth should be used, including downhole tiltmeters and microseismic monitoring. These techniques can provide both real-time data and, after data processing and interpretation, can be used in post-fracture analysis to inform fracture models and refine hydraulic fracture design. Tiltmeters measure small changes in inclination and provide a measure of rock deformation. Microseismic monitoring uses highly sensitive seismic receivers to measure the very low energy seismic activity generated by hydraulic fracturing (For further reading see, e.g., House, 1987; Maxwell et al., 2002; Le Calvez et al., 2007; Du et al., 2008; Warpinski et al., 2008; Warpinski, 2009; and Cipolla et al. 2011).

Hydraulic fracturing fluid and proppant can sometimes be preferentially taken up by certain intervals or perforations. Tracer surveys and temperature logs can be used to help determine which intervals were treated. Tracers can be either chemical or radioactive and are injected during the hydraulic fracturing operation. After hydraulic fracturing is completed, tools are inserted into the well that can detect the tracer(s). Temperature logs record the differences in temperature between zones that received fracturing fluid, which is injected at ambient surface air temperature, and in-situ formation temperatures, which can be in the hundreds of degrees Fahrenheit.

Operators should develop, submit, and implement a long-term groundwater quality monitoring program. Dedicated water quality monitoring wells should be used to help detect the presence of contaminants prior to their reaching domestic water wells. Placement of such wells should be based on detailed hydrologic flow models and the distribution and number of hydrocarbon wells. Baseline monitoring should begin at least a full year prior to any activity, with monthly or quarterly sampling to characterize seasonal variations in water chemistry. Monitoring should continue a minimum of 5 years prior to plugging and abandonment.

Reporting

At a minimum, operators must report:

- All instances of hydraulic fracturing injection pressure exceeding operating parameters as specified in the permit
- All instances of an indication of loss of mechanical integrity
- Any failure to maintain mechanical integrity
- The results of:
    - Continuous monitoring during hydraulic fracturing operations
    - Techniques used to measure actual fracture growth
    - Any mechanical integrity tests
- The detection of the presence of contaminants pursuant to the groundwater quality monitoring program
- Indications that injected fluids or displaced formation fluids may pose a danger to USDWs
- All spills and leaks
- Any non-compliance with a permit condition

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:

1. Baseline water quality analyses for all USDWs within the area of review
2. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
3. Proposed chemical additives (including proppant coating), reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:

1. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
2. Actual chemical additives used, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
3. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

Emergency and Remedial Response

Operators must develop, submit, and implement an emergency response and remedial action plan. The plan must describe the actions the operator will take in response to any emergency that may endanger human life or the environment – including USDWs – such as blowouts, fires, explosions, or leaks and spills of toxic or hazardous chemicals. The plan must include an evaluation of the ability of local resources to respond to such emergencies and, if found insufficient, how emergency response personnel and equipment will be supplemented. Operators should detail what steps they will take to respond to cases of suspected or known water contamination, including notification of users of the water source. The plan must describe what actions will be taken to replace the water supplies of affected individuals in the case of the contamination of a USDW.

The American Petroleum Institute has published recommended practices for developing a Safety and Environmental Management System (SEMS) plan, API Recommended Practice 75L: Guidance Document for the Development of a Safety and Environmental Management System for Onshore Oil and Natural Gas Production Operation and Associated Activities. This may be a useful document to reference when developing guidance.

WHAT SHOULD THE PERMIT DURATION BE AND HOW SHOULD CLASS II PLUGGING AND ABANDONMENT PROVISIONS BE ADDRESSED FOR CLASS II WELLS USING DIESEL FUELS FOR HF?

The permit should be valid for the life of the well. However, operators must request and receive approval prior to performing any hydraulic fracturing operations that occur subsequent to the initial hydraulic fracturing operation for which the permit was approved. This can be accomplished by means of a sundry or amended permit. Operators must provide updates to all relevant permit application data to the regulator.

Prior to plugging and abandoning a well, operators should determine bottom hole pressure and perform a mechanical integrity test to verify that no remedial action is required. Operators should develop and implement a well plugging plan. The plugging plan should be submitted with the permit application and should include the methods that will be used to determine bottom hole pressure and mechanical integrity; the number and type of plugs that will be used; plug setting depths; the type, grade, and quantity of plugging material that will be used; the method for setting the plugs, and; a complete wellbore diagram showing all casing setting depths and the location of cement and any perforations.

Plugging procedures must ensure that hydrocarbons and fluids will not migrate between zones, into USDWs, or to the surface. A cement plug should be placed at the surface casing shoe and extend at least 100 feet above and below the shoe. All hydrocarbon-bearing zones should be permanently sealed with a plug that extends at least 100 feet above and below the top and base of all hydrocarbon-bearing zones. Plugging of a well must include effective segregation of uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to 100 feet above the casing shoe. In the case of an open hole completion, any hydrocarbon- or fluid-bearing zones shall be isolated by cement plugs set at the top and bottom of such formations, and that extend at least 100 feet above the top and 100 feet below the bottom of the formation.

At least 60-days prior to plugging, operators must submit a notice of intent to plug and abandon. If any changes have been made to the previously approved plugging plan the operator must also submit a revised plugging plan. No later than 60-days after a plugging operation has been completed, operators must submit a plugging report, certified by the operator and person who performed the plugging operation.

After plugging and abandonment, operators must continue to conduct monitoring and provide financial assurance for an adequate time period, as determined by the regulator, that takes into account site-specific characteristics including but not limited to:

- The results of hydrologic and reservoir modeling that assess the potential for movement of contaminants into USDWs over long time scales.
- Models and data that assess the potential degradation of well components (e.g. casing, cement) over time and implications for mechanical integrity and risks to USDWs.

WHAT SHOULD THE TIME FRAME BE FOR SUBMITTING A PERMIT FOR CLASS II WELLS USING DIESEL FUELS FOR HF?

All operators who wish to drill a Class II well using diesel fuel for hydraulic fracturing must submit a permit application to the regulator. Permit applications should be submitted within a reasonable timeframe but no less than 30 days prior to when the operator intends to begin construction. Under no circumstances shall activity commence until the application is approved and a permit is issued.

WHAT ARE IMPORTANT SITING CONSIDERATIONS?

Site Characterization & Planning

Detailed site characterization and planning and baseline testing prior to any oil and gas development are crucial. Site characterization and planning must take into account cumulative impacts over the life of a project or field.

Operators must submit to the regulator a statistically significant sample, as determined by the regulator, of existing and/or new geochemical analyses of each of the following, within the area of review:

1. Any and all sources of water that serve as USDWs in order to characterize baseline water quality. This data must be made publically available through an online, geographically-based reporting system. The sampling methodology must be based on local and regional hydrologic characteristics such as rates of precipitation and recharge and seasonal fluctuations. At a minimum, characterization must include:
    a. Standard water quality and geochemistry[7]
    b. Stable isotopes
    c. Dissolved gases
    d. Hydrocarbon concentration and composition. If hydrocarbons are present in sufficient quantities for analysis, isotopic composition must be determined

[7] Including: Turbidity, Specific Conductance, Total Solids, Total Dissolved Solids, pH, Dissolved Oxygen, Redox State, Alkalinity, Calcium, Magnesium, Sodium, Potassium, Sulfate, Chloride, Fluoride, Bromide, Silica, Nitrite, Nitrate + Nitrite, Ammonia, Phosphorous, Total Organic Carbon, Aluminum, Antimony, Arsenic, Barium, Beryllium, Boron, Bromide, Cadmium, Chromium, Cobalt, Copper, Cyanide, Iron, Lead, Manganese, Mercury, Molybdenum, Nickel, Selenium, Silver, Strontium, Thallium, Thorium, Uranium, Vanadium, Zinc, Cryptosporidium, Giardia, Plate Count, Legionella, Total Coliforms, and Organic Chemicals including Volatile Organic Compounds (VOCs)

   e. Chemical compounds or constituents thereof, or reaction products that may be introduced by the drilling or hydraulic fracturing process. The use of appropriate marker chemicals is permissible provided that the operator can show scientific justification for the choice of marker(s).

   Operators should also consider testing for environmental tracers to determine groundwater age.

2. Any hydrocarbons that may be encountered both vertically and areally throughout the area of review;
3. The producing zone(s) and confining zone(s) and any other intervening zones as determined by the regulator. At a minimum, characterization must include:
   a. Mineralogy
   b. Petrology
   c. Major and trace element bulk geochemistry

Operators of wells that will be hydraulically fractured must demonstrate to the satisfaction of the regulator that the wells will be sited in a location that is geologically suitable. In order to allow the regulator to determine suitability, the owner or operator must provide:

1. A detailed analysis of regional and local geologic stratigraphy and structure including, at a minimum, lithology, geologic facies, faults, fractures, stress regimes, seismicity, and rock mechanical properties.
2. A detailed analysis of regional and local hydrology including, at a minimum, hydrologic flow and transport data and modeling and aquifer hydrodynamics; properties of the producing and confining zone(s); groundwater levels for relevant formations; discharge points, including springs, seeps, streams, and wetlands; recharge rates and primary zones, and; water balance for the area including estimates of recharge, discharge, and pumping
3. A detailed analysis of the cumulative impacts of hydraulic fracturing on the geology of producing and confining zone(s) over the life of the project. This must include, but is not limited to, analyses of changes to conductivity, porosity, and permeability; geochemistry; rock mechanical properties; hydrologic flow; and fracture mechanics.
4. A determination that the geology of the area can be described confidently and that the fate and transport of injected fluids and displaced formation fluids can be accurately predicted through the use of models.

Wells that will be hydraulically fractured must be sited such that a suitable confining zone is present. The operator must demonstrate to the satisfaction of the regulator that the confining zone:

1. Is of sufficient areal extent to prevent the movement of fluids to USDWs, based on the projected lateral extent of hydraulically induced fractures, injected hydraulic fracturing fluids, and displaced formation fluids over the life of the project;
2. Is sufficiently impermeable to prevent the vertical migration of injected hydraulic fracturing fluids or displaced formation fluids over the life of the project;
3. Is free of transmissive faults or fractures that could allow the movement of injected hydraulic fracturing fluids or displaced formation fluids to USDWs; and

4. Contains at least one formation of sufficient thickness and with lithologic and stress characteristics capable of preventing or arresting vertical propagation of fractures.
5. The regulator may require operators of wells that will be hydraulically fractured to identify and characterize additional zones that will impede or contain vertical fluid movement.

The site characterization and planning data listed above does not have to be submitted with each individual well application as long as such data is kept on file with the appropriate regulator and the well for which a permit is being sought falls within the designated area of review.

WHAT SUGGESTIONS DO YOU HAVE FOR REVIEWING THE AREA AROUND THE WELL TO ENSURE THERE ARE NO CONDUITS FOR FLUID MIGRATION, SEISMICITY, ETC.?

The area of review should be the region around a well or group of wells that will be hydraulically fractured where USDWs may be endangered. It should be delineated based on 3D geologic and reservoir modeling that accounts for the physical and chemical extent of hydraulically induced fractures, injected hydraulic fracturing fluids and proppant, and displaced formation fluids and must be based on the life of the project. The physical extent would be defined by the modeled length and height of the fractures, horizontal and vertical penetration of hydraulic fracturing fluids and proppant, and horizontal and vertical extent of the displaced formation fluids. The chemical extent would be defined by that volume of rock in which chemical reactions between the formation, hydrocarbons, formation fluids, or injected fluids may occur, and should take into account potential migration of fluids over time.

The model must take into account all relevant geologic and engineering information including but not limited to:

1. Rock mechanical properties, geochemistry of the producing and confining zone, and anticipated hydraulic fracturing pressures, rates, and volumes.
2. Geologic and engineering heterogeneities
3. Potential for migration of injected and formation fluids through faults, fractures, and manmade penetrations.
4. Cumulative impacts over the life of the project.

As actual data and measurements become available, the model must be updated and history matched. Operators must develop, submit, and implement a plan to delineate the area of review. The plan should include the time frame under which the delineation will be reevaluated, including those operational or monitoring conditions that would trigger such a reevaluation.

Within the area of review, operators must identify all wells that penetrate the producing and confining zones and provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require. If any the wells identified are improperly constructed, completed, plugged, or abandoned, corrective action must be taken to ensure that they will not become conduits for injected or formation fluids to USDWs. Operators must develop, submit, and implement a corrective action plan.

WHAT INFORMATION SHOULD BE SUBMITTED WITH THE PERMIT APPLICATION?

In addition to the requirements at 40 CFR §146.24, operators should also submit the following information:

1. Information on the geologic structure, stratigraphy, and hydrogeologic properties of the proposed producing formation(s) and confining zone(s), consistent with Site Characterization and Planning requirements, including:
    a. Maps and cross-sections of the area of review
    b. The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not provide migration pathways for injected fluids or displaced formation fluids to USDWs
    c. Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the producing and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions
    d. Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the producing and confining zone(s)
    e. Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not affect the integrity of the confining zone(s)
    f. Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area
    g. Hydrologic flow and transport data and modeling
2. A list of all wells within the area of review that penetrate the producing or confining zone and a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require.
3. Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known
4. Baseline geochemical analyses of USDWs, hydrocarbons, and the producing and confining zone, consistent with the requirements for Site Characterization & Planning
5. Proposed area of review and corrective action plan that meet the Area of Review and Corrective Action Plan requirements
6. A demonstration that the operator has met the financial responsibility requirements
7. Proposed pre-hydraulic fracturing formation testing program to analyze the physical and chemical characteristics of the producing and confining zone(s), that meet the Well Log, Core, Fluid Sampling, and Testing requirements
8. Well construction procedures that meet the Well Construction requirements
9. Proposed operating data for the hydraulic fracturing operation:
    a. Operating procedure
    b. Calculated fracture gradient of the producing and confining zone(s)

    c. Maximum pressure, rate, and volume of injected fluids and proppant and demonstration that the proposed hydraulic fracturing operation will not initiate fractures in the confining zone or cause the movement of hydraulic fracturing or formation fluids that endangers a USDW

10. Proposed chemical additives:
    a. Service companies and operators must report all proposed additives by their type (e.g. breaker, corrosion inhibitor, proppant, etc), chemical compound or constituents, and Chemical Abstracts Service (CAS) number
    b. Service companies and operators must report the proposed concentration or rate and volume percentage of all additives
11. Proposed testing and monitoring plan that meets the testing and monitoring plan requirements
12. Proposed well plugging plan that meets the plugging plan requirements
13. Proposed emergency and remedial action plan
14. Prior to granting final approval for a hydraulic fracturing operation, the regulator should consider the following information:
    a. The final area of review based on modeling and using data obtained from the logging, sampling, and testing procedures
    b. Any updates to the determination of geologic suitability of the site and presence of an appropriate confining zone based on data obtained from the logging, sampling, and testing procedures
    c. Information on potential chemical and physical interactions and resulting changes to geologic properties of the producing and confining zone(s) due to hydraulic fractures and the interaction of the formations, formation fluids, and hydraulic fracturing fluids, based on data obtained from the logging, sampling, and testing procedures
    d. The results of the logging, sampling, and testing requirements
    e. Final well construction procedures that meet the well construction requirements
    f. Status of corrective action on the wells in the area of review
    g. A demonstration of mechanical integrity
    h. Any updates to any aspect of the plan resulting from data obtained from the logging, sampling, and testing requirements.

HOW COULD CLASS II FINANCIAL RESPONSIBILITY REQUIREMENTS BE MET FOR WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

Operators must demonstrate and maintain financial responsibility by means of a bond, letter of credit, insurance, escrow account, trust fund, or some combination of these financial mechanisms or any other mechanism approved by the regulator. The financial responsibility mechanism must cover the cost of corrective action, well plugging and abandonment, emergency and remedial response, long term monitoring, and any clean up action that may be necessary as a result of contamination of a USDW.

WHAT PUBLIC NOTIFICATION REQUIREMENTS OR SPECIAL ENVIRONMENTAL JUSTICE CONSIDERATIONS SHOULD BE CONSIDERED FOR AUTHORIZATION OF WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

EPA must ensure that there are opportunities for public involvement and community engagement throughout all steps of the process.

1. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:
    a. Baseline water quality analyses for all USDWs within the area of review
    b. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
    c. Proposed chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives
2. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:
    a. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
    b. Actual chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
    c. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

WHAT ARE EFFICIENT ALTERNATIVES TO AUTHORIZE/PERMIT CLASS II WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

The use of area permits should not be allowed for wells that use diesel fuel for hydraulic fracturing. Each hydraulic fracturing operation is unique and designed for site-and well-specific needs. The fluid volumes required, chemical make-up of hydraulic fracturing fluid, and geology and hydrology of the producing and confining zones can vary from well to well.

In situations where multiple wells will be drilled from the same surface location or pad, it may be permissible to issue a group permit for all such wells. In requesting a group permit, operators must provide the regulator with an analysis demonstrating that the geology, hydrology, and operating parameters of all wells are sufficiently similar such that the issuance of a group permit will not pose increased risks to USDWs as compared to individual permits. If a group permit is approved, operators must still disclose information on injected chemicals for each individual well unless the type and volume of chemicals injected will be identical for each well. Operators must also still provide geochemical analyses of flowback and produced water for each individual well.

Conclusions

Thank you for your consideration of these comments. We are pleased that EPA is undertaking this effort to develop permitting guidance for hydraulic fracturing using diesel fuel. While this guidance is crucial to ensure that no further unpermitted hydraulic fracturing using diesel occurs, we urge EPA to begin the process of drafting new regulation that specifically addresses the unique risks hydraulic fracturing poses to USDWs.

Sincerely,

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A MEMORANDUM OF AGREEMENT

Between

The United States
Environmental Protection Agency

And

BJ Services Company,
Halliburton Energy Services, Inc., and
Schlumberger Technology Corporation

Elimination of Diesel Fuel in Hydraulic Fracturing Fluids Injected into Underground Sources of Drinking Water During Hydraulic Fracturing of Coalbed Methane Wells

12 December 2003

A MEMORANDUM OF AGREEMENT
Between
The United States Environmental Protection Agency
And

BJ Services Company,
Halliburton Energy Services, Inc., and
Schlumberger Technology Corporation

I. PREAMBLE

A. This is a voluntary agreement between the United States Environmental Protection Agency (EPA) and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation (the service companies are collectively referred to as the "Companies;" individually as "Company"), by which the Companies agree to eliminate diesel fuel in hydraulic fracturing fluids injected into coalbed methane (CBM) production wells in underground sources of drinking water (USDWs) and, if necessary, select replacements that will not cause hydraulic fracturing fluids to endanger USDWs. While the Companies do not necessarily agree that hydraulic fracturing fluids using diesel fuel endanger USDWs when they are injected into CBM 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.

B. Hydraulic fracturing is a technique used by the oil and gas industry to improve the production efficiency of production wells, including CBM production wells. A hydraulically-created fracture acts as a conduit in the rock or coal formation that allows the oil or gas to travel more freely from the rock pores. To create such a fracture, a viscous, water-based fluid is sometimes pumped into the coal seam under high pressures until a fracture is created. These fluids consist primarily of water, but in some cases they also contain various additives. Diesel fuel has been used as an additive in hydraulic fracturing fluids for the purpose of enhancing proppant delivery.

C. The Companies and EPA recognize that the primary purpose of this agreement is to eliminate the use of diesel fuel in hydraulic fracturing fluids injected into CBM production wells in USDWs.

II COMMON AGREEMENTS AND PRINCIPLES

A. The Companies and EPA acknowledge that only technically feasible and cost-effective actions to provide alternatives for diesel fuel will be sought. The determination of what is technically feasible and cost-effective will vary and it is at the discretion of each Company to make that determination.

B. The Companies and EPA will exercise good faith in fulfilling the obligations of this Memorandum of Agreement (MOA).

C. Nothing in this agreement constrains EPA or the Companies from taking actions relating to hydraulic fracturing that are authorized or required by law. Nothing in this agreement should be understood as an EPA determination that use by the Companies of any particular replacement for diesel fuel is authorized under the Safe Drinking Water Act (SDWA) or EPA's Underground Injection Control (UIC) Regulations, or that the elimination of diesel fuel or use of any replacement fluid constitutes or confers any immunity or defense in an action to enforce the SDWA or EPA's UIC regulations. Nothing in this Agreement shall, in any way, be considered a waiver of the Companies' right to challenge any subsequent regulations or limitations on the use of hydraulic fracturing or its components by any state or Federal agencies.

D. All commitments made by EPA in this MOA are subject to the availability of appropriated funds and Agency budget priorities. Nothing in this MOA, in and of itself, obligates EPA to expend appropriations or to enter into any contract, assistance agreement, interagency agreement, or other financial obligations. Any endeavor involving reimbursement or contribution of funds between EPA and the Companies will be handled in accordance with applicable laws, regulations, and procedures, and will be subject to separate agreements that will be effected in writing by representatives of the Companies and EPA, as appropriate.

E. EPA and the Companies will bear their own costs of carrying out this agreement. The Companies agree that activities undertaken in connection with this MOA are not intended to provide services to the Federal government, and they agree not to make a claim for compensation for services performed for activities undertaken in furtherance of this MOA to EPA or any other Federal agency.

F. Any promotional material that any Company develops may advise the public of the existence of this MOA and its terms, but must not imply that EPA endorses the purchase or sale of products and services provided by any Company.

G. This MOA does not create any right or benefit, substantive or procedural, enforceable by law or equity against the Companies or EPA, their officers or employees, or any other person. Nothing herein shall be deemed to create any requirement under any existing law or regulation. This MOA does not direct or apply to any person outside the Companies and EPA.

III. EPA ACTIONS

A. To the extent consistent with Agency authorities and policies governing recognition awards, EPA agrees to consider providing the Companies with recognition for their achievements in replacing diesel fuel in fracturing fluids injected into USDWs for CBM production and for their public service in protecting the environment. In addition, EPA agrees to provide appropriate information to the public, other Federal agencies and Congress, regarding actions taken by the Companies under this MOA. EPA agrees to obtain the Companies' approval on any specific language intended for public distribution that discusses the Companies' participation in this MOA and agrees to notify the Companies sufficiently in advance of EPA's intention to publicly use the Companies' name or release information, including press releases, concerning the Companies' participation in this MOA.

B. EPA agrees to contact appropriate individuals representing states, industry, and the Department of Energy to inform them of progress in implementing the MOA and to solicit their cooperation, as appropriate, in implementation of the MOA.

C. EPA agrees to issue a final version of the draft report entitled *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* as soon as reasonably possible.

D. The parties agree that nothing in this MOA is intended to affect, in any way, the existing criteria and process for identifying exempted aquifers under 40 C.F.R. Parts 144 and 146.

E. EPA agrees to consider other measures as appropriate to aid implementation of the MOA, including measures to facilitate efforts undertaken by the Companies pursuant to this MOA.

IV. THE COMPANIES' ACTIONS

A. The Companies agree to eliminate diesel fuel in hydraulic fracturing fluids injected into CBM production wells in USDWs within 30 days of signing this agreement. If necessary, the Companies may use replacement components for hydraulic fracturing fluids that will not endanger USDWs.

B. The Companies agree to notify the Assistant Administrator for EPA's Office of Water within 30 days after any decision to re-institute the use of diesel fuel additives in hydraulic fracturing fluids injected into USDWs for CBM production.

C. The Companies and EPA may, upon unanimous consent of the signatories, include additional provisions in, or make modifications to, this MOA. Such additions or modifications must contribute to the goal of preventing the endangerment of USDWs. Nothing herein shall be construed as requiring the adoption of any such additional provisions or modifications.

V. DISPUTE RESOLUTION AND TERMINATION OF AGREEMENT

A. Any Company or EPA may terminate its participation in this MOA by providing written notice to the other signatories. Such termination as to that Company (or, if EPA terminates the MOA, as to all) will be effective 30 days after the receipt of written notice and will result in no penalties or continuing obligations by the terminating Company (or, if EPA terminates the MOA, any signatory). If EPA or any Company terminates the MOA, EPA and/or that Company will refrain from representing that the Company is continuing to cooperate with EPA on replacing diesel fuel in hydraulic fracturing fluids injected in USDWs for CBM production, provided that they may continue to make reference to activities undertaken through the date of this termination. If its participation in this MOA is terminated by any Company, the MOA shall have no further force and effect for the terminating Company, and the terminating Company shall have no further obligation under the MOA.

VI. SIGNATORIES

The undersigned hereby execute this Memorandum of Agreement on behalf of their Companies and EPA. This agreement takes effect when signed by any Company and EPA.

For the United States Environmental Protection Agency:

G. Tracy Mehan, AA Date: 12/18/03

G. Tracy Mehan, III
Office of Water

For BJ Services Company:

Kenneth A. Williams
President, US/Mexico Division

Date:

Reviewed by BJ Legal

Initial Here

For Halliburton Energy Services, Inc.:

David King
Vice President

Date: 12/15/03

REVIEWED
LEGAL
DATE 12/15/2003

For Schlumberger Technology Corporation:

Ryan Cox
North American Well Services Manager

Date: 12/15/2003.

Congress of the United States
Washington, DC 20515

August 8, 2011

The Honorable Lisa Jackson
Administrator
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Dear Administrator Jackson:

We are writing in regard to the definition of "diesel fuel" that EPA will use in its upcoming guidance on permitting for oil and gas hydraulic fracturing activities.

The 2005 Energy Policy Act exempted hydraulic fracturing from the Safe Drinking Water Act unless the fluid injected contains diesel fuel. For that reason, the way in which EPA defines this term has far-reaching consequences. We encourage you to adopt a definition of "diesel fuel" that is broad enough to protect human health and to address the specific reason why Congress singled out diesel fuel in the law—because it often contains benzene, toluene, ethylbenzene and xylenes (the BTEX compounds).

In a 2004 report, EPA stated that the "use of diesel fuel in fracturing fluids poses the greatest threat" to underground sources of drinking water.[1] EPA called diesel fuel "the additive of greatest concern because it introduces BTEX compounds" into the geologic formation, from which the chemicals could then migrate into sources of drinking water.[2] The Department of Health and Human Services, the International Agency for Research on Cancer, and the EPA have all determined that benzene is a human carcinogen. Long term exposure to the chemicals toluene, ethylbenzene, or xylenes also have significant health impacts as they can damage the central nervous system, liver, and kidneys.

These concerns about diesel and the BTEX compounds contained in diesel led EPA to negotiate a memorandum of agreement with the three largest hydraulic fracturing providers to voluntarily stop using diesel fuel when performing hydraulic fracturing in underground sources of drinking water.[3] Congress also specified in the Energy Policy

[1] U.S. Environmental Protection Agency, Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coal bed Methane Reservoirs (June 2004) (EPA816-R-04-003) at 4-11.
[2] *Id.* at ES-12.
[3] Memorandum of Agreement between the U.S. Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation (Dec. 12, 2003).

Act of 2005 that the requirements of the Safe Drinking Water Act underground injection control program still apply to the use of diesel fuel in hydraulic fracturing fluids.[4]

We understand that some stakeholders have suggested that EPA limit its definition of diesel fuel to fuels sold in the United States for use in a diesel engine. Others have suggested limiting the definition to a small number of diesel formulations with specific Chemical Abstracts Service (CAS) identifying numbers, citing as justification a report the Energy and Commerce Committee Democrats sent you on January 31, 2011.[5] In that report, Democratic Committee staff calculated the volume of hydraulic fracturing products containing diesel fuel with three specific CAS numbers. The report focused on those three types of diesel fuel because of data limitations, not because the permitting requirement in the Energy Policy Act applies only to these three specific diesel types. The goal of the report was to reveal to policy-makers and the public that oil and gas companies have continued to use diesel fuel in hydraulic fracturing fluids without a permit, not to define what constitutes a diesel fuel.

When EPA raised concerns about the use of diesel fuel in hydraulic fracturing fluids and Congress acted on those concerns, there was no intent to restrict scrutiny to diesel fuels with a particular CAS number or with a certain sulfur content. Instead, diesel fuel was singled out for regulation because of the BTEX components contained in the diesel formulations. Limiting the definition of diesel fuel to only a slim set of CAS numbers or only to diesel fuels legally sold in the United States for use in a diesel engine would not be consistent with Congress's intent. It could result in a scenario in which hydraulic fracturing companies could use many forms of diesel fuel without obtaining a permit—even if the fuel contained BTEX compounds—because the diesel formulation fell outside the scope of a narrow definition.[6]

How "diesel fuel" is defined is a vital issue as the agency crafts guidance for permitting diesel fuel use for hydraulic fracturing. Since federal law contains no public disclosure requirements for hydraulic fracturing fluids, this guidance offers an opportunity to clarify permitting requirements and increase consistency and transparency of program implementation in a way that serves to protect public health and drinking water supplies. We urge you to craft a definition that provides consistency to industry while serving to protect public health and the environment.

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[4] 42 U.S.C. § 300h(d)

[5] Letter from Henry A. Waxman, Edward J. Markey, and Diana DeGette to EPA Administrator Lisa Jackson (Jan. 31, 2011) (online at http://democrats.energycommerce.house.gov/sites/default/files/documents/Jackson.EPADieselFracking.2011.1.31.pdf).

[6] For example, if EPA limited the definition of diesel to the three CAS categories examined in the Energy and Commerce Committee study, that could have the unintended consequence of excluding other diesel fuel formulations from appropriate permit requirements. For instance, fuel oil #4 is used in some diesel engines. The Committee did not obtain any evidence that oil and gas companies currently use fuel oil #4 in hydraulic fracturing; however, excluding it from permitting requirements would not be appropriate given its chemical composition.

Sincerely,

Henry A. Waxman
Ranking Member
Committee on Energy and Commerce

Edward J. Markey
Ranking Member
Committee on Natural Resources

Diana DeGette
Ranking Member
Subcommittee on Oversight and Investigations
Committee on Energy and Commerce

Rush Holt
Ranking Member
Subcommittee on Energy and Mineral Resources
Committee on Natural Resources

Similarly, on February 25, 2011, Weatherford told the Committee that it had provided a Material Safety Data Sheet (MSDS) to the Committee that incorrectly listed diesel fuel as one of the product's components. Weatherford informed the Committee that the product does not contain diesel; rather, it contains a non-diesel petroleum distillate. As a result of this error, the information originally provided to the Committee by Weatherford's overstated the company's use of products containing diesel by nearly 1.9 million gallons.

We are providing you with an updated analysis regarding the use of diesel fuel in hydraulic fracturing that reflects these corrections. The new findings indicate a higher use of diesel fuel than our original analysis. Specifically, between 2005 and 2009, oil and gas service companies injected 32.7 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 20 states.

The Committee's Investigation

On February 18, 2010, Chairman Waxman and Subcommittee Chairman Markey announced that the Committee would examine the practice of hydraulic fracturing and its potential impact on water quality across the United States. The Committee sent letters to 14 oil and gas service companies engaged in hydraulic fracturing in the United States regarding the type and volume of chemicals they used in hydraulic fracturing fluids between 2005 and 2009.[1]

These companies voluntarily provided the Committee with data on the volume of diesel fuel and other hydraulic fracturing fluids they used during the five year period.[2] For each hydraulic fracturing fluid, the companies provided the Committee with a MSDS detailing the fluid's chemical components. If the MSDS for a particular product listed a chemical component as proprietary, we asked the company that used that product to provide us with the proprietary information.

Using this information, our staff calculated how much diesel fuel and fracturing fluids containing diesel fuel these 14 companies used between 2005 and 2009.[3]

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[1] The Committee sent letters to Basic Energy Services, BJ Services, Calfrac Well Services, Complete Production Services, Frac Tech Services, Halliburton, Key Energy Services, RPC, Sanjel Corporation, Schlumberger, Superior Well Services, Trican Well Service, Universal Well Services, and Weatherford. The 14 letters, sent on February 18 and May 6, 2010, are available on the Committee's website.

[2] BJ Services, Halliburton, and Schlumberger already had provided Chairman Waxman and the Oversight Committee with data for 2005 through 2007. For BJ Services, the 2005-2007 data is limited to natural gas wells. For Schlumberger, the 2005-2007 data is limited to coalbed methane wells.

[3] The Committee reviewed all MSDSs produced to the Committee and included the following in the category of "diesel": diesel fuel, products with components with the Chemical Abstracts Service (CAS) registry number of 68476-34-6, 68476-30-2, or 68334-30-5, and products with "diesel" named as a component but lacking a CAS number.

Use of Diesel Fuel in Hydraulic Fracturing

Our findings based on these new documents continue to raise serious concerns. Between 2005 and 2009, 12 of the 14 companies used 32.7 million gallons of diesel fuel or fluids containing diesel fuel.[4] BJ Services used the most diesel fuel and fluids containing diesel, more than 11.5 million gallons, followed by Halliburton, which used 7.2 million gallons. Four other companies, RPC (4.3 million gallons), Sanjel (3.6 million gallons), Frac Tech (2.6 million gallons), and Key Energy Services (1.6 million gallons), used more than one million gallons of diesel fuel and fluids containing diesel.

These 12 companies injected these diesel-containing fluids in 20 states. Diesel-containing fluids were used most frequently in Texas, which accounted for more than half of the total volume injected, 16.7 million gallons. The companies injected at least one million gallons of diesel-containing fluids in Oklahoma (3.2 million gallons), North Dakota (3.1 million gallons), Wyoming (2.9 million gallons), Louisiana (2.9 million gallons), and Colorado (1.3 million gallons).

Diesel fuel was a significant component of the diesel-containing fluids these companies injected. The companies used 10.3 million gallons of straight diesel fuel and an additional 20 million gallons of products containing at least 30% diesel fuel.

Tables 1 and 2, which are attached to this letter, list the companies that reported using diesel-containing fluids and the states in which they injected them.

Conclusion

This new information indicates that the use of diesel fuel in hydraulic fracturing may be even higher than expected based on our original estimates. The companies' reporting errors also reinforce the need for mandatory and uniform national disclosure of the contents and use of hydraulic fracturing fluids.

We look forward to the completion of your hydraulic fracturing study and urge you to consider appropriate regulations, as well as permitting guidance, for hydraulic fracturing fluids that contain diesel fuels.

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[4] Calfrac Well Services and Universal Well Services did use any fracturing fluids containing diesel during this time period.

Sincerely,

Henry A. Waxman Ranking Member Committee on Energy and Commerce	Edward J. Markey Ranking Member Committee on Natural Resources	Diana DeGette Ranking Member Subcommittee on Oversight and Investigations

cc: The Honorable Fred Upton
Chairman

The Honorable Cliff Stearns
Chairman
Subcommittee on Oversight
and Investigations

Attachment

Table 1. Injection of Hydraulic Fracturing Fluids Containing Diesel Fuel: By Company (2005-2009)

Company	Volume (gallons)
Basic Energy Services	204,013
BJ Services	11,555,538
Complete	4,625
Frac Tech	2,558,790
Halliburton	7,207,216
Key Energy Services	1,641,213
RPC	4,314,110
Sanjel	3,641,270
Schlumberger	443,689
Superior	833,431
Trican	92,537
Weatherford	228,388
Total	**32,724,820**

Table 2. Injection of Hydraulic Fracturing Fluids Containing Diesel Fuel: By State (2005-2009)

State	Volume (gallons)
AK	39,375
AL	2,464
AR	516,555
CA	26,381
CO	1,321,275
FL	377
KS	50,489
KY	212
LA	2,922,432
MI	8,007
MS	221,044

State	Volume (gallons)
MT	662,946
ND	3,138,950
NM	574,979
OK	3,208,391
PA	32,783
TX	16,703,762
UT	330,084
WV	8,754
WY	2,955,560
Total	**32,724,820**