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June 5, 2013

The Honorable Ron Wyden
Chair
U.S. Senate Committee on Energy and Natural Resources
304 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Chairman Wyden,

Thank you for the opportunity to participate in the Senate Committee on Energy and Natural Resources Forum on Environmental Impacts of Shale Gas Development and Best Practices on May 23rd. We were honored to attend.

Attached are responses to the questions you posed regarding chemical disclosure, FracFocus, and flaring, as well as a section relating to the role and adequacy of state regulations. We have also included a response to Senator Landrieu's question regarding water contamination.

We look forward to continued discussions on this important topic.

Sincerely,

Amy Mall

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Senate Committee on Energy and Natural Resources
Full Committee Forum on Environmental Impacts of Shale Gas Development and Best Practices
May 23, 2013

Natural Resources Defense Council and Sierra Club's Response to Questions for the Record from Chairman Wyden Regarding Disclosure

1. Should the public have information on the chemicals being used before the fracking takes place?

Yes. We support full disclosure of all chemicals used in the oil and gas exploration and production process, including drilling and well stimulation.[1] There are many ways in which the public can be exposed to these chemicals. As we explain in our separate comment on water contamination, groundwater and surface waters can be contaminated as a result of activities during many phases of oil and gas exploration and development. Blowouts, which can send thousands of gallons of stimulation fluids spewing from the well, have occurred during hydraulic fracturing operations.[2] Spills of hydraulic fracturing fluids and other chemicals have polluted streams and lakes.[3] Stimulation fluids and chemicals must be transported to the well site and stored there. Flowback containing these chemicals must be stored at the well site, transported off site, and disposed of. Each of these processes poses risks of accidental spills or release into the environment.

Because the public is at risk of being exposed to chemicals used in fracking, the public has a right to know what those chemicals are, and thus, the consequences of such exposure. Many well stimulation chemicals are toxic.[4] Some, like formaldehyde, are known carcinogens.[5] Prior

[1] While much of the public's focus has been on hydraulic fracturing chemicals, many other chemicals are used in the drilling, exploration, and production process. Disclosure of all chemicals used in drilling and well stimulation should be required. In these comments we focus specifically on disclosure of well stimulation chemicals. It is important to note that hydraulic fracturing is only one method of well stimulation. Operators in the Monterey Shale of California, for example, have experimented with high-volume acidizing, using large amounts of hydrofluoric acid, which is extremely hazardous. *See, e.g.*, Rhonda Duey, *Monterey Shale - California's Sleeping Giant?*, E&P Magazine (Jun. 1, 2011). Such processes should not be exempted from chemical disclosure rules. Other methods to stimulate oil and gas production, including acidizing, pose similar risks to hydraulic fracturing. For this reason, state and federal regulatory agencies should require disclosure of all well stimulation fluids.

[2] *See, e.g.*, Andrew Maykuth, *Pa. Investigating Marcellus Well Blowout*, Philadelphia Inquirer (Jan. 26, 2011) (reporting that approximately 21,000 gallons of fluid and sand had spewed from a well during hydraulic fracturing operations).

[3] *See, e.g.*, Laura Legere, *Natural Gas Well Suffers Blowout, Releasing Fluids in Bradford County*, The Times-Tribune (Apr. 21, 2011) (stating that "[t]housands of gallons of natural gas drilling waste fluids spilled onto a farm and streams for more than 12 hours" after a blowout during hydraulic fracturing).

[4] *See* Theo Colborn et al., *Natural Gas Operations from a Public Health Perspective*, 17 Hum. & Ecological Risk Assessment: An Int'l J. 1039,1040, 1045-46.

[5] *See Id*. at 1050, tbl.2; International Agency for Research on Cancer, List of Classifications by CAS Number Registry, *available at* http://monographs.iarc.fr/ENG/Classification/index.php.

disclosure of chemicals that will be used allows the public to participate in decisionmaking and permitting processes. It also facilitates development of baseline data to be used in determining whether contamination and/or exposure has occurred. With advance disclosure and proper notice, the public, including those who live or own property near a well, can document pre-stimulation conditions, including air and water quality in the area, in case of pollution or spills. In particular, nearby water sources can be tested to determine baseline levels of the substances that will be used in the proposed stimulation fluid to document whether any future water contamination is a result of hydraulic fracturing or other well stimulation techniques. Prior disclosure also enables the public to assess the severity of the consequences associated with an accident or contamination incident and helps inform individuals deciding whether the risks warrant the expense of baseline testing. Prior disclosure and notification may also facilitate a conversation between local stakeholders, regulators and companies which can encourage the use of safer chemicals and practices, when they are available.

To ensure that baseline testing can measure pre-stimulation levels of potential contaminants, disclosure of the chemicals must be made far enough in advance to allow sufficient time for testing to be arranged and performed before stimulation begins. For this reason, we support disclosure at least thirty days in advance of fracturing or other stimulation. This period gives regulatory entities, landowners and other members of the public adequate time to identify an independent laboratory and arrange for testing to occur prior to well stimulation.

Another benefit of prior disclosure of the chemicals to be used in well stimulation on a public website is that it helps ensure immediate access to chemical information for emergency responders, and medical and public health professionals, responding to incidents at a well site when such chemicals are present. This information is critical to understanding the hazards that may be present at a site and the chemicals to which accident victims could have been exposed. Although emergency and health professionals should also have the right to receive this information from regulators and operators directly, public disclosure will assure timely access to this information.

In light of the environmental and public health needs for full prior disclosure of chemical information, we believe that disclosure requirements should not provide exemptions for trade secrets. However, if operators are allowed to exempt trade secrets from public disclosure, additional provisions are necessary to lessen the impact on the public. Operators must disclose all information claimed as a trade secret to the regulatory agency so that the agency can evaluate the legitimacy of trade secret claims and identify previously undisclosed chemicals when necessary for emergency responders and medical and public health professionals. Emergency responders and medical and public health professionals must have the option of demanding withheld information directly from the well operator, and these professionals must have the freedom to share this information as they determine necessary in the discharge of their duties.

Separately, even if certain chemical identities are withheld from public disclosures as trade secrets, operators must publicly disclose the chemical family of a fracturing fluid additive in the prior disclosure, which will provide information on the types of hazards that may be present at a site to the public and to public health and medical professionals and emergency responders. In the event of an accident, it may be crucial to have immediate access to this critical information, without waiting for withheld chemical identities to be provided by the operator or regulator.

Advance disclosure of anticipated well stimulation chemicals imposes minimal costs on the oil and gas industry and has been shown to be feasible. For instance, the state of Wyoming implemented a requirement for prior disclosure of all well stimulation chemicals in September of 2010. Oil and gas companies voiced support for these regulations.[6] Two and a half years after these rules were implemented, the Wyoming oil and gas industry continues to flourish. Unfortunately, however, prior disclosure is not the norm. Out of approximately 30 states with hydraulic fracturing, only five require any sort of prior disclosure of fracking chemicals.[7] Because a company's choice of well stimulation chemicals may need to be adjusted during the stimulation operation, companies should also be required to submit a completion report within 30 days of completing a well stimulation operation that details the chemicals that were actually used.

Advance notice of well stimulation for landowners, residents, and owners of water sources is a critical counterpart to prior disclosure:

The ends to be achieved through prior disclosure of chemicals may be frustrated if nearby parties are not notified that well stimulation is about to occur. If these parties are unaware that fracking or other well stimulation is planned in their area, prior disclosure of chemicals on a state website is useless to them. For this reason, disclosure rules should require 30-day advance notice be given to landowners, those who own or manage water wells or other sources of drinking water, and non-owner residents within no less than one half mile of any part of the wellbore.

In 2012, the Idaho legislature approved new rules requiring companies to notify all home owners, water well owners and owners of public drinking water systems located within ¼ mile of an oil and gas well of proposed well treatments.[8] Colorado's rules also provide for notification of hydraulic fracturing to landowners within 500 feet of a well to be hydraulically fractured, and require landowners to notify residents of these lands.[9] However, in most states, no notice of well stimulation is given to those most likely to be affected. To ensure that nearby parties are aware

[6] *See, e.g.,* Jim Magill, *Wyoming E&P in Fracking Probes*, Intl. Gas R. (Sept. 27, 2010) (quoting a spokesman for Encana, an oil and gas company, noting that the company had "supported the [Wyoming] regulation"); *see also* Inside the EPA, *New Hydraulic fracturing Rules Could Aid Industry Opposition to EPA Oversight*, (June 18, 2010) (quoting an industry source calling the Wyoming rules "workable").

[7] *See* Matthew McFeeley, *State Hydraulic Fracturing Disclosure Rules and Enforcement: A Comparison*, NRDC ISSUE BRIEF, 8 (July 2012) *available at* http://www.nrdc.org/energy/files/Fracking-Disclosure-IB.pdf.

[8] IDAPA 20.07.02 – 055.01.m.

[9] Colorado Oil and Gas Conservation Commission Rule 305(e).

of upcoming fracking or other well stimulation, disclosure rules should include a requirement that advance notice be given to nearby landowners, those who own water wells, and non-owner residents. We believe no less than one half mile is an appropriate zone for notice.[10]

Special considerations related to public lands and resources:

In the context of well stimulation on public lands, information on anticipated chemicals and their concentrations is also necessary for the Bureau of Land Management (BLM) and other relevant federal agencies, such as the U.S. Forest Service, to evaluate the risks that a particular stimulation treatment poses to the lands and resources these agencies manage. The BLM and other agencies cannot evaluate the risks that are posed by well stimulation without prior disclosure of the chemicals to be used in each stimulation treatment. Many people live and recreate on or adjacent to federal lands, and federal lands provide sources of clean drinking water to millions of Americans.[11] Federal agencies cannot adequately understand and manage the risks to public health and federal resources without requiring permittees to report the chemicals they anticipate using in each stimulation treatment.

BLM staff have previously stated that advance disclosure is not critical because companies generally use the same well stimulation plan within a given field, so local residents who want to conduct baseline tests and others interested in advance information can simply refer to the reports for the previous stimulation treatments that had been conducted in the field. Different companies, however, use different stimulation fluids and may change recipes based on the circumstances of a particular well. By way of example as to the problems associated with a lack of advance disclosure, in North Dakota's Bakken Formation, over 3,000 new wells have been drilled in the past five years with over 80 companies leasing, drilling and hydraulically fracturing in the area. Without prior disclosure, a landowner may not know which operator or service company will be stimulating a particular well, or if stimulation fluids are the same. Moreover, in newer fields, landowners near the first wells that are stimulated should be provided with the same opportunity to conduct baseline water quality tests as those near wells that are stimulated later.

BLM currently notifies owners of lands that lie above federally-owned oil and gas rights ("surface owners") before leasing[12] and requires that oil and gas lessees engage in good faith efforts to secure a surface use agreement and contact a surface owner before entry onto their land.[13] But no requirement ensures that a surface owner has notice of when fracturing or refracturing will occur. And no provisions protect nearby landowners, non-owning residents, or

[10] *See* Natural Resources Defense Council *et al.*, Comments on Proposed Rule on Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and State Lands at 28-29 (Sept. 10, 2012).
[11] *See, e.g.*, Amy Mall, NRDC Switchboard, *Drinking water for millions - including D.C. - at risk without stronger BLM fracking rules* (Nov. 28, 2012), http://switchboard.nrdc.org/blogs/amall/drinking_water_for_millions_-.html.
[12] BLM Instruction memorandum 2009-184, *available at* http://www.blm.gov/wo/st/en/info/regulations/Instruction_Memos_and_Bulletins/national_instruction.html.
[13] Onshore Oil and Gas Order #1, Part VI.

those who own or manage water sources nearby. BLM and operators already have contact information for surface owners that would allow them to provide notice and advance disclosure to landowners at virtually no cost. Each of these potentially affected parties should receive advance notice and disclosure of the chemicals to be used.

Conclusion: Prior disclosure provides numerous benefits and costs almost nothing.
No clear rationale exists for not requiring prior disclosure of hydraulic fracturing chemicals. Providing a list of anticipated fracking chemicals is virtually costless and has been shown to be workable in states where prior disclosure requirements exist. Given the numerous benefits discussed above, prior disclosure of chemicals should be required in advance of hydraulic fracturing.

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Natural Resources Defense Council and Sierra Club's Response to Questions for the Record from Chairman Wyden Regarding FracFocus.org

1. Is it possible to put in place a system for checking the accuracy of what is reported?

While it is theoretically possible to ensure that data on the FracFocus website is accurate via proper oversight and auditing protocols by regulatory agencies, such procedures are not currently in place. Until procedures are in place to ensure accuracy of reported data, FracFocus should not be used to satisfy mandatory disclosure requirements. For instance, where disclosure to FracFocus has been mandated by state rules, its use appears to reduce compliance with some state reporting requirements. Concentration ranges, rather than exact concentrations, are routinely reported on FracFocus even where state rules do not allow them. Compliance may be poor because agency staff are less likely to review information submitted to the website as rigorously as they review submissions directly to the agency.

Disclosure using the standardized FracFocus form can also create obstacles to compliance with state reporting requirements, leaving companies to determine how to conform to state requirements that are inconsistent with the standardized reporting form.[14] For instance, Texas rules require companies to report on FracFocus the amount and type of the base fluid used (for instance recycled water, fresh water, or some other base fluid).[15] However, the FracFocus form provides no field for entry of base fluid type and explicitly states that the figure reported in the "Total Water Volume" field "may include fresh water, produced water, and/or recycled water." If FracFocus is to be used for mandatory disclosure, regulators must ensure that each report is carefully reviewed for omissions and errors and work with the website to develop a form that requires all information required by relevant state and federal disclosure rules.

A recent study by researchers at Harvard University Law School found that FracFocus, as currently constituted, is an inappropriate tool for regulatory disclosure. Among the concerns the Harvard study noted were that trade secret claims by companies were inconsistent across states, finding that in numerous instances companies claimed that a fracking fluid additive was a trade

[14] *See* Kate Konschnik, Harvard Law School Environmental Law Program Policy Initiative, *Legal Fractures in Chemical Disclosure Laws: Why the Voluntary Chemical Disclosure Registry FracFocus Fails as a Regulatory Compliance Tool* 9 (April 23, 2013) *available at* http://blogs.law.harvard.edu/environmentallawprogram/files/2013/04/4-23-2013-LEGAL-FRACTURES.pdf.
[15] *See* 16 Tex. Admin. Code 3.29 (c)(2)(A)(viii).

secret in one state despite having disclosed its ingredients in another.[16] The study also noted that in a review of all chemicals disclosed at wells in Texas over a month-long period, 29 percent of Chemical Abstract Service numbers reported did not exist.[17] This raises questions about the credibility of information on FracFocus.

Recommendations to ensure accuracy and proper oversight include:

- FracFocus should not be used as the primary means of disclosure unless the problems identified above are first addressed.
- Where reporting to FracFocus is incorporated into a regulatory disclosure requirement, the reporting form must be made consistent with what is required by the relevant disclosure rule.
- Protocols should be developed to ensure that each report is carefully reviewed for omissions and errors by the regulatory entity requiring disclosure. These protocols should be made publicly available and compliance with the protocols should be regularly reported to the public.

2. Are there any legal repercussions resulting from false certifications on the FracFocus site?

Because this is not an issue that our organizations have investigated in detail, we are unable to provide a response.

3. Would it make sense to require the use of Chemical Abstract Service (CAS) numbers for the chemicals, as the proposed BLM regulation does?

Yes. The use of Chemical Abstract Service (CAS) numbers for the chemicals should be required. CAS numbers are unique numerical identifiers for each chemical assigned by the American Chemical Society. CAS numbers are the global standard for authoritative identification of chemicals and allow each chemical constituent to be unambiguously identified, which is essential to provide an accurate picture of the substances used in each hydraulic fracturing treatment. Without CAS numbers, uncertainty can arise as to the precise chemical being identified, its physical and chemical characteristics, and the health effects from exposure. For example, if provided the chemical name "dichlorobenzene," it is impossible to know if the substance is 1,2 dichlorobenzene, 1,3 dichlorobenzene, or 1,4 dichlorobenzene. 1,4 dichlorobenzene is considered a carcinogen but the other two are not. Separate CAS numbers exist for each type of dichlorobenzene, plus one for mixed dichlorobenzene, so that if CAS

[16] Kate Konschnik, Harvard Law School Environmental Law Program Policy Initiative, *Legal Fractures in Chemical Disclosure Laws: Why the Voluntary Chemical Disclosure Registry FracFocus Fails as a Regulatory Compliance Tool* 9 (April 23, 2013).
[17] *See Id.* at 7.

numbers are required, the chemical can be precisely identified. Unfortunately, only about half of states with disclosure rules currently require all chemical additives in fracturing fluid to be identified by their CAS numbers.

4. Who funds FracFocus currently? How much does it cost to maintain the site annually?

We do not have access to this information.

5. How long is the data retained on the FracFocus site?

The public does not have any way to know how long data is retained on FracFocus nor what the site's data management and retention policies are more generally. However, it is clear that its systems do not meet minimum standards for government records retention and management. For instance, federal agencies' systems for managing and retaining electronic records must meet certain minimum standards.[18] FracFocus does not currently meet those standards.

Federal and state regulations require protections against unauthorized alteration or deletion, as well as controls such as audit trails to ensure records are complete and unaltered.[19] By contrast, FracFocus records contain no publication date and may be changed or updated by operators at any time. When changes are made, the original record is not preserved and there is no indication that additions or deletions have occurred.[20] Additionally, FracFocus explicitly states that it "assume[s] no responsibility for the timeliness, deletion, misdelivery, or failure to store any" information.[21] If data on the site were lost, corrupted or deleted, public agencies would have no recourse.

Any regulatory system for disclosure of hydraulic fracturing should provide a clear indication when each record was published, so that compliance with the reporting deadlines can be tracked. Any subsequent alterations to an original submission should create a new record to preserve a full history of the information disclosed on separate occasions. An adequate regulatory disclosure system must also ensure that data will be properly backed up and that public records will not be lost if a problem occurs with a private website. In addition to measures to avoid

[18] *See, e.g.*, 36 C.F.R. § 1236.10(b), (c). State agencies often must adhere to similar requirements to avoid improper handling, alteration and deletion of records. To limit the scope of the discussion, we focus on federal requirements here, as an example.

[19] *See e.g.*, *Id.*, New Mex. Admin. Code 1.13.3.

[20] It is possible that the original records are preserved by the site itself. However, they are not available on the website and the fact that the site asserts it is not covered by freedom of information laws makes those records, even if they exist, unavailable for public or BLM use.

[21] *See* Website Terms and Conditions of Use §2 *available at* http://fracfocus.org/terms-of-use (accessed May 30, 2013).

accidental data loss, any disclosure system should have an explicit policy of long-term data retention. Because of the time required for certain forms of underground fluid migration, fracking and oil and gas production may cause groundwater contamination that is not discovered until years after disclosure occurs. Data regarding fluids used must be available at that time to assist in determining the source of contamination and necessary remediation or other measures.

6. What could make FracFocus more "user friendly"? Is there a way to modify the site to facilitate the aggregation of data and further analysis of what chemicals are used where?

FracFocus currently limits access to aggregate data and prevents sharing, hindering public access to information and research efforts into hydraulic fracturing. FracFocus provides no way for users to download the database in aggregate but only allows access to a single disclosure document at a time. While FracFocus has announced improvements, including requiring submissions in xml form and additional search functionality, there has been no indication that there will be any changes in the availability of aggregate information available to the public. Specifically, it appears that the site will continue to allow the public to access data by individual well only, in single pdf documents, as is currently the case. Preventing access to a database of information about hydraulic fracturing hampers researchers' efforts to better understand fracking and its impacts.

Public agencies should not use a site that prevents public data from being downloaded for scientific or other research. President Obama recently signed an executive order requiring new data held by the federal government to be published in open, machine readable format.[22] BLM's proposed adoption of FracFocus fails to meet the requirements of the executive order.

The FracFocus site's official Terms of Use also put unnecessary restrictions on public use, sharing, and aggregation of the data on the site. The Terms of Use state that a user "may not copy, reproduce, modify, republish, upload, post, transmit, or distribute any documents or information from this site in any form or by any means without prior written permission."[23] Federal prosecutors have prosecuted violations of a website's terms of use as a violation of the Computer Fraud and Abuse Act.[24] Public agencies should not use a site for public disclosure which explicitly limits the public's ability to share or republish data disclosed pursuant to law or where there is any chance that doing so could subject a member of the public to criminal liability. Users cannot link to FracFocus disclosure documents directly (the site has made it

[22] *See* Exec. Order No. 13,642 (May 9, 2013).
[23] *See Id.* at §7.
[24] *See e.g., U.S. v. Nosal*, 676 F.3d 854 (9th Cir. 2012). While the Ninth Circuit Court of Appeals has held that terms of use violations are not covered by the Computer Fraud and Abuse Act, other circuits have taken broader views. *See JBCHoldings NY, LLC v. Pakter*, 2013 WL 1149061 at 4 (S.D.N.Y. Mar. 20, 2013) (discussing broader interpretations of the Act by the First, Fifth, Seventh, and Eleventh circuits).

impossible to do so) and are prohibited from reposting disclosures by the site's terms of use. This makes it impossible to share a single disclosure without violating the site's terms of use unless permission is first obtained from FracFocus to do so. Substantial changes must be made to the availability of data on FracFocus and to its terms of use before it is an appropriate regulatory tool for public disclosure.

To be appropriate for use by regulatory agencies, the site should facilitate the aggregation of data and further analysis of chemicals used through steps such as:

- Allow users to download the database in aggregate.
- Eliminate restrictions in the site's Terms of Use which unnecessarily restrict public use, sharing, and aggregation of the data on the site.
- Allow users to link directly to FracFocus disclosure documents by providing a permanent URL for each disclosure document.

7. Other Issues

In addition to the issues discussed above, FracFocus has other, related limits. Because of these limits, government should not rely on FracFocus as their primary or official disclosure repository. One such limit is that, although prior public disclosure of anticipated chemicals is an essential part of a disclosure regime, FracFocus is not designed to accommodate prior disclosures. An adequate disclosure system must provide for both initial disclosure of anticipated chemicals as well as subsequent disclosure of chemicals actually used, and both disclosures must be retained for later examination. Another problem with FracFocus is that it is ill-suited to handling claims of trade secrecy. Where a regulator allows some information to be withheld from disclosure as a trade secret, the regulator must provide a way to challenge the claim of trade secrecy and a mechanism under which medical, public health, and emergency professionals can access withheld information. FracFocus does not currently support either need, and as a third-party website, it is unclear how FracFocus could be changed to do so. Accordingly, it would be inappropriate for regulatory agencies to rely on FracFocus as the official repository for chemical disclosures.

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Natural Resources Defense Council and Sierra Club's Response to Questions for the Record from Chairman Wyden Regarding Flaring and Gas Air Emissions

Air pollution from the oil and natural gas sector is a serious problem of nationwide scope that currently threatens the health of communities across the country. An expert panel advising the Department of Energy has long recommended concerted action to reduce these emissions.[1] The Environmental Protection Agency and several states have taken important first steps towards controlling harmful air pollution from the sector through national New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAP), and through state rules.[2] Despite these steps, much more work remains to be done to protect communities and the climate from this pollution. We appreciate the opportunity to further discuss these matters with the Committee.

We have been asked to respond to specific questions regarding flaring of natural gas. We do so below, following a section providing background information on flaring and air quality problems associated with oil and gas development. In addition, taking up the invitation to comment more broadly on environmental impacts from shale gas development, we believe it is important to emphasize at the outset that venting, leaking and release of contaminants throughout the production, processing, transmission and distribution systems[3] are also significant sources of air pollution from the oil and gas sector. Thus, flaring is just one challenge among the many serious air pollution problems from oil and gas development that the Committee should consider.

Venting and Leaking

Within the gas production sector as a whole, flaring is a less substantial pollution source of methane and smog-forming volatile organic compounds (VOCs) than venting and leaking. EPA

[1] DOE, Secretary of Energy Advisory Board Shale Gas Production Subcommittee, Second Ninety Day Report (Nov. 18, 2011) at Annex C.
[2] See, e.g., Oil and Natural Gas sector: New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants Reviews, Final Rule 77 Fed. Reg. 49,490 (Aug. 16, 2012) (final NSPS and NESHAP, drawing heavily on work done by the states of Colorado and Wyoming).
[3] See, e.g., Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards ("TSD") (2011) at 4-7, 5-6, 6-5, 7-9, 8-1, available at: http://epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf; see also Al Armendariz, Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements (Jan. 26, 2009) at 24, available at http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf.

estimates that methane escaping in these ways makes natural gas systems the third largest industrial source of greenhouse gases at the equivalent of 144.7 million metric tons of CO_2,[4] behind only power generation and refineries; adding direct CO_2 emissions from the sector edges it into the number two spot.[5] Similarly, VOC emissions from oil and gas facilities are threatening public health in communities across the country causing elevated ozone levels and exposures to hazard air pollutants like benzene.[6] These emissions can be reduced with cost-effective, proven, technologies,[7] and it is urgent that we pursue every opportunity we have to do so.

Although estimates vary, EPA's recently finalized NSPS will capture methane equivalent to about 21 million metric tons of CO_2 when fully implemented.[8] This leaves over 120 million metric tons CO_2e of methane venting and leaks to capture, or about 86% of sector emissions. Because methane often is emitted along with hazardous air pollutants and smog-forming VOCs, these remaining emissions also threaten local communities and regional air quality. EPA and the states have an array of tools that may aid in capturing or otherwise reducing these emissions. Among the most promising would be extending the NSPS, which currently capture methane only as a co-benefit of VOC controls. In addition, the current NSPS cover only new and modified pollution sources, leaving existing sources (which generate the bulk of the sector's methane emissions) out of the program. Also with significant promise for controlling emissions is setting strong standards under the National Emission Standards for Hazardous Air Pollutants (or NESHAP) provisions of the Clean Air Act. The current NESHAP standards cover only a few

[4] This figure is conservative because it uses a low conversion factor (known as a global warming potential or "GWP") to convert methane to CO_2. In fact, methane is even more potent on a short time scale than the inventory recognizes – a critical consideration as the Earth's climate moves closer to tipping points and we search for effective near-term emissions reductions opportunities. More modern GWPs for methane would significantly increase this figure.

[5] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2011, Table ES-2 (2013) [hereinafter "2013 Inventory"]; see also EPA, Greenhouse Gas Reporting Program: GHGRP 2011 Reported Data, Refineries, available at http://www.epa.gov/ghgreporting/ghgdata/reported/refineries.html (reporting emissions of 182 million tons CO2e from refineries). It should be noted that the Inventory of U.S. Greenhouse Gas Emissions and Greenhouse Gas Reporting Program employ somewhat different accounting systems, and the figure for petroleum refining is most readily ascertainable from the reporting rule. Under either the inventory or the reporting rule, adding in CO_2 emissions from natural gas systems and petroleum systems places the oil and gas category in the second spot, after only power generation. See 2013 Inventory; see also EPA, Greenhouse Gas Reporting Program: GHGRP 2011 Reported Data, Petroleum and Natural Gas Systems, available at http://www.epa.gov/ghgreporting/ghgdata/reported/petroleum.html.

[6] State of Wyoming, Department of Health. 2013. *Associations of Short-Term Exposure to Ozone and Respiratory Outpatient Clinic Visits — Sublette County, Wyoming*, 2008–2011. http://www.health.wyo.gov/news.aspx?NewsID=589; Gilman JG, Lerner BM, Kuster WC, and de Gouw J. 2013. *Source signature of volatile organic compounds from oil and natural gas operations in northeastern Colorado*. Environ Sci. Tech. 47 (3); McKenzie LM, Witter RZ, Newman LS, Adgate JL. 2012. *Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources*. Sci Total Environ. 2012 May 1;424:79-87.

[7] See, e.g., World Resources Institute, J. Bradbury et al., World Resources Institute, Clearing the Air: Reducing Upstream Greenhouse Gas Emissions from U.S. Natural Gas Systems (Apr. 2013); Natural Resources Defense Council, Leaking Profits: The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste (2012).

[8] See 77 Fed. Reg. at 49,492.

sources within the sector. In sum, more complete standards designed to regulate methane directly, to control leaks and venting at existing infrastructure, and to reduce harmful air toxics from a range of sources could greatly reduce dangerous emissions from the sector. Improved rules would have immediate and large public health benefits, cutting pollution in communities in the gas fields which are already experiencing dangerous air quality problems.

Flaring

While we view efforts to address venting and leakage emissions as among the highest priorities for national action, flaring emissions certainly merit careful attention, especially because they are readily avoidable. Flaring is a particularly serious problem in fields where unconventional oil is being produced – such as the Bakken Shale of North Dakota and the Eagle Ford play[9] in Texas. In such plays, much of states' attention has been on requiring flaring instead of venting of gas, primarily as a safety measure to prevent explosions. Even though their charge often includes reducing waste as well, some states thus far have done little to require capture and reuse or resale of gas produced along with oil, rather than simply flaring off the gas.[10] As we discuss below, improved national and state rules can address these problems.

Background on Well-head Flaring

In terms of air pollutants, flares produce significant amounts of NO_x (a smog precursor) and CO_2 from combustion of hydrocarbons, as well as smaller amounts of VOCs, methane, and particulate matter due to incomplete combustion. With regard to greenhouse gas emissions, according to data submitted to EPA under the greenhouse gas reporting rule program, (which tracks emissions from facilities emitting over 25,000 tons CO_2e per year, with the first year of data released this past February) flaring of associated gas at petroleum wells accounted for 4 million tons of CO_2 from covered facilities in 2011.[11] Flares elsewhere in the oil and gas production system added another 7 million metric tons of CO_2.[12] By comparison, venting and leaks in onshore production systems totaled 59 million metric tons CO_2e.[13]

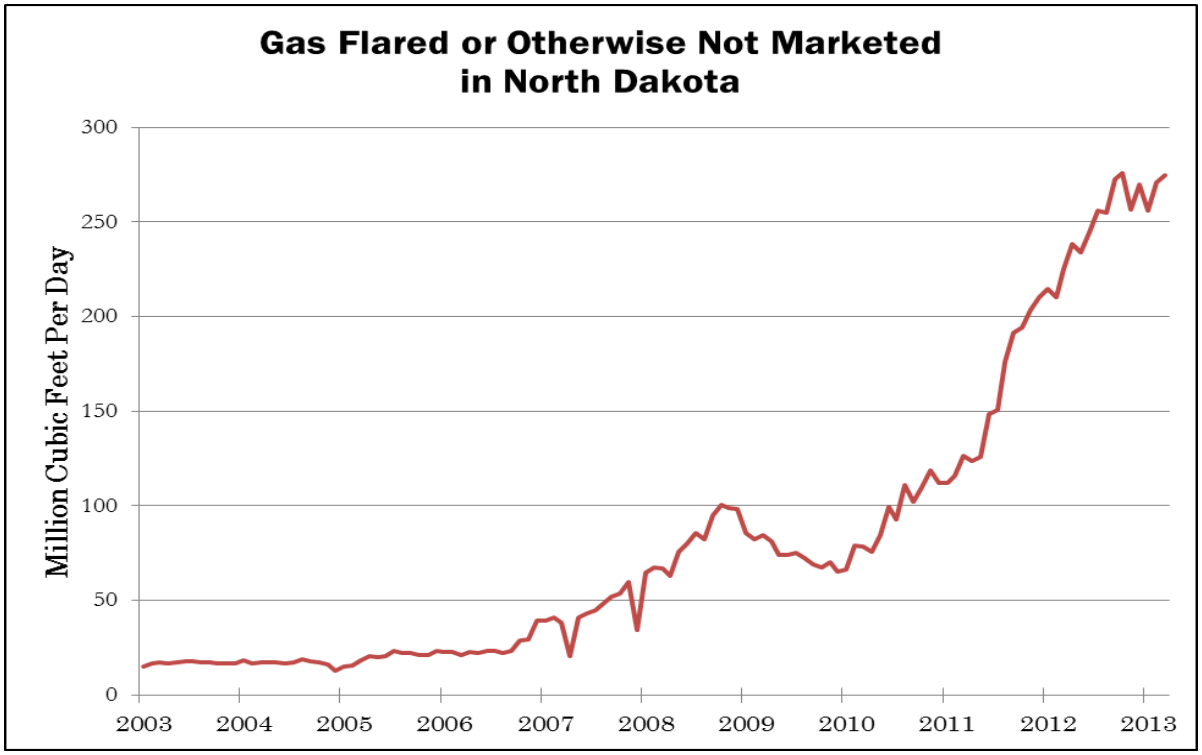
Field flares are most commonly associated with burning off associated gas from unconventional oil wells during well completions and during production before a well is linked to a pipeline, although they can be used at many other points in the system. Flaring and venting during completion of natural gas wells and co-producing wells, by contrast, should largely be eliminated

[9] The term "play" refers to hydrocarbon accumulations that share similar geologic, geographic, and temporal properties.
[10] And in many cases, generous grants of variances from flaring requirements and limited state resources have led to even those flaring requirements being poorly enforced – leaving emissions vented directly to the atmosphere.
[11] EPA, Petroleum and Natural Gas Systems 2011 Data Summary (February 2013), at 4-6, available at http://www.epa.gov/climatechange/Downloads/ghgemissions/2013Workshop/supporting-info-2011-data-summary.pdf.
[12] See id. at 5 (total onshore production flaring emissions are 11 million metric tons).
[13] Id.

by EPA's NSPS. This is because the NSPS phases in a requirement to use "green completions," a process by which gas from the completion phase that would otherwise be vented or flared is instead captured for resale or reuse, providing additional revenues and cost savings to operators. Because the NSPS does not require this process at oil wells, flaring has continued.[14] In addition, emissions from oil and gas wells were not included in the most recent NESHAP standards. Expanding the green completion requirement to cover oil field wells, and concomitantly requiring that pipeline resources keep pace with well drilling and that sources maximize onsite and nearby use of captured gas, are among the most important steps the federal government can take in the near-term to address the flaring problem, as we discuss below.

Magnitude of the problem

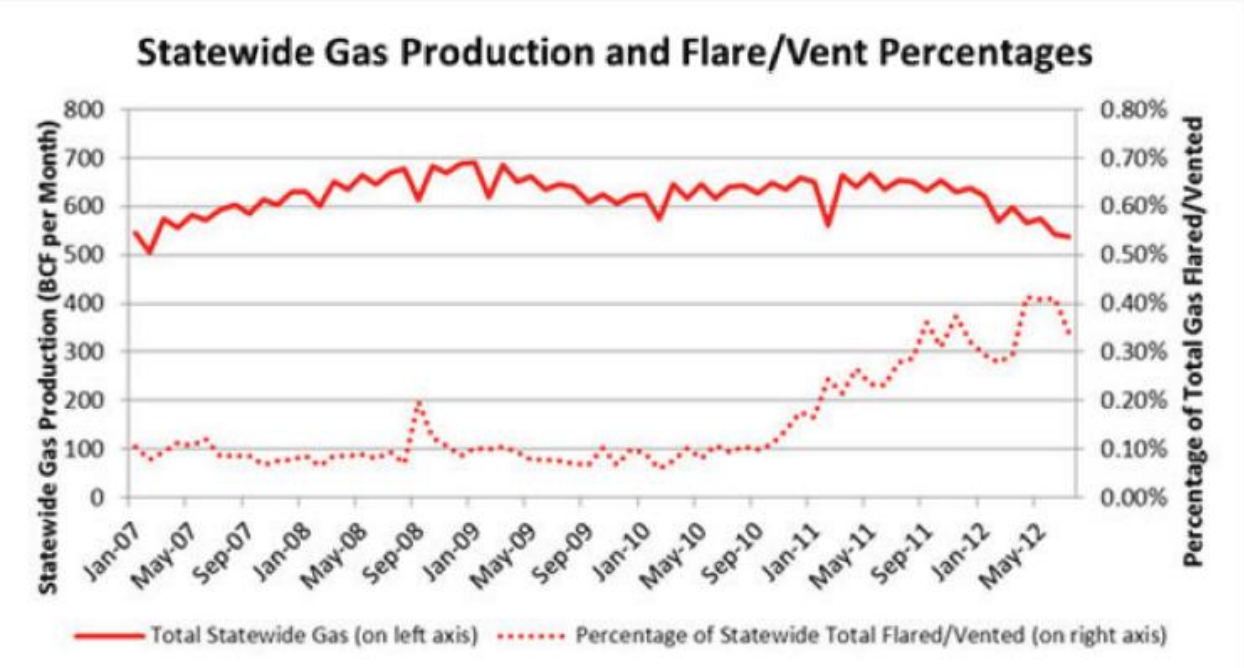
Flaring in the Bakken is extensive and has been increasing sharply in recent years, though some large producers have indicated they are looking for ways to reduce the practice.[15] Flaring has spiked in the area as the play has come online and natural gas prices have fallen.[16] In 2012, more than 83 billion cubic feet of gas was flared in North Dakota.[17]



Data Source: North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division

[14] It is our understanding that some operators of co-producing wells erroneously believe that the NSPS requirement to use green completions does not apply to them, and so flaring likely continues to occur at some portion of these co-producing wells in addition to at oil wells.
[15] *See* Saqib Rahim, EnergyWire, *Bakken's Top Producer Wants to Snuff Out Natural Gas Flaring* (Mar. 4, 2013), available at: http://www.midwestenergynews.com/2013/03/04/bakkens-top-producer-wants-to-snuff-out-flaring/.
[16] North Dakota Industrial Commission, Presentation to Bismarck Chamber of Commerce (Aug. 2012).
[17] North Dakota Industrial Commission, Gas Production Totals by County for 2012 (Apr. 2013).

Flaring has also increased in Texas as production in the Eagle Ford play (which is liquids rich) has expanded. According to the Texas Railroad Commission, the statewide percentage of gas flared has jumped four-fold since 2010 as that play has expanded.[18]



Although flaring in Texas as a whole is still low as a statewide percentage of gas production, at about 0.35%, that figure is misleading. Texas produces huge volumes of gas in a range of plays, many of which are largely pure gas plays (such as the Barnett) or have long been developed with gathering pipelines (such as plays in the Permian Basin), where flaring would not be expected in significant amounts. Flaring is much more prevalent in the Eagle Ford play, where 6% or more of gas production is likely flared.[19] In light of this troubling rate of flaring, Texas reports that it is investigating methods to improve its flaring rules.[20]

Other similar plays throughout the country, including the Monterrey Shale of California, will likely also experience flaring problems if infrastructure is not coordinated with production to ensure that green completions or similar tools are feasible before production begins.

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[18] Texas Railroad Commission, Eagle Ford Shale Task Force Report (Mar. 2013) at 80, available at: http://www.rrc.state.tx.us/commissioners/porter/reports/Eagle_Ford_Task_Force_Report-0313.pdf.

[19] As the figure above shows, flaring in Texas has greatly increased in synch with the development of the Eagle Ford, which accelerated in 2010. We therefore conservatively assume that three-quarters of flaring in Texas occurs in that play. As the figure shows, flaring has hovered around 0.4% of total gas production in the state (though it fell slightly in the last few months of 2012 data). In 2012, Texas produced 7.7 billion MCF of natural gas, see Texas Railroad Commission data at www.rrc.state.tx.us/data/production/ogismcon.pdf, so the amount of gas flared was approximately 30 million MCF. Eagle Ford production in the same year was 352 million MCF, see Eagle Ford Task Force Report at 4. If three-quarters of flared gas was flared in the Eagle Ford, that is 22.5 million MCF; that is 6% of Eagle Ford production.

[20] Id.

Air Quality Implications of Vents, Leaks, and Flares

Expanding oil and gas development is associated with significant air quality problems throughout the country. Serious ozone pollution has been reported in formerly rural regions experiencing major gas development, as well as in cities where development adds to pollution loads.[21] To address these problems, state and federal regulators will need to significantly reduce emissions from venting, flaring, and leakage.

Although the effect of flaring is difficult to disentangle from other sources in an oil or gas field, it is clear that even a single flare can significantly increase local ozone levels. Specifically, one recent study of potential emissions and air quality impacts from industry operations produced modeling results showing that a single flare could raise ozone concentrations as much as 8 km downstream by as much as 3 ppb, after just two hours of flaring.[22] To put this in context, the national ambient air quality standard (NAAQS) for ozone – which must be met taking into account pollution from all sources in an area – is currently set at 75 ppb, and ozone control strategies often focus on only a few parts per billion. Multiple flares operating in an area with other ozone pollution problems can thus exacerbate those problems. The cumulative impacts of flares throughout plays like the Bakken are degrading air quality, both on their own and combined with other field emissions.

North Dakota's ozone monitoring network, limited though it is, already shows danger signs. Monitors near or downwind of the Bakken field are already at levels approaching the current ozone NAAQS of 75 ppb, and are either above or just below the 60-70 ppb threshold which EPA's Clean Air Science Advisory Committee has repeatedly recommended. Thus, compliance both with the current standard and likely future standards is in question as the field grows.[23]

Some portion of this ozone pollution is likely linked to Bakken operations. According to EPA, VOC emissions from a pad containing two uncontrolled wells in the Bakken are on the order of 4,330 tons per year (tpy), meaning that uncontrolled pads will contribute a large volume of ozone precursors to the region.[24] Even pads controlled with flaring will likely add to the problem; as discussed above, flaring through combustion replaces VOC with NO_x, another ozone precursor. EPA projects that controlling these VOC emissions, in large part with flares, would result in

[21] See, e.g., Mark Jaffe, Denver Post, Study finds oil and gas drilling caused air pollution in the West (Feb. 20, 2013) (detailing problems in Utah, Wyoming, and Colorado), available at http://www.denverpost.com/breakingnews/ci_22623664/study-finds-oil-and-gas-drilling-caused-air.

[22] See E.P. Olaguer, The potential near-source ozone impacts of upstream oil and gas industry emissions, Journal of the Air & Waste Management Assoc. (2012).

[23] See NDDoH, Annual Report: North Dakota Air Quality Monitoring Data Summary 2011, available at: http://www.ndhealth.gov/aq/ambient/Annual%20Reports/ANN_11.pdf.

[24] EPA, Technical Support Document for the Fort Berthold FIP (Aug. 2012), EPA Docket No.EPA-R08-OAR-2012-0479 at 21-22.

approximately 8.8 tons of NO_x per well pad.[25] The Bureau of Land Management expects an increase of 6,084 wells and the same number of pads in North Dakota.[26] If all of those wells were flared, that would correspond to approximately 53,500 additional tons of NO_x emissions by 2029.

Flaring also results in the formation of fine particulate matter (PM), which can cause respiratory and cardiovascular problems and premature mortality. These effects have been tied to both long term exposures and peak events.

Continuing flaring at thousands of wells would impose an unacceptable burden for communities in or near these fields and other developing unconventional oil plays.

Response to Specific Questions on Flaring

1. What would be the best way to encourage a phase out of flaring of natural gas? I understand there will always be a need for some flaring for safety reasons or otherwise, but what would be a reasonable timeline to achieve a goal of minimal flaring across the country?

We believe EPA has a major role to play in limiting remaining flaring of associated gas in oil or gas plays. The main challenge is ensuring that gathering line systems keep pace with field development, such that sources have a destination for captured gas. A well designed regulatory system will ensure that development proceeds in this integrated fashion, thereby avoiding flaring.

In advance of such rules, in areas where lines are not available, requirements maximizing other uses for captured gas should be explored. North Dakota, for instance, has just passed a bill requiring operators to divert gas for onsite electrical power, fertilizer or fuel production, or other value-added processes which can reduce the need for gas to be flared.[27] Although we express no particular view as to the merits of that law because we have not yet fully reviewed it, we do agree that efforts to divert gas from flares should be carefully explored because these alternatives can provide other ways to reduce flaring, even without pipeline systems. Texas is undertaking a review of such options as well, and held a workshop on this topic in December 2012.[28]

Flares, meanwhile, should be designed and carefully managed to ensure high combustion efficiency. Flaring should also only be allowed for a limited duration, if it is allowed at all. In a

[25] Id.
[26] See BLM, Revised Activity and Surface Disturbance Projections for the Reasonable Foreseeable Development Scenario for Oil and Gas Activities on Bureau Managed Lands in the North Dakota Study Area (Feb. 25, 2011) at Table S2b & Table S3, available at http://www.blm.gov/pgdata/etc/medialib/blm/mt/field_offices/north_dakota/rmp/rfd.Par.31689.File.dat/NDrevisedRFD.pdf.
[27] See North Dakota House Bill No. 1134, available at http://legiscan.com/ND/research/1134.
[28] Eagle Ford Task Force Report at 84.

recent rule intended to address untenable air pollution problems of the Fort Berthold Indian Reservation in North Dakota, for instance, EPA required operators to flare at an efficiency of at least 90% for the first 90 days of production and at least 98% efficiency thereafter, if they are not capturing the gas.[29] We do not necessarily believe that these flaring efficiencies are the best that industry can achieve, but EPA's efforts to set uniform standards are significant and could be extended profitably to other plays. It is critical that any flaring period be as brief as possible, and that flares attain the highest combustion efficiency feasible through design and careful management.

At bottom, though, we continue to believe that there is no need for widespread flaring at oil production facilities.

To start, EPA should require green completions with capture for sale or reuse for these facilities. EPA has required unconventional gas well operators to capture gas for resale during well completions, rather than flaring or venting that gas.[30] Resale of recaptured gas generally pays for these processes in a matter of months, avoiding emissions while generating revenue for operators. In principle, there is no reason why such requirements should not apply to oil wells as well. We would need more information to determine how quickly such a requirement could be implemented, but believe that the industry can respond expeditiously to regulatory requirements. Then, flaring should be minimized throughout the productive life of a well. The oil and gas industry is adept at constructing pipeline and gas processing infrastructure, and will do so if required. Flare management requirements and creative reuse mandates can help limit the practice as infrastructure expands, and the latter can work side-by-side with or supplement capture for resale of gas once pipelines are in place.

2. Flaring rates in Texas and Alaska are close to zero. What is the law in Texas in regard to flaring? What makes the Bakken so different that flaring is so much more prevalent?

We currently lack information on Alaska's regulatory program for flaring, beyond the plain language of the regulations. These regulations contain a general requirement to minimize "waste," defined as "gas released, burned, or permitted to escape into the air," with a number of explicit exceptions.[31] The regulations also require reporting of such waste and give the state commission the authority to, after applying several criteria, approve venting or flaring otherwise prohibited by the regulations. As we do not have empirical or anecdotal information on implementation and enforcement of the Alaska program, it is difficult for us to determine whether the program is particularly effective in reducing or minimizing flaring. Outside of the state's regulatory structure itself, it is our understanding that the ability to reinject gas to enhance

[29] 40 C.F.R. § 49.4164. See also 78 Fed. Reg. 17,836 (Mar. 22, 2013) (promulgating this rule).
[30] 40 C.F.R. § 60.5375.
[31] See Alaska Admin. Code 25.235(b)-(d).

oil production (known as "repressuring") in conventional oil plays in Alaska has greatly enabled flaring minimization. To our knowledge, repressuring to date has not been demonstrated as feasible in unconventional plays.

We do not believe that Texas' current flaring regulations should serve as a national model. Texas has at most modest requirements applying to flaring. Rather than review the particulars of the state program and its enforcement, we think it is important to note two key points regarding flaring in Texas. First, as described above, the overall state flaring percentage is misleading due to the relative amount of production coming from various plays. Flaring is quite significant in the Eagle Ford, where one would expect to see flaring from oil operations. Second, Texas itself has recognized that its flaring regulations likely are inadequate to address the amount of flaring that is occurring and will be seen in the Eagle Ford.[32] The state is undertaking an extensive study of its regulations and is investigating ways to enhance protections.

North Dakota's Bakken Shale is marked by notably permissive flaring requirements. Even with recent amendments, North Dakota allows operators a full year of flaring as a matter of course,[33] and flaring can continue if the North Dakota Industrial Commission grants an exemption.[34] Such exemptions are available if the producer persuades the Commission that capturing the gas is "economically infeasible."[35] Because North Dakota deems such connections infeasible if the cost of capturing the gas exceeds the cost of connecting the well to a pipeline,[36] rather than if the cost cannot be borne by the operator, such exemptions appear to be very frequently granted. This limited response has led to continued flaring. Indeed, in some areas, we have reason to believe that wells are actually connected to pipelines, but operators have not installed compression sufficient to move all gas into pipelines, and so continue to flare. A more robust regulatory regime, focusing on public health rather than on maximizing operator revenues, could certainly further limit flaring duration.

3. What could be done at the federal level to help reduce the amount of natural gas being flared in the Bakken and elsewhere? If the regulatory or incentive structure isn't changed, will the amount of flared gas drop on its own, and if so how quickly?

As we indicated above, EPA has the authority and duty to include completion and production gas capture requirements for oil and gas wells in its NSPS. EPA can also readily reduce current amounts of flaring by issuing guidance confirming that wells co-producing some oil with gas are already covered by the NSPS during completions, given indications that the NSPS's coverage of co-producing wells is not commonly understood in the industry.

[32] See Eagle Ford Task Force Report at 84.
[33] NDCC 38-08-06.4.
[34] Id.
[35] Id.
[36] NDCC 43-02-03-60.2.

We do not believe that flaring will necessarily decrease of its own accord without federal intervention. Flaring has continued in the Bakken shale for years, and has similarly increased in the Eagle Ford shale. We have heard anecdotes that even where pipeline infrastructure is available, operators will flare rather than capture gas. In addition, as discussed above with regards to North Dakota, state standards limiting flaring often include open-ended provisions granting state regulators wide discretion to grant variances and such variances are common. Thus, federal standards and oversight are necessary. While state regulators should be encouraged to address these problems through their own authority, federal regulators can help ensure a level playing field between the states by setting a shared baseline for emissions control upon which states can build.

Second, the Bureau of Land Management should issue a new order to prohibit methane waste by wells subject to federal leases. As the Government Accountability Office noted in October 2010, BLM's existing waste policies are over 30 years old and do not account for data, knowledge, technologies, or practices that have advanced since those policies were issued.[37] In addition, it is essential that the federal government ensure responsible development of oil and gas resources in a world constrained by climate change and economic challenges. Updating this guidance is therefore timely and necessary.

4. Alaska addresses flaring with financial penalties. North Dakota has taken a different approach by providing incentives. What about combining these two approaches to have a combination of financial carrots and sticks to reduce or eliminate flaring?

If it is indeed true that Alaska has been successful with limiting flaring and North Dakota has not, we do not see clear value from a hybrid program. That said, state flaring programs vary widely, with implementation and enforcement playing large roles in their success or lack thereof. A detailed review investigating the most successful aspects of state programs thus is likely in order.

Conclusion

Flaring, venting, and leaking from oil and gas production take a heavy toll on air quality, public health, and climate stability. These emissions can and should be controlled cost-effectively. We appreciate the Committee's continuing work to address this serious matter.

[37] GAO, *Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases*, p. 27 GAO-11034 (October 2010).

Senate Committee on Energy and Natural Resources
Full Committee Forum on Environmental Impacts of Shale Gas Development and Best Practices
May 23rd, 2013

Sierra Club and Natural Resources Defense Council Response to Statements in the Record Regarding Role and Adequacy of State Regulation

There is a strong need for federal regulation of hydraulic fracturing (or "fracking"), as is demonstrated by the environmental and public health problems and negative experiences reported by residents of numerous communities in states across the country where fracking is taking place.

There is simply no justification for exempting hydraulic fracturing from the basic federal environmental laws that have applied to other industrial activities for four decades. Fracking presents at least as many risks as other regulated activities and has just as many interstate implications. Moreover, the current level of disclosure and regulation clearly demonstrates that states lack the technical resources and political wherewithal to govern fracking. Congress must close the loopholes in cornerstone federal environmental laws that exempt fracking from their scope.

This is not to say that states have no role to play. Under our system of "cooperative federalism," states can play the lead role in the regulation, permitting, and oversight process. Federal backstops ensure that minimum protections are in place while also allowing each state flexibility to account for its own specific circumstances. States can try out and adopt different regulatory approaches, as long as they meet federal minimum requirements. But all citizens deserve the protection of federal standards.

Several industry witnesses testified that states are already adequately regulating unconventional production, implying that federal regulation is therefore unnecessary. *E.g.*, Testimony of Jack Williams ("Strong regulations at the state level protect health and the environment and provide the public confidence that these operations are done right."). As we explain in detail in our accompanying testimony, under existing regulatory regimes, oil and gas production creates harmful air pollution and risks groundwater contamination, in addition to imposing other harmful costs such as water depletion and habitat fragmentation. Existing state regimes often fall short of the standards recommended by the Secretary of Energy's SEAB subcommittee on shale gas.

Even where state standards require the practices recommended by the SEAB, states often lack the resources to adequately monitor and enforce these standards.[1]

Federal regulation can address these problems by providing a uniform floor across the nation. EPA's NSPS and NESHAPs for air emissions from oil and gas production are an example of such standards, and will have the effect of improving air quality nationwide. This type of federal baseline regulation, which states may exceed if they wish, provides a well-established method of addressing common environmental problems.

For over forty years, the federal government has set basic national environmental standards under the Clean Water Act, Safe Drinking Water Act, Clean Air Act and other key environmental statutes, and these have applied to all of the States, regardless of geographic variation. States retain the flexibility to accept delegated authority to implement these environmental programs and to determine how best to meet the federal standards. Although some industry witnesses testified that differences in geology and other factors mean that states are better suited to regulation of fracking, these assertions have not been supported by data. Many federal rules are successfully applied to areas with differing circumstances.

For some issues, it is hard to imagine how geology could necessitate differences in regulation. Disclosure is one example: the nation needs strong disclosure rules to ensure that individuals and communities can learn the risks of fracking occurring in their regions. The need for such disclosure, the timing thereof, the mechanisms by which disclosed information is communicated to the public, and related details will be relatively constant across states. Yet even in the area of disclosure, in which states have been relatively proactive, only about half of states with fracking require disclosure of fracking chemicals.

Regional differences may provide a reason for some states to exceed the federal regulatory floor. For example, in areas where geology presents a particular risk of fluid migration, a state might choose to increase the area in which landowners must be notified of disclosure. Similarly, although a federal regulatory floor regarding air emissions is appropriate, regions suffering particular air quality problems may need to adopt stricter air pollution standards. The SEAB's recommended practices regarding waste management, casing, etc., are all worthy of being adopted as a federal regulatory floor. Because industry has not shown specific facts regarding

[1] *See, e.g.*, Earthworks, *Breaking All The Rules: The Crisis in Oil and Gas Regulatory Enforcement* (Sept. 2012) (explaining that in 2010 key states inspected as few as 9% of active wells, and that violations frequently fail to lead to effective enforcement) *available at* http://www.earthworksaction.org/library/detail/breaking_all_the_rules_the_crisis_in_oil_and_gas_regulatory_enforcement; Abrahm Lustgarten, *Update: State Oil and Gas Regulators Still Spread Thin*, ProPublica (Feb. 4, 2013) *available at* http://www.propublica.org/article/update-state-oil-and-gas-regulators-still-spread-thin; Arkansas Public Policy Panel, *Violations of Water Quality Standards from Gas Production in Arkansas* (Sept. 2011) (documenting low rates of inspection and explaining that "Gas companies were out of compliance 54 percent of the times they were inspected") *available at* http://arpanel.org/policy/reports/natural-gas/violations/view.

regional variation that make uniform federal regulation unwieldy or inappropriate, the norm of federal baseline regulations that states may choose to meet or exceed is appropriate here. Should industry make such a showing in some limited areas of regulation, there is no reason that requisite flexibility to accommodate regional differences could not be incorporated into a federal regulatory program as appropriate, as they are under other statutes.

Senate Committee on Energy and Natural Resources
Full Committee Forum on Environmental Impacts of Shale Gas Development and Best Practices
May 23, 2013

Natural Resources Defense Council and Sierra Club's Response to Question from Senator Landrieu Regarding Water Contamination

1. Has oil and gas extraction, including hydraulic fracturing, caused drinking water contamination?

Oil and gas exploration and production in the United States has left behind a legacy of pollution and environmental impacts. The oil and gas extraction process has indisputably caused drinking water contamination.

Drinking water contamination has been caused by a multitude of steps in the extraction process, including steps of the hydraulic fracturing process. Causes of drinking water contamination have included: improper well siting, poor well design and construction, including casing and cementing; blow-outs and other catastrophic accidents; leaks in wells, pipes, and waste pits; spills of hydraulic fracturing chemicals and waste; fracturing operations that were inappropriately conducted near an improperly plugged abandoned well, fractures that grew out of zone, or a combination of these causes.

These incidents are numerous, often have very serious water pollution impacts and are often undisputed by state regulators.[1] For example, a 2012 Denver Post investigation found that oil and gas companies "contaminated groundwater in 17 percent of the 2,078 spills and slow releases that companies reported to state regulators over the past five years," and found that in one county alone, 40 percent of spills reached groundwater. (Finley, 2012)

In this response, we first discuss important factual and legal context related to water contamination. Next, we set forth a few illustrative examples of specific incidents where operations in wells used to inject fluids for hydraulic fracturing have caused groundwater contamination. Again, there are many more incidents around the country; this response provides only a few examples.

[1] A number of these incidents of water contamination and pollution were summarized in the written testimony of NRDC President Frances Beinecke to this Committee in February 2013. http://www.nrdc.org/energy/files/fbeinecke-13021101.pdf. See also Hydraulic Fracturing Can Potentially Contaminate Drinking Water Sources, NRDC, http://www.nrdc.org/water/files/fracking-drinking-water-fs.pdf; and "Fractured Communities" at http://www.riverkeeper.org/wp-content/uploads/2010/09/Fractured-Communities-FINAL-September-2010.pdf.

Background:

Due to a lack of adequate investigation by state and federal regulators, perhaps caused by the absence of hydraulic fracturing ("HF") regulation that requires investigation of the HF process in drinking water contamination, the precise role of HF in many incidents of groundwater contamination is yet to be scientifically determined. As discussed further below, the Environmental Protection Agency ("EPA") has issued preliminary findings indicating that water contamination documented in Pavillion, WY, is a direct result of hydraulic fracturing, but final results from EPA's investigation are still pending. (USEPA, 2011b) While reports of drinking water contamination have occurred during or shortly after nearby HF operations, the role of HF is often not considered. In addition, academic research on this topic is lacking and existing scientific literature does not provide a full understanding of the risks and impacts of hydraulic fracturing. Compounding the lack of information are instances where drinking water contamination claims are settled privately between the water user and the oil and gas operator, because crucial scientific data regarding such incidents is often withheld from the public and academics due to confidentiality agreements. Thus, for many reasons, regulators and the public have often lacked the data or technology necessary to determine whether hydraulic fracturing has caused drinking water contamination. Research on this topic is new and ongoing; absence of further evidence or data does not demonstrate that HF is safe. It merely demonstrates that more research is imperative. In the FY 2010 appropriations process, Congress directed EPA to conduct the first comprehensive scientific investigation into the risks posed to drinking water by hydraulic fracturing. That investigation is currently underway.

Decades of experience, observation, and scientific investigation make clear that underground injection of any form presents a risk to drinking water. The Underground Injection Control ("UIC") Program of the Safe Drinking Water Act ("SDWA") was created expressly for the purpose of responding to this risk – to protect Underground Sources of Drinking Water ("USDWs") from contamination by injection wells. Through the UIC program, EPA regulates not only the act of injection itself, but the entire injection process including the siting, construction, operation, maintenance, testing, and closure of injection wells. This broad authority is recognition that the entire process of subsurface injection of fluids - not simply the act of injection – poses a risk to USDWs.

This is the proper frame in which to evaluate the impact that hydraulic fracturing has had on drinking water. Hydraulic fracturing is a form of underground injection. In 1997, the 11th Circuit of the U.S. Court of Appeals held that hydraulic fracturing "falls within the plain language of the statutory definition of 'underground injection'" and noted that the 1974 House Report accompanying the bill that eventually became the SDWA specifically stated that the law's definition of underground injection is intended to cover any contaminant that is put below

ground and flows or moves.[2] Although Congress exempted HF from regulation under the SDWA in the 2005 Energy Policy Act, hydraulic fracturing nevertheless carries the same documented risks as other forms of underground injection and should be regulated similarly. As such, in examining risk and impacts to drinking water, we must consider the entire process of underground injection of fluids pursuant to hydraulic fracturing. Wells used to inject fluids for the purpose of hydraulic fracturing have indisputably caused groundwater contamination. The root causes of these contamination incidents are varied, and include improper siting, poor well design and construction, and improper operation.

Incidents:

Bainbridge Township, Geauga County, Ohio

On December 15th, 2007, an explosion was reported in the home at 17975 English Drive, Bainbridge Township, Geauga County, Ohio. Early investigations determined that methane was entering homes in the vicinity of the explosion through domestic water wells. The Ohio Department of Natural Resources ("ODNR"), Division of Mineral Resources Management ("DMRM") inspected local gas wells to identify the source of the gas. When inspectors arrived at the English No. 1 gas well owned by Ohio Valley Energy Systems Corp ("OVESC"), representatives from OVESC were on location examining the well and discussing remedial cementing operations. The investigators determined that the English No. 1 well had been improperly constructed, that hydraulic fractures grew out of zone, and pressure was not safely managed after fracturing, allowing gas to migrate into the shallow drinking water aquifer and subsequently into domestic water wells, culminating in the explosion on English Drive. (ODNR, 2008) (Bair, Freeman, & Senko, 2010)

Primary Causes of Gas Invasion into Drinking Water Aquifers

1. Poor Primary Cement Job: A poor primary cement job left the shallow Newburg Dolomite and Ohio Shale gas-bearing zones open to the annulus behind the production casing, allowing high-pressure gas to migrate into the annulus.
2. Decision to Hydraulically Fracture the Well Despite the Poor Cement Job: Circulation of fluid and oil in the surface-production casing annulus during hydraulic fracturing indicates that the fractures grew "out-of-zone" and allowed the frac to communicate directly with the wellbore. The frac likely compromised the 80 feet of cement between the top perforation and the open annulus, causing a loss of cement bond between the formation and production casing. This likely allowed Clinton gas to also migrate into the annulus behind the production casing.

[2] Legal Environmental Assistance Foundation, Inc, v. EPA, 118 F.3d 1467 (11th Cir. 1997).

3. Shutting in the Well for 31 Days: The decision to shut in the surface-production casing annulus for 31 days allowed the annulus to become over-pressured and gas to migrate from the high-pressure annulus, through fractures, to the groundwater aquifer and eventually into domestic water wells. (ODNR, 2008) (Bair, Freeman, & Senko, 2010)

Dimock, PA

On January 1, 2009, a water well pit at a home in Dimock, Township, Susquehanna County, PA, exploded. The Pennsylvania Department of Environmental Protection ("PA DEP") began an investigation to determine the cause. Due to the proximity of the affected water well to natural gas wells drilled and operated by Cabot Oil and Gas Corporation ("Cabot"), PA DEP sought to determine if the incident was a result of Cabot's activities. In the subsequent investigation, PA DEP documented elevated levels of methane in numerous drinking water wells near the Cabot natural gas wells. (PADEP, 2009c)

PA DEP concluded that the elevated methane in drinking water was a result of Cabot's failure to properly case and cement several of its gas wells, which allowed methane to migrate from the wells into drinking water. (PADEP, 2009c) Cabot disputed this finding and contended that the methane was naturally occurring and not a result of gas drilling activities.

Nevertheless, Cabot and PA DEP entered into a Consent Order and Settlement Agreement under which Cabot was, among other things, prohibited from drilling or hydraulically fracturing any additional wells within the affected area and required to improve casing and cementing practices and replace water supplies for affected residents. (PADEP, 2009a)

Following a request from concerned residents, EPA reviewed water sample data provided by PA DEP and Cabot and then took its own additional water samples from 64 home wells to determine if harmful contaminants other than methane were present in drinking water. (USEPA 2011a, USEPA 2012a) In mid-2012, EPA completed its testing and concluded that five of 64 wells sampled had, "hazardous substances, specifically arsenic, barium or manganese, all of which are also naturally occurring substances, in…levels that could present a health concern." (USEPA, 2012b). The ATSDR is continuing its review of water sampling results in Dimock, including those collected by EPA as well as by Cabot and PA DEP. Among other things, it is examining the risks of long-term exposures to the water through showering, drinking, bathing and washing, as well as risks that might be compounded when people are exposed to multiple toxicants.

Pavillion, WY

The U.S. Environmental Protection Agency ("EPA") initiated an investigation into potential groundwater contamination near the town of Pavillion, Wyoming in response to homeowner concerns about objectionable taste and odor in well water. The domestic water wells in question overlie the Pavillion natural gas field. The field has been developed since the 1960s with the most intensive development occurring in the early 2000s. The field contains approximately 169 production wells and hydraulic fracturing has been used as a completion technique for several decades.

Water sampling began in March of 2009 and is ongoing. A preliminary draft report released by EPA in December 2011 concluded that oil and gas production activities had led to contamination of both shallow and deep groundwater. Hydraulic fracturing was identified as a source of deep groundwater contamination due to chemicals that are used in fracturing being found in groundwater. Surface pits were identified as a source of shallow groundwater contamination. (USEPA, 2011b)

The principle findings of the study are:

- Water samples taken from two EPA monitoring wells had anomalously high pH values (highly alkaline) that could have been caused by small additions of potassium hydroxide (KOH), a constituent of two hydraulic fracturing chemicals used in oil and gas wells in the area.
- Groundwater from the Wind River formation in the two EPA monitoring wells had inorganic geochemical compositions distinct from both shallow groundwater and the typical geochemical composition of Wind River formation water. Both wells had elevated potassium levels and one well had elevated chloride levels. Potassium and chloride were constituents of multiple hydraulic fracturing chemicals used in oil and gas wells in the area.
- A number of synthetic organic chemicals were detected in samples from both monitoring wells, including isopropanol, diethylene glycol, and triethylene glycol. Each of these was a constituent of one or more hydraulic fracturing chemicals used in oil and gas wells in the area. In addition, tert-butyl alcohol (TBA), which is a known break-down product of chemicals used in hydraulic fracturing, was detected in one well.
- Petroleum hydrocarbons including BTEX, trimethylbenzenes, and naphthalene were detected in one monitoring well and diesel range organics (DRO) and gasoline range organics (GRO) were detected in both wells. Each of these was a constituent of one of more hydraulic fracturing chemicals used in oil and gas wells in the area.

- Reviews of well completion reports for oil and gas wells showed that in some cases surface casing did not extend below the deepest domestic wells, production casing was not fully cemented to surface, there were multiple instances of poor cement bonding behind production casing, and hydraulic fracturing occurred in or near zones with inadequate cement.
- This area lacks a suitable confining zone to separate formations that are hydraulically fractured from groundwater.
- While some migration of gas into groundwater would be expected above gas fields such as Pavillion, isotopic chemical evidence, methane concentrations, well construction practices, and the timing of citizen complaints relative to the timing of hydraulic fracturing indicate that gas migration has been enhanced by natural gas production activities.

EPA determined that hydraulic fracturing chemicals and methane could have reached groundwater by migrating through the annular space of poorly constructed wells, through subsurface formations due to lack of a lithologic barrier (a.k.a. confining zone), or through fractures generated or enlarged by hydraulic fracturing.

Pennsylvania

Records obtained by The Scranton Times-Tribune documented that oil and gas development damaged at least 161 Pennsylvania water supplies between 2008 and the fall of 2012. Of the 969 records examined, 17 percent resulted in contamination or disruption so severe that the oil and gas companies responsible were required to replace the water source. (Legere, 2013)

As explained by The Sunday Times, these documents do not provide a full picture of contamination, and do not determine the specific role of hydraulic fracturing, for several reasons:

1. What the PA Department of Environmental Protection ("DEP") considers one "incident" may actually affect multiple individual water wells or springs.
2. DEP does not have a system for tracking or filing water contamination incident records, meaning that the records obtained by the Sunday Times may not be complete.
3. Prior to 2011, water contamination incidents that were resolved between the water user and the oil and gas operator did not have to be reported to the DEP.

Pennsylvania and New York

A study conducted by researchers at Duke University (Osborn et al., 2011) found an association between proximity to shale gas sites and methane contamination in private drinking water wells. The researchers analyzed methane levels in 60 private water wells that overlie the Marcellus shale in Pennsylvania and the Utica shale in New York and found, on average, methane concentrations were 17 times higher in areas with one or more gas well within 1 km than those areas without gas wells Notably, many of the drinking water wells in active extraction areas were found to have methane levels that exceed the current benchmark for unsafe conditions where hazard mitigation is recommended.

Additional geochemical analysis of the gasses in these wells revealed patterns which point towards the influence of gas extraction activities. Isotopic analysis of the gas revealed that methane in active areas is primarily thermogenic in origin, while methane in nonactive areas is of biogenic or mixed origin. Furthermore, ethane was detected in 21 of 26 wells from active areas while ethane and other heavy hydrocarbons were only detected in 3 of 34 wells from nonactive areas. Propane and butane were also were also detected in wells in active areas. Finally, the geochemistry of some of the gas samples from active areas matches the geochemistry of gas from local natural gas wells, indicating that they are likely sourced from the same formations, specifically Middle Devonian and older formations (of which the Marcellus is one). Conversely none of the samples from nonactive areas had compositions that matched local gas wells.

The researchers considered three mechanisms for methane migration into shallow drinking water aquifers that could explain the increased concentration of methane in active areas:

1. Natural migration
2. Leaking gas wells
3. Enhanced connectivity of the natural fracture system as a result of hydraulic fracturing

Given the depth of the Middle Devonian gas formations and the lack of evidence for migration of brine, the researchers considered the first mechanism unlikely. The researchers concluded that leakage through wells was the most likely mechanism, but that leakage through faults, possibly in combination with leakage through old, abandoned wells, was also possible. (Osborn et al., 2011)

Parker County, Texas

After investigating complaints of water contamination after nearby hydraulic fracturing in Parker County, Texas, on December 7, 2010, EPA issued an Emergency Order finding that: 1) water

samples demonstrated the presence of methane, benzene, toluene, ethane, propane, and hexane in two domestic water wells fed by an underground source of drinking water; 2) these contaminants pose a variety of risks to the health of persons and may present imminent and substantial endangerment to human health; 3) the isotopic fingerprint analysis of methane indicated that gases from the water and the gas wells are "likely to be from the same source;" and 4) the state agency with jurisdiction over such matters—the Texas Railroad Commission (RRC)—had not taken sufficient action to address the endangerment or had no intention to take such action at the time. (USEPA, 2010)

The RRC held hearings in 2011, and then issued a Final Order, finding that gas wells did not cause or contribute and are not causing or contributing to contamination of any domestic water wells. (TRRC, 2011) Shortly thereafter, EPA withdrew its Emergency Order. However, there is no evidence that the RRC has fully implemented any of the EPA's five prescriptions for addressing the endangerment, Since then, a confidential report leaked to the press, and written by an independent scientist reviewing the case, concluded that a natural gas well was "the most likely source of methane" in the domestic water wells, and that the carbon and hydrogen isotopic values of the gas wells match the values in the domestic water wells. (Thyne, 2012) News reports indicate that state regulators found that the natural gas well in question had pressure on the bradenhead, (Soraghan, 2013) and testimony and depositions by a former state regulatory employee indicate a determination that natural gas production activities were the only logical explanation for the domestic water well contamination.[3]

Although the EPA withdrew its Emergency Order in 2012, the Natural Resources Defense Council has asked the EPA to reopen the case, as there remain reported conditions that may cause imminent and substantial endangerment to the health of persons in Parker County, Texas. (NRDC, 2013)

Union Township, Tioga County, Pennsylvania

NPR's StateImpact Pennsylvania reporting project documented impacts to ground water and surface water caused by methane migration, likely through an improperly plugged and abandoned well. (Detrow, 2012) In June 2012, a water well inside the Ralston Hunting Club was reported to have overflowed and flooded the building. Nearby, a mixture of pressurized methane and water was observed emanating from the ground in what was described as a "30-foot geyser." Methane was also observed bubbling in a nearby creek. All the methane seeps were believed to be linked to a multi-well pad at which drilling and hydraulic fracturing were taking place. State regulators hypothesized that shallow gas liberated by the drilling process migrated through the

[3] Richter Dep. 116:17-117:20, Nov. 9, 2011, http://www.eenews.net/assets/2013/02/20/document_ew_01.pdf and Gore Dep. 127:2-127:8, Nov. 16, 2011, http://www.eenews.net/assets/2013/02/19/document_ew_04.pdf.

subsurface to a nearby 80-year-old improperly plugged and abandoned well, which then served as a conduit for the methane to migrate through the shallow subsurface, resulting in multiple surface seeps. A thorough scientific investigation into the causes and impacts of this incident does not exist, or has not been made publicly available.

Washington County, Pennsylvania

Initial results of an ongoing investigation by the Pennsylvania Department of Environmental Protection (PADEP, 2009b) documented methane migration that impacted several private drinking water supplies and surface soils. Investigators determined that fracturing in a gas well communicated with a nearby abandoned gas well. The abandoned well had been constructed with wooden surface casing, and fracturing created a pathway between the new gas well and the abandoned well, allowing methane to migrate into shallow ground water.

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