

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 xylene (“BTEX”) compounds it poses a major concern.<sup>1</sup> 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).<sup>2</sup> 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.”<sup>3</sup> 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.”<sup>4</sup>

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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<sup>1</sup> 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.

<sup>2</sup> 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.

<sup>3</sup> Letter from Reps. Waxman, Markey, and DeGette to EPA Administrator Lisa Jackson (Jan. 31, 2001) at 1.

<sup>4</sup> *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.<sup>5</sup>

As the Congressional investigation demonstrates, oil and gas companies ignored these clear requirements.<sup>6</sup> 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**

### **WHAT SHOULD BE CONSIDERED AS “DIESEL FUELS?”**

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.

### **WHAT WELL CONSTRUCTION REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?**

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<sup>5</sup> 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).

<sup>6</sup> 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

American 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<sup>7</sup>
  - 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

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<sup>7</sup> 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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