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UNITED STATES DISTRICT COURT
DISTRICT OF WYOMING

STATE OF WYOMING, et al,	)	
	)	**2:15-CV-00043-SWS [Lead]**
Petitioner,	)	
v.	)	**[Consolidated with 2:15-CV-00041-SWS]**
	)	
UNITED STATES DEPARTMENT OF	)	**Assigned: Hon. Scott W. Skavdahl**
THE INTERIOR; SALLY JEWELL, in her	)	
official capacity as Secretary of the Interior;	)	**RESPONDENT-INTERVENORS' BRIEF**
UNITED STATES BUREAU OF LAND	)	**IN OPPOSITION TO INDUSTRY**
MANAGEMENT; and NEIL KORNZE, in	)	**PETITIONERS' MOTION FOR**
his official capacity as Director of the	)	**PRELIMINARY INJUNCTION**

Bureau of Land Management,	**)**
	)
Respondents,	**)**
	)
SIERRA CLUB, EARTHWORKS,	**)**
WESTERN RESOURCE ADVOCATES,	**)**
CONSERVATION COLORADO	**)**
EDUCATION FUND, THE WILDERNESS	**)**
SOCIETY, and SOUTHERN UTAH	**)**
WILDERNESS ALLIANCE,	**)**
	)
Respondent-Intervenors.	**)**

TABLE OF CONTENTS

INTRODUCTION

The Bureau of Land Management's (BLM) new hydraulic fracturing rule, 80 Fed. Reg. 16128 (Mar. 26, 2015) (the Rule), represents a much-needed update to the agency's regulations governing oil and gas development on federal lands. The new Rule has many shortcomings, but it makes important improvements to the agency's existing standards, which had not been revised since 1988. The Rule expands well construction and integrity requirements, limits the use of certain types of pits, requires companies to get BLM approval before conducting hydraulic fracturing operations, and increases the information available to the agency and the public. These measures will reduce surface spills, groundwater and soil contamination, and provide BLM and the public with better informational tools to protect public health and the environment, among other benefits. See pp. 14-32, infra.

Those benefits will be lost if the preliminary injunction motion filed by Petitioners Western Energy Alliance (WEA) and Independent Petroleum Association of America (IPAA) (collectively, the Associations) is granted. BLM's response explains in detail why the Associations cannot show a likelihood of success on the merits. Case No. 2:15-cv-00041-SWS ECF Doc. (Dkt) # 20. Respondent-Intervenors Sierra Club, et al. (the Citizen Groups) therefore focus this brief on demonstrating why the Associations cannot establish the other three requirements for preliminary injunctive relief.

First, the Associations have not shown they will suffer irreparable harm from complying with the Rule. The compliance costs of the Rule do not represent irreparable harm because they are very modest: less than one fourth of one percent of the cost of drilling each new well. These expenses are too minimal to threaten any substantial harm to the oil and gas companies that make up the Associations' members. In fact, many of those companies individually generate annual profits many times larger than the entire industry-wide compliance cost of the Rule. Pp. 6-8, infra. Moreover, the Associations' claim that they will suffer irreparable harm from being required to submit confidential information to BLM is mistaken because the agency has well-established procedures to protect trade secrets. Pp. 10-11, infra.

Second, the balance of equities and public interest strongly favor allowing the Rule to take effect. Enjoining the Rule while this case is litigated will allow thousands of new oil and gas wells to be drilled using outdated and inadequate cementing and casing rules, to be fractured without BLM review and approval, and with companies managing produced water and well flowback in pits instead of much safer tanks. Delaying these protections will inevitably result in unnecessary soil and groundwater contamination, chemical spills, wildlife deaths, and other accidents. Pp. 14-32, infra. The benefits of avoiding these environmental harms far outweigh the minimal compliance costs that Association members will incur.

For example, one of the Associations' main objections is that the Rule requires their members to protect aquifers containing underground sources of drinking water as defined by the Safe Drinking Water Act (SDWA). They assert that this requirement will result in significant additional costs because oil and gas companies have been constructing wells in a manner that leaves many of these aquifers unprotected. Pp. 24-27, infra. The Associations claim that requiring protection of all underground sources of drinking water is a new burden that "will result in a stark change of practice" for the oil and gas industry. Id. But the public interest plainly is not served by letting oil and gas companies put underground sources of drinking water at risk in order to save on well construction costs. And the balance of equities on this issue strongly favors letting the Rule take effect. Id.

The Associations' motion should be denied and the Court should allow the Rule to take effect as scheduled on June 24, 2015. 80 Fed. Reg. at 16128 (effective date of Rule).

DISCUSSION

I. PRELIMINARY INJUNCTION STANDARD

To obtain a preliminary injunction, a party must demonstrate: (a) a likelihood of success on the merits; (b) that the movant is likely to suffer irreparable harm in the absence of injunctive relief; (c) that the balance of equities favors an injunction; and (d) that an injunction is in the public interest. Winter v. Natural Res. Def. Council, Inc., 555 U.S. 7, 20 (2008); Greater Yellowstone Coal. v. Flowers, 321 F.3d 1250, 1255 (10th Cir. 2003). The moving party bears the burden of establishing the four factors, and the movant's "right to relief must be clear and unequivocal." Greater Yellowstone Coal., 321 F.3d at 1255.

II. THE ASSOCIATIONS HAVE NOT SHOWN THEY WILL SUFFER IRREPARABLE HARM IN THE ABSENCE OF AN INJUNCTION.

The request for a preliminary injunction should be denied because the Associations do not face irreparable harm from having to comply with the Rule while this case is litigated. They claim to face two types of harm: (a) the cost of compliance with the Rule, and (b) potential disclosure of trade secrets. Neither argument withstands scrutiny.

A. The Cost of Complying With The Rule While This Case Is Pending Does Not Irreparably Harm The Associations.

To establish irreparable harm, a party must "demonstrate[ ] a significant risk that he or she will experience harm that cannot be compensated after the fact by monetary damages." Greater Yellowstone Coal., 321 F.3d at 1258 (emphasis and quotation omitted). Generally, economic loss alone does not represent irreparable harm because it can later be recovered through money damages. Port City Props. v. Union Pac. R.R. Co., 518 F.3d 1186, 1190 (10th Cir. 2008).

The Associations, however, contend that their cost of complying with the Rule is irreparable harm because the United States' sovereign immunity prevents them from recovering those compliance costs later from BLM as damages. Dkt # 13 (PI Mem.) at 47-48. This argument fails. A "preliminary injunction is an extraordinary equitable remedy." N. Arapaho Tribe v. Burwell, -- F. Supp. 3d --, No. 14–CV–247–SWS, 2015 WL 872190, *10 (D. Wyo. Feb. 26, 2015). Accordingly, in cases challenging agency regulations, courts have held that "ordinary compliance costs are typically insufficient to constitute irreparable harm." Freedom Holdings, Inc. v. Spitzer, 408 F.3d 112, 115 (2d Cir. 2005); see also Am. Hospital Ass'n v. Harris, 625 F.2d 1328, 1331 (7th Cir. 1980) ("injury resulting from attempted compliance with government regulation ordinarily is not irreparable harm").

The Associations' reliance on Chamber of Commerce of the United States v. Edmondson, 594 F.3d 742 (10th Cir. 2010), and Direct Marketing Ass'n v. Huber, No. 10-CV-1546, 2011 WL 250556 (D. Colo. Jan. 26, 2011), is misplaced because both cases involved Constitutional violations – not merely regulatory compliance costs. "When an alleged constitutional right is involved, most courts hold that no further showing of irreparable injury is necessary." Kikumura v. Hurley, 242 F.3d 950, 963 (10th Cir. 2001) (quoting 11A Charles Alan Wright, Arthur R. Miller & Mary Kay Kane, Federal Practice and Procedure § 2948.1 (2d ed. 1995)); Guzzo v. Mead, No. 14-CV-200-SWS, 2014 WL 5317797, *5 (Oct. 17, 2014).

In Chamber of Commerce, the Tenth Circuit found "a strong likelihood" that certain state immigration restrictions violated the Supremacy Clause of the U.S. Constitution. 594 F.3d at 770. Similarly, in Direct Marketing Assoc. v. Huber, the Court ruled that a state statute likely violated the Constitution's Commerce Clause. 2011 WL 250556 at *5.[1] These two cases are

[1] While the Huber court mentioned compliance costs, its primary basis for finding irreparable harm was the constitutional violation. Id. at *6; see also Direct Marketing Ass'n v. Huber, 2012 WL 1079175, *9 (D. Colo. Mar. 30, 2012) (later decision in same case relying solely on constitutional violation for finding of irreparable harm). Similarly, the court in Chamber of

readily distinguishable from the Administrative Procedure Act claims asserted by the Associations here. The Tenth Circuit has not enjoined federal regulations based on statutory claims and modest compliance costs like those asserted in this case.

The Associations' argument that routine compliance costs represent irreparable harm would effectively eliminate this prong of the injunction standard whenever a business challenges an agency regulation: "Any time a corporation complies with a government regulation that requires corporation action, it spends money and loses profits; yet it could hardly be contended that proof of such an injury, alone, would satisfy the requisite for a preliminary injunction." A.O. Smith Corp. v. Federal Trade Comm'n, 530 F.2d 515, 527 (3d Cir. 1976). The harm supporting an injunction must be "great" and "substantial." Heideman v. South Salt Lake City, 348 F.3d 1182, 1189-90 (10th Cir. 2003) (citing Wisconsin Gas Co. v. FERC, 758 F.2d 669, 674 (D.C. Cir. 1985)). The Associations' theory flies in the face of black-letter law that injunctive relief is an "extraordinary" remedy not normally available for economic harms. Greater Yellowstone Coal., 321 F.3d at 1256.

Even where compliance costs are not recoverable, a plaintiff seeking to enjoin an agency regulation must make "a strong showing that the economic loss would significantly damage its business above and beyond a simple diminution in profits." Mylan Pharmaceuticals, Inc. v. Shalala, 81 F. Supp. 2d 30, 43 (D.D.C. 2000); see also, Heideman, 348 F.3d at 1189 (affirming denial of injunction where plaintiffs failed to present evidence supporting allegation that businesses "had been forced out of business" by ordinance). Ordinary and reasonable compliance costs do not justify preliminary injunctive relief. Power Mobility Coal. v. Leavitt, 404 F. Supp. 2d 190, 204-05 (D.D.C. 2005) (no irreparable harm from cost of complying with

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Commerce observed that the plaintiff suffered injury from the risk of enforcement and other sanctions associated with the unconstitutional law. 594 F.3d at 771.

new Health and Human Services regulation); see also, Safari Club Int'l v. Jewell, 47 F. Supp. 3d 29, 36 (D.D.C. 2014) ("'economic loss does not, in and of itself, constitute irreparable harm' unless, of course, the loss 'threatens the very existence of the movant's business'") (quoting Wisconsin Gas Co., 758 F.2d at 674); cf. Kansas Health Care Ass'n, Inc. v. Kansas Dep't of Soc. and Rehab. Servs., 822 F. Supp. 687, 690, 698 (D. Kan. 1993), aff'd, 31 F.3d 1536 (10th Cir. 1994) (granting preliminary injunction against state nursing home reimbursement rates that were insufficient to provide adequate care to poor patients).[2]

The Associations do not even attempt to satisfy this standard. Instead, they simply assert that the compliance costs of the Rule as estimated by BLM – about $32 million per year or $11,400 per well – constitute irreparable harm. See PI Mem. at 48 (stating that "the Court need not calculate costs with precision to conclude that imposition of the rule will cause irreparable harm; BLM's estimates alone prove that the final rule will impose compliance costs that Petitioners' members cannot recover due to sovereign immunity"); 80 Fed. Reg. at 16130 (BLM estimate of compliance costs).

Imposing industry-wide costs of $32 million per year does not come close to "threaten[ing] the very existence" of any oil and gas companies, Safari Club, 47 F. Supp. 3d at 36, or damaging the industry "beyond a simple [and very small] diminution in profits." Mylan

[2] Many of the cases cited by the Associations, in fact, recognize and apply this standard. See Smoking Everywhere, Inc. v. U.S. Food & Drug Admin., 680 F. Supp. 2d 62, 76-77 (D.D.C. 2010) (recognizing the rule but granting injunction because "the potential for economic loss absent preliminary injunctive relief is sufficiently grave to threaten plaintiffs' very existence"); Nat'l Med. Care, Inc. v. Shalala, 1995 WL 465650, *3 (D.D.C. June 6, 1995) ("as a general matter, the costs of compliance with a regulatory scheme do not constitute irreparable injury"); Central Valley Chrysler-Plymouth v. Calif. Air Res. Bd., 2002 WL 34499459, *7 (E.D. Cal. June 11, 2002) (recognizing rule but finding that "fixed costs of up to hundreds of millions of dollars" and "other competitive injuries such as loss of goodwill" justified injunctive relief).

Pharaceuticals, 81 F. Supp. 2d at 43. To the contrary, many members of the Associations are large public companies with annual revenues measured in the billions of dollars. Many of these companies individually have annual profits that dwarf the total industry-wide cost of complying with the Rule.

For example, Western Energy Alliance's sustaining members include publicly-traded companies like Halliburton (2014 annual revenues of $32.9 billion, with $3.5 billion in net income), Noble Energy ($5.1 billion in 2014 revenue, with net income of $1.2 billion), and Encana (2014 revenues of $8 billion and operating earnings of $1 billion).[3] Similarly, the Chairman of IPAA is employed by Ultra Petroleum Corp., a publicly-traded company with 2014 revenues of $1.23 billion and net income of $543 million.[4] And IPAA's Colorado regional director is affiliated with Whiting Petroleum, which had 2014 sales of more than $3 billion and generates hundreds of millions in annual net earnings.[5] Any one of these companies could bear the entire industry-wide compliance cost of the Rule with only a modest reduction in its profitability. These costs do not represent irreparable harm to the Associations' members. See, e.g., Mylan Pharmaceuticals, 81 F. Supp. 2d at 43 (holding that $3 million in lost revenue did not represent irreparable harm where it amounted to only 0.4 percent of company's $750 million annual sales); see also, Williams v. Whiteman, 36 F.3d 1106, 1994 WL 504421, *2 (10th Cir. 1994) (unpublished) (affirming denial of injunction based on regulatory costs where "the amount

[3] http://www.westernenergyalliance.org/alliance/our-members (WEA web site); http://ir.halliburton.com/phoenix.zhtml?node-id=huzgm86r&c=67605&p=irol-reportsAnnual (Halliburton 2014 Annual Report at 1); http://investors.nobleenergyinc.com/financials.cfm (Noble Energy financials); http://encana.com/pdf/investors/financial/annual-reports/2014/annual-report-2014.pdf#page=51 (Encana 2014 annual report at 8).

[4] http://www.ipaa.org/about/board-of-directors/michael-d-watford/ (IPAA web site); http://phx.corporate-ir.net/phoenix.zhtml?c=62256&p=irol-reportsannual (Ultra Petroleum 2014 SEC Form 10-K at 40).

[5] See http://www.ipaa.org/about/board-of-directors/ (IPAA web site); http://www.whiting.com/investor-relations/ (2014 Whiting annual report at 2).

of money potentially at stake is very small relative to the revenues of individual hospitals and the Kansas hospital industry as a whole").[6]

The lack of any irreparable harm becomes even clearer when costs are estimated on a per-well basis: complying with the Rule increases the cost of developing each new well by a fraction of one percent. BLM estimated that the per-well cost amounted to only $11,400, which averages to "approximately 0.13 to 0.21 percent of the cost of drilling a well." 80 Fed. Reg. at 16130. Even if the Associations' inflated cost estimates were assumed to double or triple that figure, the requirements of the Rule would represent less than one percent of the expense of drilling each well. The Associations have not shown how these modest marginal costs would cause "great" or "substantial" harm to member companies, Heideman, 348 F.3d at 1189-90, much less "threaten the[ir] very existence." Safari Club, 47 F. Supp. 3d at 36.

B. The Associations Have Not Shown Their Member Companies Will Suffer A Competitive Injury From Disclosing Trade Secret Information If The Rule Takes Effect.

The Associations also claim they will suffer irreparable harm because seeking approval of a hydraulic fracturing operation under the Rule supposedly "will require [their] members to disclose their proprietary . . . information, which BLM will then disclose to the public and other companies." PI Mem. at 49. This theory does not establish a likelihood of irreparable harm.

[6] BLM's preamble to the Rule discusses its impact on "small businesses." 80 Fed. Reg. at 16209. But "small business" is defined broadly to include oil and gas companies with "fewer than 500 employees." Id. Under this standard, Ultra Petroleum – with $1.23 billion in 2014 revenues – counts as a "small business." See p. 7, supra; http://phx.corporate-ir.net/phoenix.zhtml?c=62256&p=irol-faq (web site indicating Ultra has about 160 employees). So do other Association members such as PDC Energy (300 employees and 2014 net income of $155.4 million), see http://www.pdce.com/careers (PDC web site); http://files.shareholder.com/downloads/AMDA-2XXE2L/0x0x764630/3381B0CF-4600-4161-B94A-CBF320EE9C4B/Income_Statement_-_Annual.pdf (PDC financials), and energy companies like Bill Barrett Corporation (2014 revenue of $472 million and 225 employees), http://www.billbarrettcorp.com/images/uploads/2014_Annual_Report1.pdf (2014 annual report at 46); http://www.billbarrettcorp.com/about-us/company-history/ (web site).

As an initial matter, the Associations fail to support their claim that the information BLM requires for approval of hydraulic fracturing operations generally qualifies as a trade secret. BLM noted that these details "would not routinely meet any of the criteria within the Freedom of Information Act regulations (43 CFR part 2) which would require such information to be held as confidential information." 80 Fed. Reg. at 16154. For example, Colorado already makes much of this information publicly available on an agency web site, such as the formation being fractured, the volumes of fluids used, the trajectory of the wellbore, the number and size of perforations, the maximum pressure applied, and other details. See, e.g., completed interval reports and directional drilling plans for Encana well 8508D-21 N22 496 and Berry Petroleum Company well 05-045-13096-00, included in Appendix of Exhibits (attached as Ex. 1) at 352-68; cf. PI Mem. at 33 (asserting that these details are proprietary information).[7]

While the Associations assert broadly that "the potential of competitive injury [is not] in doubt," they offer no evidence to support this claim. PI Mem. at 32-33; see Dkt ## 11-1 ¶ 7, 11-2 ¶ 7 (supporting affidavits make conclusory assertions about trade secrets without explanation). This is exactly the kind of unsupported speculation that courts have not accepted as a basis for injunctive relief. See, e.g., Heideman, 348 F.3d at 1189 (affirming denial of injunction where plaintiffs failed to offer evidence supporting attorney's argument about irreparable harm); Herff Jones, Inc. v. Oklahoma Graduate Servs., Inc., 237 F. App'x 384, 388 (10th Cir. 2007)

[7] While this is an administrative record review case, the Court may consider extra-record evidence when evaluating the irreparable harm, balance of equities and public interest requirements for injunctive relief. See, e.g., Greater Yellowstone Coalition, 321 F.3d at 1259-1261 (considering non-record evidence addressing irreparable harm in administrative record review case). The Court also is not bound by the Federal Rules of Evidence when considering a motion for preliminary injunction. Heideman, 348 F.3d at 1188.

(affirming finding of no irreparable harm where plaintiff presented no evidence that defendants were using disputed confidential information and trade secrets).[8]

In any case, the Associations wrongly assume that genuinely confidential business information provided to BLM will get no protection from public disclosure. BLM (like many other federal agencies) has well-established procedures to preserve the confidentiality of proprietary information filed with the agency. "As with any submission of information to a Federal agency, the submitter may segregate the information it believes is a trade secret, and explain and justify its request that the information be withheld from the public." 80 Fed. Reg. at 16173; see also, 43 C.F.R. § 2.26 (Interior Department regulations "encourag[ing] . . . submitters to designate confidential information in good faith at the time of submission"). When submitted to BLM, the Trade Secrets Act prohibits the disclosure of information that "concerns or relates to the trade secrets" or other confidential business information "of any person, firm, partnership, corporation or association" unless authorized by law. 18 U.S.C. § 1905.[9]

[8] In addition, Black Hills Alliance v. U.S. Forest Serv., 603 F. Supp. 117 (D. S.D. 1984), does not support the Associations' argument that Freedom of Information Act exemption 9 shields "all geological and geophysical information and data . . . concerning wells." PI Mem. at 30. Black Hills discusses the legislative history of exemption 9, which makes clear that its purpose is to prevent unfair advantage to speculators who are bidding to lease lands for mineral exploration. 603 F. Supp. at 122. In contrast, by the time a company is seeking approval to fracture an oil and gas well, it already has leased those minerals from BLM. See New Mexico v. BLM, 565 F.3d 683, 689 (10th Cir. 2009) (describing staged sequence of leasing and drilling permits). The Associations fail to show that disclosure of such information when their members already hold the rights to develop the minerals would cause them any competitive injury. Cf., Starkey v. U.S. Dep't of Interior, 238 F. Supp. 2d 1188, 1195-96 (S.D. Cal. 2002) (applying exemption 9 where release of aquifer-related data would have caused competitive injury).

[9] Because FLPMA and the Mineral Leasing Act provide general grants of rulemaking authority, BLM does have the authority to adopt rules requiring the disclosure of trade secrets to BLM, notwithstanding the Freedom of Information Act exemptions or the Trade Secrets Act. See Nardone Declaration Ex. B at 25-27 and cites therein (Dkt # 38-4 in Case No. 2:15-cv-00043-SWS).

If BLM later receives a Freedom of Information Act (FOIA) request, its regulations require the agency to "promptly notify a submitter in writing" if "[t]he requested information has been designated in good faith by the submitter as information considered protected from disclosure under Exemption 4 of the FOIA." 43 C.F.R. § 2.27. The company submitting the information then is given an opportunity to object to release of the information and explain why it represents a trade secret before BLM releases it. Id. §§ 2.28, 2.30-2.32. If BLM decides to release the information over an objection, the agency provides the company with ten days advance notice of its decision so that the company can take additional steps to challenge that decision. Id. § 2.33. The Associations offer no reason to believe these procedures will not be followed, or that BLM will not protect information that genuinely qualifies as a trade secret.

As a result, the Rule does not cause any imminent competitive injury to the Associations' members. Any harm that may result if BLM later overrules a company's objection to a FOIA request, or otherwise releases information, is purely speculative and would arise from a subsequent decision by BLM staff. The affected company can challenge any such agency decision at the appropriate time. There is no basis for this Court to conclude that a preliminary injunction against the Rule is needed to prevent such harm.

III. THE BALANCE OF EQUITIES AND PUBLIC INTEREST WEIGH AGAINST ENJOINING THE RULE.

On the other hand, enjoining the Rule would have a substantial adverse impact on the environment, the Citizen Groups, and other members of the public who are affected by oil and gas development on public lands. The Associations are not asking this Court to maintain the status quo on the ground while this case is litigated – instead, they seek to drill and fracture thousands of new wells under outdated and inadequate rules. See 80 Fed. Reg. at 16130 (estimating Rule will affect 2,800-3,800 operations per year). For that reason, the public interest and balance of equities strongly weigh against granting the relief sought by the Associations.[10]

As an initial matter, the balance of equities and public interest favor BLM because it is exercising its statutory authority under the Federal Land Policy and Management Act (FLPMA) to "prevent unnecessary or undue degradation" of public lands, 43 U.S.C. § 1732(b), and to issue regulations that "protect the quality of . . . ecological, environmental, air and . . . water resource[s]" on those lands. 43 U.S.C. §§ 1701(a)(8), 1740; see 80 Fed. Reg. at 16217 (BLM citation of authority for adoption of Rule). When an agency acts under Congressionally-delegated authority to protect the environment, the "balance of equities tips towards" allowing those protections to take effect. Safari Club Int'l v. Salazar, 852 F. Supp. 2d 102, 125 (D. D.C. 2012). Similarly, the public interest will be served by allowing BLM to implement these statutory directives. See N. Arapaho Tribe v. Burwell, -- F. Supp. 2d --, No. 14–CV–247–SWS, 2015 WL 872190, *16 (D. Wyo. Feb. 26, 2015); Kansas Hospital Ass'n v. Whiteman, 835 F. Supp. 1556, 1566-67 (D. Kan. 1993), aff'd sub nom. Williams, 36 F.3d 1106 (10th Cir. 1994) (unpublished).

This public interest is underscored by the broad public support for environmentally protective regulations. Approximately 1.35 million comments were received by BLM on the 2013 revised draft rule, 80 Fed. Reg. at 16131, with the overwhelming majority of commenters urging BLM to adopt stronger protections (in fact, stronger than the agency ultimately adopted)

[10] The Citizen Groups address the balance of equities and public interest factors together because they overlap to a great degree in this case. See Nken v. Holder, 556 U.S. 418, 435 (2009) (balance of harms and public interest factors for stay "merge when the Government is the opposing party").

in the final Rule. That widespread public support should be afforded respect when considering whether to let the Rule take effect.

Moreover, the environmental protections that the Rule will provide strongly weigh against injunctive relief. The Supreme Court has held that "[i]f [environmental] injury is sufficiently likely . . . the balance of harms will usually favor" protecting the environment. Amoco Prod. Co. v. Vill. of Gambell, Alaska, 480 U.S. 531, 545 (1987); see e.g., Kootenai Tribe of Idaho v. Veneman, 313 F.3d 1094, 1124-25 (9th Cir. 2002) (balance of harms did not support preliminary injunction against federal rule protecting national forest roadless areas).

Numerous courts also have recognized that the public interest is served by protecting the environment. See, e.g., Davis v. Mineta, 302 F.3d 1104, 1116 (10th Cir. 2002); San Luis Valley Ecosystem Council v. U.S. Fish & Wildlife Serv., 657 F. Supp. 2d 1233, 1242 (D. Colo. 2009) (granting injunctive relief to prevent risks of groundwater contamination and other impacts from oil and gas development); Drakes Bay Oyster Co. v. Salazar, 921 F. Supp. 2d 972, 995-97 (N.D. Cal. 2013), aff'd sub nom. Drakes Bay Oyster Co. v. Jewell, 747 F.3d 1073 (9th Cir. 2013) (despite irreparable harm to company that was required to shut down, balance of harms and public interest did not favor preliminary injunction where the business was harming native ecosystems and its closure advanced Congressional policy of protecting area as wilderness).

For example, in Wilson v. Amoco Corp., 989 F. Supp. 1159 (D. Wyo. 1998), the court balanced the equities in a case involving groundwater and soil contamination from an oil and gas tank farm, refinery and large waste impoundment. The court ruled that the cost to the company from requiring additional remediation expenses "is eminently less than the injury that potentially could befall Plaintiffs and the Casper environment." Id. at 1177. The court went on to find that the public interest in environmental protection outweighed the costs to the company because

"Casper citizens have a right to expect contamination-free groundwater and soils, [and] a clean river." Id. at 1178.

As discussed below, the Rule represents a necessary update to BLM regulations and will reduce oil and gas-related accidents that contaminate groundwater and soils. The Rule also will increase the information available to the public about hydraulic fracturing on public lands. In doing so, the Rule will benefit the Citizen Groups and numerous other members of the public by reducing damage to land, water and wildlife from waste pits, protecting water wells and aquifers from contamination due to well construction defects and hydraulic fracturing-related accidents, and providing informational tools so that members of the public can better protect their health and safety. See Dkt ## 26-2, 26-3 (Conservation Groups' declarations supporting intervention). All of these benefits serve the public interest and outweigh the minimal compliance costs the Association members will incur. Pp. 6-8, supra.

The Associations dismiss the benefits of the Rule by arguing that there is "no substantiated [ ] existence of [a] problem," because of a supposed "lack of evidence linking the hydraulic fracturing process to groundwater contamination." PI Mem. at 24-25. This disregards the numerous fracturing-related accidents that have occurred in recent years. It also ignores a variety of activities – such as the use of waste pits, and inadequate well construction – that have caused numerous incidents of groundwater contamination and other damage that the Rule seeks to address. Moreover, the Rule will substantially increase the information available to the public, which is a well-recognized need.

A. BLM's Rule Represents A Necessary Update.

Since the 1980s the oil and gas industry has changed dramatically, but BLM's regulations have not. BLM notes in its preamble that the Rule is "a much-needed complement to existing regulations . . . which were finalized nearly thirty years ago, in light of the increasing use and complexity of hydraulic fracturing coupled with advanced horizontal drilling technology." 80 Fed. Reg. at 16128. While the Associations assert that hydraulic fracturing has been used for "decades," PI Mem. at 24-25 n. 23, the reality is that the scale and impacts associated with that process have grown dramatically in recent years. In 2011, the Secretary of Energy's Subcommittee on shale gas development dismissed a similar argument, pointing out that "modern shale gas fracturing of two mile long laterals has only been done for something less than a decade." Appendix at 14; see also id. at 9 ("it was only in 2002 and 2003 that the two technologies working together – hydraulic fracturing and horizontal drilling – made shale gas commercial").

The advent of "unconventional" oil and gas development combining hydraulic fracturing with directional or horizontal drilling has dramatically increased the scale and intensity of this industrial activity. Hydraulically fractured wells are commonly exposed to higher pressures over a longer period of time, as fracturing is conducted in multiple stages on long horizontal wells. Appendix at 91. A 2014 study published by the National Academy of Sciences found that unconventional wells in Pennsylvania were six times more likely to have cementing or casing problems compared with conventional wells. Appendix at 113. Moreover, fracturing requires enormous volumes of chemicals and fluids: an average hydraulic fracturing job today uses 3-7 million gallons of water, and about 150,000 - 350,000 gallons of chemicals per well.[11] Depending on the site, 15 - 80 percent of this returns to the surface as "flowback" that must be managed. 80 Fed. Reg. at 16200. None of this was common in the late 1980s when BLM developed its existing rules.

[11] Getches-Wilkinson Center for Natural Resources, Energy and the Environment Intermountain Oil and Gas BMP Project, http://www.oilandgasbmps.org/resources/fracing.php (last visited June 3, 2015).

In addition, the rise of unconventional oil and gas development has resulted in a substantial increase in the sheer number of wells and density of drilling on federal lands. Between 1986 and 2008, the number of wells drilled each year more than tripled. In some states, the growth on federal lands was even more striking. In Utah, for example, the annual number of new wells jumped by nearly 900 percent during that period. And in Wyoming, it increased by 550 percent from 1986 to 2007. Appendix at 124 (BLM statistics).

BLM's existing regulations, however, did not address hydraulic fracturing in any detail. As BLM explains, the regulations:

> [a] did not provide for BLM's review or approval of the operator's hydraulic fracturing plans to assure that resources would be protected;
> [b] they did not specify the content of the reports about the [fracturing] operations;
> [c] they did not require verification and testing to assure that the wellbore could withstand the pressures of hydraulic fracturing operations;
> [d] they did not provide for public notice of chemicals used in the operations; and
> [e] they did not require proper management of recovered fluids prior to BLM's approval of a permanent disposal plan.

Wells Decl. ¶ 10 (Dkt # 20-2). BLM has sought to address this situation by promulgating a much-needed update of its regulations.

The Rule grew in part out of recommendations by the Secretary of Energy's Advisory Subcommittee on Natural Gas. 80 Fed. Reg. at 16128. In 2011, at the direction of President Obama, the Secretary of Energy established a panel of experts to examine issues related to hydraulic fracturing and make recommendations on how to improve its safety and environmental performance (the Secretary of Energy Advisory Committee). Appendix at 35. The Committee made numerous recommendations, including improving public information about shale gas operations, requiring disclosure of chemicals used in hydraulic fracturing, and strengthening requirements for casing and cementing wells. <u>See</u> Appendix at 121 (BLM environmental assessment for the Rule). BLM's Rule partially implements some of the Committee's recommendations.

B. The Rule Addresses Significant Environmental Harms Caused By Unconventional Oil and Gas Development.

The heart of the Associations' argument is that the Rule will provide little or no benefit because "the regulatory status quo has a proven track record of environmental stewardship." PI Mem. at 51. This is simply wrong. The Secretary of Energy's Advisory Committee observed that "[t]here are serious environmental impacts underlying [public] concerns [about unconventional oil and gas development] and these adverse environmental impacts need to be prevented, reduced and, where possible, eliminated as soon as possible." The Committee went on to emphasize the need for strong regulation: "with anticipated increase in U.S. hydraulically fractured wells, if effective environmental action is not taken today, the potential environmental consequences will grow to a point that the country will be faced with a more serious problem." Appendix at 9-10. It concluded that "the nation has important work to do in strengthening the design of a regulatory system" that can adequately manage this rapidly-changing industry. Appendix at 12.

The oil and gas industry's track record shows that there is ample room for improvement. For example:

- The State of Pennsylvania has identified more than 240 cases since 2008 where a water well has been impacted by oil and gas drilling operations. Appendix at 125-132.
- As of 2012, monitoring of Sublette County water wells in Wyoming's Pinedale Anticline oil and gas field had detected petroleum hydrocarbons in 15 percent of the wells tested (48 of 312 wells), with 12 of those wells exceeding groundwater quality standards. Appendix at 370-71 (Sublette County report).

- In Colorado, state records show that more than 600 reported spills occurred at oil and gas sites during 2013. These involved more than 16,000 barrels (674,000 gallons) of produced water and more than 2,431 barrels (102,000 gallons) of oil. About 22 percent of those spills (on average, more than two each week) contaminated Colorado surface water or ground water. Appendix 136-38 (summaries of state records).
- Also in 2013, oil and gas companies in New Mexico reported 934 spills to the state's Oil Conservation Division. Nearly half of those spills (436) involved releases of produced water, which occurred an average of more than once a day in 2013. Appendix at 139 (summary of state records).
- In 2013, a peer-reviewed study was released in Colorado finding that even after remediation, more than half of oil and gas sites where spills had occurred still showed elevated groundwater levels of benzene, which is a known carcinogen. Appendix at 142.
- A 2015 article published by the National Academy of Sciences found that hydraulic fracturing fluid compounds had contaminated a shallow aquifer in Pennsylvania, likely from inadequate well construction, subsurface fractures and a leaking surface pit. Appendix at 331.
- A January 2015 survey of peer-reviewed scientific research on unconventional oil and gas development found that the large majority of studies published in recent years "indicated negative impacts of shale and/or tight gas development" involving public health, air pollution, water pollution, or other impacts. Appendix at 143-162.

In the absence of updated federal rules, states have created a patchwork of regulations that address the oil and gas industry. The Secretary of Energy Advisory Committee observed that "[w]hile many states . . . regulate aspects of [shale gas] operations, the efficacy of the regulations is far from clear." Appendix at 12. Some states already have requirements that address some of the issues covered by the BLM Rule. But many states lack these protections, and no state appears to have regulations that meet or exceed the protections of the BLM regulations across the board. BLM noted that state "regulations continue to be inconsistent across states." 80 Fed. Reg. at 16178. Moreover, the information that states collect as part of regulating oil and gas development "is neither uniform nor uniformly accessible to the BLM." Id. at 16154.

The Rule is also needed because BLM has a statutory obligation under FLPMA to manage federal lands to protect ecological, environmental, air and water resources, and prevent undue degradation, on public lands. P. 12, supra. The agency "is not allowed to delegate its [statutory] responsibilities to the states." 80 Fed. Reg. at 16178. Accordingly, the Rule "will establish a consistent standard across Federal and Indian lands" as part of "fulfill[ing] BLM's stewardship and trust responsibilities." Id.

In doing so, the Rule will yield important benefits that would be lost if it is enjoined.

1. Pits

The Rule will address a major cause of oil and gas spills by limiting the use of pits to store flowback fluids and produced water . In 2008, for example, New Mexico surveyed its records and found more than 700 incidents where ground water had been contaminated by oilfield products or wastes stored in pits. Appendix at 180. Numerous other cases have been documented in other states. See Appendix at 180-85 (collecting examples). For example, in 2008 a Colorado resident fell ill after drinking tap water, not knowing that his water well had been contaminated by petroleum compounds (including high levels of benzene, toluene, and xylenes) from a nearby production pit. See Appendix at 181 (describing case), 217-19 (news coverage). In addition, pits have been documented to kill numerous wildlife such as birds. Appendix at 301-330 (2013 Fish & Wildlife Service report).

With limited exceptions, BLM's rule will require the use of tanks rather than pits for management of fluids recovered from the well prior to adoption of a permanent disposal plan. 80 Fed. Reg. at 16220 (43 C.F.R. § 3162.3-3(h)). Few if any state regulations go this far in limiting the use of pits, although many companies voluntarily use tanks for some of their operations. See id. at 16199-202 (discussing extent to which Rule will affect operations in different states).[12]

While produced water and flowback pits are not the only source of spills, they are widely recognized as a major issue. A 2012 General Accounting Office study observed that "produced water and fracturing fluids returned during the flowback process contain a wide range of contaminants and pose a risk to water quality, if not properly managed. . . . The risk of a leak or spill is particularly a concern for surface impoundments as improper liners can tear, and impoundments can overflow." Appendix at 87-88. BLM observed in its environmental assessment for the Rule that "leaks in pits that may result from a puncture in the liner could not

[12] Because the new regulation addresses the period "between the commencement of hydraulic fracturing operations and [BLM's] approval of a produced water disposal plan," 43 C.F.R. § 3162.3-3(h), the Associations argue that they can circumvent this requirement by obtaining BLM approval of a produced water disposal plan before drilling the well. PI Mem. at 11. To the extent such an approach is permitted, it would only reduce the cost of compliance and undercut the Associations' argument that a preliminary injunction is merited.

Moreover, BLM's economic analysis suggests that the Rule will have an effect for a significant number of wells. See 80 Fed. Reg. at 16202 (estimating applicability at 28.3 percent of operations in Colorado, 20.4 percent in Montana, 25 percent in North Dakota, and 7.7 percent in Wyoming). But even where companies are permitted to avoid tanks by using a disposal plan, the Rule may yield environmental benefits: Onshore Order No. 7, which governs disposal plans, requires that lined pits for disposal on-site must have leak detection system unless the water being disposed is clean enough not to present a threat to water quality. 58 Fed. Reg. 47354, 47362-364 (Sept. 8, 1993) (Order paragraphs III.B.1.b, III.E.2.d; III.D.2). In contrast, temporary on-site pits today generally do not have leak detection systems. See Appendix at 122 (BLM environmental assessment).

easily be identifiable because flow back fluids are typically stored in temporary pits, which do not have leak detection systems." Appendix at 122. In contrast, BLM concluded that:

> The **use of storage tanks would almost eliminate the risk of flow back fluids [ ] damaging various environmental resources**, which include soils, surface and groundwater sources, and wildlife. By using storage tanks, flow back fluids would be entirely contained within vessels, having no connection to the surrounding environment. Wildlife would not have the ability to come into contact with flow back fluids that could potentially be hazardous . . . . In addition, because tanks are placed above-ground, any potential spills or leaks would be easily identifiable and a clean-up response could be executed fairly promptly. This prompt response would ensure that spills or leaks do not settle for an extended period and percolate through the ground.

Appendix at 122 (emphasis added). The BLM Rule does not eliminate the larger problem of spills, or address all categories of oil and gas pits. But requiring the use of tanks instead of pits for fluids recovered from the well represents an important step. For example, BLM has leased, or is considering leasing, lands in watersheds that supply municipal drinking water for communities in western Colorado, Denver, and Ohio among others.[13] Reducing the risk of pit-related spills in these areas will directly benefit millions of residents.

The Rule's restriction on pits also helps fill a gap in federal environmental regulation. Flowback and produced water can contain a variety of hazardous constituents, including benzene, oil and other petroleum hydrocarbons, arsenic, lead, chromium and other metals, salts, naturally occurring radioactive materials, compounds from drilling and fracturing fluids, and other carcinogenic chemicals. Appendix at 87-88, 170-72. These waste streams often would qualify as hazardous waste under the Resource Conservation and Recovery Act (RCRA) – and be regulated much more strictly – if generated by other industries. But because they are associated with oil and gas exploration, these wastes enjoy an exemption from RCRA's "cradle

[13] http://switchboard.nrdc.org/blogs/amall/drinking_water_for_millions_-.html ; http://switchboard.nrdc.org/blogs/amall/drinking_water_for_denver_also.html (last viewed June 2, 2015).

to grave" management requirements for hazardous waste. 42 U.S.C. § 6921(b)(2)(A), (B); Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. 25446, 25447 (July 6, 1988).[14]

Given the lack of regulation under RCRA, it is even more important that BLM be allowed to exercise its own authority to require management of these wastes in a way that limits the risk they pose to soil and groundwater. The public interest and balance of equities do not support foregoing these benefits by enjoining the Rule. See San Luis Valley Ecosystem Council, 657 F. Supp. 2d at 1242; Wilson, 989 F. Supp. 1177-78.

2. Cementing and casing

BLM's Rule also takes steps to address another major cause of water contamination: inadequate well casing and cementing. For example, the widely-reported groundwater contamination in Pavilion, Wyoming has been linked to problems with well casing and cementing. See Appendix at 222-231 (media coverage).[15] In several states including Colorado and Wyoming, well integrity problems have caused explosions and well blowouts. See Nardone Decl. Ex. B at 9 (Dkt # 26-3).

These were not isolated incidents. A 2014 survey of more than 41,000 oil and gas wells drilled in Pennsylvania between 2000 and 2012 found that up to nine percent of unconventional

[14] See, e.g., Appendix at 87-88; 53 Fed. Reg. at 25455 (estimating that 10-70 percent of exploration and production wastes would be hazardous if RCRA exemption were lifted); see also, Environmental Protection Agency (EPA) hazardous waste web page, http://www.epa.gov/osw/laws-regs/regs-haz.htm (last viewed June 3, 2015) (describing RCRA's cradle to grave "system for controlling hazardous waste from the time it is generated until its ultimate disposal").

[15] Part of the contamination also resulted from leaking oil and gas pits. Id. While the EPA's 2011 preliminary conclusion that the contamination was caused by hydraulic fracturing has been criticized, several sources have supported the findings regarding well construction and pits. Appendix at 222-231.

wells had cementing or casing problems that could affect groundwater.[16] And a 2011 study published by the National Academy of Sciences found systematic evidence for methane contamination of drinking water associated with shale-gas extraction in that state. The researchers identified leaky well casings as a likely cause. Appendix at 232-236, cited at 80 Fed. Reg. at 16194 n. 11. Similarly, the National Institutes of Health released preliminary study results in 2015 finding that for households with a ground-fed water supply, proximity of natural gas wells may be associated with skin and respiratory conditions in residents living within a kilometer of natural gas extraction activities. This study identified leaky well casings as a potential pathway by which residents could be exposed to drilling chemicals. Appendix at 237-242.

Similar problems exist on federal lands. A 2012 Congressional investigation found that BLM's existing "casing and cementing procedures are frequently not followed." Appendix at 258. More than twenty percent of major violations identified by BLM between 1998 and 2011 involved non-compliance with casing and cementing requirements. Appendix at 246-47, 259-60. The investigation also highlighted how widespread the risk is that usable drinking water will be contaminated by drilling on federal lands. At the Committee's request, BLM reviewed 706 randomly-selected oil and gas wells. It found that fully 30 percent of these federal wells were hydraulically fractured "in, near, or below an underground source of drinking water." Appendix at 256-57.[17]

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[16] Appendix 113, 116; see also, Nardone Decl. Ex. B at 8-9 (Dkt # 26-3) (discussing other studies in Pennsylvania and Alberta, Canada).

[17] Seven percent of the wells were fractured within an underground source of drinking water. Those occurred when coal bed natural gas wells were drilled within coal seams that contained usable groundwater. Id.

The BLM Rule seeks to address several of the problems identified above. For example, the Rule requires companies to "monitor and record" cementing operations, run cement evaluation logs, and submit a cement operating report to BLM prior to commencing hydraulic fracturing operations. 80 Fed. Reg. at 16217, 16219 (43 C.F.R. § 3162.3-3(e)). The Rule also provides more detailed requirements for further testing and approval by BLM when cementing problems occur. Id. In addition, companies must perform mechanical integrity tests on the well before fracturing and provide the results of those tests to BLM. Id. (43 C.F.R. § 3162.3-3(f)); id. at 16221 (43 C.F.R. § 3162.3-3(i)(9)). And companies must monitor and record the "annulus pressure" (i.e., the pressure in the space between the casing (pipe) and the wall of the wellbore) during hydraulic fracturing to identify any changes that would indicate a problem with well integrity. Id. at 16219-220 (43 C.F.R. § 3162.3-3(g)). The annulus pressure monitoring record must also be submitted to BLM. Id.

All of these requirements should reduce the number of cases where groundwater is contaminated by improperly-constructed wells. First, while the Rule reflects best industry practices, not all states require such measures. 80 Fed. Reg. at 16161. In addition, the new more detailed federal requirements are likely to improve the care and performance by companies. In particular, the requirement to provide documentation of monitoring and testing results to BLM on a routine basis should reduce the level of non-compliance with cementing and casing requirements that the congressional study identified. See p. 23, supra. Enjoining the Rule would eliminate these benefits for thousands of wells drilled on federal land during the course of this litigation.

Granting the preliminary injunction motion also may have a far-reaching impact by allowing companies to jeopardize numerous underground sources of drinking water. The Rule requires that companies ensure well casing and cementing isolates and protects all "usable water zones." 80 Fed. Reg. at 16219 (43 C.F.R. § 3162.3-3(e)); id. at 16222 (43 C.F.R. § 3162.5-2) (requiring companies to "isolate all usable water and other mineral-bearing formations and protect them from contamination"). The Rule defines "[u]sable water" to include formations that qualify as "underground source[s] of drinking water" under the Safe Drinking Water Act. 80 Fed. Reg. at 16217 (43 C.F.R. § 3160.0-5 (referencing SDWA regulation 40 C.F.R. § 144.3)). Consistent with SDWA, the Rule requires protecting aquifers with water containing up to 10,000 parts per million (ppm) of total dissolved solids (TDS). Id.; see also, 40 C.F.R. § 144.3 (SDWA regulations definition of "underground source of drinking water"). The 10,000 ppm threshold is consistent with the agency's existing regulatory standard issued in 1988. See 80 Fed. Reg. at 16141 (discussing Onshore Order No. 2); Dkt # 20 at 23-25.

The Associations assert, however, that oil and gas companies have not been complying with the requirement to protect all of these usable water sources. Apparently, many operators have constructed wells to protect only aquifers containing up to 5,000 ppm, rather than 10,000 ppm TDS. PI Mem. at 16-21; see also 80 Fed. Reg. at 16142. In fact, much of the Association's preliminary injunction request is based on the argument that complying with the existing requirement to protect all usable sources of drinking water "will result in a stark change of practice" for the oil and gas industry. PI Mem. at 21. The Associations seek to enjoin the Rule because their members do not want to bear the "additional costs of casing and cementing associated with isolating formations" that contain underground sources of drinking water under SDWA. PI Mem. at 36-37.

The balance of equities and public interest plainly do not favor an injunction to benefit companies that have not been complying with BLM's existing regulatory standard. See Davis v.

Mineta, 302 F.3d at 1116 (balance of harms weighed against project proponent whose financial loss was "self-inflicted" wound from failing to comply with law). And for those companies already complying with the standard, the Rule will not impose any additional burden. 80 Fed. Reg. at 16196. Even the Associations concede that "[m]any wells might not have any incremental casing and cementing costs" under the 10,000 ppm standard. PI Mem. at 37.

But even if the Rule does represent "a stark change in practice" for the oil and gas industry, PI Mem. at 21, that effect weighs heavily in favor of allowing the Rule to take effect. For decades, the United States has had a policy – contained in its SDWA regulations – that aquifers with up to 10,000 ppm TDS should be protected as potential drinking water sources. 40 C.F.R. § 144.3; see also, H.R. Rep. No. 93-1185 (1974), reprinted in 1974 U.S.C.C.A.N. 6454, 6484, 1974 WL 11641 (SDWA legislative history stating that "the Committee expects [EPA's] regulations at least to require States to provide protection for subsurface waters having less than 10,000 p.p.m. dissolved solids . . . even though water containing as much as 9,000 p.p.m. would probably require treatment prior to human consumption").

While water with those levels of TDS must be treated before it can be used for drinking, that does not mean these aquifers should not be protected. As the State of Wyoming argued in another case: "all groundwater in the State is important and should be protected for future consumptive uses." Wilson, 989 F. Supp. at 1176. BLM explained in the preamble that "[g]iven the increasing water scarcity [in much of the United States] and technological improvements in water treatment equipment, it is not unreasonable to assume aquifers with TDS levels above 5,000 ppm are usable now or will be usable in the future." 80 Fed. Reg. at 16142. Protecting the water in those aquifers also ensures it can be used for industrial or agricultural purposes, or preserving its natural role in supporting ecosystems. The public interest strongly favors allowing

BLM to protect these aquifers. See Safari Club, 852 F. Supp. 2d at 124-25; Kansas Hospital Ass'n, 835 F. Supp. at 1566-67.

Essentially, the Associations ask this Court to enjoin the Rule so that their members can continue putting underground sources of drinking water at risk by drilling thousands of new oil and gas wells while this case is litigated. Doing so would likely result in many cases of aquifer contamination that will be difficult or impossible to remediate at a later date. This environmental harm far outweighs any marginal economic cost companies will incur to protect these aquifers during the pendency of this case. See Kootenai Tribe, 313 F.3d at 1124-25; San Luis Valley Ecosystem Council, 657 F. Supp. 2d at 1242.

3. Advance BLM review and approval of hydraulic fracturing operations

Another benefit of the Rule is its new requirement that BLM approve all hydraulic fracturing operations in advance. 80 Fed. Reg. at 16218 (43 C.F.R. § 3162.3-3(c)). Previously, BLM did not require companies to seek agency approval before routine fracturing of a well. Moreover, few if any states with substantial federal oil and gas activity require advance approval to hydraulically fracture a well.

As with pits, the Rule's requirement for prior approval of fracturing operations helps fill a regulatory gap. Normally, underground injection of chemicals and other materials is regulated by the Safe Drinking Water Act underground injection control (UIC) program. 42 U.S.C. §§ 300h-300h-8. In the late 1990s, as hydraulic fracturing began becoming more common, the Eleventh Circuit Court of Appeals ruled that it was subject to SDWA's UIC requirements. Legal Assistance Found., Inc. v. U.S. Envtl. Protection Agency, 118 F.3d 1467, 1474, 1478 (11th Cir. 1997) ("[I]t is clear that Congress dictated that all underground injection be regulated under the" SDWA) (emphasis original). SDWA prohibits any underground injection unless a permit is issued by the EPA or appropriate state agency, and requires that information be submitted with the permit application so that agencies can ensure underground drinking water sources are not endangered. See 42 U.S.C. §§ 300h(b)(1)(A)-(D); 40 C.F.R. Part 144; see, e.g., 2 C.C.R. 404-1, Rules 325, 326(a) (Colorado UIC regulations).

In 2005, however, Congress exempted hydraulic fracturing operations from the SDWA, except when diesel fuel is used. Energy Policy Act of 2005, Pub. L. No. 109-58 § 322 (2005) (codified at 42 U.S.C. § 300h(d)(1)(B)). This created a regulatory gap that has allowed companies to inject millions of gallons of fluids and chemicals on federal land without getting approval from either state or federal regulators. The 2005 SDWA exemption, however, did not limit BLM's authority under other statutes such as FLPMA. With the Rule, BLM exercises its authority to ensure the safety of hydraulic fracturing operations.

The Rule requires companies seeking approval for hydraulic fracturing operations to provide detailed information to BLM, including:

(a) wellbore geology;

(b) the depths of all usable aquifers;

(c) the "confining zone" of the subsurface that the company believes will isolate the area being fractured from usable aquifers;

(d) the location of any existing faults and fractures that may intersect the confining zone;

(e) the estimated direction and length of the fractures that the operation will create;

(f) the source of water to be used; and

(g) the volume of fluids to be used in the fracturing operation.

80 Fed. Reg. at 16129, 16218-219 (43 C.F.R. § 3162.3-3(d)).

Advance agency review and approval of hydraulic fracturing operations will provide a number of benefits. In particular, BLM can ensure that an adequate "confining zone" exists to isolate usable aquifers from the formation being fractured. In addition, the agency will be able identify existing natural fractures or other potential subsurface pathways by which fracturing fluid could migrate into other formations or aquifers. For example, a 2012 National Academy of Sciences paper concluded that shallow aquifers "could be at greater risk of contamination from shale gas development because of a preexisting network of cross-formational pathways that has enhanced hydraulic connectivity to deeper geological formations." Appendix at 278.

BLM also noted in the preamble to the Rule that there have been "numerous official reports" of "frack hits" in recent years. 80 Fed. Reg. at 16189. A "frack hit" occurs where induced fractures, fracturing fluid, and/or pressure connect with existing fractures or other wells in the subsurface, resulting in "a blow out and spill" at the surface or compromising the integrity of the other wells. 80 Fed. Reg. at 16194. These accidents "generally go unrecorded by state regulators" unless incidentally mentioned on spill reports. See Appendix at 280 (news account describing growing issue of frack hits); Wells Decl. Attachment 5 (Dkt # 20-2) (p. 44 of 222) (company pointing out that notification of frack hits is "not currently required in New Mexico"). Frack hits are expected to become even more common in the future as companies drill multiple wells in close proximity on each well pad. Appendix at 280-83; see, e.g., Wells Decl. Attachments 4-5 (Dkt # 20-2) (examples of frack hits). BLM concluded that these accidents "show that the industry is in need of regulation to protect other wells and to prevent contamination of surface and possibly sub-surface resources caused by frack hits." 80 Fed. Reg. at 16189. The Rule will help BLM ensure that fracturing does not cause frack hits or other unexpected migration of fluids.

The benefits of BLM's new approval requirement also weigh in favor of denying the Associations' request for injunction, because they will be lost for numerous wells if the Rule is enjoined during the pendency of this case. In contrast, the approval process represents a very modest cost to companies because the required information "should be readily available or known to the operator." 80 Fed. Reg. at 16196. While the Associations complain about potential delays from "*yet another permit*", PI Mem. at 45 (emphasis original), they fail to show that the new approval process will present a significant burden. For example, the Rule allows the hydraulic fracturing approval to be consolidated with the application for permit to drill process under existing rules, or to be done at a later date if the company so chooses. 80 Fed. Reg. at 16218 (43 C.F.R. § 3162.3-3(c)).[18]

4. Public information and transparency

One of the important benefits of the Rule is the additional transparency it will bring to the drilling process, and the information it will make available to the public. Researchers have described the growth of unconventional oil and gas development as "an uncontrolled health experiment on an enormous scale" because communities and agencies do not have adequate information about its potential impacts. Appendix at 285.

The Rule will help address this issue. As noted above, the Rule requires companies to provide a variety of information to BLM when seeking approval for fracturing operations. P. 30, supra. Additional details are also required to be submitted after fracturing is done, including the chemical additives used in the hydraulic fracturing fluid, the volume and sources of water used,

[18] While complaints about permitting delays are a common refrain from the Associations, the facts show that the permitting process is not slowing down oil and gas development. To the contrary, BLM statistics show that as of September 2014, companies held nearly 6,000 approved federal permits that were not being drilled. Appendix at 284. In addition, most of the time required for permit approval cannot be blamed on BLM. Instead, the majority of the delays occur while the applicant is correcting deficiencies in the initial permit application. Appendix at 286.

the fracture lengths, the results of mechanical integrity and other tests, and other information. 80 Fed. at 16220-221 (43 C.F.R. § 3162.3-3(i)). This additional transparency will be valuable for a variety of reasons.

In particular, disclosing the chemicals used in well stimulation helps those who might be exposed to them to determine what compounds they may have been exposed to, who is at fault for any exposure, and the appropriate response. Nearby residents benefit from disclosure because it enables them to conduct appropriate baseline testing and is a basis for future monitoring of water quality. Local governments need to know the chemicals used to ensure that emergency responders have the training, personal protective equipment, and plans needed to respond to accidents, and that they are adequately protected from chemicals. Medical professionals need to know the chemicals used when diagnosing and treating exposure to the chemicals, and to study the public health effects of well stimulation. And disclosure will likely incentivize drillers to use safer chemicals. See Nardone Declaration Exhibit B at 19 (Dkt # 38-4 in Case No. 2:15-cv-00043-SWS). BLM also explains that one benefit of the disclosure requirement will be that it will better enable BLM to respond to accidents when they occur. 77 Fed. Reg. 27691, 27700-27702 (May 11, 2012) (initial proposed rule).

In addition, disclosure of these chemicals allows policy makers and agency staff to conduct more thorough environmental reviews of the risks and consequences of fracturing. For example, after Congress exempted non-diesel hydraulic fracturing from the SDWA UIC program in 2005, energy companies (who were not obtaining UIC permits under the SDWA) assured the public that hydraulic fracturing chemicals were entirely benign. Energy in Depth, a trade group representing many oil and gas producers, claimed in January 2010 that "diesel fuel is simply not used in fracturing operations." See Appendix at 293 (Jan. 31, 2011 letter from Hon. H. Waxman, et al. to L. Jackson). In reality, however, service companies continued to use diesel fuel in some hydraulic fracturing treatments without the knowledge of the EPA or state regulators. When the issue came to light several years later, state and federal regulators had almost no information about the use of diesel fuel in fracturing, or whether it had affected sources of drinking water.[19] The Rule will prevent a similar situation from occurring in the future.

While some states already require disclosure of hydraulic fracturing chemicals, the Rule has stricter requirements than many state laws and will provide benefits for those states. See Nardone Decl. Exhibit B at 19-20 (Dkt # 38-4 in Case No. 2:15-cv-00043-SWS); see also Nardone Decl. at 9 (Dkt # 26-3). Moreover, the additional information required by the Rule for BLM approvals, and following completion of fracturing, will improve public transparency in numerous states.[20] The public interest and balance of equities both favor denying injunctive relief here, so that this information is available to the public. See Safari Club, 852 F. Supp. 2d at 126 (public interest favored denial of injunction against Endangered Species Act regulation, because the regulation triggered opportunities for public participation in protecting the species).

IV. THE ASSOCIATIONS HAVE NOT SHOWN A LIKELIHOOD OF SUCCESS ON THE MERITS.

Finally, the Associations fail to satisfy the fourth requirement for an injunction because they are unlikely to succeed on the merits. On this point, the Citizen Groups generally

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[19] See, e.g., Appendix at 288 (Feb. 18, 2011 Colorado Oil and Gas Conservation Commission memorandum describing how Colorado's ability to investigate the use of diesel fuel after the fact was limited because "[o]ur regulations do not [generally] require operators to report the constituents of their fracturing fluids").

[20] Unfortunately, the Rule allows companies to make their disclosures to an industry-funded web site, Frac Focus, rather than BLM itself. The Rule also allows companies to withhold some of this information as a trade secret subject to inadequate safeguards. 80 Fed. Reg. at 16221 (43 C.F.R. § 3162.3-3(j)); Nardone Decl Ex. B at 24-34 (Dkt # 38-4 in Case No. 2:15-cv-00043-SWS). These provisions may limit the benefits described above.

incorporate by reference BLM's arguments in opposition to the preliminary injunction motion. See Dkt # 20 at 2-46.

CONCLUSION

For the reasons stated above, the Associations' motion for preliminary injunction should be DENIED.

Dated: June 4, 2015

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CERTIFICATE OF SERVICE

I hereby certify that on June 4, 2015, I filed a true and correct copy of **Respondent-Intervenors' Brief In Opposition To Industry Petitioners' Motion For Preliminary Injunction** via the Court's ECF system, with notification sent to those listed below.

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APPENDIX
PART 1

APPENDIX INDEX

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Secretary of Energy Advisory Board

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Shale Gas Production Subcommittee 90-Day Report

August 18, 2011

U.S. DEPARTMENT OF ENERGY

The SEAB Shale Gas Production Subcommittee
Ninety-Day Report – August 18, 2011

Executive Summary

The Shale Gas Subcommittee of the Secretary of Energy Advisory Board is charged with identifying measures that can be taken to reduce the environmental impact and improve the safety of shale gas production.

Natural gas is a cornerstone of the U.S. economy, providing a quarter of the country's total energy. Owing to breakthroughs in technology, production from shale formations has gone from a negligible amount just a few years ago to being almost 30 percent of total U.S. natural gas production. This has brought lower prices, domestic jobs, and the prospect of enhanced national security due to the potential of substantial production growth. But the growth has also brought questions about whether both current and future production can be done in an environmentally sound fashion that meets the needs of public trust.

This 90-day report presents recommendations that if implemented will reduce the environmental impacts from shale gas production. The Subcommittee stresses the importance of a process of continuous improvement in the various aspects of shale gas production that relies on best practices and is tied to measurement and disclosure. While many companies are following such a process, much-broader and more extensive adoption is warranted. The approach benefits all parties in shale gas production: regulators will have more complete and accurate information; industry will achieve more efficient operations; and the public will see continuous, measurable improvement in shale gas activities.

A list of the Subcommittee's findings and recommendations follows.

- o <u>Improve public information about shale gas operations</u>: Create a portal for access to a wide range of public information on shale gas development, to include current data available from state and federal regulatory agencies. The portal should be open to the public for use to study and analyze shale gas operations and results.

- <u>Improve communication among state and federal regulators</u>: Provide continuing annual support to STRONGER (the State Review of Oil and Natural Gas Environmental Regulation) and to the Ground Water Protection Council for expansion of the *Risk Based Data Management System* and similar projects that can be extended to all phases of shale gas development.

- <u>Improve air quality</u>: Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable. The Subcommittee supports adoption of rigorous standards for new and existing sources of methane, air toxics, ozone precursors and other air pollutants from shale gas operations. The Subcommittee recommends:

  (1) Enlisting a subset of producers in different basins to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data from shale gas operations and make these data publically available;

  (2) Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of shale gas operations through out the lifecycle of natural gas use in comparison to other fuels; and

  (3) Encouraging shale-gas production companies and regulators to expand immediately efforts to reduce air emissions using proven technologies and practices.

- <u>Protection of water quality</u>: The Subcommittee urges adoption of a systems approach to water management based on consistent measurement and public disclosure of the flow and composition of water at every stage of the shale gas production process. The Subcommittee recommends the following actions by shale gas companies and regulators – to the extent that such actions have not already been undertaken by particular companies and regulatory agencies:

  (1) Measure and publicly report the composition of water stocks and flow throughout the fracturing and clean-up process.

  (2) Manifest all transfers of water among different locations.

  (3) Adopt best practices in well development and construction, especially casing, cementing, and pressure management. Pressure testing of cemented casing and state-of-the-art cement bond logs should be used to confirm formation isolation. Microseismic surveys should be carried out to assure that hydraulic fracture growth is limited to the gas producing formations. Regulations and inspections are needed to confirm that operators

have taken prompt action to repair defective cementing jobs. The regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing.

(4) Additional field studies on possible methane leakage from shale gas wells to water reservoirs.

(5) Adopt requirements for background water quality measurements (e.g., existing methane levels in nearby water wells prior to drilling for gas) and report in advance of shale gas production activity.

(6) Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters.

- <u>Disclosure of fracturing fluid composition</u>: The Subcommittee shares the prevailing view that the risk of fracturing fluid leakage into drinking water sources through fractures made in deep shale reservoirs is remote. Nevertheless the Subcommittee believes there is no economic or technical reason to prevent public disclosure of all chemicals in fracturing fluids, with an exception for genuinely proprietary information. While companies and regulators are moving in this direction, progress needs to be accelerated in light of public concern.

- <u>Reduction in the use of diesel fuel</u>: The Subcommittee believes there is no technical or economic reason to use diesel in shale gas production and recommends reducing the use of diesel engines for surface power in favor of natural gas engines or electricity where available.

- <u>Managing short-term and cumulative impacts on communities, land use, wildlife, and ecologies</u>. Each relevant jurisdiction should pay greater attention to the combination of impacts from multiple drilling, production and delivery activities (e.g., impacts on air quality, traffic on roads, noise, visual pollution), and make efforts to plan for shale development impacts on a regional scale. Possible mechanisms include:

  (1) Use of multi-well drilling pads to minimize transport traffic and need for new road construction.

  (2) Evaluation of water use at the scale of affected watersheds.

  (3) Formal notification by regulated entities of anticipated environmental and community impacts.

(4) Preservation of unique and/or sensitive areas as off-limits to drilling and support infrastructure as determined through an appropriate science-based process.

(5) Undertaking science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.

(6) Establishment of effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of surface and mineral rights owners.

- Organizing for best practice: The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice, defined as improvements in techniques and methods that rely on measurement and field experience, is needed to improve operational and environmental outcomes. The Subcommittee favors a national approach including regional mechanisms that recognize differences in geology, land use, water resources, and regulation. The Subcommittee is aware that several different models for such efforts are under discussion and the Subcommittee will monitor progress during its next ninety days. The Subcommittee has identified several activities that deserve priority attention for developing best practices:

  Air: (a) Reduction of pollutants and methane emissions from all shale gas production/delivery activity. (b) Establishment of an emission measurement and reporting system at various points in the production chain.

  Water: (a) Well completion – casing and cementing including use of cement bond and other completion logging tools. (b) Minimizing water use and limiting vertical fracture growth.

- Research and Development needs. The public should expect significant technical advances associated with shale gas production that will significantly improve the efficiency of shale gas production and that will reduce environmental impact. The move from single well to multiple-well pad drilling is one clear example. Given the economic incentive for technical advances, much of the R&D will be performed by the oil and gas industry. Nevertheless the federal government has a role especially in basic R&D, environment protection, and safety. The current level of federal support for unconventional gas R&D is small, and the Subcommittee recommends that the Administration and the Congress set an appropriate mission for R&D and level funding.

The Subcommittee believes that these recommendations, combined with a continuing focus on and clear commitment to measurable progress in implementation of best practices based on technical innovation and field experience, represent important steps toward meeting public concerns and ensuring that the nation's resources are responsibly being responsibly developed.

Introduction

On March 31, 2011, President Barack Obama declared that "recent innovations have given us the opportunity to tap large reserves – perhaps a century's worth" of shale gas. In order to facilitate this development, ensure environmental protection, and meet public concerns, he instructed Secretary of Energy Steven Chu to form a subcommittee of the Secretary of Energy Advisory Board (SEAB) to make recommendations to address the safety and environmental performance of shale gas production.[1] The Secretary's charge to the Subcommittee, included in Annex A, requested that:

> Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracturing.

This is the 90-day report submitted by the Subcommittee to SEAB in fulfillment of its charge. There will be a second report of the Subcommittee after 180 days. Members of the Subcommittee are given in Annex B.

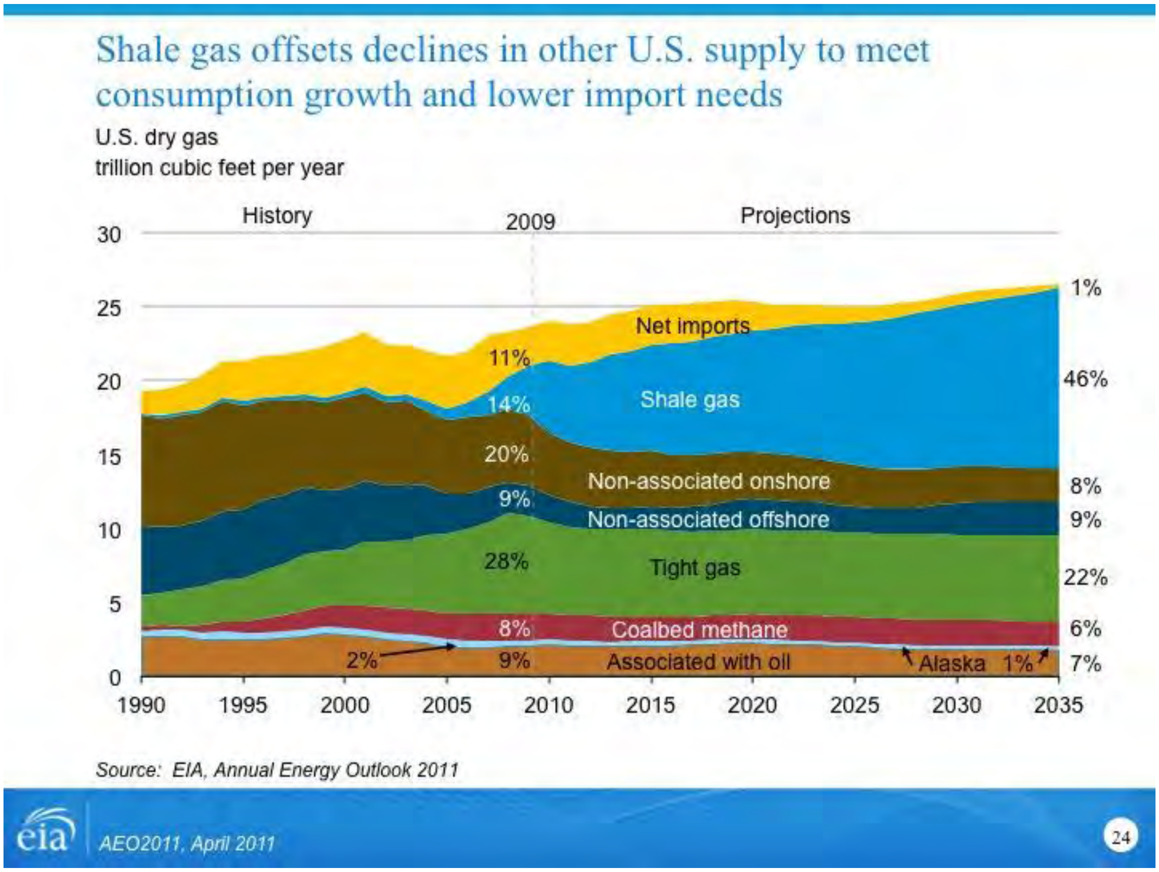
Context for the Subcommittee's deliberations

The Subcommittee believes that the U.S. shale gas resource has enormous potential to provide economic and environmental benefits for the county. Shale gas is a widely distributed resource in North America that can be relatively cheaply produced, creating jobs across the country. Natural gas – if properly produced and transported – also offers climate change advantages because of its low carbon content compared to coal.

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Domestic production of shale gas also has the potential over time to reduce dependence on imported oil for the United States. International shale gas production will increase the diversity of supply for other nations. Both these developments offer important national security benefits.[2]

The development of shale gas in the United States has been very rapid. Natural gas from all sources is one of America's major fuels, providing about 25 percent of total U.S. energy. Shale gas, in turn, was less than two percent of total U.S. natural gas production in 2001. Today, it is approaching 30 percent.[3] But it was only around 2008 that the significance of shale gas began to be widely recognized. Since then, output has increased four-fold. It has brought new regions into the supply mix. Output from the Haynesville shale, mostly in Louisiana, for example, was negligible in 2008; today, the Haynesville shale alone produces eight percent of total U.S. natural gas output. According to the U.S. Energy Information Administration (EIA), the rapid expansion of shale gas production is expected to continue in the future. The EIA projects shale gas to be 46 percent of domestic production by 2035. The following figure shows the stunning change.



The economic significance is potentially very large. While estimates vary, well over 200,000 of jobs (direct, indirect, and induced) have been created over the last several years by the development of domestic production of shale gas, and tens of thousands more will be created in the future.[4] As late as 2007, before the impact of the shale gas revolution, it was assumed that the United States would be importing large amounts of liquefied natural gas from the Middle East and other areas. Today, the United States is essentially self-sufficient in natural gas, with the only notable imports being from Canada, and expected to remain so for many decades. The price of natural gas has fallen by more than a factor of two since 2008, benefiting consumers in the lower cost of home heating and electricity.

The rapid expansion of production is rooted in change in applications of technology and field practice. It had long been recognized that substantial supplies of natural gas were embedded in shale rock. But it was only in 2002 and 2003 that the combination of two technologies working together – hydraulic fracturing and horizontal drilling – made shale gas commercial.

These factors have brought new regions into the supply mix. Parts of the country, such as regions of the Appalachian mountain states where the Marcellus Shale is located, which have not experienced significant oil and gas development for decades, are now undergoing significant development pressure. Pennsylvania, for example, which produced only one percent of total dry gas production in 2009, is one of the most active new areas of development. Even states with a history of oil and gas development, such as Wyoming and Colorado, have experienced significant development pressures in new areas of the state where unconventional gas is now technically and economically accessible due to changes in drilling and development technologies.

The urgency of addressing environmental consequences

As with all energy use, shale gas must be produced in a manner that prevents, minimizes and mitigates environmental damage and the risk of accidents and protects public health and safety. Public concern and debate about the production of shale gas has grown as shale gas output has expanded.

The Subcommittee identifies four major areas of concern: (1) Possible pollution of drinking water from methane and chemicals used in fracturing fluids; (2) Air pollution; (3) Community disruption during shale gas production; and (4) Cumulative adverse impacts that intensive shale production can have on communities and ecosystems.

There are serious environmental impacts underlying these concerns and these adverse environmental impacts need to be prevented, reduced and, where possible, eliminated as soon as possible. Absent effective control, public opposition will grow, thus putting continued production at risk. Moreover, with anticipated increase in U.S. hydraulically fractured wells, if effective environmental action is not taken today, the potential environmental consequences will grow to a point that the country will be faced a more serious problem. Effective action requires both strong regulation and a shale gas industry in which all participating companies are committed to continuous improvement.

The rapid expansion of production and rapid change in technology and field practice, requires federal and state agencies to adapt and evolve their regulations. Industry's pursuit of more efficient operations often has environmental as well as economic benefits, including waste minimization, greater gas recovery, less water usage, and a reduced operating footprint. So there are many reasons to be optimistic that continuous improvement of shale gas production in reducing existing and potential undesirable impacts can be a cooperative effort among the public, companies in the industry, and regulators.

Subcommittee scope, procedure and outline of this report

Scope: The Subcommittee has focused exclusively on production of natural gas (and some liquid hydrocarbons) from shale formations with hydraulic fracturing stimulation in either vertical or horizontal wells. The Subcommittee is aware that some of the observations and recommendations in this report could lead to extension of its findings to other oil and gas operations, but our intention is to focus singularly on issues related to shale gas development. We caution against applying our findings to other areas, because the Subcommittee has not considered the different development practices and other types of geology, technology, regulation and industry practice.

These shale plays in different basins have different geological characteristics and occur in areas with very different water resources. In the Eagle Ford, in Texas, there is almost no flow-back water from an operating well following hydraulic fracturing, while in the Marcellus, primarily in Ohio, New York, Pennsylvania and West Virginia, the flow-back water is between 20 and 40 percent of the injected volume. This geological diversity means that engineering practice and regulatory oversight will differ widely among regions of the country.

The Subcommittee describes in this report a comprehensive and collaborative approach to managing risk in shale gas production. The Subcommittee believes that a more systematic commitment to a process of *continuous improvement* to identify and implement best practices is needed, and should be embraced by all companies in the shale gas industry. Many companies already demonstrate their commitment to the kind of process we describe here, but the public should be confident that this is the practice across the industry.

This process should involve discussions and other collaborative efforts among companies involved in shale gas production (including service companies), state and federal regulators, and affected communities and public interests groups. The process should identify best practices that evolve as operational experience increases, knowledge of environmental effects and effective mitigation grows, and know-how and technology changes. It should also be supported by technology peer reviews that report on individual companies' performance and should be seen as a compliment to, not a substitute for, strong regulation and effective enforcement. There will be three benefits:

- For industry: As all firms move to adopt identified best practices, continuous improvement has the potential to both enhance production efficiency and reduce environmental impacts over time.

- For regulators: Sharing data and best practices will better inform regulators and help them craft policies and regulations that will lead to sounder and more efficient environmental practices than are now in place.

- For the public: Continuous improvement coupled with rigorous regulatory oversight can provide confidence that processes are in place that will result in improved safety and less environmental and community impact.

The realities of regional diversity of shale gas resources and rapid change in production practices and technology mean that a single best engineering practice cannot set for all locations and for all time. Rather, the appropriate starting point is to understand what are regarded as "best practices" today, how the current regulatory system works in the context of those operating in different parts of the country, and establishing a culture of continuous improvement.

The Subcommittee has considered the safety and environmental impact of all steps in shale gas production, not just hydraulic fracturing.[5] Shale gas production consists of several steps, from well design and surface preparation, to drilling and cementing steel casing at multiple stages of well construction, to well completion. The various steps include perforation, water and fracturing fluid preparation, multistage hydraulic fracturing, collection and handling of flow-back and produced water, gas collection, processing and pipeline transmission, and site remediation.[6] Each of these activities has safety and environmental risks that are addressed by operators and by regulators in different ways according to location. In light of these processes, the Subcommittee interprets its charge to assess this entire system, rather than just hydraulic fracturing.

<u>The Subcommittee's charge is not to assess the balance of the benefits of shale gas use against these environmental costs</u>. Rather, the Subcommittee's charge is to identify steps that can be taken to reduce the environmental and safety risks associated with shale gas development and, importantly, give the public concrete reason to believe that environmental impacts will be reduced and well managed on an ongoing basis, and that problems will be mitigated and rapidly corrected, if and when they occur.

<u>It is not within the scope of the Subcommittee's 90-day report to make recommendations about the proper regulatory roles for state and federal governments</u>. However, the Subcommittee emphasizes that effective and capable regulation is essential to protect the public interest. The challenges of protecting human health and the environment in light of the anticipated rapid expansion of shale gas production require the joint efforts of state and federal regulators. This means that resources dedicated to oversight of the industry must be sufficient to do the job and that there is adequate regulatory staff at the state and federal level with the technical expertise to issue, inspect, and enforce regulations. Fees, royalty payments and severance taxes are appropriate sources of funds to finance these needed regulatory activities.

The nation has important work to do in strengthening the design of a regulatory system that sets the policy and technical foundation to provide for continuous improvement in the protection of human health and the environment. While many states and several federal agencies regulate aspects of these operations, the efficacy of the regulations is far from clear. Raw statistics about enforcement actions and compliance are not sufficient to draw conclusions about regulatory effectiveness. Informed conclusions about the state of shale gas operations require analysis of the vast amount of data that is publically available, but there are surprisingly few published studies of this publically available data. Benchmarking is needed for the efficacy of existing regulations and consideration of additional mechanisms for assuring compliance such as disclosure of company performance and enforcement history, and operator certification of performance subject to stringent fines, if violated.

Subcommittee Procedure: In the ninety days since its first meeting, the Subcommittee met with representatives of industry, the environmental community, state regulators, officials of the Environmental Protection Agency, the Department of Energy, the Department of the Interior, both the United States Geologic Survey (USGS) and the Bureau of Land Management (BLM), which has responsibility for public land regulation,[7] and a number of individuals from industry and not-for-profit groups with relevant expertise and interest. The Subcommittee held a public meeting attended by over four hundred citizens in Washington Country, PA, and visited several Marcellus shale gas sites. The Subcommittee strove to hold all of its meeting in public although the Subcommittee held several private working sessions to review what it had learned and to deliberate on its course of action. A website is available that contains the Subcommittee meeting agendas, material presented to the Subcommittee, and numerous public comments.[8]

Outline of this report: The Subcommittee findings and recommendations are organized in four sections:

- Making information about shale gas production operations more accessible to the public – an immediate action.
- Immediate and longer term actions to reduce environmental and safety risks of shale gas operations
- Creation of a Shale Gas Industry Operation organization, on national and/or regional basis, committed to continuous improvement of best operating practices.
- R&D needs to improve safety and environmental performance – immediate and long term opportunities for government and industry.

The common thread in all these recommendations is that measurement and disclosure are fundamental elements of good practice and policy for all parties. Data enables companies to identify changes that improve efficiency and environmental performance and to benchmark against the performance of different companies. Disclosure of data permits regulators to identify cost/effective regulatory measures that better protect the environment and public safety, and disclosure gives the public a way to measure progress on reducing risks.

Making shale gas information available to the public

The Subcommittee has been struck by the enormous difference in perception about the consequences of shale gas activities. Advocates state that fracturing has been performed safety without significant incident for over 60 years, although modern shale gas fracturing of two mile long laterals has only been done for something less than a decade. Opponents point to failures and accidents and other environmental impacts, but these incidents are typically unrelated to hydraulic fracturing *per se* and sometimes lack supporting data about the relationship of shale gas development to incidence and consequences.[9] An industry response that hydraulic fracturing has been performed safely for decades rather than engaging the range of issues concerning the public will not succeed.

Some of this difference in perception can be attributed to communication issues. Many in the concerned public use the word "fracking" to describe all activities associated with shale gas development, rather than just the hydraulic fracturing process itself. Public concerns extend to accidents and failures associated with poor well construction and operation, surface spills, leaks at pits and impoundments, truck traffic, and the cumulative impacts of air pollution, land disturbance and community disruption.

The Subcommittee believes there is great merit to creating a national database to link as many sources of public information as possible with respect to shale gas development and production. Much information has been generated over the past ten years by state and federal regulatory agencies. Providing ways to link various databases and, where possible, assemble data in a comparable format, which are now in perhaps a hundred different locations, would permit easier access to data sets by interested parties.

Members of the public would be able to assess the current state of environmental protection and safety and inform the public of these trends. Regulatory bodies would be better able to assess and monitor the trends in enforcement activities. Industry would be able to analyze data on production trends and comparative performance in order to identify effective practices.

The Subcommittee recommends creation of this national database. A rough estimate for the initial cost is $20 million to structure and construct the linkages necessary for assembling this virtual database, and about $5 million annual cost to maintain it. This recommendation is not aimed at establishing new reporting requirements. Rather, it focuses on creating linkages among information and data that is currently collected and technically and legally capable of being made available to the public. What analysis of the data should be done is left entirely for users to decide.[10]

There are other important mechanisms for improving the availability and usefulness of shale gas information among various constituencies. The Subcommittee believes two such mechanisms to be exceptionally meritorious (and would be relatively inexpensive to expand).

The first is an existing organization known as STRONGER – the State Review of Oil and Natural Gas Environmental Regulation. STRONGER is a not-for-profit organization whose purpose is to accomplish genuine peer review of state regulatory activities. The peer reviews (conducted by a panel of state regulators, industry representatives, and environmental organization representatives with respect to the processes and policies of the state under review) are published publicly, and provide a means to share information about environmental protection strategies, techniques, regulations, and measures for program improvement. Too few states participate in STRONGER's voluntary review of state regulatory programs. The reviews allow for learning to be shared by states and the expansion of the STRONGER process should be encouraged. The Department of Energy, the Environmental Protection Agency, and the American Petroleum Institute have supported STRONGER over time.[11]

The second is the Ground Water Protection Council's project to extend and expand the *Risk Based Data Management System, which* allows states to exchange information about defined parameters of importance to hydraulic fracturing operations.[12]

The Subcommittee recommends that these two activities be funded at the level of $5 million per year beginning in FY2012. Encouraging these multi-stakeholder mechanisms will help provide greater information to the public, enhancing regulation and improving the efficiency of shale gas production. It will also provide support for STRONGER to expand its activities into other areas such as air quality, something that the Subcommittee encourages the states to do as part of the scope of STRONGER peer reviews.

Recommendations for immediate and longer term actions to reduce environmental and safety risks of shale gas operations

1. Improvement in air quality by reducing emissions of regulated pollutants and methane.

Shale gas production, including exploration, drilling, venting/flaring, equipment operation, gathering, accompanying vehicular traffic, results in the emission of ozone precursors (volatile organic compounds (VOCs), and nitrogen oxides), particulates from diesel exhaust, toxic air pollutants and greenhouse gases (GHG), such as methane.

As shale gas operations expand across the nation these air emissions have become an increasing matter of concern at the local, regional and national level. Significant air quality impacts from oil and gas operations in Wyoming, Colorado, Utah and Texas are well documented, and air quality issues are of increasing concern in the Marcellus region (in parts of Ohio, Pennsylvania, West Virginia and New York).[13]

The Environmental Protection Agency has the responsibility to regulate air emissions and in many cases delegate its authority to states. On July 28, 2011, EPA proposed amendments to its regulations for air emissions for oil and gas operations. If finalized and fully implemented, its proposal will reduce emissions of VOCs, air toxics and, collaterally, methane. EPA's proposal does not address many existing types of sources in the natural gas production sector, with the notable exception of hydraulically fractured well re-completions, at which "green" completions must be used. ("Green" completions use equipment that will capture methane and other air contaminants, avoiding its release.) EPA is under court order to take final action on these clean air measures in 2012. In addition, a number of states – notably, Wyoming and Colorado – have taken proactive steps to address air emissions from oil and gas activities.

The Subcommittee supports adoption of emission standards for both new and existing sources for methane, air toxics, ozone-forming pollutants, and other major airborne contaminants resulting from natural gas exploration, production, transportation and distribution activities. The Subcommittee also believes that companies should be required, as soon as practicable, to measure and disclose air pollution emissions, including greenhouse gases, air toxics, ozone precursors and other pollutants. Such disclosure should include direct measurements wherever feasible; include characterization of chemical composition of the natural gas measured; and be reported on a publically accessible website that allows for searching and aggregating by pollutant, company, production activity and geography.

Methane emissions from shale gas drilling, production, gas processing, transmission and storage are of particular concern because methane is a potent greenhouse gas: 25 to 72 times greater warming potential than carbon dioxide on 100-year and 20-year time scales respectively.[14] Currently, there is great uncertainty about the scale of methane emissions.

The Subcommittee recommends three actions to address the air emissions issue.

First, inadequate data are available about how much methane and other air pollutants are emitted by the consolidated production activities of a shale gas operator in a given area, with such activities encompassing drilling, fracturing, production, gathering, processing of gas and liquids, flaring, storage, and dispatch into the pipeline transmission and distribution network. Industry reporting of greenhouse gas emissions in 2012 pursuant to EPA's reporting rule will provide new insights, but will not eliminate key uncertainties about the actual amount and variability in emissions.

The Subcommittee recommends enlisting a subset of producers in different basins, on a voluntary basis, to immediately launch projects to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data.

These pioneering data sets will be useful to regulators and industry in setting benchmarks for air emissions from this category of oil and gas production, identifying cost-effective procedures and equipment changes that will reduce emissions; and guiding practical regulation and potentially avoid burdensome and contentious regulatory procedures. Each project should be conducted in a transparent manner and the results should be publicly disclosed.

There needs to be common definitions of the emissions and other parameters that should be measured and measurement techniques, so that comparison is possible between the data collected from the various projects. Provision should be made for an independent technical review of the methodology and results to establish their credibility. The Subcommittee will report progress on this proposal during its next phase.

<u>The second recommendation regarding air emissions concerns the need for a thorough assessment of the greenhouse gas footprint for cradle-to-grave use of natural gas</u>. This effort is important in light of the expectation that natural gas use will expand and substitute for other fuels. There have been relatively few analyses done of the question of the greenhouse gas footprint over the entire fuel-cycle of natural gas production, delivery and use, and little data are available that bear on the question. A recent peer-reviewed article reaches a pessimistic conclusion about the greenhouse gas footprint of shale gas production and use – a conclusion not widely accepted.[15] DOE's National Energy Technology Laboratory has given an alternative analysis.[16] Work has also been done for electric power, where natural gas is anticipated increasingly to substitute for coal generation, reaching a more favorable conclusion that natural gas results in about one-half the equivalent carbon dioxide emissions.[17]

The Subcommittee believes that additional work is needed to establish the extent of the footprint of the natural gas fuel cycle in comparison to other fuels used for electric power and transportation because it is an important factor that will be considered when formulating policies and regulations affecting shale gas development. These data will help answer key policy questions such as the time scale on which natural gas fuel switching strategies would produce real climate benefits through the full fuel cycle and the level of methane emission reductions that may be necessary to ensure such climate benefits are meaningful.

The greenhouse footprint of the natural gas fuel cycle can be either estimated indirectly by using surrogate measures or preferably by collecting actual data where it is practicable to do so. In the selection of methods to determine actual emissions, preference should be given to direct measurement wherever feasible, augmented by emissions factors that have been empirically validated. Designing and executing a comprehensive greenhouse gas footprint study based on actual data – the Subcommittee's recommended approach -- is a major project. It requires agreement on measurement equipment, measurement protocols, tools for integrating and analyzing data from different regions, over a multiyear period. Since producer, transmission and distribution pipelines, end-use storage and natural gas many different companies will necessarily be involved. A project of this scale will be expensive. Much of the cost will be borne by firms in the natural gas enterprise that are or will be required to collect and report air emissions. These measurements should be made as rapidly as practicable. Aggregating, assuring quality control and analyzing these data is a substantial task involving significant costs that should be underwritten by the federal government.

It is not clear which government agency would be best equipped to manage such a project. The Subcommittee recommends that planning for this project should begin immediately and that the Office of Science and Technology Policy, should be asked to coordinate an interagency effort to identify sources of funding and lead agency responsibility. This is a pressing question so a clear blueprint and project timetable should be produced within a year.

Third, the Subcommittee recommends that industry and regulators immediately expand efforts to reduce air emissions using proven technologies and practices. Both methane and ozone precursors are of concern. Methane leakage and uncontrolled venting of methane and other air contaminants in the shale gas production should be eliminated except in cases where operators demonstrate capture is technically infeasible, or where venting is necessary for safety reasons and where there is no alternative for capturing emissions. When methane emissions cannot be captured, they should be flared whenever volumes are sufficient to do so.

Ozone precursors should be reduced by using cleaner engine fuel, deploying vapor recovery and other control technologies effective on relevant equipment." Wyoming's emissions rules represent a good starting point for establishing regulatory frameworks and for encouraging industry best practices.

2. Protecting water supply and water quality.

The public understandably wants implementation of standards to ensure shale gas production does not risk polluting drinking water or lakes and streams. The challenge to proper understanding and regulation of the water impacts of shale production is the great diversity of water use in different regional shale gas plays and the different pattern of state and federal regulation of water resources across the country. The U.S. EPA has certain authorities to regulate water resources and it is currently undertaking a two-year study under congressional direction to investigate the potential impacts of hydraulic fracturing on drinking water resources.[18]

Water use in shale gas production passes through the following stages: (1) water acquisition, (2) drilling and hydraulic fracturing (surface formulation of water, fracturing chemicals and sand followed by injection into the shale producing formation at various locations), (3) collection of return water, (4) water storage and processing, and (5) water treatment and disposal.

The Subcommittee offers the following observations with regard to these water issues:

(1) Hydraulic fracturing stimulation of a shale gas well requires between 1 and 5 million gallons of water. While water availability varies across the country, in most regions water used in hydraulic fracturing represents a small fraction of total water consumption. Nonetheless, in some regions and localities there are significant concerns about consumptive water use for shale gas development.[19] There is considerable debate about the water intensity of natural gas compared to other fuels for particular applications such as electric power production.[20]

One of the commonly perceived risks from hydraulic fracturing is the possibility of leakage of fracturing fluid through fractures into drinking water. Regulators and geophysical experts agree that the likelihood of properly injected fracturing fluid reaching drinking water through fractures is remote where there is a large depth separation between drinking water sources and the producing zone. In the great majority of regions where shale gas is being produced, such separation exists and there are few, if any, documented examples of such migration. An improperly executed fracturing fluid injection can, of course, lead to surface spills and leakage into surrounding shallow drinking water formations. Similarly, a well with poorly cemented casing could potentially leak, regardless of whether the well has been hydraulically fractured.

With respect to stopping surface spills and leakage of contaminated water, the Subcommittee observes that extra measures are now being taken by some operators and regulators to address the public's concern that water be protected. The use of mats, catchments and groundwater monitors as well as the establishment of buffers around surface water resources help ensure against water pollution and should be adopted.

Methane leakage from producing wells into surrounding drinking water wells, exploratory wells, production wells, abandoned wells, underground mines, and natural migration is a greater source of concern. The presence of methane in wells surrounding a shale gas production site is not *ipso facto* evidence of methane leakage from the fractured producing well since methane may be present in surrounding shallow methane deposits or the result of past conventional drilling activity.

However, a recent, credible, peer-reviewed study documented the higher concentration of methane originating in shale gas deposits (through isotopic abundance of C-13 and the presence of trace amounts of higher hydrocarbons) into wells surrounding a producing shale production site in northern Pennsylvania.[21] <u>The Subcommittee recommends several studies be commissioned to confirm the validity of this study and the extent of methane migration that may take place in this and other regions</u>.

(2) Industry experts believe that methane migration from shale gas production, when it occurs, is due to one or another factors: drilling a well in a geological unstable location; <u>loss of well integrity as a result of poor well completion (cementing or casing) or poor production pressure management</u>. Best practice can reduce the risk of this failure mechanism (as discussed in the following section). Pressure tests of the casing and state-of-the-art cement bond logs should be performed to confirm that the methods being used achieve the desired degree of

formation isolation. Similarly, frequent microseismic surveys should be carried out to assure operators and service companies that hydraulic fracture growth is limited to the gas-producing formations. Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing (squeeze jobs).

(3) A producing shale gas well yields flow-back and other produced water. The flow-back water is returned fracturing water that occurs in the early life of the well (up to a few months) and includes residual fracturing fluid as well as some solid material from the formation. Produced water is the water displaced from the formation and therefore contains substances that are found in the formation, and may include brine, gases (e.g. methane, ethane), trace metals, naturally occurring radioactive elements (e.g. radium, uranium) and organic compounds. Both the amount and the composition of the flow-back and produced water vary substantially among shale gas plays – for example, in the Eagle Ford area, there is very little returned water after hydraulic fracturing whereas, in the Marcellus, 20 to 40 percent of the fracturing fluid is produced as flow-back water. In the Barnett, there can significant amounts of saline water produced with shale gas if hydraulic fractures propagate downward into the Ellenburger formation.

(4) The return water (flow-back + produced) is collected (frequently from more than a single well), processed to remove commercially viable gas and stored in tanks or an impoundment pond (lined or unlined). For pond storage evaporation will change the composition. Full evaporation would ultimately leave precipitated solids that must be disposed in a landfill. <u>Measurement of the composition of the stored return water should be a routine industry practice</u>.

(5) There are four possibilities for disposal of return water: <u>reuse</u> as fracturing fluid in a new well (several companies, operating in the Marcellus are recycling over 90 percent of the return water); <u>underground injection into disposal wells</u> (this mode of disposal is regulated by the EPA); <u>waste water treatment</u> to produce clean water (though at present, most waste water treatment plants are not equipped with the capability to treat many of the contaminants associated with shale gas waste water); and <u>surface runoff</u> which is forbidden.

Currently, the approach to water management by regulators and industry is not on a "systems basis" where all aspect of activities involving water use is planned, analyzed, and managed on an integrated basis. The difference in water use and regulation in different shale plays means that there will not be a single water management integrated system applicable in all locations. Nevertheless, the Subcommittee believes certain common principles should guide the development of integrated water management and identifies three that are especially important:

- Adoption of a life cycle approach to water management from the beginning of the production process (acquisition) to the end (disposal): all water flows should be tracked and reported quantitatively throughout the process.
- Measurement and public reporting of the composition of water stocks and flow throughout the process (for example, flow-back and produced water, in water ponds and collection tanks).
- Manifesting of all transfers of water among locations.

Early case studies of integrated water management are desirable so as to provide better bases for understanding water use and disposition and opportunities for reduction of risks related to water use. The Subcommittee supports EPA's retrospective and prospective case studies that will be part of the EPA study of hydraulic fracturing impacts on drinking water resources, but these case studies focus on identification of possible consequences rather than the definition of an integrated water management system, including the measurement needs to support it. The Subcommittee believes that development and use of an integrated water management system has the potential for greatly reducing the environmental footprint and risk of water use in shale gas production and recommends that regulators begin working with industry and other stakeholders to develop and implement such systems in their jurisdictions and regionally.

Additionally, agencies should review field experience and modernize rules and enforcement practices – especially regarding well construction/operation, management of flow back and produced water, and prevention of blowouts and surface spills – to ensure robust protection of drinking and surface waters. Specific best practice matters that should receive priority attention from regulators and industry are described below.

3. Background water quality measurements.

At present there are widely different practices for measuring the water quality of wells in the vicinity of a shale gas production site. Availability of measurements in advance of drilling would provide an objective baseline for determining if the drilling and hydraulic fracturing activity introduced any contaminants in surrounding drinking water wells.

The Subcommittee is aware there is great variation among states with respect to their statutory authority to require measurement of water quality of private wells, and that the process of adopting practical regulations that would be broadly acceptable to the public would be difficult. Nevertheless, the value of these measurements for reassuring communities about the impact of drilling on their community water supplies leads the Subcommittee to recommend that states and localities adopt systems for measurement and reporting of background water quality in advance of shale gas production activity. These baseline measurements should be publicly disclosed, while protecting landowner's privacy.

4. Disclosure of the composition of fracturing fluids.

There has been considerable debate about requirements for reporting all chemicals (both composition and concentrations) used in fracturing fluids. Fracturing fluid refers to the slurry prepared from water, sand, and some added chemicals for high pressure injection into a formation in order to create fractures that open a pathway for release of the oil and gases in the shale. Some states (such as Wyoming, Arkansas and Texas) have adopted disclosure regulations for the chemicals that are added to fracturing fluid, and the U.S. Department of Interior has recently indicated an interest in requiring disclosure for fracturing fluids used on federal lands.

The DOE has supported the establishment and maintenance of a relatively new website, FracFocus.org (operated jointly by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission) to serve as a voluntary chemical registry for individual companies to report all chemicals that would appear on Material Safety Data Sheets (MSDS) subject to certain provisions to protect "trade secrets." While FracFocus is off to a good start with voluntary reporting growing rapidly, the restriction to MSDS data means that a large universe of chemicals frequently used in hydraulic fracturing treatments goes unreported. MSDS only report chemicals that have been deemed to be hazardous in an occupational setting under standards adopted by OSHA (the Occupational Safety and Health Administration); MSDA reporting does not include other chemicals that might be hazardous if human exposure occurs through environmental pathways. Another limitation of FracFocus is that the information is not maintained as a database. As a result, the ability to search for data is limited and there are no tools for aggregating data.

The Subcommittee believes that the high level of public concern about the nature of fracturing chemicals suggests that the benefit of immediate and complete disclosure of all chemical components and composition of fracturing fluid completely outweighs the restriction on company action, the cost of reporting, and any intellectual property value of proprietary chemicals. The Subcommittee believes that public confidence in the safety of fracturing would be significantly improved by complete disclosure and that the barrier to shield chemicals based on trade secret should be set very high. Therefore the Subcommittee recommends that regulatory entities immediately develop rules to require disclosure of all chemicals used in hydraulic fracturing fluids on both public and private lands. Disclosure should include all chemicals, not just those that appear on MSDS. It should be reported on a well-by-well basis and posted on a publicly available website that includes tools for searching and aggregating data by chemical, well, by company, and by geography.

5. Reducing the use of diesel in shale gas development

Replacing diesel with natural gas or electric power for oil field equipment will decrease harmful air emissions and improve air quality. Although fuel substitution will likely happen over time because of the lower cost of natural gas compared diesel and because of likely future emission restrictions, the Subcommittee recommends conversion from diesel to natural gas for equipment fuel or to electric power where available, as soon as practicable. The process of conversion may be slowed because manufacturers of compression ignition or spark ignition engines may not have certified the engine operating with natural gas fuel for off-road use as required by EPA air emission regulations.[22]

Eliminating the use of diesel as an additive to hydraulic fracturing fluid**.** The Subcommittee believes there is no technical or economic reason to use diesel as a stimulating fluid. Diesel is a refinery product that consists of several components possibly including some toxic impurities such as benzene and other aromatics. (EPA is currently considering permitting restrictions of the use of diesel fuels in hydraulic fracturing under Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) Class II.) Diesel is convenient to use in the oil field because it is present for use fuel for generators and compressors.

Diesel has two uses in hydraulic fracturing and stimulation. In modest quantities diesel is used to solubilize other fracturing chemical such as guar. Mineral oil (a synthetic mixture of C-10 to C-40 hydrocarbons) is as effective at comparable cost. Infrequently, diesel is use as a fracturing fluid in water sensitive clay and shale reservoirs. In these cases, light crude oil that is free of aromatic impurities picked up in the refining process, can be used as a substitute of equal effectiveness and lower cost compared to diesel, as a non-aqueous fracturing fluid.

6. Managing short-term and cumulative impacts on communities, land use, wildlife and ecologies.

Intensive shale gas development can potentially have serious impacts on public health, the environment and quality of life – even when individual operators conduct their activities in ways that meet and exceed regulatory requirements. The combination of impacts from multiple drilling and production operations, support infrastructure (pipelines, road networks, etc.) and related activities can overwhelm ecosystems and communities.

The Subcommittee believes that federal, regional, state and local jurisdictions need to place greater effort on examining these cumulative impacts in a more holistic manner; discrete permitting activity that focuses narrowly on individual activities does not reach to these issues. Rather than suggesting a simple prescription that every jurisdiction should follow to assure adequate consideration of these impacts, the Subcommittee believes that each relevant jurisdiction should develop and implement processes for community engagement and for preventing, mitigating and remediating surface impacts and community impacts from production activities. There are a number of threshold mechanisms that should be considered:

- Optimize use of multi-well drilling pads to minimize transport traffic and needs for new road construction.
- Evaluate water use at the scale of affected watersheds.
- Provide formal notification by regulated entities of anticipated environmental and community impacts.
- Declare unique and/or sensitive areas off-limits to drilling and support infrastructure as determined through an appropriate science-based process.
- Undertake science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.
- Establish effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.
- Mitigate noise, air and visual pollution.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of mineral rights owners.

Organizing for continuous improvement of "best practice"

In this report, the term "Best Practice" refers to industry techniques or methods that have proven over time to accomplish given tasks and objectives in a manner that most acceptably balances desired outcomes and avoids undesirable consequences. Continuous best practice in an industry refers to the evolution of best practice by adopting process improvements as they are identified, thus progressively improving the level and narrowing the distribution of performance of firms in the industry. Best practice is a particularly helpful management approach in a field that is growing rapidly, where technology is changing rapidly, and involves many firms of different size and technical capacity.

Best practice does not necessarily imply a single process or procedure; it allows for a range of practice that is believed to be equally effective at achieving desired out comes. This flexibility is important because it acknowledges the possibility that different operators in different regions will select different solutions.

The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice through development of standards, diffusion of these standards, and assessing compliance among its members can be an important mechanism for improving shale gas companies' commitment to safety and environmental protection as it carries out its business. The Subcommittee envisions that the industry organization would be governed by a board of directors composed of member companies, on a rotating basis, along with external members, for example from non-governmental organizations and academic institutions, as determined by the board.

Strong regulations and robust enforcement resources and practices are a prerequisite to protecting health, safety and the environment, but the job is easier where companies are motivated and committed to adopting best engineering and environmental practice. Companies have economic incentives to adopt best practice, because it improves operational efficiency and, if done properly, improves safety and environmental protection.

Achievement of best practice requires management commitment, adoption and dissemination of standards that are widely disseminated and periodically updated on the basis of field experience and measurements. A trained work force, motivated to adopt best practice, is also necessary. Creation of an industry organization dedicated to excellence in shale gas operations intended to advance knowledge about best practice and improve the interactions among companies, regulators and the public would be a major step forward.

The Subcommittee is aware that shale gas producers and other groups recognize the value of a best practice management approach and that industry is considering creating a mechanism for encouraging best practice. The design of such a mechanism involves many considerations including the differences in the shale production and regulations in different basins, making most effective use of mechanisms that are currently in place, and respecting the different capabilities of large and smaller operators. The Subcommittee will monitor progress on this important matter and continue to make its views known about the characteristics that such a mechanism and supporting organization should possess to maximize its effectiveness.

It should be stressed that any industry best practice mechanism would need to comply with anti-trust laws and would not replace any existing state or federal regulatory authority.

Priority best practice topics

Air
- Measurement and disclosure of air emissions including VOCs, methane, air toxics, and other pollutants.
- Reduction of methane emission from all shale gas operations

Water
- Integrated water management systems
- Well completion – casing and cementing
- Characterization and disclosure of flow back and other produced water

The Subcommittee has identified a number of promising best practice opportunities. Five examples are given in the call-out box. Two examples are discussed below to give a sense of the opportunities that presented by best practice focus.

Well integrity: an example. Well integrity is an example of the potential power of best practice for shale gas production. Well integrity encompasses the planning, design and execution of a well completion (cementing, casing and well head placement). It is fundamental to good outcomes in drilling oil and gas wells.

Methane leakage to water reservoirs is widely believed to be due to poor well completion, especially poor casing and cementing. Casing and cementing programs should be designed to provide optimal isolation of the gas-producing zone from overlaying formations. The number of cemented casings and the depth ranges covered will depend on local geologic and hydrologic conditions. However, there need to be multiple engineered barriers to prevent communication between hydrocarbons and potable aquifers. In addition, the casing program needs to be designed to optimize the potential success of cementing operations. Poorly cemented cased wells offer pathways for leakage; properly cemented and cased wells do not.

Well integrity is an ideal example of where a best practice approach, adopted by the industry, can stress best practice and collect data to validate continuous improvement. The American Petroleum Institute, for example, has focused on well completion in its standards activity for shale gas production.[23]

At present, however, there is a wide range in procedures followed in the field with regard to casing placement and cementing for shale gas drilling. There are different practices with regard to completion testing and different regulations for monitoring possible gas leakage from the annulus at the wellhead. In some jurisdictions, regulators insist that gas leakage can be vented; others insist on containment with periodic pressure testing. There are no common leakage criteria for intervention in a well that exhibits damage or on the nature of the intervention. It is very likely that over time a focus on best practice in well completion will result in safer operations and greater environmental protection. The best practice will also avoid costly interruptions to normal operations. The regulation of shale gas development should also include inspections at safety-critical stages of well construction and hydraulic fracturing.

<u>Limiting water use by controlling vertical fracture growth</u>: – a second example. While the vertical growth of hydraulic fractures does not appear to have been a causative factor in reported cases where methane from shale gas formations has migrated to the near surface, it is in the best interest of operators and the public to limit the vertical extent of hydraulic fractures to the gas bearing shale formation being exploited. By improving the efficiency of hydraulic fractures, more gas will be produced using less water for fracturing – which has economic value to operators and environmental value for the public.

The vertical propagation of hydraulic fractures results from the variation of earth stress with depth and the pumping pressure during fracturing. The variation of earth stress with depth is difficult to predict, but easy to measure in advance of hydraulic fracturing operations. Operators and service companies should assure that through periodic direct measurement of earth stresses and microseismic monitoring of hydraulic fracturing operations, everything possible is being done to limit the amount of water and additives used in hydraulic fracturing operations.

<u>Evolving best practices must be accompanied by metrics that permit tracking of the progress in improving shale gas operations performance and environmental impacts</u>. The Subcommittee has the impression that the current standard- setting processes do not utilize metrics. Without such metrics and the collection of relevant measured data,

operators lack the ability to track objectively the progress of the extensive process of setting and updating standards.

Research and development needs

The profitability, rapid expansion, and the growing recognition of the scale of the resource mean that oil and gas companies will mount significant R&D efforts to improve performance and lower cost of shale gas exploration and production. In general the oil and gas industry is a technology-focused and technology-driven industry, and it is safe to assume that there will be a steady advance of technology over the coming years.

In these circumstances the federal government has a limited role in supporting R&D. The proper focus should be on sponsoring R&D and analytic studies that address topics that benefit the public or the industry but which do not permit individual firms to attain a proprietary position. Examples are environmental and safety studies, risk assessments, resource assessments, and longer-term R&D (such as research on methane hydrates). Across many administrations, the Office of Management and Budget (OMB) has been skeptical of any federal support for oil and gas R&D, and many Presidents' budget have not included any request for R&D for oil and gas. Nonetheless Congress has typically put money into the budget for oil & gas R&D.

The following table summarizes the R&D outlays of the DOE, EPA, and USGS for unconventional gas:

Unconventional Gas R&D Outlays for Various Federal Agencies ($ millions)					
	FY2008	**FY2009**	**FY2010**	**FY2011**	**FY2012 request**
DOE Unconventional Gas					
EPAct Section 999 Program Funds					
RPSEA Administered	$14	$14	$14	$14	0
NETL Complementary	$9	$9	$9	$4	0
Annual Appropriated Program Funds					
Environmental	$2	$4	$2	0	0
Unconventional Fossil Energy	0	0	$6	0	0
Methane Hydrate projects	$15	$15	$15	$5	$10
Total Department of Energy	$40	$42	$46	$23	$10
Environmental Protection Agency	$0	$0	$1.9	$4.3	$6.1
USGS	$4.5	$4.6	$5.9	$7.4	$7.6
Total Federal R&D	**$44.5**	**$46.6**	**$53.8**	**$34.7**	**$23.7**

Near Term Actions:

The Subcommittee believes that given the scale and rapid growth of the shale gas resource in the nation's energy mix, the federal government should sponsor some R&D for unconventional gas, focusing on areas that have public and industry wide benefit and addresses public concern. The Subcommittee, at this point, is only in a position to offer some initial recommendations, not funding levels or to assignment of responsibility to particular government agencies. The DOE, EPA, the USGS, and DOI Bureau of Land Management all have mission responsibility that justify a continuing, tailored, federal R&D effort.

RPSEA is the Research Partnership to Secure Energy for America, a public/private research partnership authorized by the 2005 Energy Policy Act at a level of $50 million from offshore royalties. Since 2007, the RPSEA program has focused on unconventional gas. The Subcommittee strongly supports the RPSEA program at its authorized level.[24]

The Subcommittee recommends that the relevant agencies, the Office of Science and Technology Policy (OSTP), and OMB discuss and agree on an appropriate mission and level of funding for unconventional natural gas R&D. If requested, the Subcommittee, in the second phase of its work, could consider this matter in greater detail and make recommendations for the Administration's consideration.

In addition to the studies mentioned in the body of the report, the Subcommittee mentions several additional R&D projects where results could reduce safety risk and environmental damage for shale gas operations:

1. Basic research on the relationship of fracturing and micro-seismic signaling.
2. Determination of the chemical interactions between fracturing fluids and different shale rocks – both experimental and predictive.
3. Understanding induced seismicity triggered by hydraulic fracturing and injection well disposal.[25]
4. Development of "green" drilling and fracturing fluids.
5. Development of improved cement evaluation and pressure testing wireline tools assuring casing and cementing integrity.

Longer term prospects for technical advance

The public should expect significant technical advance on shale gas production that will substantially improve the efficiency of shale gas production and that will in turn reduce environmental impact. The expectation of significant production expansion in the future offers a tremendous incentive for companies to undertake R&D to improve efficiency and profitability. The history of the oil and gas industry supports such innovation, in particular greater extraction of the oil and gas in place and reduction in the unit cost of drilling and production.

The original innovations of directional drilling and formation fracturing plausibly will be extended by much more accurate placement of fracturing fluid guided by improved interpretation of micro-seismic signals and improved techniques of reservoir testing. As an example, oil services firms are already offering services that provide near-real-time monitoring to avoid excessive vertical fracturing growth, thus affording better control of fracturing fluid placement. Members of the Subcommittee estimate that an improvement in in efficiency of water use could be between a factor of two and four. There will be countless other innovations as well.

There has already been a major technical innovation – the switch from single well to pad-based drilling and production of multiple wells (up to twenty wells per pad have been drilled). The multi-well pad system allows for enhanced efficiency because of repeating operations at the same site and a much smaller footprint (e.g. concentrated gas gathering systems; many fewer truck trips associated with drilling and completion, especially related to equipment transport; decreased needs for road and pipeline constructions, etc.). It is worth noting that these efficiencies may require pooling acreage into large blocks.

Conclusion

The public deserves assurance that the full economic, environmental and energy security benefits of shale gas development will be realized without sacrificing public health, environmental protection and safety. Nonetheless, accidents and incidents have occurred with shale gas development, and uncertainties about impacts need to be quantified and clarified. Therefore the Subcommittee has highlighted important steps for more thorough information, implementation of best practices that make use of technical innovation and field experience, regulatory enhancement, and focused R&D, to ensure that shale operations proceed in the safest way possible, with enhanced efficiency and minimized adverse impact. If implemented these measures will give the public reason to believe that the nation's considerable shale gas resources are being developed in a way that is most beneficial to the nation.

ANNEX A – CHARGE TO THE SUBCOMMITTEE

From: Secretary Chu

To: William J. Perry, Chairman, Secretary's Energy Advisory Board (SEAB)

On March 30, 2011, President Obama announced a plan for U.S. energy security, in which he instructed me to work with other agencies, the natural gas industry, states, and environmental experts to improve the safety of shale gas development. The President also issued the Blueprint for a Secure Energy Future ("Energy Blueprint"), which included the following charge:

> **"Setting the Bar for Safety and Responsibility:** To provide recommendations from a range of independent experts, the Secretary of Energy, in consultation with the EPA Administrator and Secretary of Interior, should task the Secretary of Energy Advisory Board (SEAB) with establishing a subcommittee to examine fracking issues. The subcommittee will be supported by DOE, EPA and DOI, and its membership will extend beyond SEAB members to include leaders from industry, the environmental community, and states. The subcommittee will work to identify, within 90 days, any immediate steps that can be taken to improve the safety and environmental performance of fracking and to develop, within six months, consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment." *Energy Blueprint (page 13).*

The President has charged us with a complex and urgent responsibility. I have asked SEAB and the Natural Gas Subcommittee, specifically, to begin work on this assignment immediately and to give it the highest priority.

This memorandum defines the task before the Subcommittee and the process to be used.

Membership:

In January of 2011, the SEAB created a Natural Gas Subcommittee to evaluate what role natural gas might play in the clean energy economy of the future. Members of the Subcommittee include John Deutch (chair), Susan Tierney, and Dan Yergin. Following consultation with the Environmental Protection Agency and the Department of the Interior, I have appointed the following additional members to the Subcommittee: Stephen Holditch, Fred Krupp, Kathleen McGinty, and Mark Zoback.

The varied backgrounds of these members satisfies the President's charge to include individuals with industry, environmental community, and state expertise. To facilitate an expeditious start, the Subcommittee will consist of this small group, but additional members may be added as appropriate.

Consultation with other Agencies:

The President has instructed DOE to work in consultation with EPA and DOI, and has instructed all three agencies to provide support and expertise to the Subcommittee. Both agencies have independent regulatory authority over certain aspects of natural gas production, and considerable expertise that can inform the Subcommittee's work.

- The Secretary and Department staff will manage an interagency working group to be available to consult and provide information upon request of the Subcommittee.
- The Subcommittee will ensure that opportunities are available for EPA and DOI to present information to the Subcommittee.
- The Subcommittee should identify and request any resources or expertise that lies within the agencies that is needed to support its work.
- The Subcommittee's work should at all times remain independent and based on sound science and other expertise held from members of the Subcommittee.
- The Subcommittee's deliberations will involve only the members of the Subcommittee.
- The Subcommittee will present its final report/recommendations to the full SEAB Committee.

Public input:

In arriving at its recommendations, the Subcommittee will seek timely expert and other advice from industry, state and federal regulators, environmental groups, and other stakeholders.

- To assist the Subcommittee, DOE's Office of Fossil Energy will create a website to describe the initiative and to solicit public input on the subject.
- The Subcommittee will meet with representatives from state and federal regulatory agencies to receive expert information on subjects as the Subcommittee deems necessary.
- The Subcommittee or the DOE (in conjunction with the other agencies) may hold one or more public meetings when appropriate to gather input on the subject.

Scope of work of the Subcommittee:

The Subcommittee will provide the SEAB with recommendations as to actions that can be taken to improve the safety and environmental performance of shale gas extraction processes, and other steps to ensure protection of public health and safety, on topics such as:

- well design, siting, construction and completion;
- controls for field scale development;
- operational approaches related to drilling and hydraulic fracturing;
- risk management approaches;
- well sealing and closure;
- surface operations;
- waste water reuse and disposal, water quality impacts, and storm water runoff;

- protocols for transparent public disclosure of hydraulic fracturing chemicals and other information of interest to local communities;
- optimum environmentally sound composition of hydraulic fracturing chemicals, reduced water consumption, reduced waste generation, and lower greenhouse gas emissions;
- emergency management and response systems;
- metrics for performance assessment; and
- mechanisms to assess performance relating to safety, public health and the environment.

The Subcommittee should identify, at a high level, the best practices and additional steps that could enhance companies' safety and environmental performance with respect to a variety of aspects of natural gas extraction. Such steps may include, but not be limited to principles to assure best practices by the industry, including companies' adherence to these best practices. Additionally, the Subcommittee may identify high-priority research and technological issues to support prudent shale gas development.

Delivery of Recommendations and Advice:

- Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracking."
- Within 180 days of its first meeting, the Subcommittee will report to SEAB "consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment."
- At each stage, the Subcommittee will report its findings to the full Committee and the SEAB will review the findings.
- The Secretary will consult with the Administrator of EPA and the Secretary of the Interior, regarding the recommendations from SEAB.

Other:

- The Department will provide staff support to the Subcommittee for the purposes of meeting the requirements of the Subcommittee charge. The Department will also engage the services of other agency Federal employees or contractors to provide staff services to the Subcommittee, as it may request.
- DOE has identified $700k from the Office of Fossil Energy to fund this effort, which will support relevant studies or assessments, report writing, and other costs related to the Subcommittee's process.
- The Subcommittee will avoid activity that creates or gives the impression of giving undue influence or financial advantage or disadvantage for particular companies involved in shale gas exploration and development.
- The President's request specifically recognizes the unique technical expertise and scientific role of the Department and the SEAB. As an agency not engaged in regulating this activity, DOE is expected to provide a sound, highly credible evaluation of the best practices and best ideas for employing these practices safely that can be made available to companies and relevant regulators for appropriate action. Our task does not include making decisions about regulatory policy.

ANNEX B – MEMBERS OF THE SUBCOMMITTEE

John Deutch, Institute Professor at MIT (Chair) **-** John Deutch served as Director of Energy Research, Acting Assistant Secretary for Energy Technology and Under Secretary of Energy for the U.S. Department of Energy in the Carter Administration and Undersecretary of Acquisition & Technology, Deputy Secretary of Defense and Director of Central Intelligence during the first Clinton Administration. Dr. Deutch also currently serves on the Board of Directors of Raytheon and Cheniere Energy and is a past director of Citigroup, Cummins Engine Company and Schlumberger. A chemist who has published more than 140 technical papers in physical chemistry, he has been a member of the MIT faculty since 1970, and has served as Chairman of the Department of Chemistry, Dean of Science and Provost. He is a member of the Secretary of Energy Advisory Board.

Stephen Holditch, Head of the Department of Petroleum Engineering at Texas A&M University and has been on the faculty since 1976 - Stephen Holditch, who is a member of the National Academy of Engineering, serves on the Boards of Directors of Triangle Petroleum Corporation and Matador Resources Corporation. In 1977, Dr. Holditch founded S.A. Holditch & Associates, a petroleum engineering consulting firm that specialized in the analysis of unconventional gas reservoirs. Dr. Holditch was the 2002 President of the Society of Petroleum Engineers. He was the Editor of an SPE Monograph on hydraulic fracturing treatments, and he has taught short courses for 30 years on the design of hydraulic fracturing treatments and the analyses of unconventional gas reservoirs. Dr. Holditch worked for Shell Oil Company prior to joining the faculty at Texas A&M University.

Fred Krupp, President, Environmental Defense Fund **-** Fred Krupp has overseen the growth of EDF into a recognized worldwide leader in the environmental movement. Krupp is widely acknowledged as the foremost champion of harnessing market forces for environmental ends. He also helped launch a corporate coalition, the U.S. Climate Action Partnership, whose Fortune 500 members - Alcoa, GE, DuPont and dozens more - have called for strict limits on global warming pollution. Mr. Krupp is coauthor, with Miriam Horn, of New York Times Best Seller, *Earth: The Sequel*. Educated at Yale and the University of Michigan Law School, Krupp was among 16 people named as America's Best Leaders by U.S. News and World Report in 2007.

Kathleen McGinty, Kathleen McGinty is a respected environmental leader, having served as President Clinton's Chair of the White House Council on Environmental Quality and Legislative Assistant and Environment Advisor to then-Senator Al Gore.

More recently, she served as Secretary of the Pennsylvania Department of Environmental Protection. Ms. McGinty also has a strong background in energy. She is Senior Vice President of Weston Solutions where she leads the company's clean energy development business. She also is an Operating Partner at Element Partners, an investor in efficiency and renewables. Previously, Ms. McGinty was Chair of the Pennsylvania Energy Development Authority, and currently she is a Director at NRG Energy and Iberdrola USA.

Susan Tierney, Managing Principal, Analysis Group **-** Susan Tierney is a consultant on energy and environmental issues to public agencies, energy companies, environmental organizations, energy consumers, and tribes. She chairs the Board of the Energy Foundation, and serves on the Boards of Directors of the World Resources Institute, the Clean Air Task Force, among others. She recently, co-chaired the National Commission on Energy Policy, and chairs the Policy Subgroup of the National Petroleum Council's study of North American natural gas and oil resources. Dr. Tierney served as Assistant Secretary for Policy at the U.S. Department of Energy during the Clinton Administration. In Massachusetts, she served as Secretary of Environmental Affairs, Chair of the Board of the Massachusetts Water Resources Agency, Commissioner of the Massachusetts Department of Public Utilities and executive director of the Massachusetts Energy Facilities Siting Council.

Daniel Yergin, Chairman, IHS Cambridge Energy Research Associates **-** Daniel Yergin is the co-founder and chairman of IHS Cambridge Energy Research Associates. He is a member of the U.S. Secretary of Energy Advisory Board, a board member of the Board of the United States Energy Association and a member of the U.S. National Petroleum Council. He was vice chair of the 2007 National Petroleum Council study, *Hard Truths* and is vice chair of the new National Petroleum Council study of North American natural gas and oil resources. He chaired the U.S. Department of Energy's Task Force on Strategic Energy Research and Development. Dr. Yergin currently chairs the Energy Security Roundtable at the Brookings Institution, where he is a trustee, and is member of the advisory board of the MIT Energy Initiative. Dr. Yergin is also CNBC's Global Energy Expert. He is the author of the Pulitzer Prize-winning book, *The Prize: The Epic Quest for Oil, Money and Power.* His new book – *The Quest: Energy, Security, and the Remaking of the Modern World* – will be published in September 2011..

Mark Zoback, Professor of Geophysics, Stanford University - Mark Zoback is the Benjamin M. Page Professor of Geophysics at Stanford University. He is the author of a textbook, *Reservoir Geomechanics*, and author or co-author of over 300 technical research papers. He was co-principal investigator of the San Andreas Fault Observatory at Depth project (SAFOD) and has been serving on a National Academy of Engineering committee investigating the Deepwater Horizon accident. He was the chairman and co-founder of GeoMechanics International and serves as a senior adviser to Baker Hughes, Inc. Prior to joining Stanford University, he served as chief of the Tectonophysics Branch of the U.S. Geological Survey Earthquake Hazards Reduction Program.

ENDNOTES

1 http://www.whitehouse.gov/sites/default/files/blueprint_secure_energy_future.pdf

2 The James Baker III Institute for Public Policy at Rice University has recently released a report on *Shale Gas and U.S. National Security,* Available at: http://bakerinstitute.org/publications/EF-pub-DOEShaleGas-07192011.pdf.

3 As a shale of total dry gas production in the "lower '48", shale gas was 6 percent in 2006, 8 percent in 2007, at which time its share began to grow rapidly – reaching 12 percent in 2008, 16 percent in 2009, and 24 percent in 2010. In June 2011, it reached 29 percent. Source: Energy Information Adminstration and Lippman Consulting.

4 Timothy Considine, Robert W. Watson, and Nicholas B. Considine, "The Economy Opportunities of Shale Energy Development," Manhattan Institute, May 2011, Table 2, page 6.

5 Essentially all fracturing currently uses water at the working fluid. The possibility exists of using other fluids, such as nitrogen, carbon dioxide or foams as the working fluid.

6 The Department of Energy has a shale gas technology primer available on the web at: http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/Shale_Gas_March_2011.pdf

7 See the Bureau of Land Management *Gold Book* for a summary description of the DOI's approach: http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/energy/oil_and_gas.Par.18714.File.dat/OILgas.pdf

8 http://www.shalegas.energy.gov/

9 The 2011 *MIT Study on the Future of Natural Gas,* gives an estimate of about 50 widely reported incidents between 2005 and 2009 involving groundwater contamination, surface spills, off-site disposal issues, water issues, air quality and blow outs, Table 2.3 and Appendix 2E. http://web.mit.edu/mitei/research/studies/naturalgas.html

10 The Ground Water Protection Council and the Interstate Oil and Gas Compact Commission are considering a project to create a *National Oil and Gas Data Portal* with similar a objective, but broader scope to encompass all oil and gas activities.

11 Information about STRONGER can be found at: http://www.strongerinc.org/

12 The RBMS project is supported by the DOE Office of Fossil Energy, DOE grant #DE-FE0000880 at a cost of $1.029 million. The project is described at: http://www.netl.doe.gov/technologies/oil-gas/publications/ENVreports/FE0000880_GWPC_Kickoff.pdf

13 See, for example: John Corra, "Emissions from Hydrofracking Operations and General Oversight Information for Wyoming," presented to the U.S. Department of Energy Natural Gas Subcommittee of the Secretary of Energy Advisory Board, July 13, 2011; Al Armendariz, "Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements," Southern Methodist University, January 2009; Colorado Air Quality Control Commission, "Denver Metro Area & North Front Range Ozone Action Plan," December 12, 2008; Utah Department of Environmental Quality, "2005 Uintah Basin Oil and Gas Emissions Inventory," 2005.

14 IPCC 2007 –The Physical Science Basis, Section 2.10.2).

15 Robert W. Howarth, Renee Santoro, and Anthony Ingraffea, *Methane and the greenhouse-gas*

footprint of natural gas from shale formations, Climate Change, The online version of this article (doi:10.1007/s10584-011-0061-5) contains supplementary material.

[16] Timothy J. Skone, *Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States,* DOE, NETL, May 2011, available at: http://www.netl.doe.gov/energy-analyses/pubs/NG_LC_GHG_PRES_12MAY11.pdf

[17] Paulina Jaramillo, W. Michael Griffin, and H. Scott Mathews, *Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation*, Environmental Science & Technology, 41, 6290-6296 (2007).

[18] The EPA draft hydraulic fracturing study plan is available along with other information about EPA hydraulic fracturing activity at: http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm

[19] See, for example, "South Texas worries over gas industry's water use during drought," Platts, July 5, 2011, found at: http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/3555776; "Railroad Commission, Halliburton officials say amount of water used for fracking is problematic," Abeline Reporter News, July 15, 2011, found at: http://www.reporternews.com/news/2011/jul/15/railroad-commission-halliburton-officials-say-of/?print=1; "Water Use in the Barnett Shale," Texas Railroad Commission Website, updated January 24, 2011, found at: http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php.

[20] See, for example, *Energy Demands on Water Resources, DOE Report to Congress,* Dec 2006, http://www.sandia.gov/energy-water/docs/121-RptToCongress-EWwEIAcomments-FINAL.pdf

[21] Stephen G. Osborna, Avner Vengoshb, Nathaniel R. Warnerb, and Robert B. Jackson, *Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing*, Proceedings of the National Academy of Science, 108, 8172-8176, (2011).

[22] See EPA Certification Guidance for Engines Regulated Under: 40 CFR Part 86 (On-Highway Heavy-Duty Engines) and 40 CFR Part 89 (Nonroad CI Engines); available at: http://www.epa.gov/oms/regs/nonroad/equip-hd/420b98002.pdf

[23] API standards documents addressing hydraulic fracturing are: API HF1, Hydraulic Fracturing Operations-Well Construction and Integrity Guidelines, First Edition/October 2009, API HF2, Water Management Associated with Hydraulic Fracturing, First Edition/June 2010, API HF3, Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing, First Edition/January 2011, available at: http://www.api.org/policy/exploration/hydraulicfracturing/index.cfm

[24] Professor Steven Holditch, one of the Subcommittee members, is chair of the RPSEA governing committee.

[25] Extremely small microearthquakes are triggered as an integral part of shale gas development. While essentially all of these earthquakes are so small as to pose no hazard to the public or facilities (they release energy roughly equivalent to a gallon of milk falling of a kitchen counter), earthquakes of larger (but still small) magnitude have been triggered during hydraulic fracturing operations and by the injection of flow-back water after hydraulic fracturing. It is important to develop a hazard assessment and remediation protocol for triggered earthquakes to allow operators and regulators to know what steps need to be taken to assess risk and modify, as required, planned field operations.

United States Government Accountability Office

GAO

Report to Congressional Requesters

September 2012

OIL AND GAS

Information on Shale Resources, Development, and Environmental and Public Health Risks

GAO

Accountability * Integrity * Reliability

GAO Accountability * Integrity * Reliability

Highlights

Highlights of GAO-12-732, a report to congressional requesters

September 2012

OIL AND GAS

Information on Shale Resources, Development, and Environmental and Public Health Risks

Why GAO Did This Study

New applications of horizontal drilling techniques and hydraulic fracturing—in which water, sand, and chemical additives are injected under high pressure to create and maintain fractures in underground formations—allow oil and natural gas from shale formations (known as "shale oil" and "shale gas") to be developed. As exploration and development of shale oil and gas have increased—including in areas of the country without a history of oil and natural gas development—questions have been raised about the estimates of the size of these resources, as well as the processes used to extract them.

GAO was asked to determine what is known about the (1) size of shale oil and gas resources and the amount produced from 2007 through 2011 and (2) environmental and public health risks associated with the development of shale oil and gas. GAO reviewed estimates and data from federal and nongovernmental organizations on the size and production of shale oil and gas resources. GAO also interviewed federal and state regulatory officials, representatives from industry and environmental organizations, oil and gas operators, and researchers from academic institutions.

GAO is not making any recommendations in this report. We provided a draft of this report to the Department of Energy, the Department of the Interior, and the Environmental Protection Agency for review. The Department of the Interior and the Environmental Protection Agency provided technical comments, which we incorporated as appropriate. The Department of Energy did not provide comments.

View GAO-12-732. For more information, contact Frank Rusco at (202) 512-3841 or ruscof@gao.gov.

What GAO Found

Estimates of the size of shale oil and gas resources in the United States by the Energy Information Administration (EIA), U.S. Geological Survey (USGS), and the Potential Gas Committee—three organizations that estimate the size of these resources—have increased over the last 5 years, which could mean an increase in the nation's energy portfolio. For example, in 2012, EIA estimated that the amount of technically recoverable shale gas in the United States was 482 trillion cubic feet—an increase of 280 percent from EIA's 2008 estimate. However, according to EIA and USGS officials, estimates of the size of shale oil and gas resources in the United States are highly dependent on the data, methodologies, model structures, and assumptions used to develop them. In addition, less is known about the amount of technically recoverable shale oil than shale gas, in part because large-scale production of shale oil has been under way for only the past few years. Estimates are based on data available at a given point in time and will change as additional information becomes available. In addition, domestic shale oil and gas production has experienced substantial growth; shale oil production increased more than fivefold from 2007 to 2011, and shale gas production increased more than fourfold from 2007 to 2011.

Oil and gas development, whether conventional or shale oil and gas, pose inherent environmental and public health risks, but the extent of these risks associated with shale oil and gas development is unknown, in part, because the studies GAO reviewed do not generally take into account the potential long-term, cumulative effects. For example, according to a number of studies and publications GAO reviewed, shale oil and gas development poses risks to air quality, generally as the result of (1) engine exhaust from increased truck traffic, (2) emissions from diesel-powered pumps used to power equipment, (3) gas that is flared (burned) or vented (released directly into the atmosphere) for operational reasons, and (4) unintentional emissions of pollutants from faulty equipment or impoundments—temporary storage areas. Similarly, a number of studies and publications GAO reviewed indicate that shale oil and gas development poses risks to water quality from contamination of surface water and groundwater as a result of erosion from ground disturbances, spills and releases of chemicals and other fluids, or underground migration of gases and chemicals. For example, tanks storing toxic chemicals or hoses and pipes used to convey wastes to the tanks could leak, or impoundments containing wastes could overflow as a result of extensive rainfall. According to the New York Department of Environmental Conservation's 2011 Supplemental Generic Environmental Impact Statement, spilled, leaked, or released chemicals or wastes could flow to a surface water body or infiltrate the ground, reaching and contaminating subsurface soils and aquifers. In addition, shale oil and gas development poses a risk to land resources and wildlife habitat as a result of constructing, operating, and maintaining the infrastructure necessary to develop oil and gas; using toxic chemicals; and injecting fluids underground. However, the extent of these risks is unknown. For example, the studies and publications GAO reviewed on air quality conditions provide information for a specific site at a specific time but do not provide the information needed to determine the overall cumulative effects that shale oil and gas activities may have on air quality. Further, the extent and severity of environmental and public health risks identified in the studies and publications GAO reviewed may vary significantly across shale basins and also within basins because of location- and process-specific factors, including the location and rate of development; geological characteristics, such as permeability, thickness, and porosity of the formations; climatic conditions; business practices; and regulatory and enforcement activities.

Contents

Abbreviations

BLM	Bureau of Land Management
Btu	British thermal unit
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
NORM	naturally occurring radioactive materials
Tcf	technically recoverable gas
USGS	U.S. Geological Survey

G A O
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September 5, 2012

Congressional Requesters

For decades, the United States has relied on imports of oil and natural gas to meet domestic needs. As recently as 2007, the expectation was that the nation would increasingly rely on imports of natural gas to meet its growing demand. However, recent improvements in technology have allowed companies that develop petroleum resources to extract oil and natural gas from shale formations,[1] known as "shale oil" and "shale gas," respectively, which were previously inaccessible because traditional techniques did not yield sufficient amounts for economically viable production. In particular, as we reported in January 2012, new applications of horizontal drilling techniques and hydraulic fracturing—a process that injects a combination of water, sand, and chemical additives under high pressure to create and maintain fractures in underground rock formations that allow oil and natural gas to flow—have prompted a boom in shale oil and gas production.[2] According to the Department of Energy (DOE), America's shale gas resource base is abundant, and development of this resource could have beneficial effects for the nation, such as job creation.[3] According to a report by the Baker Institute, domestic shale gas development could limit the need for expensive imports of these resources—helping to reduce the U.S. trade deficit.[4] In addition, replacing older coal burning power generation with new natural gas-fired generators could reduce greenhouse gas emissions and result in fewer air pollutants

[1]Shale oil differs from "oil shale." Shale is a sedimentary rock that is predominantly composed of consolidated clay-sized particles. Oil shale requires a different process to extract. Specifically, to extract the oil from oil shale, the rock needs to be heated to very high temperatures—ranging from about 650 to 1,000 degrees Fahrenheit—in a process known as retorting. Oil shale is not currently economically viable to produce. For additional information on oil shale, see GAO, *Energy-Water Nexus: A Better and Coordinated Understanding of Water Resources Could Help Mitigate the Impacts of Potential Oil Shale Development*, GAO-11-35 (Washington, D.C.: Oct. 29, 2010).

[2]GAO, *Energy-Water Nexus: Information on the Quantity, Quality, and Management of Water Produced during Oil and Gas Production*, GAO-12-156 (Washington, D.C.: Jan. 9, 2012).

[3]EIA is a statistical agency within DOE that provides independent data, forecasts, and analyses.

[4]The Baker Institute is a public policy think tank located on the Rice University campus.

for the same amount of electric power generated.[5] Early drilling activity in shale formations was centered primarily on natural gas, but with the falling price of natural gas companies switched their focus to oil and natural gas liquids, which are a more valuable product.[6]

As exploration and development of shale oil and gas have increased in recent years—including in areas of the country without a history of oil and natural gas activities—questions have been raised about the estimates of the size of domestic shale oil and gas resources, as well as the processes used to extract them.[7] For example, some organizations have questioned the accuracy of the estimates of the shale gas supply. In particular, some news organizations have reported concerns that such estimates may be inflated. In addition, concerns about environmental and public health effects of the increased use of horizontal drilling and hydraulic fracturing, particularly on air quality and water resources, have garnered extensive public attention. According to the International Energy Agency, some questions also exist about whether switching from coal to natural gas will lead to a reduction in greenhouse gas emissions—based, in part, on uncertainty about additional emissions from the development of shale gas. These concerns and other considerations have led some communities and certain states to impose restrictions or moratoriums on drilling operations to allow time to study and better understand the potential risks associated with these practices.

In this context, you asked us to provide information on shale oil and gas. This report describes what is known about (1) the size of shale oil and gas resources in the United States and the amount produced from 2007 through 2011—the years for which data were available—and (2) the environmental and public health risks associated with development of shale oil and gas.[8]

[5]EIA reported that using natural gas over coal would lower emissions in the United States, but some researchers have reported that greater reliance on natural gas would fail to significantly slow climate change.

[6]The natural gas liquids include propane, butane, and ethane, and are separated from the produced gas at the surface in lease separators, field facilities, or gas processing plants.

[7]For the purposes of this report, resources represent all oil or natural gas contained within a formation and can be divided into resources and reserves.

[8]For the purposes of this report, we refer to risk as a threat or vulnerability that has potential to cause harm.

To determine what is known about the size of shale oil and gas resources and the amount of shale oil and gas produced, we collected data from federal agencies, state agencies, private industry, and academic organizations. Specifically, to determine what is known about the size of these resources, we obtained information for technically recoverable and proved reserves estimates for shale oil and gas from the EIA, the U.S. Geological Survey (USGS), and the Potential Gas Committee—a nongovernmental organization composed of academics and industry representatives. We interviewed key officials from these agencies and the committee about the assumptions and methodologies used to estimate the resource size. Estimates of proved reserves of shale oil and gas are based on data provided to EIA by operators—companies that develop petroleum resources to extract oil and natural gas.[9] To determine what is known about the amount of shale oil and gas produced from 2007 through 2011, we obtained data from EIA—which is responsible for estimating and reporting this and other energy information. To assess the reliability of these data, we examined EIA's published methodology for collecting this information and interviewed key EIA officials regarding the agency's data collection efforts. We also met with officials from states, representatives from private industry, and researchers from academic institutions who are familiar with these data and EIA's methodology. We discussed the sources and reliability of the data with these officials and found the data sufficiently reliable for the purposes of this report. For all estimates we report, we reviewed the methodologies used to derive them and also found them sufficiently reliable for the purposes of this report.

To determine what is known about the environmental and public health risks associated with the development of shale oil and gas,[10] we reviewed studies and other publications from federal agencies and laboratories, state agencies, local governments, the petroleum industry, academic institutions, environmental and public health groups, and other nongovernmental associations. We identified these studies by conducting

[9]Proved reserves refer to the amount of oil and gas that have been discovered and defined.

[10]Operators may use hydraulic fracturing to develop oil and natural gas from formations other than shale, but for the purposes of this report we focused on development of shale formations. Specifically, coalbed methane and tight sandstone formations may rely on these practices and some studies and publications we reviewed identified risks that can apply to these formations. However, many of the studies and publications we identified and reviewed focused primarily on shale formations.

a literature search, and by asking for recommendations during interviews with federal, state, and tribal officials; representatives from industry, trade organizations, environmental, and other nongovernmental groups; and researchers from academic institutions. For a number of studies, we interviewed the author or authors to discuss the study's findings and limitations, if any. We believe we have identified the key studies through our literature review and interviews, and that the studies included in our review have accurately identified currently known potential risks for shale oil and gas development. However, it is possible that we may not have identified all of the studies with findings relevant to our objectives, and the risks we present may not be the only issues of concern.

The risks identified in the studies and publications we reviewed cannot, at present, be quantified, and the magnitude of potential adverse affects or likelihood of occurrence cannot be determined for several reasons. First, it is difficult to predict how many or where shale oil and gas wells may be constructed. Second, the extent to which operators use effective best management practices to mitigate risk may vary. Third, based on the studies we reviewed, there are relatively few studies that are based on comparing predevelopment conditions to postdevelopment conditions—making it difficult to detect or attribute adverse conditions to shale oil and gas development. In addition, changes to the federal, state, and local regulatory environments and the effectiveness of implementing and enforcing regulations will affect operators' future activities and, therefore, the level of risk associated with future development of oil and gas resources. Moreover, risks of adverse events, such as spills or accidents, may vary according to business practices which, in turn, may vary across oil and gas companies, making it difficult to distinguish between risks associated with the process to develop shale oil and gas from risks that are specific to particular business practices. To obtain additional perspectives on issues related to environmental and public health risks, we interviewed federal officials from DOE's National Energy Technical Laboratory, the Department of the Interior's Bureau of Land Management (BLM) and Bureau of Indian Affairs, and the Environmental Protection Agency (EPA); state regulatory officials from Arkansas, Colorado, Louisiana, North Dakota, Ohio, Oklahoma, Pennsylvania, and Texas;[11] tribal officials from the Osage Nation; shale oil and gas operators;

[11]We selected these states because they are involved with shale oil and gas development.

representatives from environmental and public health organizations; and other knowledgeable parties with experience related to shale oil and gas development, such as researchers from the Colorado School of Mines, the University of Texas, Oklahoma University, and Stanford University. Appendix I provides additional information on our scope and methodology.

We conducted this performance audit from November 2011 to September 2012 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

This section includes (1) an overview of oil and natural gas, (2) the shale oil and gas development process, (3) the regulatory framework, (4) the location of shale oil and gas in the United States, and (5) information on estimating the size of these resources.

Overview

Oil and natural gas are found in a variety of geologic formations. Conventional oil and natural gas are found in deep, porous rock or reservoirs and can flow under natural pressure to the surface after drilling. In contrast to the free-flowing resources found in conventional formations, the low permeability of some formations, including shale, means that oil and gas trapped in the formation cannot move easily within the rock. On one extreme—oil shale, for example—the hydrocarbon trapped in the shale will not reach a liquid form without first being heated to very high temperatures—ranging from about 650 to 1,000 degrees Fahrenheit—in a process known as retorting. In contrast, to extract shale oil and gas from the rock, fluids and proppants (usually sand or ceramic beads used to hold fractures open in the formation) are injected under high pressure to create and maintain fractures to increase permeability, thus allowing oil or gas to be extracted. Other formations, such as coalbed methane formations and tight sandstone formations,[12] may also require stimulation to allow oil or gas to be extracted.[13]

Most of the energy used in the United States comes from fossil fuels such as oil and natural gas. Oil supplies more than 35 percent of all the energy the country consumes, and almost the entire U.S. transportation fleet—cars, trucks, trains, and airplanes—depends on fuels made from oil. Natural gas is an important energy source to heat buildings, power the industrial sector, and generate electricity. Natural gas provides more than 20 percent of the energy used in the United States,[14] supplying nearly half of all the energy used for cooking, heating, and powering other home appliances, and generating almost one-quarter of U.S. electricity supplies.

The Shale Oil and Gas Development Process

The process to develop shale oil and gas is similar to the process for conventional onshore oil and gas, but shale formations may rely on the use of horizontal drilling and hydraulic fracturing—which may or may not be used on conventional wells. Horizontal drilling and hydraulic fracturing are not new technologies, as seen in figure 1, but advancements, refinements, and new uses of these technologies have greatly expanded oil and gas operators' abilities to use these processes to economically develop shale oil and gas resources. For example, the use of multistage hydraulic fracturing within a horizontal well has only been widely used in the last decade.[15]

[12]Conventional sandstone has well-connected pores, but tight sandstone has irregularly distributed and poorly connected pores. Due to this low connectivity or permeability, gas trapped within tight sandstone is not easily produced.

[13]For coalbed methane formations, the reduction in pressure needed to extract gas is achieved through dewatering. As water is pumped out of the coal seams, reservoir pressure decreases, allowing the natural gas to release (desorb) from the surface of the coal and flow through natural fracture networks into the well.

[14]Ground Water Protection Council and ALL Consulting, *Modern Shale Gas Development in the United States: A Primer*, a special report prepared at the request of the Department of Energy (Washington, D.C.: April 2009).

[15]Hydraulic fracturing is often conducted in stages. Each stage focuses on a limited linear section and may be repeated numerous times.

Figure 1: History of Horizontal Drilling and Hydraulic Fracturing

First, operators locate suitable shale oil and gas targets using seismic methods of exploration,[16] negotiate contracts or leases that allow mineral development, identify a specific location for drilling, and obtain necessary permits; then, they undertake a number of activities to develop shale oil and gas. The specific activities and steps taken to extract shale oil and gas vary based on the characteristics of the formation, but the development phase generally involves the following stages: (1) well pad

[16]The seismic method of exploration introduces energy into the subsurface through explosions in shallow "shot holes" by striking the ground forcefully (with a truck-mounted thumper), or by vibration methods. A portion of the energy returns to the surface after being reflected from the subsurface strata. This energy is detected by surface instruments, called geophones, and the information carried by the energy is processed by computers to interpret subsurface conditions.

preparation and construction, (2) drilling and well construction, and (3) hydraulic fracturing.[17]

Well Pad Preparation and Construction

The first stage in the development process is to prepare and construct the well pad site. Typically, operators must clear and level surface vegetation to make room for numerous vehicles and heavy equipment—such as the drilling rig—and to build infrastructure—such as roads—needed to access the site.[18] Then operators must transport the equipment that mixes the additives, water, and sand needed for hydraulic fracturing to the site—tanks, water pumps, and blender pumps, as well as water and sand storage tanks, monitoring equipment, and additive storage containers . Based on the geological characteristics of the formation and climatic conditions, operators may (1) excavate a pit or impoundment to store freshwater, drilling fluids, or drill cuttings—rock cuttings generated during drilling; (2) use tanks to store materials; or (3) build temporary transfer pipes to transport materials to and from an off-site location.

Drilling and Well Construction

The next stage in the development process is drilling and well construction. Operators drill a hole (referred to as the wellbore) into the earth through a combination of vertical and horizontal drilling techniques. At several points in the drilling process, the drill string and bit are removed from the wellbore so that casing and cement may be inserted. Casing is a metal pipe that is inserted inside the wellbore to prevent high-pressure fluids outside the formation from entering the well and to prevent drilling mud inside the well from fracturing fragile sections of the wellbore. As drilling progresses with depth, casings that are of a smaller diameter than the hole created by the drill bit are inserted into the wellbore and bonded in place with cement, sealing the wellbore from the surrounding formation.

Drilling mud (a lubricant also known as drilling fluid) is pumped through the wellbore at different densities to balance the pressure inside the wellbore and bring rock particles and other matter cut from the formation back to the rig. A blowout preventer is installed over the well as a safety measure to prevent any uncontrolled release of oil or gas and help

[17]The specific order of activities and steps may vary.

[18]According to the New York Department of Environmental Conservation's 2011 Supplemental Generic Environmental Impact Statement, the average size of a well pad is 3.5 acres.

maintain control over pressures in the well. Drill cuttings, which are made up of ground rock coated with a layer of drilling mud or fluid, are brought to the surface. Mud pits provide a reservoir for mixing and holding the drilling mud. At the completion of drilling, the drilling mud may be recycled for use at another drilling operation.

Instruments guide drilling operators to the “kickoff point”—the point that drilling starts to turn at a slight angle and continues turning until it nears the shale formation and extends horizontally. Production casing and cement are then inserted to extend the length of the borehole to maintain wellbore integrity and prevent any communication between the formation fluids and the wellbore. After the casing is set and cemented, the drilling operator may run a cement evaluation log by lowering an electric probe into the well to measure the quality and placement of the cement. The purpose of the cement evaluation log is to confirm that the cement has the proper strength to function as designed—preventing well fluids from migrating outside the casing and infiltrating overlying formations. After vertical drilling is complete, horizontal drilling is conducted by slowly angling the drill bit until it is drilling horizontally. Horizontal stretches of the well typically range from 2,000 to 6,000 feet long but can be as long as 12,000 feet long, in some cases.

Throughout the drilling process, operators may vent or flare some natural gas, often intermittently, in response to maintenance needs or equipment failures. This natural gas is either released directly into the atmosphere (vented) or burned (flared). In October 2010, we reported on venting and flaring of natural gas on public lands.[19] We reported that vented and flared gas on public lands represents potential lost royalties for the federal government and contributes to greenhouse gas emissions. Specifically, venting releases methane and volatile organic compounds, and flaring emits carbon dioxide, both greenhouse gases that contribute to global climate change. Methane is a particular concern since it is a more potent greenhouse gas than carbon dioxide.

Hydraulic Fracturing

The next stage in the development process is stimulation of the shale formation using hydraulic fracturing. Before operators or service companies perform a hydraulic fracture treatment of a well, a series of

[19] GAO, *Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases*, GAO-11-34 (Washington, D.C.: Oct. 29, 2010).

tests may be conducted to ensure that the well, wellhead equipment, and fracturing equipment can safely withstand the high pressures associated with the fracturing process. Minimum requirements for equipment pressure testing can be determined by state regulatory agencies for operations on state or private lands. In addition, fracturing is conducted below the surface of the earth, sometimes several thousand feet below, and can only be indirectly observed. Therefore, operators may collect subsurface data—such as information on rock stresses[20] and natural fault structures—needed to develop models that predict fracture height, length, and orientation prior to drilling a well. The purpose of modeling is to design a fracturing treatment that optimizes the location and size of induced fractures and maximizes oil or gas production.

To prepare a well to be hydraulically fractured, a perforating tool may be inserted into the casing and used to create holes in the casing and cement. Through these holes, fracturing fluid—that is injected under high pressures—can flow into the shale (fig. 2 shows a used perforating tool).

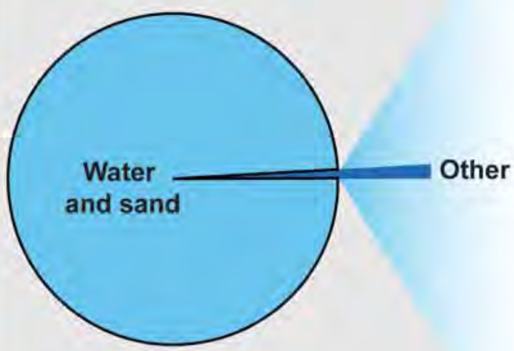
[20]Stresses in the formation generally define a maximum and minimum stress direction that influence the direction a fracture will grow.

Figure 2: Perforating Tool

Source: GAO.

Fracturing fluids are tailored to site specific conditions, such as shale thickness, stress, compressibility, and rigidity. As such, the chemical additives used in a fracture treatment vary. Operators may use computer models that consider local conditions to design site-specific hydraulic fluids. The water, chemicals, and proppant used in fracturing fluid are typically stored on-site in separate tanks and blended just before they are injected into the well. Figure 3 provides greater detail about some chemicals commonly used in fracturing.

Figure 3: Examples of Common Ingredients Found in Fracturing Fluid



Additive type	Use	Main compound
Acid	Removes near well damage	Hydrochloric acid
Biocide	Controls bacterial growth	Glutaraldehyde
Breaker	Delays breakdown of the geling agent	Ammonium persulfate
Corrosion inhibitor	Prevent corrosion of pipe	N,n-dimethyl formamide
Crosslinker	Maintains fluid viscosity as temperature increases	Borate salts
Friction reducers	Decreases pumping friction	Polyacrylamide
Gelling agents	Improves proppant placement	Guar gum
KCl	Creates a brine carrier fluid	Potassium chloride
Oxygen scavenger	Prevents corrosion of well tubulars	Ammonium bisulfite
pH adjusting agent	Adjusts the pH of fluid to maintain the effectiveness of other components	Sodium carbonate
Scale inhibitor	Prevents scale deposits in the pipe	Ethylene glycol
Surfactant	Winterizing agent	Isopropanol

Sources: Department of Energy and Groundwater Protection Council.

The operator pumps the fracturing fluid into the wellbore at pressures high enough to force the fluid through the perforations into the surrounding formation—which can be shale, coalbeds, or tight sandstone—expanding existing fractures and creating new ones in the process. After the fractures are created, the operator reduces the pressure. The proppant stays in the formation to hold open the fractures and allow the release of oil and gas. Some of the fracturing fluid that was injected into the well will return to the surface (commonly referred to as flowback) along with water that occurs naturally in the oil- or gas-bearing formation—collectively referred to as produced water. The produced water is brought to the surface and collected by the operator, where it can be stored on-site in impoundments, injected into underground wells, transported to a wastewater treatment plant, or reused by the operator in other ways.[21] Given the length of horizontal wells, hydraulic fracturing is often conducted in stages, where each stage focuses on a limited linear section and may be repeated numerous times.

Once a well is producing oil or natural gas, equipment and temporary infrastructure associated with drilling and hydraulic fracturing operations is no longer needed and may be removed, leaving only the parts of the infrastructure required to collect and process the oil or gas and ongoing produced water. Operators may begin to reclaim the part of the site that will not be used by restoring the area to predevelopment conditions. Throughout the producing life of an oil or gas well, the operator may find it necessary to periodically restimulate the flow of oil or gas by repeating the hydraulic fracturing process. The frequency of such activity depends on the characteristics of the geologic formation and the economics of the individual well. If the hydraulic fracturing process is repeated, the site and surrounding area will be further affected by the required infrastructure, truck transport, and other activity associated with this process.

Regulatory Framework

Shale oil and gas development, like conventional onshore oil and gas production, is governed by a framework of federal, state, and local laws and regulations. Most shale development in the near future is expected to occur on nonfederal lands and, therefore, states will typically take the lead in regulatory activities. However, in some cases, federal agencies oversee shale oil and gas development. For example, BLM oversees shale oil and gas development on federal lands. In large part, the federal laws, regulations, and permit requirements that apply to conventional onshore oil and gas exploration and production activities also apply to shale oil and gas development.

- *Federal*. A number of federal agencies administer laws and regulations that apply to various phases of shale oil and gas development. For example, BLM manages federal lands and approximately 700 million acres of federal subsurface minerals, also known as the federal mineral estate. EPA administers and enforces key federal laws, such as the Safe Drinking Water Act, to protect

[21]Underground injection is the predominant practice for disposing of produced water. In addition to underground injection, a limited amount of produced water is managed by discharging it to surface water, storing it in surface impoundments, and reusing it for irrigation or hydraulic fracturing.

human health and the environment. Other federal land management agencies, such as the U.S. Department of Agriculture's Forest Service and the Department of the Interior's Fish and Wildlife Service, also manage federal lands, including shale oil and gas development on those lands.

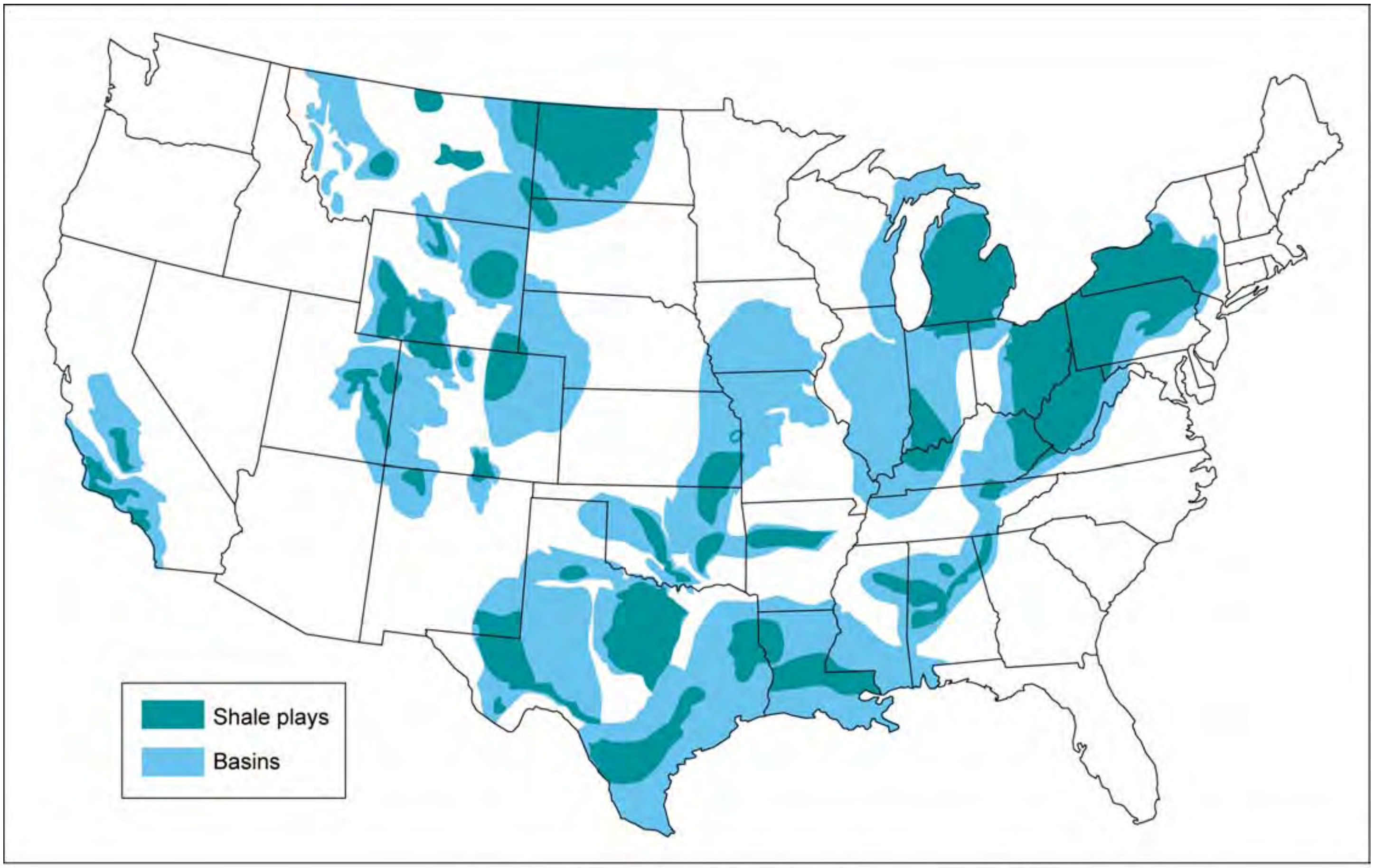
- *State.* State agencies implement and enforce many of the federal environmental regulations and may also have their own set of state laws covering shale oil and gas development.
- *Other.* Additional requirements regarding shale oil and gas operations may be imposed by various levels of government for specific locations. Entities such as cities, counties, tribes, and regional water authorities may set additional requirements that affect the location and operation of wells.

GAO is conducting a separate and more detailed review of the federal and state laws and regulations that apply to unconventional oil and gas development, including shale oil and gas.

Location of Shale Oil and Gas in the United States

Shale oil and gas are found in shale plays—a set of discovered or undiscovered oil and natural gas accumulations or prospects that exhibit similar geological characteristics—on private, state-owned, and federal lands across the United States. Shale plays are located within basins, which are large-scale geological depressions, often hundreds of miles across, that also may contain other oil and gas resources. Figure 4 shows the location of shale plays and basins in the contiguous 48 states.

Figure 4: Shale Plays and Basins in the Contiguous 48 States



Sources: Energy Information Administration (shale location data); (map) copyright © Corel Corp., all rights reserved.

A shale play can be developed for oil, natural gas, or both. In addition, a shale gas play may contain "dry" or "wet" natural gas. Dry natural gas is a mixture of hydrocarbon compounds that exists as a gas both underground in the reservoir and during production under standard temperature and pressure conditions. Wet natural gas contains natural gas liquids, or the portion of the hydrocarbon resource that exists as a gas when in natural underground reservoir conditions but that is liquid at surface conditions. The natural gas liquids are typically propane, butane, and ethane and are separated from the produced gas at the surface in lease separators, field facilities, or gas processing plants. Operators may then sell the natural gas liquids, which may give wet shale gas plays an economic advantage over dry gas plays. Another advantage of liquid petroleum and natural gas liquids is that they can be transported more easily than natural gas. This is because, to bring natural gas to markets and consumers, companies must build an extensive network of gas pipelines. In areas where gas pipelines are not extensive, natural gas produced along with liquids is often vented or flared.

Estimating the Size of Shale Oil and Gas Resources

Estimating the size of shale oil and gas resources serves a variety of needs for consumers, policymakers, land and resource managers, investors, regulators, industry planners, and others. For example, federal and state governments may use resource estimates to estimate future revenues and establish energy, fiscal, and national security policies. The petroleum industry and the financial community use resource estimates to establish corporate strategies and make investment decisions.

A clear understanding of some common terms used to generally describe the size and scope of oil and gas resources is needed to determine the relevance of a given estimate. For an illustration of how such terms describe the size and scope of shale oil and gas, see figure 5.

The most inclusive term is in-place resource. The in-place resource represents all oil or natural gas contained in a formation without regard to technical or economic recoverability. In-place resource estimates are sometimes very large numbers, but often only a small proportion of the total amount of oil or natural gas in a formation may ever be recovered. Oil and gas resources that are in-place, but not technically recoverable at this time may, in the future, become technically recoverable.

Technically recoverable resources are a subset of in-place resources that include oil or gas, including shale oil and gas that is producible given available technology. Technically recoverable resources include those that are economically producible and those that are not. Estimates of technically recoverable resources are dynamic, changing to reflect the potential of extraction technology and knowledge about the geology and composition of geologic formations. According to the National Petroleum Council,[22] technically recoverable resource estimates usually increase

[22]The National Petroleum Council is a federally chartered and privately funded advisory committee that advises, informs, and makes recommendations to the Secretary of Energy on oil and natural gas matters.

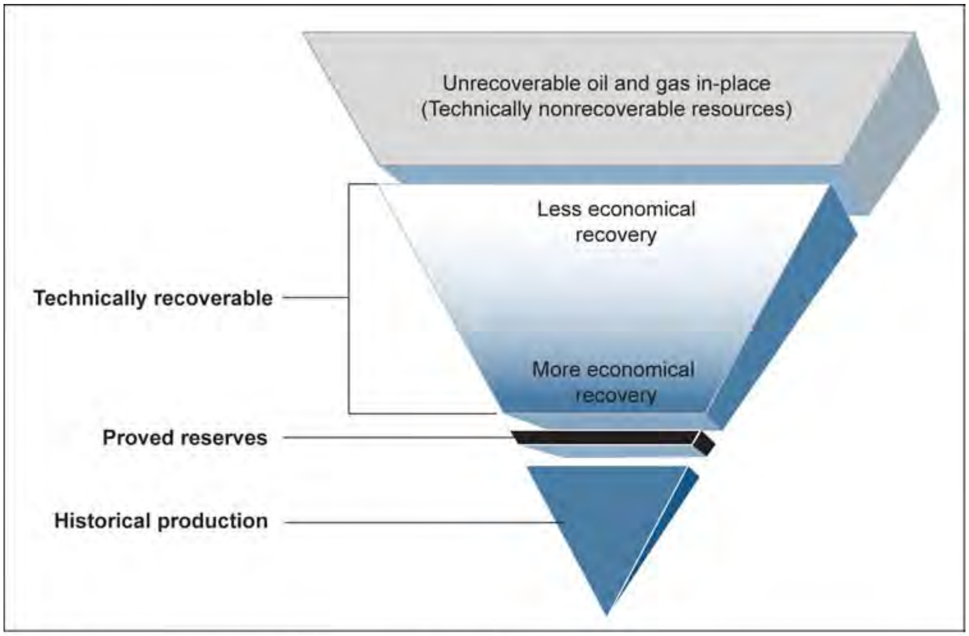
over time because of the availability of more and better data, or knowledge of how to develop a new play type (such as shale formations).

Proved reserve estimates are more precise than technically recoverable resources and represent the amount of oil and gas that have been discovered and defined, typically by drilling wells or other exploratory measures, and which can be economically recovered within a relatively short time frame. Proved reserves may be thought of as the “inventory” that operators hold and define the quantity of oil and gas that operators estimate can be recovered under current economic conditions, operating methods, and government regulations. Estimates of proved reserves increase as oil and gas companies make new discoveries and report them to the government; oil and gas companies can increase their reserves as they develop already-discovered fields and improve production technology. Reserves decline as oil and gas reserves are produced and sold. In addition, reserves can change as prices and technologies change. For example, technology improvements that enable operators to extract more oil or gas from existing fields can increase proved reserves. Likewise, higher prices for oil and gas may increase the amount of proved reserves because more resources become financially viable to extract.[23] Conversely, lower prices may diminish the amount of resources likely to be produced, reducing proved reserves.

Historical production refers to the total amount of oil and gas that has been produced up to the present. Because these volumes of oil and gas have been measured historically, this is the most precise information available as it represents actual production amounts.

[23]For example, secondary recovery operations can be costly (such as using a well to inject water into an oil reservoir and push any remaining oil to operating wells), but the costs may be justified if prices are high enough.

Figure 5: Common Terminology to Describe the Size and Scope of Shale Oil and Gas



Sources: GAO; based on illustration by the Congressional Research Service.

Note: This illustration is not necessarily to scale because all volumes, except historical production, are subject to significant uncertainty.

Certain federal agencies have statutory responsibility for collecting and publishing authoritative statistical information on various types of energy sources in the United States. EIA collects, analyzes, and disseminates independent and impartial energy information, including data on shale oil and gas resources. Under the Energy Policy and Conservation Act of 2000, as amended, USGS estimates onshore undiscovered technically recoverable oil and gas resources in the United States.[24] USGS has conducted a number of national estimates of undiscovered technically recoverable oil and natural gas resources over several decades. USGS geologists and other experts estimate undiscovered oil and gas—that is, oil and gas that has not been proven to be present by oil and gas companies—based on geological survey data and other information about

[24]Pub. L. No. 106-469 § 604 (2000), 114 Stat. 2029, 2041-42, codified, as amended, at 42 U.S.C. § 6217.

the location and size of different geological formations across the United States. In addition to EIA and USGS, experts from industry, academia, federal advisory committees, private consulting firms, and professional societies also estimate the size of the resource.

Domestic Shale Oil and Gas Estimates and Production

Estimates of the size of shale oil and gas resources in the United States have increased over time as has the amount of such resources produced from 2007 through 2011. Specifically, over the last 5 years, estimates of (1) technically recoverable shale oil and gas and (2) proved reserves of shale oil and gas have increased, as technology has advanced and more shale has been drilled. In addition, domestic shale oil and gas production has experienced substantial growth in recent years.

Estimates of Technically Recoverable Shale Oil and Gas Resources

EIA, USGS, and the Potential Gas Committee have increased their estimates of the amount of technically recoverable shale oil and gas over the last 5 years, which could mean an increase in the nation's energy portfolio; however, less is known about the amount of technically recoverable shale oil than shale gas, in part because large-scale production of shale oil has been under way for only the past few years. The estimates are from different organizations and vary somewhat because they were developed at different times and using different data, methods, and assumptions, but estimates from all of these organizations have increased over time, indicating that the nation's shale oil and gas resources may be substantial. For example, according to estimates and reports we reviewed, assuming current consumption levels without consideration of a specific market price for future gas supplies, the amount of domestic technically recoverable shale gas could provide enough natural gas to supply the nation for the next 14 to 100 years. The increases in estimates can largely be attributed to improved geological information about the resources, greater understanding of production levels, and technological advancements.

Estimates of Technically Recoverable Shale Oil Resources

In the last 2 years, EIA and USGS provided estimates of technically recoverable shale oil.[25] Each of these estimates increased in recent years as follows:

- In 2012, EIA estimated that the United States possesses 33 billion barrels of technically recoverable shale oil,[26] mostly located in four shale formations—the Bakken in Montana and North Dakota; Eagle Ford in Texas; Niobrara in Colorado, Kansas, Nebraska, and Wyoming; and the Monterey in California.
- In 2011, USGS estimated that the United States possesses just over 7 billion barrels of technically recoverable oil in shale and tight sandstone formations. The estimate represents a more than threefold increase from the agency's estimate in 2006. However, there are several shale plays that USGS has not evaluated for shale oil because interest in these plays is relatively new. According to USGS officials, these shale plays have shown potential for production in recent years and may contain additional shale oil resources. Table 1 shows USGS' 2006 and 2011 estimates and EIA's 2011 and 2012 estimates.

Table 1: USGS and EIA Estimates of Total Remaining Technically Recoverable U.S. Oil Resources

Barrels of oil in billions

	USGS		EIA	
	2006	**2011**	**2011**	**2012**
Estimated technically recoverable shale oil and tight sandstone resources	2	7	32	33
Estimated technically recoverable oil resources other than shale[a]	142	133	187	201

Source: GAO analysis of EIA and USGS data.

[25]As noted previously, for the purposes of this report, we use the term "shale oil" to refer to oil from shale and other tight formations, which is recoverable by hydraulic fracturing and horizontal drilling techniques and is described by others as "tight oil." Shale oil and tight oil are extracted in the same way, but differ from "oil shale." Oil shale is a sedimentary rock containing solid organic material that converts into a type of crude oil only when heated.

[26]Comparatively, the United States currently consumes about 7 billion barrels of oil per year, about half of which are imported from foreign sources.

[a]Includes estimates for conventional offshore oil and gas, as well as natural gas liquids. In addition, the USGS estimates for 2006 and 2011 include a 2006 estimate of technically recoverable offshore conventional oil resources totaling 86 billion barrels of oil and natural gas liquids from the former Minerals Management Service, which has since been reorganized into the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement.

Overall, estimates of the size of technically recoverable shale oil resources in the United States are imperfect and highly dependent on the data, methodologies, model structures, and assumptions used. As these estimates are based on data available at a given point in time, they may change as additional information becomes available. Also these estimates depend on historical production data as a key component for modeling future supply. Because large-scale production of oil in shale formations is a relatively recent activity, their long-term productivity is largely unknown. For example, EIA estimated that the Monterey Shale in California may possess about 15.4 billion barrels of technically recoverable oil. However, without a longer history of production, the estimate has greater uncertainty than estimates based on more historical production data. At this time, USGS has not yet evaluated the Monterey Shale play.

Estimates of Technically Recoverable Shale Gas Resources

The amount of technically recoverable shale gas resources in the United States has been estimated by a number of organizations, including EIA, USGS, and the Potential Gas Committee (see fig. 6). Their estimates were as follows:

- In 2012, EIA estimated the amount of technically recoverable shale gas in the United States at 482 trillion cubic feet.[27] This represents an increase of 280 percent from EIA's 2008 estimate.
- In 2011, USGS reported that the total of its estimates for the shale formations the agency evaluated in all previous years[28] shows the

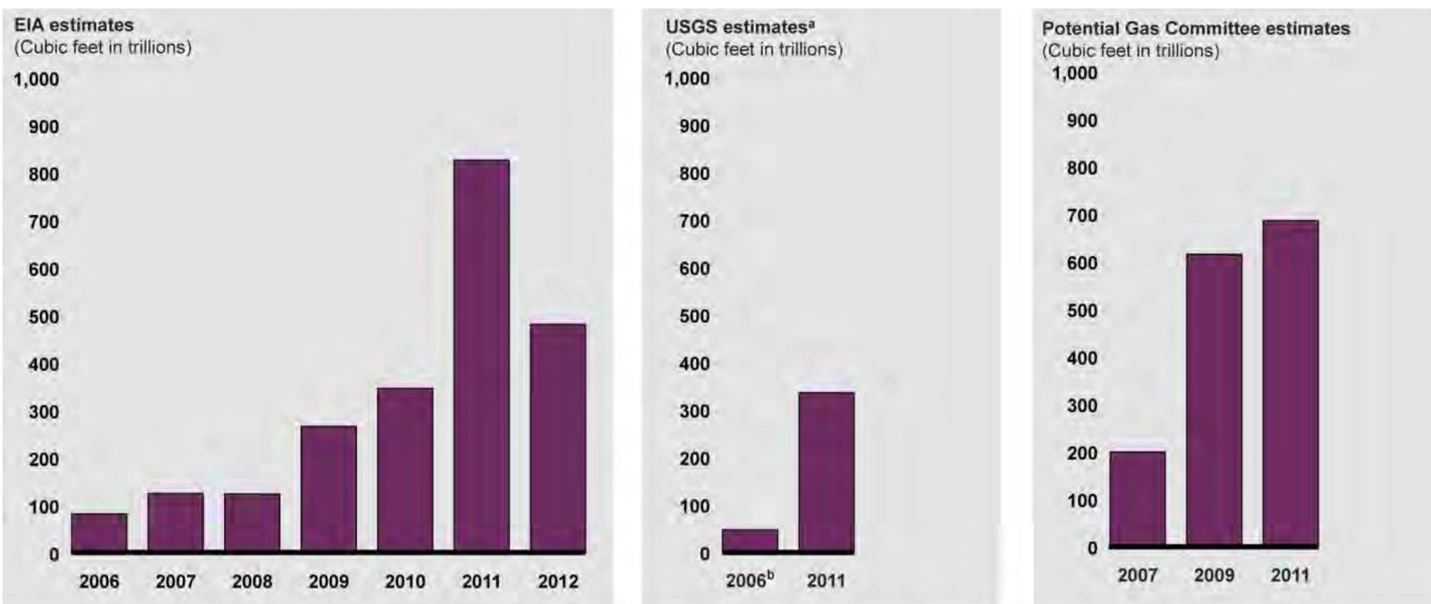
[27]EIA estimates are based on natural gas production data from 2 years prior to the reporting year; for example, EIA's 2012 estimate is based on 2010 data; the date cited here reflects the fact that EIA reported this latest estimate in 2012.

[28]USGS estimates are based on updated data in a few—but not all—individual geological areas, combined with data from other areas from all previous years. Each year USGS estimates new information for a few individual geological areas. For example, the 2011 USGS estimate includes updated 2011 data for the Appalachian Basin, the Anadarko Basin, and the Gulf Coast, combined with estimates for all other areas developed before 2011. See appendix III for additional information on USGS estimates. The date cited here reflects the fact that USGS reported this latest estimate in 2011.

amount of technically recoverable shale gas in the United States at about 336 trillion cubic feet. This represents an increase of about 600 percent from the agency's 2006 estimate.

- In 2011, the Potential Gas Committee estimated the amount of technically recoverable shale gas in the United States at about 687 trillion cubic feet.[29] This represents an increase of 240 percent from the committee's 2007 estimate.

Figure 6: Estimates of Technically Recoverable Shale Gas from EIA, USGS, and the Potential Gas Committee (2006 through 2012)



Sources: GAO analysis of EIA, Potential Gas Commitee, and USGS estimates.

Notes: Natural gas is generally priced and sold in thousand cubic feet (abbreviated Mcf, using the Roman numeral for 1,000). Units of a trillion cubic feet (Tcf) are often used to measure large quantities, as in resources or reserves in the ground, or annual national energy consumption. One Tcf is enough natural gas to heat 15 million homes for 1 year or fuel 12 million natural gas-fired vehicles for 1 year. In 2012, EIA reduced its estimate of technically recoverable shale gas in the Marcellus Shale by about 67 percent. According to EIA officials, the decision to revise the estimate was based primarily on the availability of new production data, which was highlighted by the release of the USGS

[29]Potential Gas Committee estimates are based on natural gas production data from the previous year; for example, committee's 2011 estimate is based on 2010 data. The date cited here reflects the fact that the Potential Gas Committee reported this latest estimate in 2011.

estimate. In 2011, EIA used data from a contractor to estimate that the Marcellus Shale possessed about 410 trillion cubic feet of technically recoverable gas. After EIA released its estimates in 2011, USGS released its first estimate of technically recoverable gas in the Marcellus in almost 10 years. USGS estimated that there were 84 trillion cubic feet of natural gas in the Marcellus—which was 40 times more than its previous estimate reported in 2002 but significantly less than EIA's estimate. In 2012, EIA announced that it was revising its estimate of the technically recoverable gas in the Marcellus Shale from 410 to 141 trillion cubic feet. EIA reported additional details about its methodology and data in June 2012. See U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 2012, With Projections to 2035 (DOE/EIA-0383 [2012], Washington, D.C., June 25, 2012).

[a]The 2006 USGS estimate of about 54 trillion cubic feet represents those assessments that had been done up to the end of 2006. As such, the estimate is partially dependent on how the agency scheduled basin studies and assessments from 2000 through 2006, rather than purely on changes in USGS views of resource potential since 2006.

[b]The Potential Gas Committee did not report separate estimates of shale gas until 2007 and has updated this estimate every 2 years since then.

In addition to the estimates from the three organizations we reviewed, operators and energy forecasting consultants prepare their own estimates of technically recoverable shale gas to plan operations or for future investment. In September 2011, the National Petroleum Council aggregated data on shale gas resources from over 130 industry, government, and academic groups and estimated that approximately 1,000 trillion cubic feet of shale gas is available for production domestically. In addition, private firms that supply information to the oil and gas industry conduct assessments of the total amount of technically recoverable natural gas. For example, ICF International, a consulting firm that provides information to public- and private-sector clients, estimated in March 2012 that the United States possesses about 1,960 trillion cubic feet of technically recoverable shale gas.

Based on estimates from EIA, USGS, and the Potential Gas Committee, five shale plays—the Barnett, Haynesville, Fayetteville, Marcellus, and Woodford—are estimated to possess about two-thirds of the total estimated technically recoverable gas in the United States (see table 2).

Table 2: Estimated Technically Recoverable Shale Gas Resources, by Play

Shale play	Location	Technically recoverable gas, in trillion cubic feet (Tcf)
Barnett	North Texas	43-53
Fayetteville	Arkansas	13-110
Haynesville	Louisiana and East Texas	66-110
Marcellus	Northeast United States	84-227[a]
Woodford	Oklahoma	11-27

Sources: GAO analysis of EIA, USGS, and Potential Gas Committee data.

Note: The estimated technically recoverable gas shown here represents the range of estimates for these plays determined by EIA, USGS, and the Potential Gas Committee.

[a]This estimate of the Marcellus also includes estimated shale gas from other nearby lands in the Appalachian area; but, according to an official for the estimating organization, the Marcellus Shale is the predominant source of gas in the basin.

As with estimates for technically recoverable shale oil, estimates of the size of technically recoverable shale gas resources in the United States are also highly dependent on the data, methodologies, model structures, and assumptions used and may change as additional information becomes available. These estimates also depend on historical production data as a key component for modeling future supply. Because most shale gas wells generally were not in place until the last few years, their long-term productivity is untested. According to a February 2012 report released by the Sustainable Investments Institute and the Investor Responsibility Research Center Institute, production in emerging shale plays has been concentrated in areas with the highest known gas production rates, and many shale plays are so large that most of the play has not been extensively tested.[30] As a result, production rates achieved to date may not be representative of future production rates across the formation. EIA reports that experience to date shows production rates from neighboring shale gas wells can vary by as much as a factor of 3 and that production rates for different wells in the same formation can vary by as much as a factor of 10. Most gas companies estimate that production in a given well will drop sharply after the first few years and

[30]The Sustainable Investments Institute (Si2) is a nonprofit membership organization founded in 2010 to conduct research and publish reports on organized efforts to influence corporate behavior. The Investor Responsibility Research Center Institute is a nonprofit organization established in 2006 that provides information to investors.

then level off, continuing to produce gas for decades, according to the Sustainable Investments Institute and the Investor Responsibility Research Center Institute.

Estimates of Proved Reserves of Shale Oil and Gas

Estimates of proved reserves of shale oil and gas increased from 2007 to 2009. Operators determine the size of proved reserves based on information collected from drilling, geological and geophysical tests, and historical production trends. These are also the resources operators believe they will develop in the short term—generally within the next 5 years—and assume technological and economic conditions will remain unchanged.

Estimates of proved reserves of shale oil. EIA does not report proved reserves of shale oil separately from other oil reserves; however, EIA and others have noted an increase in the proved reserves of oil in the nation, and federal officials attribute the increase, in part, to oil from shale and tight sandstone formations. For example, EIA reported in 2009 that the Bakken Shale in North Dakota and Montana drove increases in oil reserves, noting that North Dakota proved reserves increased over 80 percent from 2008 through 2009.

Estimates of proved reserves of shale gas. According to data EIA collects from about 1,200 operators, proved reserves of shale gas have grown from 23 trillion cubic feet in 2007 to 61 trillion cubic feet in 2009, or an increase of 160 percent.[31] More than 75 percent of the proved shale gas reserves are located in three shale plays—the Barnett, Fayetteville, and the Haynesville.

Shale Oil and Gas Production

From 2007 through 2011, annual production of shale oil and gas has experienced significant growth. Specifically, shale oil production increased more than fivefold, from 39 to about 217 million barrels over this 5-year period, and shale gas production increased approximately fourfold, from 1.6 to about 7.2 trillion cubic feet, over the same period. To

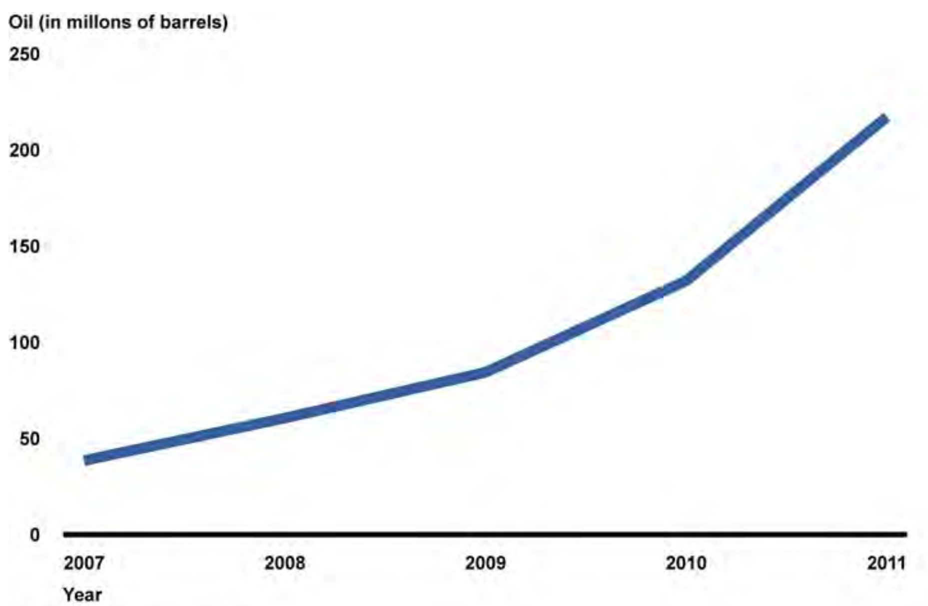
[31]Reserves are key information for assessing the net worth of an operator. Oil and gas companies traded on the U.S. stock exchange are required to report their reserves to the Securities and Exchange Commission. According to an EIA official, EIA reports a more complete measure of oil and gas reserves because it receives reports of proved reserves from both private and publically held companies.

put this shale production into context, the annual domestic consumption of oil in 2011 was about 6,875 million barrels of oil, and the annual consumption of natural gas was about 24 trillion cubic feet. The increased shale oil and gas production was driven primarily by technological advances in horizontal drilling and hydraulic fracturing that made more shale oil and gas development economically viable.

Shale Oil Production

Annual shale oil production in the United States increased more than fivefold, from about 39 million barrels in 2007 to about 217 million barrels in 2011, according to data from EIA (see fig. 7).[32] This is because new technologies allowed more oil to be produced economically, and because of recent increases in the price for liquid petroleum that have led to increased investment in shale oil development.

Figure 7: Estimated Production of Shale Oil from 2007 through 2011 (in millions of barrels of oil)



Source: GAO analysis of EIA data.

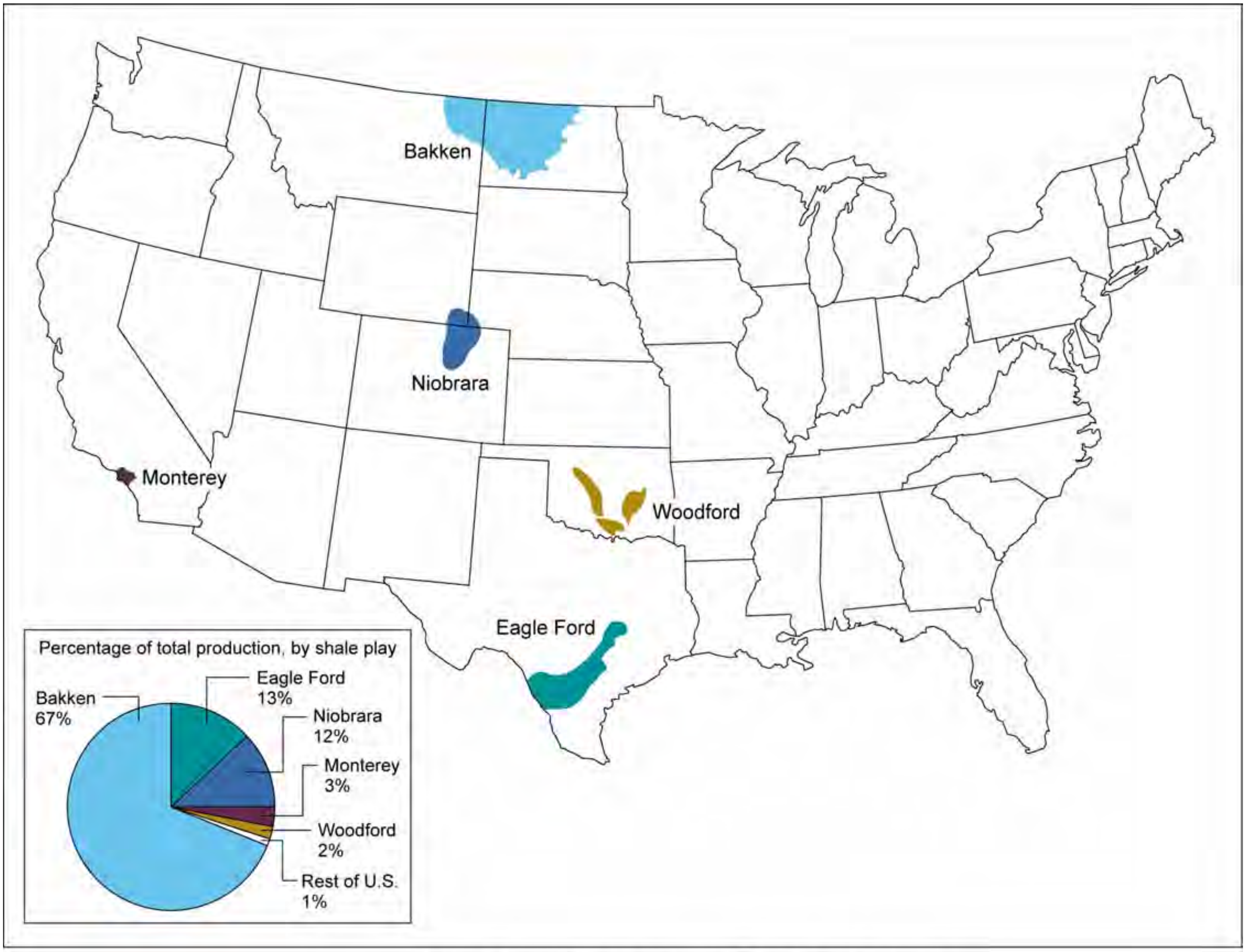
[32]As noted previously, for the purposes of this report, we use the term "shale oil" to refer to oil from shale and other tight formations, which is recovered by hydraulic fracturing and horizontal drilling and is described by others as "tight oil." Shale oil and tight oil are extracted in the same way, but differ from "oil shale." Oil shale is a sedimentary rock containing solid organic material that converts into a type of crude oil only when heated.

In total, during this period, about 533 million barrels of shale oil was produced. More than 65 percent of the oil was produced in the Bakken Shale (368 million barrels; see fig. 8).[33] The remainder was produced in the Niobrara (62 million barrels), Eagle Ford (68 million barrels), Monterey (18 million barrels), and the Woodford (9 million barrels). To put this in context, shale oil production from these plays in 2011 constituted about 8 percent of U.S. domestic oil consumption, according to EIA data.[34]

[33]EIA provided us with estimated shale oil production data from a contractor, HPDI LLC., for 2007 through 2011. EIA uses these data for the purposes of estimating recent shale oil production. EIA has not routinely reported shale oil production data separately from oil production.

[34]In addition to production from these shale oil plays, EIA officials told us that oil was produced from "tight oil" plays such as the Austin Chalk. The technology for producing tight oil is the same as for shale oil, and EIA uses the term "tight oil" to encompass both shale oil and tight oil that are developed with the same type of technology. In addition, EIA officials added that the shale oil data presented here is approximate because the data comes from a sample of similar plays. Overtime, this production data will become more precise as more data becomes available to EIA.

Figure 8: Shale Oil Production, by Shale Play (from 2007 through 2011)

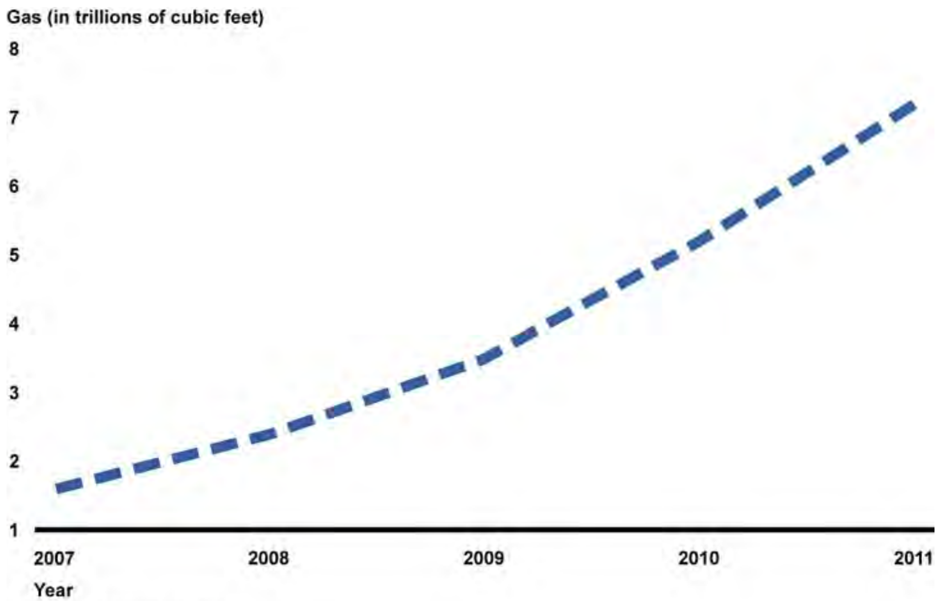


Sources: GAO analysis of EIA data; (map) copyright © Corel Corp., all rights reserved.

Shale Gas Production

Shale gas production in the United States increased more than fourfold, from about 1.6 trillion cubic feet in 2007 to about 7.2 trillion cubic feet in 2011, according to estimated data from EIA (see fig. 9).[35]

Figure 9: Estimated Production of Shale Gas from 2007 through 2011 (in trillions of cubic feet)



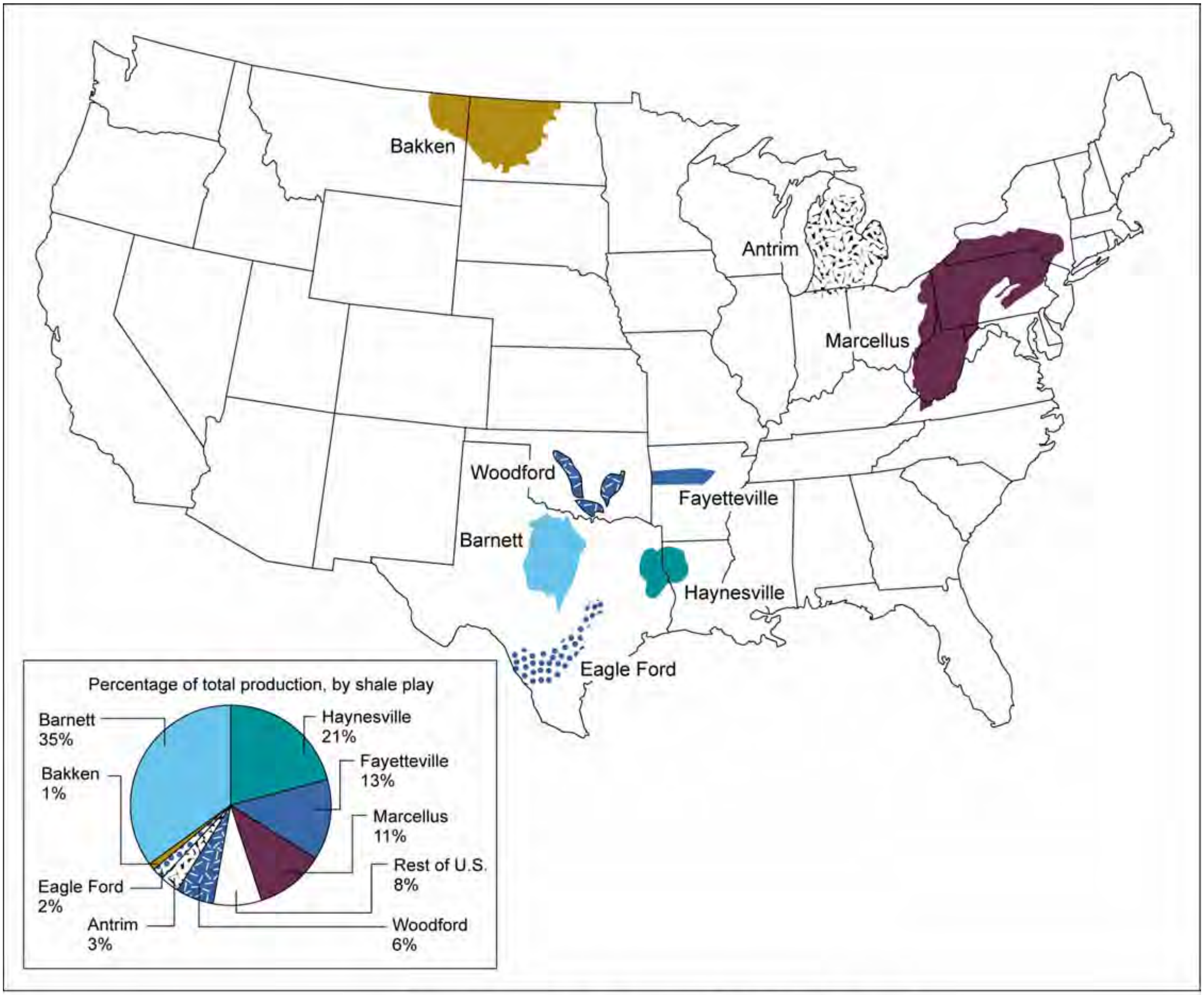
Source: GAO analysis of EIA data.

In total, during this period, about 20 trillion cubic feet of shale gas was produced—representing about 300 days of U.S. consumption, based on 2011 consumption rates. More than 75 percent of the gas was produced in four shale plays—the Barnett, Marcellus, Fayetteville, and Haynesville (see fig.10). From 2007 through 2011, shale gas' contribution to the nation's total natural gas supply grew from about 6 percent in 2007 to approximately 25 percent in 2011 and is projected, under certain assumptions, to increase to 49 percent by 2035, according to an EIA report. Overall production of shale gas increased from calendar years 2007 through 2011, but production of natural gas on federal and tribal

[35]EIA provided us with estimated shale gas production data from a contractor, Lippman Consulting, Inc., for 2007 through 2011. EIA uses these data for the purposes of estimating recent shale gas production. EIA has separately reported shale gas production data using reports from states for the years 2008 and 2009.

lands—including shale gas and natural gas from all other sources—decreased by about 17 percent, according to an EIA report. EIA attributes this decrease to several factors, including the location of shale formations—which, according to an EIA official, appear to be predominately on nonfederal lands.

Figure 10: Shale Gas Production, by Shale Play (from 2007 through 2011)



Sources: GAO analysis of EIA data; (map) copyright © Corel Corp., all rights reserved.

The growth in production of shale gas has increased the overall supply of natural gas in the U.S. energy market. Since 2007, increased shale gas production has contributed to lower prices for consumers, according to EIA and others.[36] These lower prices create incentives for wider use of natural gas in other industries. For example, several reports by government, industry, and others have observed that if natural gas prices remain low, natural gas is more likely to be used to power cars and trucks in the future. In addition, electric utilities may build additional natural gas-fired generating plants as older coal plants are retired. At the same time, some groups have expressed concern that greater reliance on natural gas may reduce interest in developing renewable energy.

Development of Wet Gas

EIA reported that operators have recently moved away from the development of shale plays that are primarily dry gas in favor of developing plays with higher concentrations of natural gas liquids. At current natural gas prices, natural gas liquids are a much more valuable product than dry gas. This is because the end products and byproducts of natural gas liquids contain more energy per unit of volume and have uses beyond heating and power generation and may be converted into products that can be more easily transported and traded in the global market. Shale plays with significant natural gas liquids include the Eagle Ford and Marcellus.

The greater availability of domestic shale gas has also decreased the need for natural gas imports. For example, EIA has noted that volumes of natural gas imported into the United States have fallen in recent years—in 2007, the nation imported 16 percent of the natural gas consumed and in 2010, the nation imported 11 percent—as domestic shale gas production has increased. This trend is also illustrated by an increase in applications for exporting liquefied natural gas to other countries. In its 2012 annual energy outlook, EIA predicted that, under certain scenarios, the United States will become a net exporter of natural gas by about 2022.[37]

Shale Oil and Gas Development Pose Environmental and Public Health Risks, but the Extent is Unknown and Depends on Many Factors

Developing oil and gas resources—whether conventional or from shale formations—poses inherent environmental and public health risks, but the extent of risks associated with shale oil and gas development is unknown, in part, because the studies we reviewed do not generally take into account potential long-term, cumulative effects. In addition, the severity of adverse effects depend on various location- and process-specific factors, including the location of future shale oil and gas development and the rate at which it occurs, geology, climate, business practices, and regulatory and enforcement activities.

[36]According to a 2012 report from the Bipartisan Policy Center, natural gas prices declined roughly 37 percent from February 2008 to January 2010.

[37]Department of Energy, Energy Information Administration, *Annual Energy Outlook 2012, With Projections to 2035*, DOE/EIA-0383 (Washington, D.C.: June 25, 2012).

Shale Oil and Gas Development Pose Risks to Air, Water, Land and Wildlife

Oil and gas development, which includes development from shale formations, poses inherent risks to air quality, water quantity, water quality, and land and wildlife.

Air Quality

According to a number of studies and publications we reviewed, shale oil and gas development pose risks to air quality. These risks are generally the result of engine exhaust from increased truck traffic, emissions from diesel-powered pumps used to power equipment, intentional flaring or venting of gas for operational reasons, and unintentional emissions of pollutants from faulty equipment or impoundments.

Construction of the well pad, access road, and other drilling facilities requires substantial truck traffic, which degrades air quality. According to a 2008 National Park Service report, an average well, with multistage fracturing, can require 320 to 1,365 truck loads to transport the water, chemicals, sand, and other equipment—including heavy machinery like bulldozers and graders—needed for drilling and fracturing. The increased traffic creates a risk to air quality as engine exhaust that contains air pollutants such as nitrogen oxides and particulate matter that affect public health and the environment are released into the atmosphere.[38] Air quality may also be degraded as fleets of trucks traveling on newly graded or unpaved roads increase the amount of dust released into the air—which can contribute to the formation of regional haze.[39] In addition to the dust, silica sand (see fig. 11)—commonly used as proppant in the hydraulic fracturing process—may pose a risk to human health, if not properly handled. According to a federal researcher from the Department of Health and Human Services, uncontained sand particles and dust pose threats to workers at hydraulic fracturing well sites. The official stated that particles from the sand, if not properly contained by dust control mechanisms, can lodge in the lungs and potentially cause silicosis.[40]

[38]Nitrogen oxides are regulated pollutants commonly known as NOx that, among other things, contribute to the formation of ozone and have been linked to respiratory illness, decreased lung function, and premature death. Particulate matter is a ubiquitous form of air pollution commonly referred to as soot. GAO, *Diesel Pollution: Fragmented Federal Programs That Reduce Mobile Source Emissions Could Be Improved*, GAO-12-261 (Washington, D.C.: Feb. 7, 2012).

[39]T. Colborn, C. Kwiatkowski, K. Schultz, and M. Bachran, "Natural Gas Operations From a Public Health Perspective," *International Journal of Human & Ecological Risk Assessment* 17, no. 5 (2011).

[40]Silicosis is an incurable lung disease caused by inhaling fine dusts of silica sand.

The researcher expects to publish the results of research on public health risks from proppant later in 2012.

Figure 11: Silica Sand Proppant

Source: GAO.

Use of diesel engines to supply power to drilling sites also degrades air quality. Shale oil and gas drilling rigs require substantial power to drill and case wellbores to the depths of shale formations. This power is typically provided by transportable diesel engines, which generate exhaust from the burning of diesel fuel. After the wellbore is drilled to the target formation, additional power is needed to operate the pumps that move large quantities of water, sand, or chemicals into the target formation at high pressure to hydraulically fracture the shale—generating additional exhaust. In addition, other equipment used during operations—including pneumatic valves and dehydrators—contribute to air emissions. For example, natural gas powers switches that turn valves on and off in the production system. Each time a valve turns on or off, it “bleeds” a small amount of gas into the air. Some of these pneumatic valves vent gas continuously. A dehydrator circulates the chemical glycol to absorb moisture in the gas but also absorbs small volumes of gas. The absorbed gas vents to the atmosphere when the water vapor is released from the glycol.[41]

Releases of natural gas during the development process also degrade air quality. As part of the process to develop shale oil and gas resources, operators flare or vent natural gas for a number of operational reasons, including lowering the pressure to ensure safety or when operators purge water or hydrocarbon liquids that collect in wellbores to maintain proper well function. Flaring emits carbon dioxide, and venting releases methane and volatile organic compounds. Venting and flaring are often a necessary part of the development process but contribute to greenhouse gas emissions.[42] According to EPA analysis, natural gas well completions involving hydraulic fracturing vent approximately 230 times more natural gas and volatile organic compounds than natural gas well completions that do not involve hydraulic fracturing.[43] As we reported in July 2004, in addition to the operational reasons for flaring and venting, in areas where the primary purpose of drilling is to produce oil, operators flare or vent associated natural gas because no local market exists for the gas and transporting to a market may not be economically feasible.[44] For example, according to EIA, in 2011, approximately 30 percent of North Dakota's natural gas production from the Bakken Shale was flared by operators due to insufficient natural gas gathering pipelines, processing plants, and transporting pipelines. The percentage of flared gas in North Dakota is considerably higher than the national average; EIA reported that, in 2009,

[41]GAO-11-34.

[42]Methane and other chemical compounds found in the earth's atmosphere create a greenhouse effect. Under normal conditions, when sunlight strikes the earth's surface, some of it is reflected back toward space as infrared radiation or heat. Greenhouse gases such as carbon dioxide and methane impede this reflection by trapping heat in the atmosphere. While these gases occur naturally on earth and are emitted into the atmosphere, the expanded industrialization of the world over the last 150 years has increased the amount of emissions from human activity (known as anthropogenic emissions) beyond the level that the earth's natural processes can handle.

[43]EPA, Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas industry (Research Triangle Park, NC: April 2012).

[44]GAO, *Natural Gas Flaring and Venting: Opportunities to Improve Data and Reduce Emissions*, GAO-04-809 (Washington, D.C.: July 14, 2004).

less than 1 percent of natural gas produced in the United States was vented or flared.

Storing fracturing fluid and produced water in impoundments may also pose a risk to air quality as evaporation of the fluids have the potential to release contaminants into the atmosphere. According to the New York Department of Environmental Conservation's 2011 Supplemental Generic Environmental Impact Statement, analysis of air emission rates of some of the compounds used in the fracturing fluids in the Marcellus Shale reveals the potential for emissions of hazardous air pollutants, in particular methanol, from the fluids stored in impoundments.

As with conventional oil and gas development, emissions can also occur as faulty equipment or accidents, such as leaks or blowouts, release concentrations of methane and other gases into the atmosphere. For example, corrosion in pipelines or improperly tightened valves or seals can be sources of emissions. In addition, according to EPA officials, storage vessels for crude oil, condensate, or produced water are significant sources of methane, volatile organic compounds and hazardous air pollutant emissions.

A number of studies we reviewed evaluated air quality at shale gas development sites. However, these studies are generally anecdotal, short-term, and focused on a particular site or geographic location. For example, in 2010, the Pennsylvania Department of Environmental Protection conducted short-term sampling of ambient air concentrations in north central Pennsylvania. The sampling detected concentrations of natural gas constituents including methane, ethane, propane, and butane in the air near Marcellus Shale drilling operations, but according to this state agency, the concentration levels were not considered significant enough to cause adverse health effects.[45]

The studies and publications we reviewed provide information on air quality conditions at a specific site at a specific time but do not provide the information needed to determine the overall cumulative effect that

[45]Methane emissions represent a waste of resources and a fractional contribution to greenhouse gas levels.

shale oil and gas activities have on air quality.[46] The cumulative effect shale oil and gas activities have on air quality will be largely determined by the amount of development and the rate at which it occurs, and the ability to measure this will depend on the availability of accurate information on emission levels. However, the number of wells that will ultimately be drilled cannot be known in advance—in part because the productivity of any particular formation at any given location and depth is not known until drilling occurs. In addition, as we reported in 2010, data on the severity or amount of pollutants released by oil and gas development, including the amount of fugitive emissions, are limited.

Water Quantity

According to a number of studies and publications we reviewed, shale oil and gas development poses a risk to surface water and groundwater because withdrawing water from streams, lakes, and aquifers for drilling and hydraulic fracturing could adversely affect water sources.[47] Operators use water for drilling, where a mixture of clay and water (drilling mud) is used to carry rock cuttings to the surface, as well as to cool and lubricate the drill bit. Water is also the primary component of fracturing fluid. Table 3 shows the average amount of freshwater used to drill and fracture a shale oil or gas well.

Table 3: Average Freshwater Use per Well for Drilling and Hydraulic Fracturing

	Average freshwater used (in gallons)	
Shale play	**For drilling**	**For hydraulic fracturing**
Barnett	250,000	4,600,000
Eagle Ford	125,000	5,000,000
Haynesville	600,000	5,000,000
Marcellus	85,000	5,600,000
Niobrara	300,000	3,000,000

Source: GAO analysis of data reported by George King, Apache Corporation (2011).

Note: The amount of water required to hydraulically fracture a single well varies considerably as fracturing of shale oil and gas becomes dominated by more complex, multistaged fracturing activities.

[46]According to a 2008 National Park Service report, on a site-by-site basis, emissions may not be significant but on a regional basis may prove significant as states and parks manage regional ozone transport.

[47]An aquifer is an underground layer of rock or unconsolidated sand, gravel, or silt that will yield groundwater to a well or spring.

According to a 2012 University of Texas study,[48] water for these activities is likely to come from surface water (rivers, lakes, ponds), groundwater aquifers, municipal supplies, reused wastewater from industry or water treatment plants, and recycling water from earlier fracturing operations.[49] As we reported in October 2010, withdrawing water from nearby streams and rivers could decrease flows downstream, making the streams and rivers more susceptible to temperature changes—increases in the summer and decreases in the winter. Elevated temperatures could adversely affect aquatic life because many fish and invertebrates need specific temperatures for reproduction and proper development. Further, decreased flows could damage or destroy riparian vegetation. Similarly, withdrawing water from shallow aquifers—an alternative water source—could temporarily affect groundwater resources. Withdrawals could lower water levels within these shallow aquifers and the nearby streams and springs to which they are connected. Extensive withdrawals could reduce groundwater discharge to connected streams and springs, which in turn could damage or remove riparian vegetation and aquatic life. Withdrawing water from deeper aquifers could have longer-term effects on groundwater and connected streams and springs because replenishing deeper aquifers with precipitation generally takes longer.[50] Further, groundwater withdrawal could affect the amount of water available for other uses, including public and private water supplies.

Freshwater is a limited resource in some arid and semiarid regions of the country where an expanding population is placing additional demands on water. The potential demand for water is further complicated by years of drought in some parts of the country and projections of a warming climate. According to a 2011 Massachusetts Institute of Technology study,[51] the amount of water used for shale gas development is small in

[48]Charles G. Groat, Ph.D. and Thomas W. Grimshaw, Ph.D., *Fact-Based Regulation for Environmental Protection in Shale Gas Development* (Austin, Texas: The Energy Institute, The University of Texas at Austin, February, 2012).

[49]Operators are pursuing a variety of techniques and technologies to reduce freshwater demand, such as recycling their own produced water and hydraulic fracturing fluids. We recently reported that some shale gas operators have begun reusing produced water for hydraulic fracturing of additional wells (see GAO-12-156).

[50]GAO-11-35.

[51]Massachusetts Institute of Technology, *The Future of Natural Gas: An Interdisciplinary MIT Study* (2011) (web.mit.edu/mitei/research/studies/report-natural-gas.pdf).

comparison to other water uses, such as agriculture and other industrial purposes. However, the cumulative effects of using surface water or groundwater at multiple oil and gas development sites can be significant at the local level, particularly in areas experiencing drought conditions.

Similar to shale oil and gas development, development of gas from coalbed methane formations poses a risk of aquifer depletion. To develop natural gas from such formations, water from the coal bed is withdrawn to lower the reservoir pressure and allow the methane to desorb from the coal. According to a 2001 USGS report, dewatering coalbed methane formations in the Powder River Basin in Wyoming can lower the groundwater table and reduce water available for other uses, such as livestock and irrigation.[52]

The key issue for water quantity is whether the total amount of water consumed for the development of shale oil and gas will result in a significant long-term loss of water resources within a region, according to a 2012 University of Texas study. This is because water used in shale oil and gas development is largely a consumptive use and can be permanently removed from the hydrologic cycle, according to EPA and Interior officials. However, it is difficult to determine the long-term effect on water resources because the scale and location of future shale oil and gas development operations remains largely uncertain. Similarly, the total volume that operators will withdraw from surface water and aquifers for drilling and hydraulic fracturing is not known until operators submit applications to the appropriate regulatory agency. As a result, the cumulative amount of water consumed over the lifetime of the activity—key information needed to assess the effects of water withdrawals—remains largely unknown.

Water Quality

According to a number of studies and publications we reviewed, shale oil and gas development pose risks to water quality from contamination of surface water and groundwater as a result of spills and releases of produced water, chemicals, and drill cuttings; erosion from ground disturbances; or underground migration of gases and chemicals.

[52]USGS, *A Field Conference On Impacts of Coalbed Methane Development in the Powder River Basin, Wyoming,* Open-File Report 01-126 (Denver, CO: 2001).

Spills and Releases

Shale oil and gas development poses a risk to water quality from spills or releases of toxic chemicals and waste that can occur as a result of tank ruptures, blowouts, equipment or impoundment failures, overfills, vandalism, accidents (including vehicle collisions), ground fires, or operational errors. For example, tanks storing toxic chemicals or hoses and pipes used to convey wastes to the tanks could leak, or impoundments containing wastes could overflow as a result of extensive rainfall. According to New York Department of Environmental Conservation's 2011 Supplemental Generic Environmental Impact Statement, spilled, leaked, or released chemicals or wastes could flow to a surface water body or infiltrate the ground, reaching and contaminating subsurface soils and aquifers. In August 2003, we reported that damage from oil and gas related spills on National Wildlife Refuges varied widely in severity, ranging from infrequent small spills with no known effect on wildlife to large spills causing wildlife death and long-term water and soil contamination.[53]

Drill cuttings, if improperly managed, also pose a risk to water quality. Drill cuttings brought to the surface during oil and gas development may contain naturally occurring radioactive materials (NORM),[54] along with other decay elements (radium-226 and radium-228), according to an industry report presented at the Society of Petroleum Engineers Annual Technical Conference and Exhibition.[55] According to the report, drill cuttings are stored and transported through steel pipes and tanks—which the radiation cannot penetrate. However, improper transport and handling of drill cuttings could result in water contamination. For example, NORM

[53]GAO, *National Wildlife Refuges: Opportunities to Improve the Management and Oversight of Oil and Gas Activities on Federal Lands*, GAO-03-517 (Washington, D.C.: Aug. 28, 2003).

[54]Naturally occurring radioactive materials (NORM) are present at varying degrees in virtually all environmental media, including rocks and soils. According to a DOE report, human exposure to radiation comes from a variety of sources, including naturally occurring radiation from space, medical sources, consumer products, and industrial sources. Normal disturbances of NORM-bearing rock formations by activities such as drilling do not generally pose a threat to workers, the general public or the environment, according to studies and publications we reviewed.

[55]J. Daniel Arthur, Brian Bohm, David Cornue. "Environmental Considerations of Modern Shale Gas Development" (presented at the Society of Petroleum Engineers Annual Technical Conference and Exhibition, New Orleans, Louisiana, October 2009).

concentrations can build up in pipes and tanks, if not properly disposed, and the general public or water could come into contact with them, according to an EPA fact sheet.[56]

The chemical additives in fracturing fluid, if not properly handled, also poses a risk to water quality if they come into contact with surface water or groundwater. Some additives used in fracturing fluid are known to be toxic, but data are limited for other additives. For example, according to reports we reviewed, operators may include diesel fuel—a refinery product that consists of several components, possibly including some toxic impurities such as benzene and other aromatics—as a solvent and dispersant in fracturing fluid. While some additives are known to be toxic, less is known about potential adverse effects on human health in the event that a drinking water aquifer was contaminated as a result of a spill or release of fracturing fluid, according to the 2011 New York Department of Environmental Conservation's Supplemental Generic Environmental Impact Statement. This is largely because the overall risk of human health effects occurring from hydraulic fracturing fluid would depend on whether human exposure occurs, the specific chemical additives being used, and site-specific information about exposure pathways and environmental contaminant levels.

The produced water and fracturing fluids returned during the flowback process contain a wide range of contaminants and pose a risk to water quality, if not properly managed.[57] Most of the contaminants occur naturally, but some are added through the process of drilling and hydraulic fracturing. In January 2012, we reported that the range of contaminants found in produced water can include,[58] but is not limited to

- salts, which include chlorides, bromides, and sulfides of calcium, magnesium, and sodium;

[56]EPA, *Radioactive Waste from Oil and Gas Drilling*, EPA 402-F-06-038 (Washington, D.C.: April 2006).

[57]A 2009 report from DOE and the Groundwater Protection Council—a nonprofit organization whose members consist of state ground water regulatory agencies—estimates that from 30 percent to 70 percent of the original fluid injected returns to the surface.

[58]GAO-12-156.

- metals, which include barium, manganese, iron, and strontium, among others;
- oil, grease, and dissolved organics, which include benzene and toluene, among others;
- NORM; and
- production chemicals, which may include friction reducers to help with water flow, biocides to prevent growth of microorganisms, and additives to prevent corrosion, among others.

At high levels, exposure to some of the contaminants in produced water could adversely affect human health and the environment. For example, in January 2012, we reported that, according to EPA, a potential human health risk from exposure to high levels of barium is increased blood pressure.[59] From an environmental standpoint, research indicates that elevated levels of salts can inhibit crop growth by hindering a plant's ability to absorb water from the soil. Additionally, exposure to elevated levels of metals and production chemicals, such as biocides, can contribute to increased mortality among livestock and wildlife.

Operators must transport or store produced water prior to disposal. According to a 2012 University of Texas report, produced water temporarily stored in tanks (see fig. 12) or impoundments prior to treatment or disposal may be a source of leaks or spills, if not properly managed. The risk of a leak or spill is particularly a concern for surface impoundments as improper liners can tear, and impoundments can overflow.[60] For example, according to state regulators in North Dakota, in 2010 and 2011, impoundments overflowed during the spring melt season because operators did not move fluids from the impoundments—which

[59]GAO-12-156.

[60]The composition of pit lining depends on regulatory requirements, which vary from state to state.

were to be used for temporary storage—to a proper disposal site before the spring thaw.[61]

Figure 12: Storage Tank for Produced Water in the Barnett Shale

Source: GAO.

Unlike shale oil and gas formations, water permeates coalbed methane formations, and its pressure traps natural gas within the coal. To produce natural gas from coalbed methane formations, water must be extracted to lower the pressure in the formation so the natural gas can flow out of the coal and to the wellbore. In 2000, USGS reported that water extracted from coalbed methane formations is commonly saline and, if not treated

[61]In response, the state passed a new law that will significantly reduce the number of pits. Under the new law, operators can use pits for temporary storage of fluid from the flowback process but must drain and reclaim the pits no more than 72 hours after hydraulic fracturing is complete.

and disposed of properly, could adversely affect streams and threaten fish and aquatic resources.

According to several reports, handling and transporting toxic fluids or contaminants poses a risk of environmental contamination for all industries, not just oil and gas development; however, the large volume of fluids and contaminants—fracturing fluid, drill cuttings, and produced water—that is associated with the development of shale oil and gas poses an increased risk for a release to the environment and the potential for greater effects should a release occur in areas that might not otherwise be exposed to these chemicals.

Erosion

Oil and gas development, whether conventional or shale oil and gas, can contribute to erosion, which could carry sediments and pollutants into surface waters. Shale oil and gas development require operators to undertake a number of earth-disturbing activities, such as clearing, grading, and excavating land to create a pad to support the drilling equipment. If necessary, operators may also construct access roads to transport equipment and other materials to the site. As we reported in February 2005, as with other construction activities, if sufficient erosion controls to contain or divert sediment away from surface water are not established then surfaces are exposed to precipitation and runoff could carry sediment and other harmful pollutants into nearby rivers, lakes, and streams.[62] For example, in 2012, the Pennsylvania Department of Environmental Protection concluded that an operator in the Marcellus Shale did not provide sufficient erosion controls when heavy rainfall in the area caused significant erosion and contamination of a nearby stream from large amounts of sediment.[63] As we reported in February 2005, sediment clouds water, decreases photosynthetic activity, and destroys organisms and their habitat.

[62]GAO, *Storm Water Pollution: Information Needed on the Implications of Permitting Oil and Gas Construction Activities*, GAO-05-240 (Washington, D.C.: Feb. 9, 2005).

[63]In response, the state required the operator to install silt fences, silt socks, gravel surfacing of the access road, and a storm water capture ditch.

Underground Migration

According to a number of studies and publications we reviewed, underground migration of gases and chemicals poses a risk of contamination to water quality.[64] Underground migration can occur as a result of improper casing and cementing of the wellbore as well as the intersection of induced fractures with natural fractures, faults, or improperly plugged dry or abandoned wells. Moreover, there are concerns that induced fractures can grow over time and intersect with drinking water aquifers. Specifically:

Improper casing and cementing. A well that is not properly isolated through proper casing and cementing could allow gas or other fluids to contaminate aquifers as a result of inadequate depth of casing,[65] inadequate cement in the annular space around the surface casing, and ineffective cement that cracks or breaks down under the stress of high pressures. For example, according to a 2008 report by the Ohio Department of Natural Resources, a gas well in Bainbridge, Ohio, was not properly isolated because of faulty sealing, allowing natural gas to build up in the space around the production casing and migrate upward over about 30 days into the local aquifer and infiltrating drinking water wells.[66] The risk of contamination from improper casing and cementing is not unique to the development of shale formations. Casing and cementing practices also apply to conventional oil and gas development. However, wells that are hydraulically fractured have some unique aspects. For example, hydraulically fractured wells are commonly exposed to higher pressures than wells that are not hydraulically fractured. In addition, hydraulically fractured wells are exposed to high pressures over a longer period of time as fracturing is conducted in multiple stages, and wells may be refractured multiple times—primarily to extend the economic life of the well when production declines significantly or falls below the estimated reservoir potential.

[64]Methane can occur naturally in shallow bedrock and unconsolidated sediments and has been known to naturally seep to the surface and contaminate water supplies, including water wells. Methane is a colorless, odorless gas and is generally considered nontoxic, but there could be an explosive hazard if gas is present in significant volumes and the water well is not properly vented.

[65]The depth for casing and cementing may be determined by state regulations.

[66]Ohio Department of Natural Resources, *Report on the Investigation of the Natural Gas Invasion of Aquifers in Bainbridge Township of Geauga County, Ohio* (September 2008).

Natural fractures, faults, and abandoned wells. If shale oil and gas development activities result in connections being established with natural fractures, faults, or improperly plugged dry or abandoned wells, a pathway for gas or contaminants to migrate underground could be created—posing a risk to water quality. These connections could be established through either induced fractures intersecting directly with natural fractures, faults, or improperly plugged dry or abandoned wells or as a result of improper casing and cementing that allow gas or other contaminants to make such connections. In 2011, the New York State Department of Environmental Conservation reported that operators generally avoid development around known faults because natural faults could allow gas to escape, which reduces the optimal recovery of gas and the economic viability of a well. However, data on subsurface conditions in some areas are limited. Several studies we reviewed report that some states are unaware of the location or condition of many old wells. As a result, operators may not be fully aware of the location of abandoned wells and natural fractures or faults.

Fracture growth. A number of such studies and publications we reviewed report that the risk of induced fractures extending out of the target formation into an aquifer—allowing gas or other fluids to contaminate water—may depend, in part, on the depth separating the fractured formation and the aquifer. For example, according to a 2012 Bipartisan Policy Center report, [67] the fracturing process itself is unlikely to directly affect freshwater aquifers because fracturing typically takes place at a depth of 6,000 to 10,000 feet, while drinking water tables are typically less than 1,000 feet deep.[68] Fractures created during the hydraulic fracturing process are generally unable to span the distance between the targeted shale formation and freshwater bearing zones. According to a 2011 industry report, fracture growth is stopped by natural subsurface barriers

[67]Bipartisan Policy Center, *Shale Gas: New Opportunities, New Challenges* (Washington, D.C.: January 2012).

[68]Some coalbed methane formations are much closer to drinking water aquifers than are shale formations. In 2004, EPA reviewed incidents of drinking water well contamination believed to be associated with hydraulic fracturing in coalbed methane formations. EPA found no confirmed cases linked to the injection of fracturing fluid or subsequent underground movement of fracturing fluids. The report states that, although thousands of coalbed methane formations are fractured annually, EPA did not find confirmed evidence that drinking water wells had been contaminated by the hydraulic fracturing process.

and the loss of hydraulic fracturing fluid.[69] When a fracture grows, it conforms to a general direction set by the stresses in the rock, following what is called fracture direction or orientation. The fractures are most commonly vertical and may extend laterally several hundred feet away from the well, usually growing upward until they intersect with a rock of different structure, texture, or strength. These are referred to as seals or barriers and stop the fracture's upward or downward growth. In addition, as the fracturing fluid contacts the formation or invades natural fractures, part of the fluid is lost to the formation. The loss of fluids will eventually stop fracture growth according to this industry report.

From 2001 through 2010, an industry consulting firm monitored the upper and lower limits of hydraulically induced fractures relative to the position of drinking water aquifers in the Barnett and Eagle Ford Shale, the Marcellus Shale, and the Woodford Shale.[70] In 2011, the firm reported that the results of the monitoring show that even the highest fracture point is several thousand feet below the depth of the deepest drinking water aquifer. For example, for over 200 fractures in the Woodford Shale, the typical distance between the drinking water aquifer and the top of the fracture was 7,500 feet, with the highest fracture recorded at 4,000 feet from the aquifer. In another example, for the 3,000 fractures performed in the Barnett Shale, the typical distance from the drinking water aquifer and the top of the fracture was 4,800 feet, and the fracture with the closest distance to the aquifer was still separated by 2,800 feet of rock. Table 4 shows the relationship between shale formations and the depth of treatable water in five shale gas plays currently being developed.

[69] George E. King, Apache Corporation, "Explaining and Estimating Fracture Risk: Improving Fracture Performance in Unconventional Gas and Oil Wells" (presented at the Society of Petroleum Engineers Hydraulic Fracturing Conference, The Woodlands, Texas, February 2012).

[70] Kevin Fisher, Norm Warpinski, Pinnacle—A Haliburton Service, "Hydraulic Fracture-Height Growth: Real Data" (presented at the Society of Petroleum Engineers Technical Conference and Exhibition, Denver, Colorado, October 2011).

Table 4: Shale Formation and Treatable Water Depth

Distance in feet

Shale play	Depth to shale	Depth to base of treatable water	Distance between shale and base of treatable water
Barnett	6,500- 8,500	1,200	5,300- 7,300
Fayetteville	1,000- 7,000	500	500- 6,500
Haynesville	10,500- 13,500	400	10,100- 13,100
Marcellus	4,000- 8,500	850	2,125- 7,650
Woodford	6,000- 11,000	400	5,600- 10,600

Source: GAO analysis of data presented in a report prepared at the request of the DOE.

Note: Depths to base of treatable water are approximate. According to the report, the depth to base of treatable water was based on data from state oil and gas agencies and state geological survey data.

Several government, academic, and nonprofit organizations evaluated water quality conditions or groundwater contamination incidents in areas experiencing shale oil and gas development. Among the studies and publications we reviewed that discuss the potential contamination of drinking water from the hydraulic fracturing process in shale formations are the following:

- In 2011, the Center for Rural Pennsylvania analyzed water samples taken from 48 private water wells located within about 2,500 feet of a shale gas well in the Marcellus Shale.[71] The analysis compared predrilling samples to postdrilling samples to identify any changes to water quality. The analysis showed that there were no statistically significant increases in pollutants prominent in drilling waste fluids—such as total dissolved solids, chloride, sodium, sulfate, barium, and strontium—and no statistically significant increases in methane. The study concluded that gas well drilling had not had a significant effect on the water quality of nearby drinking water wells.

- In 2011, researchers from Duke University studied shale gas drilling and hydraulic fracturing and the potential effects on shallow groundwater systems near the Marcellus Shale in Pennsylvania and the Utica Shale in New York. Sixty drinking water samples were collected in Pennsylvania and New York from bedrock aquifers that

[71]The Center for Rural Pennsylvania, *The Impact of Marcellus Gas Drilling on Rural Drinking Water Supplies* (Harrisburg, Pennsylvania: October 2011).

overlie the Marcellus or Utica Shale formations—some from areas with shale gas development and some from areas with no shale gas development.[72] The study found that methane concentrations were detected generally in 51 drinking water wells across the region—regardless of whether shale gas drilling occurred in the area—but that concentrations of methane were substantially higher closer to shale gas wells. However, the researchers reported that a source of the contamination could not be determined. Further, the researchers reported that they found no evidence of fracturing fluid in any of the samples.

- In 2011, the Ground Water Protection Council evaluated state agency groundwater investigation findings in Texas and categorized the determinations regarding causes of groundwater contamination resulting from the oil and gas industry.[73] During the study period—from 1993 through 2008—multistaged hydraulic fracturing stimulations were performed in over 16,000 horizontal shale gas wells. The evaluation of the state investigations found that there were no incidents of groundwater contamination caused by hydraulic fracturing.

In addition, regulatory officials we met with from eight states—Arkansas, Colorado, Louisiana, North Dakota, Ohio, Oklahoma, Pennsylvania, and Texas—told us that, based on state investigations, the hydraulic fracturing process has not been identified as a cause of groundwater contamination within their states.

A number of studies discuss the potential contamination of water from the hydraulic fracturing process in shale formations. However, according to several studies we reviewed, there are insufficient data for predevelopment (or baseline) conditions for groundwater. Without data to compare predrilling conditions to postdrilling conditions, it is difficult to determine if adverse effects were the result of oil and gas development, natural occurrences, or other activities. In addition, while researchers

[72]Stephen G. Osborn, Avner Vengosh, Nathaniel R. Warner, and Robert B. Jackson, "Methane Contamination of Drinking Water Accompanying Gas-well Drilling and Hydraulic Fracturing," *Proceedings of the National Academy of Science* 108, no. 20 (2011).

[73]Ground Water Protection Council, *State Oil and Gas Agency Groundwater Investigations And Their Role in Advancing Regulatory Reforms: A Two-State Review: Ohio and Texas* (Oklahoma City, Oklahoma: August 2011).

have evaluated fracture growth, the widespread development of shale oil and gas is relatively new. As such, little data exist on (1) fracture growth in shale formations following multistage hydraulic fracturing over an extended time period, (2) the frequency with which refracturing of horizontal wells may occur, (3) the effect of refracturing on fracture growth over time,[74] and (4) the likelihood of adverse effects on drinking water aquifers from a large number of hydraulically fractured wells in close proximity to each other.

Ongoing Studies Related to Water Quality

Ongoing studies by federal agencies, industry groups, and academic institutions are evaluating the effects of hydraulic fracturing on water resources so that, over time, better data and information about these effects should become available to policymakers and the public. For example, EPA's Office of Research and Development initiated a study in January 2010 to examine the potential effects of hydraulic fracturing on drinking water resources. According to agency officials, the agency anticipates issuing a progress report in 2012 and a final report in 2014. EPA is also conducting an investigation to determine the presence of groundwater contamination within a tight sandstone formation being developed for natural gas near Pavillion, Wyoming, and, to the extent possible, identify the source of the contamination. In December 2011, EPA released a draft report outlining findings from the investigation. The report is not finalized, but the agency indicated that it had identified certain constituents in groundwater above the production zone of the Pavillion natural gas wells that are consistent with some of the constituents used in natural gas well operations, including the process of hydraulic fracturing. DOE researchers are also testing the vertical growth of fractures during hydraulic fracturing to determine whether fluids can travel thousands of feet through geologic faults into water aquifers close to the surface.

Land and Wildlife

Oil and gas development, whether conventional or shale oil and gas, poses a risk to land resources and wildlife habitat as a result of constructing, operating, and maintaining the infrastructure necessary to develop oil and gas; using toxic chemicals; and injecting waste products underground.

[74]According to research presented in the New York Department of Environmental Conservation's Supplemental Generic Environmental Impact Statement, refracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture dimensions.

Habitat Degradation

According to studies and publications we reviewed, development of oil and gas, whether conventional or shale oil and gas, poses a risk to habitat from construction activities. Specifically, clearing land of vegetation and leveling the site to allow access to the resource, as well as construction of roads, pipelines, storage tanks, and other infrastructure needed to extract and transport the resource can fragment habitats.[75] In August 2003, we reported that oil and gas infrastructure on federal wildlife refuges can reduce the quality of habitat by fragmenting it.[76] Fragmentation increases disturbances from human activities, provides pathways for predators, and helps spread nonnative plant species.

In addition, spills of oil, gas, or other toxic chemicals have harmed wildlife and habitat. Oil and gas can injure or kill wildlife by destroying the insulating capacity of feathers and fur, depleting oxygen available in water, or exposing wildlife to toxic substances. Long-term effects of oil and gas contamination on wildlife are difficult to determine, but studies suggest that effects of exposure include reduced fertility, kidney and liver damage, immune suppression, and cancer. In August 2003, we reported that even small spills may contaminate soil and sediments if they occur frequently.[77] Further, noise and the presence of new infrastructure associated with shale gas development may also affect wildlife. A study by the Houston Advanced Research Center and the Nature Conservancy investigated the effects of noise associated with gas development on the Attwater's Prairie Chicken—an endangered species. The study explored how surface disruptions, particularly construction of a rig and noise from diesel generators would affect the animal's movement and habitat.[78] The results of the study found that the chickens were not adversely affected by the diesel engine generator's noise but that the presence of the rig caused the animals to temporarily disperse and avoid the area.

[75]Habitat fragmentation occurs when a network of roads and other infrastructure is constructed in previously undeveloped areas.

[76]GAO-03-517.

[77]GAO-03-517.

[78]James F. Bergan, Richard Haut, Jared Judy, and Liz Price. "Living In Harmony—Gas Production and the Attwater's Prairie Chicken" (presented at the Society of Professional Engineers Annual Technical Conference, Florence, Italy, September 2010).

A number of studies we reviewed identified risks to habitat and wildlife as a result of shale oil and gas activities. However, because shale oil and gas development is relatively new in some areas, the long-term effects—after operators are to have restored portions of the land to predevelopment conditions—have not been evaluated. Without these data, the cumulative effects of shale oil and gas development on habitat and wildlife are largely unknown.

Induced Seismicity

According to several studies and publications we reviewed, the hydraulic fracturing process releases energy deep beneath the surface to break rock but the energy released is not large enough to trigger a seismic event that could be felt on the surface. However, a process commonly used by operators to dispose of waste fluids—underground injection—has been associated with earthquakes in some locations. For example, a 2011 Oklahoma Geological Survey study reported that underground injection can induce seismicity. In March 2012, the Ohio Department of Natural Resources reported that "there is a compelling argument" that the injection of produced water into underground injection wells was the cause of the 2011 earthquakes near Youngstown, Ohio. In addition, the National Academy of Sciences released a study in June 2012 that concluded that underground injection of wastes poses some risk for induced seismicity, but that very few events have been documented over the past several decades relative to the large number of disposal wells in operation.

The available research does not identify a direct link between hydraulic fracturing and increased seismicity, but there could be an indirect effect to the extent that increased use of hydraulic fracturing produces increased amounts of water that is disposed of through underground injection. In addition, according to the National Academy of Science's 2012 report, accurately predicting magnitude or occurrence of seismic events is generally not possible, in part, because of a lack of comprehensive data on the complex natural rock systems at energy development sites.

Extent of Risks Is Unknown and Depends on Many Factors

The extent and severity of environmental and public health risks identified in the studies and publications we reviewed may vary significantly across shale basins and also within basins because of location- and process-specific factors, including the location and rate of development; geological characteristics, such as permeability, thickness, and porosity of the formations in the basin; climatic conditions; business practices; and regulatory and enforcement activities.

Location and rate of development. The location of oil and gas operations and the rate of development can affect the extent and severity of environmental and public health risks. For example, as we reported in October 2010, while much of the natural gas that is vented and flared is considered to be unavoidably lost, certain technologies and practices can be applied throughout the production process to capture some of this gas, according to the oil and gas industry and EPA. The technologies' technical and economic feasibility varies and sometimes depends on the location of operations. For example, some technologies require a substantial amount of electricity, which may be less feasible for remote production sites that are not on the electrical grid. In addition, the extent and severity of environmental risks may vary based on the location of oil and gas wells. For example, in areas with high population density that are already experiencing challenges adhering to federal air quality limits, increases in ozone levels because of emissions from oil and gas development may compound the problem.

Geological characteristics. Geological characteristics can affect the extent and severity of environmental and public health risks associated with shale oil and gas development. For example, geological differences between tight sandstone and shale formations are important because, unlike shale, tight sandstone has enough permeability to transmit groundwater to water wells in the region. In a sense, the tight sandstone formation acts as a reservoir for both natural gas and for groundwater. In contrast, shale formations are typically not permeable enough to transmit water and are not reservoirs for groundwater. According to EPA officials, hydraulic fracturing in a tight sandstone formation that is a reservoir for both natural gas and groundwater poses a greater risk of contamination than the same activity in a deep shale formation.

Climatic conditions. Climatic factors, such as annual rainfall and surface temperatures, can also affect the environmental risks for a specific region or area. For example, according to a 2007 study funded by DOE, average rainfall amounts can be directly related to soil erosion.[79] Specifically,

[79]ALL Consulting and the Interstate Oil and Gas Compact Commission, *Improving Access to Onshore Oil and Gas Resources on Federal Lands* (a special report prepared at the request of the U.S. Department of Energy National Energy and Technology Laboratory, March 2007).

areas with higher precipitation levels may be more susceptible to soil compaction and rutting during the well pad construction phase. In another example, risk of adverse effects from exposures to toxic air contaminants can vary substantially between drilling sites, in part, because of the specific mix of emissions and climatic conditions that affect the transport and dispersion of emissions. Specifically, wind speed and direction, temperature, as well as other climatic conditions, can influence exposure levels of toxic air contaminants. For example, according to a 2012 study from the Sustainable Investments Institute and the Investor Responsibility Research Center Institute, the combination of air emissions from gas operations, snow on the ground, bright sunshine, and temperature inversions during winter months have contributed to ozone creation in Sublette County, Wyoming.[80]

Business practices. A number of studies we reviewed indicate that some adverse effects from shale oil and gas development can be mitigated through the use of technologies and best practices. For example, according to standards and guidelines issued jointly by the Departments of the Interior and Agriculture, mitigation techniques, such as fencing and covers, should be used around impoundments to prevent livestock or wildlife from accessing fluids stored in the impoundments.[81] In another example, EPA's Natural Gas STAR program has identified over 80 technologies and practices that can cost effectively reduce methane emissions, a potent greenhouse gas, during oil and gas development. However, the use of these technologies and business practices are typically voluntary and rely on responsible operators to ensure that necessary actions are taken to prevent environmental contamination. Further, the extent to which operators use these mitigating practices is unknown and could be particularly challenging to identify given the significant increase in recent years in the development of shale oil and gas by a variety of operators, both large and small.

Regulatory and enforcement activities. Potential changes to the federal, state, and local regulatory environment will affect operators' future

[80]Susan Williams, "Discovering Shale Gas: An Investor Guide to Hydraulic Fracturing," Sustainable Investments Institute and Investor Responsibility Research Center Institute (New York, NY: February 2012).

[81]United States Department of the Interior and United States Department of Agriculture. *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development*. BLM/WO/ST-06/021+3071/REV 07 (Denver, CO: 2007).

activities and can therefore affect the risks or level of risks associated with shale oil and gas development. Shale oil and gas development is regulated by multiple levels of government—including federal, state, and local. Many of the laws and regulations applicable to shale oil and gas development were put in place before the increase in operations that has occurred in the last few years, and various levels of government are evaluating and, in some cases, revising laws and regulations to respond to the increase in shale oil and gas development. For example, in April 2012, EPA promulgated New Source Performance Standards for the oil and gas industry that, when fully phased-in by 2015, will require emissions reductions at new or modified oil and gas well sites, including wells using hydraulic fracturing. Specifically, these new standards, in part, focus on reducing the venting of natural gas and volatile organic compounds during the flowback process. In addition, areas without prior experience with oil and gas development are just now developing new regulations. These governments' effectiveness in implementing and enforcing this framework will affect future activities and the level of associated risk.

Agency Comments

We provided a draft of this report to the Department of Energy, the Department of the Interior, and the Environmental Protection Agency for review and comment. We received technical comments from Interior's Assistant Secretary, Policy, Management, and Budget, and from Environmental Protection Agency officials, which we have incorporated as appropriate. In an e-mail received August 27, 2012, the Department of Energy liaison stated the agency had no comments on the report.

As agreed with your offices, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies of this report to the appropriate congressional committees, the Secretary of Energy, the Secretary of the Interior, the EPA Administrator, and other interested parties. In addition, the report will be available at no charge on the GAO website at http://www.gao.gov.

If you or your staff members have any questions about this report, please contact me at (202) 512-3841 or ruscof@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff who made key contributions to this report are listed in appendix IV.

Frank Rusco

Frank Rusco
Director, Natural Resources and Environment

List of Requesters

The Honorable Barbara Boxer
Chairman
Committee on Environment and Public Works
United States Senate

The Honorable Sheldon Whitehouse
Chairman
Subcommittee on Oversight
Committee on Environment and Public Works
United States Senate

The Honorable Benjamin L. Cardin
Chairman
Subcommittee on Water and Wildlife
Committee on Environment and Public Works
United States Senate

The Honorable Henry A. Waxman
Ranking Member
Committee on Energy and Commerce
House of Representatives

The Honorable Edward J. Markey
Ranking Member
Committee on Natural Resources
House of Representatives

The Honorable Diana DeGette
Ranking Member
Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
House of Representatives

The Honorable Robert P. Casey, Jr.
United States Senate

Appendix I: Scope and Methodology

Our objectives for this review were to determine what is known about (1) the size of shale oil and gas resources in the United States and the amount produced from 2007 through 2011—the years for which data were available—and (2) the environmental and public health risks associated with development of shale oil and gas.

To determine what is known about the size of shale oil and gas resources, we collected data from federal agencies, state agencies, private industry, and academic organizations. Specifically, to determine what is known about the size of these resources, we obtained information for technically recoverable and proved reserves estimates for shale oil and gas from the Energy Information Administration (EIA), the U.S. Geological Survey (USGS), and the Potential Gas Committee—a nongovernmental organization composed of academic and industry officials. We interviewed key officials about the assumptions and methodologies used to estimate the resource size. Estimates of proved reserves of shale oil and gas are based on data provided to EIA by operators. In addition to the estimates provided by these three organizations, we also obtained and presented technically recoverable shale oil and gas estimates from two private organizations—IHS Inc., and ICF International—and one national advisory committee representing the views of the oil and gas industry and other stakeholders—the National Petroleum Council. For all estimates we report, we conducted a review of the methodologies used in these estimates for fatal flaws; we did not find any fatal flaws in these methodologies.

To determine what is known about the amount of produced shale oil and gas from 2007 through 2011, we obtained data from EIA—the federal agency responsible for estimating and reporting this and other energy information. EIA officials provided us with estimated oil and gas production data, including data estimating shale oil and gas estimates from states and two private firms—HPDI, LLC and Lippman Consulting, Inc. To assess the reliability of these data, we examined EIA's published methodology for collecting this information and interviewed key EIA officials regarding the agency's data collection and validation efforts. We also interviewed officials from three state agencies, representatives from five private companies, and researchers from three academic institutions who are familiar with these data and EIA's methodology and discussed the sources and reliability of the data. We determined that these data were sufficiently reliable for the purposes of this report.

To determine what is known about the environmental and public health risks associated with the development of shale oil and gas[1], we identified and reviewed more than 90 studies and other publications from federal agencies and laboratories, state agencies, local governments, the petroleum industry, academic institutions, environmental and public health groups, and other nongovernmental associations. The studies and publications we reviewed included scientific and industry periodicals, government-sponsored research, reports or other publications from nongovernmental organizations, and presentation materials. We identified these studies by conducting a literature search and by asking for recommendations during our interviews with stakeholders. For a number of studies, we interviewed the author or authors to discuss the study's findings and limitations, if any. We believe we have identified the key studies through our literature review and interviews, and that the studies included in our review have accurately identified potential risks for shale oil and gas development. However, given our methodology, it is possible that we may not have identified all of the studies with findings relevant to our objectives, and the risks we present may not be the only issues of concern. The widespread use of horizontal drilling and hydraulic fracturing to develop shale oil and gas is relatively new. Studying the effects of an activity and completing a formal peer-review process can take numerous months or years. Because of the relative short time frame for operations and the lengthy time frame for studying effects, we did not limit the review to peer-reviewed publications.

The risks identified in the studies and publications we reviewed cannot, at present, be quantified, and the magnitude of potential adverse affects or likelihood of occurrence cannot be determined for several reasons. First, it is difficult to predict how many or where shale oil and gas drilling operations may be constructed. Second, operators' use of effective best practices to mitigate risk may vary. Third, based on the studies we reviewed, there are relatively few that are based on evaluating predevelopment conditions to postdevelopment conditions—making it difficult to detect or attribute adverse changes to shale oil and gas development. In addition, changes to the federal, state, and local

[1]Operators may use hydraulic fracturing to develop oil and natural gas from formations other than shale. Specifically, coalbed and tight sand formations may rely on these practices, and some studies and publications we reviewed identified risks that can apply to these formations. However, many of the studies and publications we identified and reviewed focused primarily on the development of shale formations.

regulatory environment and the effectiveness in implementation and enforcement will affect operators' future activities. Moreover, risks of adverse events, such as spills or accidents, may vary according to business practices, which in turn, may vary across oil and gas companies making it difficult to distinguish between risks that are inherent to the development of shale oil and gas from risks that are specific to particular business practices.

To obtain additional perspectives on issues related to environmental and public health risks, we interviewed a nonprobability sample of stakeholders representing numerous agencies and organizations. (See app. II for a list of agencies and organizations contacted.) We selected these agencies and organizations to be broadly representative of differing perspectives regarding environmental and public health risks. In particular, we obtained views and information from federal officials from the Department of Energy's National Energy Technical Laboratory, the Department of the Interior's Bureau of Land Management and Bureau of Indian Affairs, and the Environmental Protection Agency; state regulatory officials from Arkansas, Colorado, Louisiana, North Dakota, Ohio, Oklahoma, Pennsylvania, and Texas; tribal officials from the Osage Nation; shale oil and gas operators; representatives from environmental and public health organizations; and other knowledgeable parties with experience related to shale oil and gas development, such as researchers from the Colorado School of Mines, the University of Texas, Oklahoma University, and Stanford University. The findings from our interviews with stakeholders and officials cannot be generalized to those we did not speak with.

We conducted this performance audit from November 2011 to September 2012 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Appendix II: List of Agencies and Organizations Contacted

Federal Agencies	Congressional Research Service Department of Energy's National Energy Technology Laboratory Department of Health and Human Services Department of the Interior's Bureau of Indian Affairs Department of the Interior's Bureau of Land Management Department of the Interior's U.S. Geological Survey Environmental Protection Agency
State Agencies	Arkansas Department of Environmental Quality Arkansas Oil and Gas Commission Colorado Oil and Gas Conservation Commission Louisiana Department of Natural Resources North Dakota Industrial Commission Ohio Department of Natural Resources Ohio Environmental Protection Agency Oklahoma Geological Survey Oklahoma Corporation Commission Texas Railroad Commission
Academic Institutions	Colorado School of Mines Oklahoma University Stanford University University of Texas at Arlington University of Texas Energy Center and Bureau of Economic Geology
Environmental Organizations	Clean Water Action Pennsylvania Earthworks Oil and Gas Accountability Project Environmental Defense Fund Subra Consulting Western Resource Advocates
Public Health Organizations	The Endocrine Disruption Exchange National Association of County and City Health Officials Southwest Pennsylvania Environmental Health Project
Industry	ALL Consulting American Exploration and Production Council American Petroleum Institute Apache Corporation

	Chesapeake Energy Colorado Oil and Gas Association Devon Energy Powell Shale Digest
Others	Ground Water Protection Council Martin Consulting Red River Watershed Management Institute Osage Tribal Nation

Appendix III: Additional Information on USGS Estimates

The USGS estimates potential oil and gas resources in about 60 geological areas (called “provinces”) in the United States. Since 1995, USGS has conducted oil and gas estimates at least once in all of these provinces; about half of these estimates have been updated since the year 2000 (see table 5). USGS estimates for an area are updated once every 5 years or more, depending on factors such as the importance of an area.

Table 5: USGS Estimates

Name of USGS province	Most recent assessment year
Northern Alaska	2006
Central Alaska	2004
Southern Alaska	2011
Western Oregon-Wash.	2009
Eastern Oregon-Wash.	2006
Northern Coastal	1995
Sonoma-Livermore	1995
Sacramento Basin	2006
San Joaquin Basin	2004
Central Coastal	1995
Santa Maria Basin	1995
Ventura Basin	1995
Los Angeles Basin	1995
Idaho-Snake River Downwarp	1995
Western Great Basin	1995
Eastern Great Basin	2004
Uinta-Piceance Basin	2002
Paradox Basin	1995
San Juan Basin	2002
Albuquerque-Sante Fe Rift	1995
Northern Arizona	1995
S. Ariz.-S.W. New Mexico	1995
South-Central New Mexico	1995
Montana Thrust Belt	2002
Central Montana	2001
Southwest Montana	1995
Hanna, Laramie, Shirley	2005

Name of USGS province	Most recent assessment year
Williston Basin (includes Bakken Shale Formation)	2008
Powder River Basin	2006
Big Horn Basin	2008
Wind River Basin	2005
Wyoming Thrust Belt	2004
Southwestern Wyoming	2002
Park Basins	1995
Denver Basin	2003
Las Animas Arch	1995
Raton Basin-Sierra Grande Uplift	2005
Palo Duro Basin	1995
Permian Basin (includes Barnett Shale)	2007
Bend Arch-Ft. Worth Basin	2004
Marathon Thrust Belt	1995
Western Gulf Coast (includes Eagle Ford Shale)	2011
East Texas Basin Province	2011
Louisiana-Mississippi Salt Basins Province	2011
Florida Peninsula	2000
Superior	1995
Cambridge Arch-Central Kansas	1995
Nemaha Uplift	1995
Forest City Basin	1995
Anadarko Basin	2011
Sedgwick Basin/Salina Basin	1995
Cherokee Platform	1995
Southern Oklahoma	1995
Arkoma Basin	2010
Michigan Basin	2005
Illinois Basin	2007
Black Warrior Basin	2002
Cincinnati Arch	1995
Appalachian Basin (includes Marcellus Shale)	2011
Blue Ridge Thrust Belt	1995
Piedmont	1995

Source: USGS.

Appendix IV: GAO Contact and Staff Acknowledgments

GAO Contact

Frank Rusco, (202) 512-3841 or ruscof@gao.gov

Staff Acknowledgments

In addition to the contact named above, Christine Kehr, Assistant Director; Lee Carroll; Nirmal Chaudhary; Cindy Gilbert; Alison O'Neill; Marietta Revesz, Dan C. Royer; Jay Spaan; Kiki Theodoropoulos; and Barbara Timmerman made key contributions to this report.

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SEE COMMENTARY

Assessment and risk analysis of casing and cement impairment in oil and gas wells in Pennsylvania, 2000–2012

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Edited by William H. Schlesinger, Cary Institute of Ecosystem Studies, Millbrook, NY, and approved May 30, 2014 (received for review December 17, 2013)

Casing and cement impairment in oil and gas wells can lead to methane migration into the atmosphere and/or into underground sources of drinking water. An analysis of 75,505 compliance reports for 41,381 conventional and unconventional oil and gas wells in Pennsylvania drilled from January 1, 2000–December 31, 2012, was performed with the objective of determining complete and accurate statistics of casing and cement impairment. Statewide data show a sixfold higher incidence of cement and/or casing issues for shale gas wells relative to conventional wells. The Cox proportional hazards model was used to estimate risk of impairment based on existing data. The model identified both temporal and geographic differences in risk. For post-2009 drilled wells, risk of a cement/casing impairment is 1.57-fold [95% confidence interval (CI) (1.45, 1.67); *P* < 0.0001] higher in an unconventional gas well relative to a conventional well drilled within the same time period. Temporal differences between well types were also observed and may reflect more thorough inspections and greater emphasis on finding well leaks, more detailed note taking in the available inspection reports, or real changes in rates of structural integrity loss due to rushed development or other unknown factors. Unconventional gas wells in northeastern (NE) Pennsylvania are at a 2.7-fold higher risk relative to the conventional wells in the same area. The predicted cumulative risk for all wells (unconventional and conventional) in the NE region is 8.5-fold [95% CI (7.16, 10.18); *P* < 0.0001] greater than that of wells drilled in the rest of the state.

shale oil and gas | casing integrity | cement integrity | onshore wells | wellbore integrity

Oil and natural gas production has increased substantially in the United States in recent years, predominantly due to innovations such as high-volume hydraulic fracturing and directional drilling in shale formations (1). Concurrent with this increase, concerns have mounted regarding effects of this oil and gas development process on groundwater quality, human health, public safety, and the climate, due, in part, to subsurface migration of methane and other associated hydrocarbon gases and volatile organic compounds. Economic development of gas and oil from shale formations requires a high well density, at least one well per 80 surface acres, over large continuous areas of a play. Osborn et al. (2) and Jackson et al. (3) identified a positive relationship between the concentration of thermogenic methane in private water wells in Pennsylvania and the proximity of those water wells to the nearest unconventional (i.e., Marcellus shale) gas production well. These studies also identified three possible mechanisms for explaining this relationship, and concluded that the most likely of these is subsurface migration from leaking gas wells. Other researchers have observed thermogenic and other subsurface-sourced methane in atmospheric concentrations high above background levels near conventional and unconventional gas development (4–6), suggesting that leaking wells may also contribute to fugitive methane and other associated gas emissions, with clear climatic and air quality consequences (7).

Leaking oil and gas wells have long been recognized as a potential mechanism of subsurface migration of thermogenic and biogenic methane, as well as heavier n-alkanes, to the surface (7–11). A leaking well, in this context, is one in which zonal isolation along the wellbore is compromised due to a structural integrity failure of one or more of the cement and/or casing barriers. Such loss of integrity can lead to direct emissions to the atmosphere through one or more leaking annuli and/or subsurface migration of fluids (gas and/or liquid) to groundwater, surface waters, or the atmosphere. Cement barriers may fail at any time over the life of a well for a number of reasons, including hydrostatic imbalances caused by inappropriate cement density, inadequately cleaned bore holes, premature gelation of the cement, excessive fluid loss in the cement, high permeability in the cement slurry, cement shrinkage, radial cracking due to pressure fluctuations in the casings, poor interfacial bonding, and normal deterioration with age (12). Casing may fail due to failed casing joints, casing collapse, and corrosion (13). Loss of zonal isolation creates pressure differentials between the formations intersected by the wellbore and the open barrier(s). The pressure gradient thus created allows for the flow of gases or other formation fluids between geological zones (i.e., interzonal migration) and possibly to the surface (14–16), where it might manifest as sustained casing pressure (SCP) or sustained casing vent flow.

Annuli are often vented, as noted in inspection records, and may contribute to fugitive emissions from the well site. Low-pressure

Significance

Previous research has demonstrated that proximity to unconventional gas development is associated with elevated concentrations of methane in groundwater aquifers in Pennsylvania. To date, the mechanism of this migration is poorly understood. Our study, which looks at more than 41,000 conventional and unconventional oil and gas wells, helps to explain one possible mechanism of methane migration: compromised structural integrity of casing and cement in oil and gas wells. Additionally, methane, being the primary constituent of natural gas, is a strong greenhouse gas. The identification of mechanisms through which methane may migrate to the atmosphere as fugitive emissions is important to understand the climate dimensions of oil and gas development.

Author contributions: A.R.I. designed research; R.L.S. performed research; M.T.W. and R.L.S. analyzed data; and A.R.I., M.T.W., R.L.S., and S.B.C.S. wrote the paper.

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See Commentary on page 10902.

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ENVIRONMENTAL SCIENCES

leaks may continue to be periodically bled off and monitored, although recent studies warn that bleeding pressure to zero may actually lead to gas migration (17). High-risk (e.g., rapid repressuring of the annulus following bleed down) leaks must be structurally remedied (i.e., cement squeeze, gel squeeze, use of packers, topping off cement). State regulations (Pennsylvania code 25 §78.86) mandate that wells with leaks that cannot be vented or adequately repaired be permanently plugged, which may reduce but not eliminate the interzonal flow of gases and liquids. Leaks that continue undetected or inadequately remedied may lead to the contamination of shallow aquifers, accumulation of explosive gases within and around residences and other structures, and emission of methane and other associated gases to the atmosphere.

Although not every instance of loss of zonal isolation will lead to such events, the incidence rate of cement/casing impairments and failures can provide some insight into the scale of current and future problems. However, the structural integrity failure rate of oil and gas well barriers continues to be a subject of debate. The rates most commonly cited (from 2 to >50%) are based upon industry reporting for offshore wells in the Gulf of Mexico (13, 14) and Canadian onshore (mostly conventional) wells (16). Watson and Bachu (16) note that wells drilled during periods of rapid development activity and/or wellbores deviated from vertical (e.g., horizontal wellbores) may be more prone to casing vent flow and/or gas migration away from the wellhead.

Due to the lack of publicly available structural integrity monitoring records for onshore wells from industry, more recent studies have used data from state well inspection records to estimate the proportion of unconventional wells drilled that develop cement and/or casing structural integrity issues. For instance, Considine et al. (18) analyzed Pennsylvania Department of Environmental Protection (PADEP) notice of violation (NOV) records for 2008–2011 and found that between 1% and 2% of wells had one or more potential structural integrity issues during that time period. Vidic et al. (19), using the 2008–2013 data from the PADEP database, found that 3.4% of all monitored unconventional wells drilled to date in Pennsylvania might have structural integrity failures based on NOVs related to cement/casing integrity. However, neither study adequately accounts for non-NOV indicators of cement/casing integrity impairment or temporal or spatial dimensions of such impairments.

Earlier work found that the NOV count alone does not account for all incidences of cement/casing failure (20). State regulatory agencies and the oil and gas industry monitor many of the wells showing signs of SCP or other indicators of cement and/or casing impairment. Remedial action is often attempted once or many times on a monitored well, but a NOV is not issued by the agency. Additionally, violation codes are sometimes entered incorrectly as non-cement/casing issues and later corrected in violation comments. By not accounting for these, previous assessments based on PADEP inspection records (18, 19) may underestimate the actual proportion of wells with cement and/or casing problems in Pennsylvania.

Failure to account for temporal dimensions of the data may also skew results. Previous studies on cement/casing impairment have noted that wells drilled during boom periods may be more susceptible to loss of zonal isolation because operators might cut corners in an attempt to increase the number of wells drilled over a short period (16). The increased risk of zonal isolation problems as wells age and the increased probability of identifying these issues with more inspections may also create a time lag between the date that drilling of the well commences (i.e., the spud date) and the entry of a cement/casing issue in the inspection records. This time lag is due to the fact that wells drilled in recent years have not been subject to the same duration of analysis or number of inspections as older wells. Thus, inspection records on newer wells are incomplete relative to those of older wells.

Here, we offer an in-depth analysis of the complete inspection records, including NOVs, observations and corrections noted in the inspector comments, for 32,678 oil and gas production wells drilled in Pennsylvania between 2000 and 2012. We use a time-dependent risk analysis model to assess the cumulative risk of cement/casing problems for wells based on the historical occurrence of cementing/casing impairment events.

Results and Discussion

Comparison of state inspection and well spud reports (where the "spud" date is the start date of drilling) indicates a loss of well integrity in 1.9% of the oil and gas production wells spudded between 2000 and 2012. This value agrees well with some previous estimates in the literature; however, this superficial indication comes with important caveats and is an incomplete assessment. The data suggest large differences in structural integrity issues between well types, with unconventional wells showing a sixfold higher incidence of cement and/or casing issues relative to conventional wells statewide (Table 1 and *SI Appendix*, Table S14). Even within the unconventional well category, a wide range (1.49–9.84%) of incident rates is observed among wells spudded during different time periods and in different regions. Unconventional wells spudded before 2009 in the northeastern (NE) counties of the state are associated with the highest occurrence of loss of structural integrity (9.84%). It can be argued that this subcategory reflects a small number of observed cases (61 wells) and the earliest industry experience in the Marcellus play, and thus should not be used as an indication of current practices. However, unconventional wells spudded in the NE region since 2009 (2,714 wells) show a similarly high rate of occurrence (9.18%).

As already noted, direct comparison of rates of loss of well integrity in young wells to those of much older wells is misleading. Assuming an increased risk of cement/casing issues as the materials (cement/casing) age, it must follow that the risk of structural integrity loss and likelihood of state inspectors identifying a cement/casing problem will increase through time as a well accumulates additional inspections. Thus, a well spudded 3 y ago, which will ideally have a 3-y record of inspections from which to draw observations, is more likely to have an indicator

Table 1. Percentage of wells showing loss of structural integrity by temporal (pre- and post-2009 spuds), geographic (non-NE and NE counties), and well type (conventional and unconventional) categories

	Non-NE counties		NE counties	
Wells spudded	Conventional	Unconventional	Conventional	Unconventional
Pre-2009	0.73%	1.49%	5.21%	9.84%
Post-2009	2.08%	1.88%	2.27%	9.14%

Statewide, rate of loss of structural integrity for conventional and unconventional wells spudded between 2000–2012 are 1.0% and 6.2%, respectively (weighted average = 1.9%).

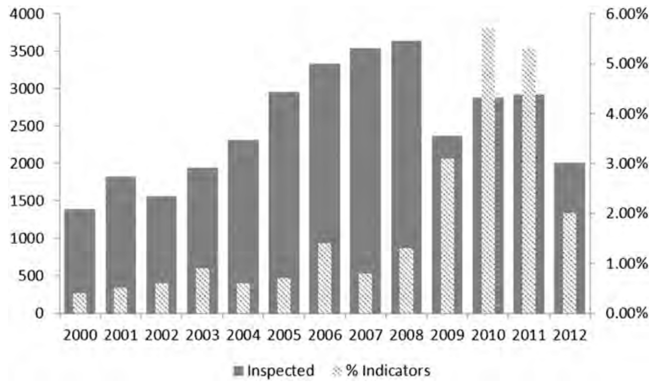

Fig. 1. Annual trends of indicators for wells spudded in the state of Pennsylvania, 2000–2012. The percentage of spuds with integrity issues reflects the number of unique wells spudded in a given year for which an indicator was found at any time within the inspection record (13 y). The rates of incidence noted in the inspection records for pre-2009 spuds hover around 1% for the several years before spiking in 2010. These trends may represent differences in state emphasis on locating leaking wells following widely publicized contamination events or actual increases in loss of structural integrity.

of cement/casing integrity loss noted in the inspection record than a similar well spudded only 1 y ago and associated with just one-third of the observation time. The effects of this temporal dependency can be seen in Fig. 1. Annual trends for wells spudded in 2010 and 2011 show rates of incidence similar to the cumulative unconventional rate reported in Table 1 (unconventional wells make up 57.5% and 66.3% of spuds in 2010 and 2011, respectively). However, wells spudded in 2012 and subject to an observation period ≤1 y appear to have a much lower incidence of cement/casing issues. This raises an important question: Are wells spudded in 2012 more sound than those spudded in previous years, or is the apparent decline in indicators in state inspection reports an artifact of an incomplete inspection history?

Note that incomplete inspection records may also occur in older wells that have not been regularly inspected through time. Inspection records for modeled wells indicate an average of 2.75 inspections per well statewide, despite nearly 71.6% of wells being >3 y old. Moreover, PADEP records indicate that of the more than 41,000 oil and gas production wells spudded between 2000 and 2013, 24% of conventional and 4% of unconventional well spuds have never received facility-level inspections or the relevant inspections are not included in the PADEP online database (8,703 wells in total). It should be noted that these wells might have received inspections under the client- or site-level category, which generally are carried out as part of large-scale contamination/gas migration investigations, but these types of inspections are not included in our analysis because the details of such inspections often do not include a full listing of wells of interest. Assuming that the individual wells observed in these larger scale investigations did, in fact, receive facility-level inspections and are included in our analysis, we would expect a negligible impact from excluding client- and site-level investigations because the individual well inspections would have likely been flagged by at least one of the indicators before a large-scale contamination event. The impact of wells investigated in the client- and site-level inspections but not receiving a facility-level inspection (i.e., not included in this analysis) may be significant but cannot be assessed with the data available. Not all wells inspected in large-scale contamination investigations are found to be leaking and, although the count of impairment events from such wells could increase, the rate of impairment (the number of events per wells inspected) might not.

Hazard analysis captures such temporal dependencies through the nonparametric baseline hazard rates and hazard ratios of the inspection count variable, thus allowing us to predict what the incidence rate for wells might be if they were to acquire comparable observation times and inspection counts. Results from hazard modeling of temporal and geographic strata are given next.

Hazard Model: Temporal Strata. Wells spudded before 2009 make up almost 72% of the total wells modeled but just 31% of the total count of unique wells with documented cement/casing indicator events from the 2000–2012 modeled dataset. Unconventional wells make up 16.8% of the wells in this stratum. The first unconventional well in the modeled dataset has a 2002 spud date; however, unconventional drilling activity remained relatively low until 2009 (Fig. 2). Pre-2009 unconventional wells show a modest but statistically insignificant increase in hazard [1.07-fold greater risk relative to pre-2009 conventional wells, 95% confidence interval (CI) (0.18, 1.52); Table 2]. However, in the post-2009 stratum, risk of a cement/casing event is 1.58-fold [95% CI (1.45, 1.67); $P < 0.0001$] higher in an unconventional well relative to a conventional well spudded within the same time period (Table 2).

Fig. 3 shows estimated cumulative hazards for conventional and unconventional wells across the state for pre- and post-2009 strata, respectively. These figures are plotted in the units of the Nelson–Aalen estimator of the cumulative hazard function (i.e., the definite integral, from zero up to the indexed time, of the hazard function). These plots are used for visually examining differences in distributions in time-to-event data and are interpreted here as the fractional probability that a well will be identified as having a cement and/or casing problem at time t, assuming that the event has not occurred before time t. Wells spudded after January 1, 2009, show significantly higher ($P < 0.0001$) predicted hazards across comparable analysis times, regardless of well type, relative to pre-2009 well spuds [4.58 hazard ratio, 95% CI (3.84–5.47)].

It is unclear whether these temporal differences reflect more thorough inspections and greater emphasis on finding well leaks, more detailed note taking in the available inspection reports, or real changes in rates of structural integrity loss. The percentage of wells inspected in the first year has risen, from an average of 76% in pre-2009 spuds to 88.7% in the post-2009 spuds (*SI Appendix*, Table S3), and this may partially account for the increase in documented cement/casing problems. Additionally, more than one-half (53.2%) of the nonevent wells (i.e., no indicator of loss of structural integrity found) lack inspector

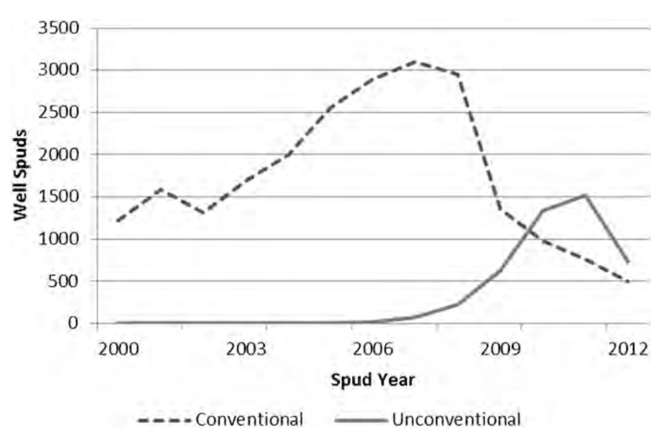

Fig. 2. Conventional and unconventional spud counts: 2000–2012 (Source: PADEP, 2013).

Table 2. Statewide data: Effects of model covariates for pre- and post-2009 well spuds

	Pre-2009 spuds			Wells spudded 2009–2012		
Covariate	HR	95% CI		HR	95% CI	
Well type	1.07	0.18	1.52	1.58	1.45	1.67
Inspection count	1.177	1.154	1.201	1.059	1.048	1.069

The hazard ratio (HR) reflects the multiplicative change in risk at any time due to a change in the covariate. A change in well type reflects the change from conventional to unconventional. A change in inspection count reflects a single (+1) increase to the total inspection count for a well.

comments and other information necessary to determine whether a cement/casing issue ever occurred. These wells, by default, are modeled as nonevents. The majority of such wells (73%) were spudded before 2009. This lack of data for older wells may result in an underestimation of events in the pre-2009 stratum. As such, results from our modeling should be considered conservative.

Note that the full analysis time for the statewide dataset is 676 wk (13 y). Naturally, more recently spudded wells will have a shorter analysis time (1–208 wk for wells spudded since 2009). However, inspection records indicate that 52.9% of pre-2009 spuds have a <2-y inspection record, with an average of 2.4 inspections per well across the entire time period (*SI Appendix*, Table S4). This suggests that the majority of these active, older wells are no longer being inspected. Continued annual inspections may increase the predicted cumulative risk of structural

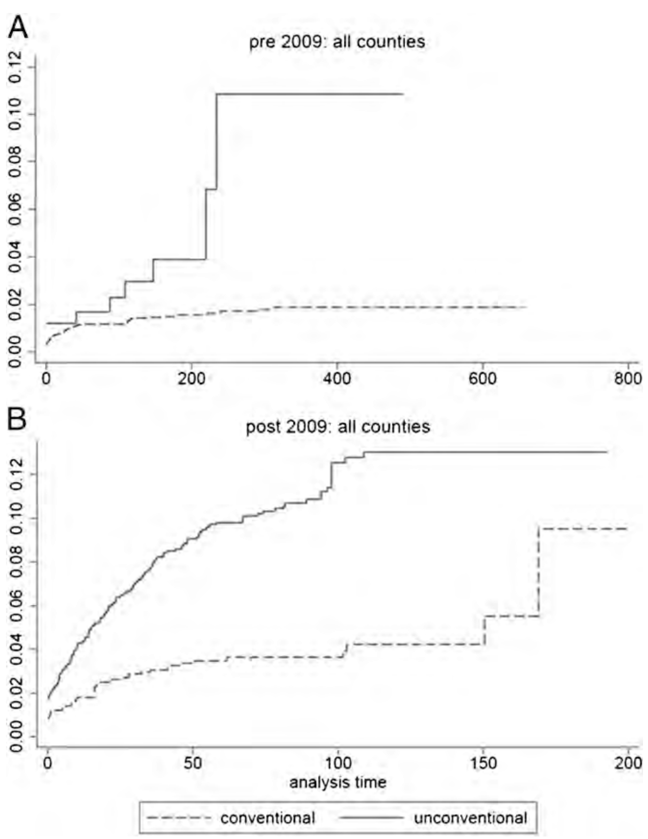

Fig. 3. Nelson–Aalen cumulative hazard for pre-2009 (*A*) and post-2009 (*B*) spuds by well type. The vertical axis is the fractional probability of an event occurring at a given analysis time.

integrity issues for these wells beyond what is reported here, indicating, again, that results from our analysis are conservative. Each additional inspection in the pre-2009 stratum increases the risk of identifying a cement or casing problem by 17.7% [1.18 hazard ratio, 95% CI (1.15, 1.20); Table 3] relative to the hazards shown in Fig. 3. The effect of increased inspections on younger wells (post-2009 spuds) is smaller but statistically significant [1.06 hazard ratio, 95% CI (1.05–1.07); Table 3].

Hazard Model: Geographic Strata. The NE counties of the state (Bradford, Cameron, Clinton, Lycoming, Potter, Sullivan, Susquehanna, Tioga, Wayne, and Wyoming) make up just 11% of the total wells spudded (3,030 wells) but 54.7% of the state's unconventional wells and 88.8% of the cement/casing events in unconventional wells. There are 266 total structural integrity indicator events in the NE region, or ∼52% of events statewide. The predicted cumulative hazard for all wells (unconventional and conventional) in the NE region is 8.5-fold [95% CI (7.16, 10.18)] greater than that of wells drilled in the rest of the state (Table 3). The log-rank test for this regional difference is extremely significant ($P < 0.0001$).

As with the statewide data, effects of covariates in the NE counties indicate significant increases in the risk of finding an indicator in the inspection records. Unconventional wells in the NE region are at a 2.7-fold higher risk relative to the region's conventional wells [95% CI (1.43, 4.95); Table 3]. Additional inspections in these counties have a similar effect on risk as that found for post-2009 spuds statewide [1.06 hazard ratio, 95% CI (1.05, 1.08); Table 3].

Figs. 4–6 reveal increased cumulative hazards for wells in the NE counties relative to other areas of the state, as well as increased cumulative hazards associated with unconventional wells ($P < 0.001$) and post-2009 spudded wells ($P = 0.005$) in the region. These figures, like Fig. 3, are plotted in units of the cumulative hazard function. Overall, NE wells show a risk of an identified integrity issue within the first 3 to 4 y (156–208 wk) of operation of ∼20% (Fig. 4). The cumulative hazard for unconventional wells in the region is predicted to increase upward of 40% by year 7 of the analysis (364 wk; Figs. 5 and 6).

Conclusion

Pennsylvania state inspection records show compromised cement and/or casing integrity in 0.7–9.1% of the active oil and gas wells drilled since 2000, with a 1.6- to 2.7-fold higher risk in unconventional wells spudded since 2009 relative to conventional well types. Hazard modeling suggests that the cumulative loss of structural integrity in wells across the state may actually be slightly higher than this, and upward of 12% for unconventional wells drilled since January 2009. This wide range of estimates is influenced by significantly higher rates of impairment in wells spudded in the NE counties of the state (average of 12.5%, range: 2.2–50%), with predicted cumulative hazards exceeding 40% (Figs. 5 and 6).

These results, particularly in light of numerous contamination complaints and explosions (21–23) nationally in areas with high concentrations of unconventional oil and gas development and

Table 3. NE counties data: Effects of model covariates

Covariate	HR	95% CI	
Well type	2.657	1.428	4.946
Inspection count	1.065	1.047	1.083
Temporal stratum	1.580	1.152	2.167

The HR reflects the multiplicative change in risk at any time due to a change in the covariate. A change in well type reflects the change from conventional to unconventional. A change in inspection count reflects a single (+1) increase to the total inspection count for a well.

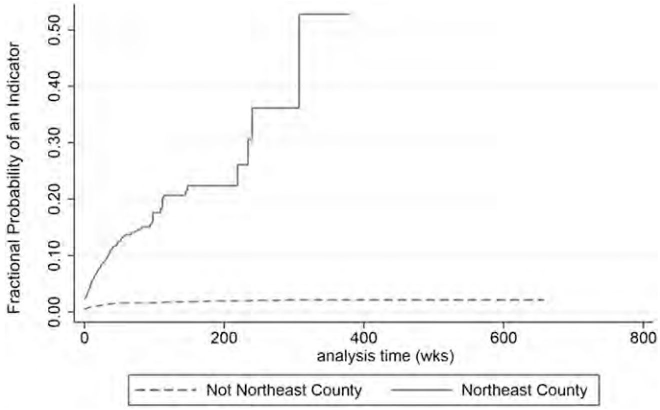

Fig. 4. Nelson–Aalen cumulative hazard: NE vs. non-NE counties for combined conventional and unconventional wells. The vertical axis is the fractional probability of an event occurring at a given analysis time.

the increased awareness of the role of methane in anthropogenic climate change (24), should be cause for concern. A recent investigative report of water contamination cases confirmed PADEP determination letters and enforcement orders indicating that at least 90 private water supplies across the state were damaged due to subsurface gas migration between 2008 and 2012 (25). The NE region of Pennsylvania, in particular, has experienced several widely publicized methane migration cases related to loss of structural integrity of wells, including the Dimock, Susquehanna County [Commonwealth of Pennsylvania Department of Environmental Protection (DEP) Consent Order to Cabot Oil & Gas, December 15, 2010] and Towanda, Bradford County (Commonwealth of Pennsylvania DEP Consent Order to Chesapeake Appalachia LLC, May 16, 2011) groundwater contamination cases. PADEP records cite unconventional wells spudded between 2009 and 2010 in both of these cases. Incidence rates inferred from direct comparison of indicator counts and the number of wells inspected in these townships as of December 31, 2012, are 21.2% and 15.4%, respectively; however, hazard modeling predicts a cumulative 7-y hazard for similar wells in the region twofold higher (Figs. 5 and 6; $t = 364$).

Our aim in this study was to quantify the rate of barrier impairment in a population of modern on-shore oil and gas wells, and in doing so, we have noted significant temporal and spatial differences in risk of impairment. It is beyond the scope of this paper to explain these spatial and temporal differences. Various biasing effects might influence these differences and are the

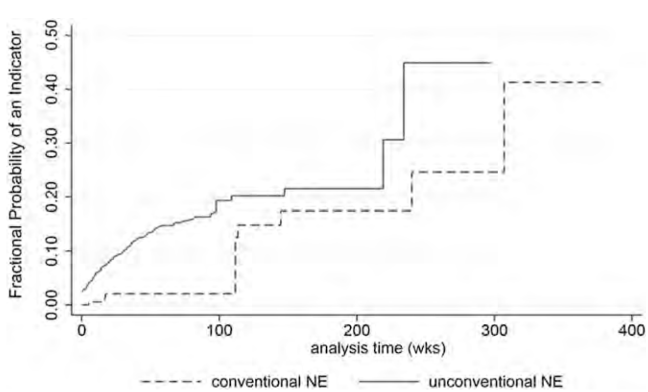

Fig. 5. Nelson–Aalen cumulative hazard for NE counties by well type. The vertical axis is the fractional probability of an event occurring at a given analysis time.

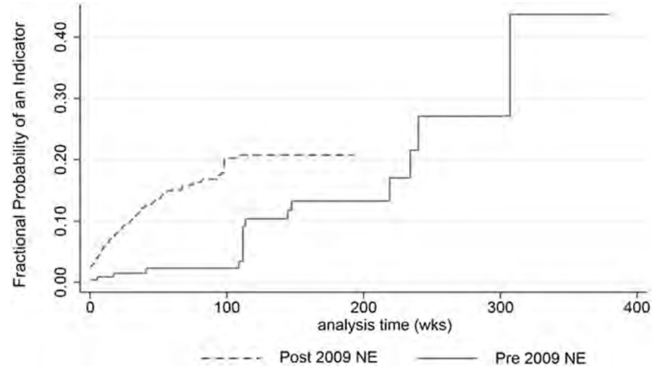

Fig. 6. Nelson–Aalen cumulative hazard for NE counties by temporal strata. The vertical axis is the fractional probability of an event occurring at a given analysis time.

focus of our continuing study of this problem. Moreover, results presented here represent a snapshot in time of an evolving situation. This study presents the state of structural integrity loss in oil and gas wells over a 13-y period in the state of Pennsylvania as inferred from publicly available data, while also presenting a risk assessment model of future performance. It should be a priority to update and validate this model with well monitoring and evaluation data reported to the PADEP from the industry as they are collected. Finally, although this study discusses one possible primary mechanism of methane migration to groundwater aquifers and fugitive emissions to the atmosphere, more studies are needed to investigate the association between the structural integrity loss in oil and gas wells and the incidence of these unwanted events.

Methods

Database. The database created here is based upon spud reports from the PADEP Office of Oil and Gas Management website for conventional and unconventional gas, oil, combined gas and oil, and coal-bed methane wells spudded from January 1, 2000–December 31, 2012 (www.depweb.state.pa.us/portal/server.pt/community/oil_and_gas_reports/20297). Spud reports provide data on well characteristics, including American Petroleum Institute (API) well identification, spud date, well type, production type, and well location (county, municipality, and geographic coordinate information). We exclude storage, injection, and undetermined purpose wells to focus exclusively on oil and gas production wells.

Compliance Reports. The compliance reports for oil and gas well inspections carried out over the same time period (www.depweb.state.pa.us/portal/server.pt/community/oil_and_gas_compliance_report/20299) are then cross-referenced with the well inventory by matching API identification codes. PADEP compliance reports provide data on inspection category (i.e., site, client, facility), inspection type (e.g., administrative review, drilling, routine), inspection date, violations issued, and comments noted by PADEP inspection staff regarding the inspection and/or violation(s) issued. We exclude client and site inspection categories, because these inspections generally reflect multiwell, large-scale compliance assessments and rarely identify individual wells. We also do not include construction (i.e., site clearing), asbestos program, Chapter 94, joint external/internal, Nuclear Regulatory Commission, and road-spreading inspection types. Construction inspections occur before well spudding, and thus are not relevant to well integrity. The remaining excluded inspection types are also considered not relevant to the study question. Excluded inspections accounted for <0.5% of total inspections carried out over the 2000–2012 time frame.

Indicators Search. Inspector comments indicate barrier remediation and/or ongoing monitoring of annular gas or pressure (indicators of impaired structural integrity) for numerous wells that were not issued an NOV. To ensure that we captured these wells, we filtered both the "Inspection_Comment" and "Violation_Comment" fields for the most common keywords associated with failure of primary cement/casing or common remediation measures. Keywords used in the filtering and their relevancy to impaired primary cementing and casings are presented in *SI Appendix*, Table S6. Keyword filter results are then human-read thoroughly to confirm an indication of impaired well integrity and to separate filter results that do not indicate an integrity issue (e.g., gas meter readings = 0, nonremediation perforations, "no visible bubbling"). A detailed discussion of the indicators and their temporal and geographic distributions is provided in *SI Appendix*.

Violation codes provide a more direct indication of a potential well impairment. PADEP violation codes relevant to cement and casing integrity are listed in *SI Appendix*, Table S7. The compliance reports indicate multiple misentries in the original violation code noted by an inspector, which are later corrected in the "Violation_Comment" field. We assume that wells with any one of the violations or a combination of violations listed in *SI Appendix*, Table S7 and entered in either the "Violation_Code" or "Violation_Comment" field in inspection reports are indicative of a well with impaired cement and/or casing. We note that not all violations will result in groundwater contamination events. The relative importance of key violation codes and the temporal and geographic distributions of total violation counts are discussed in detail in *SI Appendix*.

Hazard Analysis. The Cox proportional hazards model (26) is a semiparametric model that uses a multivariate regression technique to model the instantaneous probability of observing an event (i.e., occurrence of a cement/casing indicator in the inspection record) at time t, given that an observed case (i.e., a well) has survived to time t (i.e., has not experienced an inspection where a cement/casing indicator was found) as a function of predictive covariates (well type and total number of inspections received). All wells enter observation at $t = 0$, regardless of spud date, and observation continues until the last known date of inspection or the occurrence of a cement/casing indicator in a well's inspection history. Addition details and definitions of key model terms and concepts are provided in *SI Appendix*.

Time of analysis of a well, as the dependent variable in the statistical model, cannot be a null or a negative value. Wells showing no record of inspection (8,703 wells) have null t values, and are therefore removed from the model dataset. We also found 5,223 wells, 100 of which were associated with comment or violation indicators, where the time since spud to first inspection was negative. Because construction/site clearing inspections were removed from the database in previous steps, we assume that either the spud dates or inspection dates for these wells were entered incorrectly; these data are also removed from the dataset. The impact of removing these inspections from the modeled dataset is negligible, because the overall impairment rate (1.9%) for these wells mirrors that of the statewide data. The resulting modeled statewide dataset contains 27,455 wells that are associated with 75,505 inspections.

Multiple inspections per unique well number are mined to return only a single set of entries per well: well characteristics (i.e., county, well type, spud date), event status (a binary code assigned to each well stating whether an indicator was found at any point in the life of the well: Y = 1, N = 0), date of first inspection, date of first mention of indicator if found, date of last inspection (for nonevent wells), and total number of inspections carried out.

An assumption of the Cox proportional hazards model is that the hazard ratio is constant over time. The validation of this assumption for the various models, using the Grambsch and Therneau test (27), is presented in *SI Appendix*, Table S1. The proportional hazards test for individual covariates passed for well type ($P = 0.06$) and inspection counts ($P = 0.09$) in the full dataset. The proportional hazards model assumption also holds for the pre/post-2009 analyses. Well type (i.e., unconventional, conventional) and inspection counts (i.e., number of times a well is inspected during the analysis time) are used as covariates in these models.

Temporal and geographic (i.e., county) strata are run in separate analyses. Interannual log-rank statistics were used to assess whether any groups of well spuds were statistically significantly different in terms of their predicted failure risk. We stratified the data accordingly to allow for separate regressions of temporal period (before January 1, 2009, and after that date). We also stratified the data by region to assess the relative geographic distributions [the NE counties (Bradford, Cameron, Clinton, Lycoming, Potter, Sullivan, Susquehanna, Tioga, Wayne, and Wyoming) compared with the rest of the state] of wells with indications of cement/casing problems. Log-rank tests (28) were used to assess geographic variation.

As robustness checks to the Cox proportional hazards model, parametric Weibull and Gompertz regression models (28) were also fit to the full data and the temporal and geographic strata, and the magnitude substantive conclusions did not change.

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ENVIRONMENTAL ASSESSMENT
U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

PROPOSED HYDRAULIC FRACTURING RULE

DOI-BLM-WO300-2012-XXX-EA

I. Introduction

This assessment examines the environmental impacts that may occur as a result of the Bureau of Land Management's (BLM) proposed rule that would revise 43 CFR 3162.3-2, *Subsequent Well Operations* and 43 CFR 3162.5-2, *Control of wells*, and add a new section 3162.3-3, *Subsequent well operations; Hydraulic fracturing*, and analyzes three other action alternatives in addition to the proposed rule. The analysis within this document determines whether this particular regulatory action requires preparation of an environmental impact statement (EIS) pursuant to the *National Environmental Policy Act of 1969* (NEPA), 42 U.S.C. 4321 *et seq*.

On May 11, 2012, the BLM published a notice in the *Federal Register* announcing an initial proposed rule to regulate hydraulic fracturing on public land and Indian land. The notice initiated a 30-day period inviting the public to comment on the BLM's initial proposed rule. The environmental document that supported the publication of the initial proposed rule evaluated three alternatives, including the initial proposed rule. Since publication, the BLM received numerous requests for extension of the comment period. Due to the complexity of the rule and the controversial nature of well stimulation procedures, the BLM extended the comment period until September 10, 2012. The BLM received over 177,000 comments on the initial proposed rule from individuals, Federal and state governments and agencies, interest groups, and industry representatives. Many of the comments were substantive, prompting modification to the initial proposed rule.

The BLM has prepared a revised proposed rule that incorporates the modifications that were made to the initial proposed rule. The revised rule is presented in this environmental assessment as a new alternative. The five alternatives analyzed in this document are:

1. Alternative A – Proposed Action, Initial Proposed Well Stimulation Rule[1] – Under this alternative, the BLM would promulgate the well stimulation rule entitled *Oil and Gas; Well*

[1] Activities that would be subject to the provisions being considered under this alternative are referred to as *well stimulation activities* or *well stimulation operations*.

Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands, which was published in the Federal Register on May 11, 2012 (77 FR 27691).

2. Alternative B – No Action – Under this alternative, the BLM would neither promulgate a rule to amend existing regulations nor add any new regulation.
3. Alternative C – Unlined Pits – This alternative is identical to the Proposed Action except oil and gas operators would not be required to line the pits that store the fluids flowed back from a well after well stimulation operations are complete.
4. Alternative D – Storage Tank Requirement – This alternative is identical to the Proposed Action except it requires oil and gas operators to use storage tanks to manage flowback.
5. Alternative E – BLM Preferred Alterative, Revised Proposed Hydraulic Fracturing Rule[2] – Under this alternative, the BLM would promulgate the revised proposed hydraulic fracturing rule entitled *Oil and Gas; Hydraulic Fracturing, on Federal and Indian Lands*. This alternative is similar to the Proposed Action except it contains modifications that are of such a nature that warrants the BLM's preparation of a revised proposed rule.

The BLM's Proposed Action and associated action alternatives include provisions that direct operators to undertake certain procedures prior to, during, and subsequent to hydraulically fracturing an oil and gas well. These actions would take place on the ground and may have an effect on the human environment – beneficial and adverse. This document evaluates what those effects may be. This document is not intended to analyze the effects that may result from actual hydraulic fracturing activities. Impacts caused by hydraulic fracturing are analyzed at more appropriate levels of the BLM's decision-making process. These decision points include when the BLM prepares a land use plan for a given resource area where there is a potential for oil and gas exploration and development activity to occur, when the BLM evaluates the cumulative impacts of development within a more focused area, such as one or more oil and gas fields, or when the BLM evaluates the impacts of an operators proposal to drill one well or a group of wells. If the BLM's proposal constitutes a major Federal action that may result in a significant effect on the human environment, the NEPA requires the BLM to prepare a detailed statement so it may fully consider those impacts.

a) Background and Overview

The BLM estimates that about 90 percent of wells currently drilled on Federal and Indian lands (approximately 3,400 wells each year) are completed using hydraulic fracturing techniques. Over the past 10 years, there have been significant advances in horizontal drilling technology, a now common and integral component of hydraulic fracturing. Horizontal drilling, combined with completion of the well perforations by improved hydraulic fracturing practices, has led to oil and gas production from geologic formations that were previously considered to be uneconomical to develop. The resulting expansion of oil and gas development into new parts of the country and new developments in existing oil and gas regions has elevated the public's awareness of this practice and its potential impacts to water quality and availability.

[2] Activities that would be subject to the provisions being considered under this alternative are referred to as *hydraulic fracturing activities* or *hydraulic fracturing operations*.

The BLM's existing hydraulic fracturing regulations are found at 43 CFR 3162.3-2. These regulations were established in 1982 and last revised in 1988 — 24 years ago — and long before the latest hydraulic fracturing technologies became widely used. Under the current regulations, which address subsequent well operations (including hydraulic fracturing, redrilling, casing repairs, and other activities after completing a well), operators must provide a sundry report (*i.e*., Form 3160-5) of "routine" hydraulic fracturing operations after the operation has concluded. For "nonroutine" fracturing operations, the operator must seek approval from the BLM before operations may begin, and they must then submit a subsequent report just as is required for "routine" hydraulic fracturing operations. The current regulations do not define the terms "routine" or "nonroutine," nor has the BLM provided additional guidance to its authorizing officers to delineate routine from non-routine.

In response to public interest and concern, the Department of the Interior (Department) held a forum on hydraulic fracturing in November 2010 in Washington, D.C., which was attended by more than 130 interested parties. The BLM hosted open forums during late April 2011 in Bismarck, ND, Little Rock, AR, and Golden, CO. Over 600 members of the public attended the April forums. Comments included concerns about water quality, water consumption, and a desire for improved environmental safeguards for surface operations, as well as calls for the disclosure of the chemicals and materials used in fracturing fluid.

In addition to the Department's efforts, the Secretary of Energy's Advisory Board Subcommittee on Natural Gas issued initial recommendations on hydraulic fracturing on August 18, 2011. The report recommended, among other things, public disclosure of the chemicals used in fracturing fluids, broader use of water quality sampling before wells are drilled and strict standards for wellbore construction including pressure testing of cement casings and the use of cement bond logs (CBL). On November 18, 2011, the initial report was followed by a final report. One of the key recommendations for Federal action in the final report was to improve public information about shale gas operations. The development of gas from shale formations is one of the key innovations allowed by the expanded use of hydraulic fracturing. This information would include the fluids used in hydraulic fracturing. The final report also recommended pressure testing of cement casings and the use of CBLs. These reports are available to the public from the Department of Energy's web site at http://www.shalegas.energy.gov.

The BLM proposes to promulgate regulations consistent with its trust responsibilities on tribal lands and with its obligations pursuant to the *Federal Land Policy and Management Act* (FLPMA) to prevent unnecessary or undue degradation of the public lands, in response to the public interest and concern, and taking into consideration the Energy Department's recommendations. A few examples of provisions under consideration include: (i) a requirement to perform a mechanical integrity test of the wellbore to ensure the casing can withstand the fracturing pressures that are anticipated for the hydraulic fracturing operation, (ii) a requirement to perform a cement evaluation log (CEL) on a "type well" prior to initiating hydraulic fracturing operations on a group of wells, on each well drilled that is not part of a field development proposal, or where there is evidence of an inadequate cement job in order to help ensure that the occurrences of usable water aquifers encountered during drilling, completion, and by the well during production operations have been isolated to protect them from contamination, and (iii) provisions that would address potential petitions for exemptions from public disclosure of would be no requirement to line the pits that are used to store the fluids that flow back to the surface during and after well stimulation activity.

If pits are unlined, there is a potential risk for the fluids that are stored in the pits to percolate into the ground, especially in circumstances where the ground is highly porous. If the fluids used during the well stimulation process are hazardous, toxic, or may pose some other sort of risk to the environment, groundwater resources could be impacted, where they exist. Depending on the characteristics of the flow back fluid (high/low viscosity or high/low volatility) and the geology in which the fluid would flow through (high/low conductivity, isotropic, or anisotropic), there is the potential for nearby soils to be affected as well. Soils that are contaminated would have less nutrient availability, which in turn would negatively affect the vegetation resources that thrive off of these nutrients. If a pit liner were installed prior to the use of the pit, there would be less likelihood for flow back fluids stored in a pit to percolate into the ground and affect adjacent water, soil, or vegetation resources.

d) Direct and Indirect Effects of Alternative D – Storage Tank Requirement

Under Alternative D, impacts to the environment would be identical in nature to those beneficial and adverse impacts discussed under the Proposed Action. However, under this alternative, there would be a requirement to use storage tanks to store the fluids that flow back to the surface during and after well stimulation activity. Operators would not have an option to use a lined pit.

The use of storage tanks would almost eliminate the risk of flow back fluids from damaging various environmental resources, which include soils, surface and groundwater sources, and wildlife. By using storage tanks, flow back fluids would be entirely contained within vessels, having no connection with the surrounding environment. Wildlife would not have the ability to come into contact with flow back fluids that could potentially be hazardous, toxic, or harmful in other ways, especially to avian species that are attracted to these water sources when stored in a pit. In addition, because tanks are placed above-ground, any potential spills or leaks would be easily identifiable and a clean-up response could be executed fairly promptly. This prompt response would ensure that spills or leaks do not settle for an extended period and percolate through the ground. It is possible for a lined pit to achieve the same soils and groundwater protection goals as storage tanks. However, leaks in pits that may result from a puncture in the liner could not easily be identifiable because flow back fluids are generally stored in temporary pits, which do not have leak detection systems. Air quality would also benefit from the use of tanks. Odors and other air emissions that come from flow back fluids would not be contained, but rather controlled in a closed tank as compared to an open pit where odors and other air emissions from the fluid are emitted from a larger fluid surface area. Tanks would control and reduce the amounts of those air emissions.

Potential negative effects that may result could include the presence of tanks on well pad locations for extended periods of time. For example, flow back fluids return to the surface at different rates based on the characteristics of the formation they came from. Fluids injected into the ground do not necessarily return to the surface immediately. These tanks would have to remain on location until permanent production tanks are constructed on location to store fluids. This would generally take up to six months after a well is completed as Onshore Oil and Gas

Order Number 1 requires earthwork for reclamation on all areas not needed for active production operations to be completed within six months of completing a well, weather permitting. While these tanks are on location they could attract the eye of a casual observer, especially in areas with sensitive visual resources. In some cases these tanks are trailer-hitched tanks that are already low-profiled or they could be tall cylindrical tanks. Depending on where the development takes place – in a sensitive or non-sensitive visual resource area – and where the key observation points are located in relation to these sites, visual impacts will vary. However, the existence of the overall footprint of construction (well pad, access road, or pipeline route) would attract more attention as compared to just the tanks alone, which are only component of the overall development footprint. Because the use of these tanks would be temporary and the casual observer's view would most likely be attracted to the overall footprint of development as compared to just the tanks alone, visual impacts from flow back fluid storage tanks are expected to be low.

The types of operations an operator chooses to utilize as part of his overall development plan will vary from one area or one operator to the next. For example, there are operations that would find frack locations where all fracking equipment (including flow back storage tanks) is centrally stored to be more beneficial. In such cases, there would not be a need for temporary flow back storage tanks on a location, especially for flow back fluids that return within a short period after the frack job is completed. Residual flow back fluids that return to the surface would more than likely be diverted into permanent storage tanks constructed on location. However, for the purpose of this analysis, a basic scenario that assumes flow back storage tanks would be used at each well location is used to help describe the types of impacts that would most likely occur as a result of requiring operators to use tanks to store flow back fluids.

e) Direct and Indirect Effects of Alternative E – BLM Preferred Alternative, Revised Proposed Hydraulic Fracturing Rule

Under the BLM's Preferred Alternative, beneficial impacts to the environment would be similar in nature to those impacts discussed under this Proposed Action. However, there are slight differences. The following items describe how the beneficial impacts from each major change will vary from the beneficial impacts of this Proposed Action.

- The initial proposed rule covered all types of well stimulation activities, which included hydraulic fracturing and acidizing. This alternative covers hydraulic fracturing only. It would not cover other well stimulation activities, such as acidizing.

  Not being able to approve acidizing jobs leaves the BLM without the opportunity to review an operator's plan to perform the activity. However, because acidizing is a procedure that is considered to be a workover activity on a well that does not result in the types of downhole impacts that have been attributed to hydraulic fracturing, this activity was removed from the scope of this alternative. Workover activities include a variety of remedial operations on a producing well to try to increase production. Downhole refers to equipment or mechanical operations that take place down a well bore. The environmental benefits in this change would be similar to the Proposed Action because the public's concern and the scientific

Data last updated October 29, 2014

Number of Well Bores Started (Spud) During the Fiscal Year on Federal Lands

Geographic State	FY 1984(1)	FY 1985(1)	FY 1986(1)	FY 1987(1)	FY 1988(1)	FY 1989(1)	FY 1990(1)	FY 1991(1)	FY 1992(1)	FY 1993(1)	FY 1994(1)	FY 1995(1)	FY 1996(1)	FY 1997(1)	FY 1998(2)	FY 1999(2)	FY 2000(2)	FY 2001(2)	FY 2002(2)	FY 2003(2)	FY 2004(2)	FY 2005(3)	FY 2006	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014
Alabama			1		3	5	10	10	2	1		1						1	1		6	0				1			1	0	0
Alaska		3	7			2	2	4			1	2	1		1	6	12	13	13	7	7	6	6	7	9	7				2	6
Arizona		2		3	1			1			1														1						
Arkansas		5	28	7	5	7	12	5	6	6	7	9	18	6	4	6	11	1	7	5	4	6	11	13	12	14	13	7	3	13	14
California		213	28	106	38	105	124	174	39	133	121	125	143	154	480	223	108	91	100	108	97	147	135	155	231	162	210	414	284	205	210
Colorado		83	194	27	162	98	149	124	83	146	164	87	49	26	58	67	121	158	156	206	195	207	386	400	527	340	411	453	318	215	229
Connecticut																															
Delaware																															
Florida				1	1	1	2	2																							
Georgia																															
Hawaii																															
Idaho		1	1		1																										
Illinois					1		2	2	2	5	1	2	1		1																
Indiana																															
Iowa																															
Kansas		7	4	2	7	7	5	10	10	6	14	8	22	21	7	1	5	8	3	6			5	5		2	1	1			
Kentucky					5	6	3	11	5	9	5	1		2				2													
Louisiana		24	7	2		7	9	5		8	5	9	6	29	14	6	9	5	2	9	14	15	39	39	24	6		2		1	1
Maine																															
Maryland																															
Massachusetts																															
Michigan		2		1	5	2	6	3	2	5	3	15	8	7	1		2	1	1	1	7		1	2		1	2				
Minnesota																															
Mississippi			6	8	17	15	9	14	8	5	7	9	10	7	1	7	7	5	7	6	3	4	11	11	1	3	1	1	2	7	9
Missouri		6																													
Montana		165	78	76	66	77	88	76	46	16	30	62	19	81	63	91	108	117	109	124	98		107	131	120	51	63	23	29	21	22
Nebraska		2	3	3	9	2	1	1	1	4	1	2		2	1						1		1	1	1	1					
Nevada		27	20	13	16	23	23	22	24	20	26	23	21	13	9	1			3	4	4	5	8	8	4	2	2	3	1	3	3
New Hampshire																															
New Jersey																															
New Mexico		369	534	353	482	441	778	862	402	505	646	624	586	663	792	609	920	1,000	821	1,077	726	218	968	1,088	1,000	706	731	709	851	672	702
New York							2		1							1				1						2					
North Carolina									1																						
North Dakota		43	42	14	28	6	25	26	25	18	17	18	21	10	36	2	19	35	54	65	48		96	114	66	66	95	118	144	167	174
Ohio		3	1	4	5		1	9	14	5	5			2	1	4	1	8	1	1	2		2	3	1		2	2		2	2
Oklahoma		5	10	4	53	13	4	10	21	9	3	9	28	32	7	7	13	11	6	7	5		13	13	18	6	2	1	8	9	9
Oregon		1																													
Pennsylvania					3										1				1				5	5		5	1			6	21
Rhode Island																															
South Carolina																															
South Dakota		9	7	3	5	4	10	6	5	2	5	6	2	5	9	2	1	2		3			7	8	2	2		3	4	1	2
Tennessee							12																								
Texas		14	10	12	11	7	14	10	8	23	29	31	32	19	6	3	13	21	10	10	15		17	18	14	13	25	43	15	18	18
Utah		103	85	81	107	55	59		200	173	95	126	123	159	249	100	252	363	233	275	226	37	181	582	736	429	317	431	584	447	457
Vermont																															
Virginia								96	2	3	1	1			2				1						2	2					
Washington					1	1										1															
West Virginia				1	1		5	9		4					4	2		4	4	1											
Wisconsin																															
Wyoming		381	487	302	493	347	472	291	307	435	443	282	320	498	605	480	1,259	1,602	1,338	1,041	1,244	1,097	2,709	2,740	2,275	1,446	1,290	1,049	776	620	665
TOTAL		1,468	1,553	1,023	1,526	1,231	1,827	1,783	1,214	1,541	1,630	1,452	1,410	1,736	2,352	1,619	2,861	3,448	2,871	2,957	2,702	1,742	4,708	5,343	5,044	3,267	3,166	3,260	3,022	2,413	2,544

(1) Data from Public Lands Statistics.

(2) Data from AFMSS.

(3) Due to AFMSS shut down in FY 2005 data is incomplete as of 11/18/2005. Data will be updated as soon as system is fully updated for FY 2005.

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Water Supply Determination Letters

The following list identifies cases where DEP determined that a private water supply was impacted by oil and gas activities. The oil and gas activities referenced in the list below include operations associated with both conventional and unconventional drilling activities that either resulted in a water diminution event or an increase in constituents above background conditions. This list is intended to identify historic water supply impacts and does not necessarily represent ongoing impacts. Many of the water supply complaints listed below have either returned to background conditions, have been mitigated through the installation of water treatment controls or have been addressed through the replacement of the original water supply. This list is dynamic in nature and will be updated to reflect new water supply impacts as they are reported to DEP and a determination is made; however, the list will retain cases of water supply impacts even after the impact has been resolved.

A redacted copy of the water supply determination letter/order can be viewed by clicking on the “Complaint #” or “ORDER” cell in the table. Each row on the list represents a single water supply determination. A single water supply determination may be represented by multiple “Complaint #s” (i.e., when more than one Complaint # is included in the same row) and, conversely, separate water supplies may be identified using the same “Complaint #” (i.e., when multiple rows list the same Complaint #). The list also identifies the municipality and county where each water supply is located along with the date of the water supply determination letter or the date the order was issued.

	DOGO	Complaint #	County	Twp/Boro	Date Letter Sent
1	East	258482	Susquehanna	Dimock	Jan. 2009
2	East	ORDER	Susquehanna	Dimock	12/15/2010
3	East	ORDER	Susquehanna	Dimock	12/15/2010
4	East	ORDER	Susquehanna	Dimock	12/15/2010
5	East	ORDER	Susquehanna	Dimock	12/15/2010
6	East	ORDER	Susquehanna	Dimock	12/15/2010
7	East	ORDER	Susquehanna	Dimock	12/15/2010
8	East	ORDER	Susquehanna	Dimock	12/15/2010
9	East	ORDER	Susquehanna	Dimock	12/15/2010
10	East	ORDER	Susquehanna	Dimock	12/15/2010
11	East	ORDER	Susquehanna	Dimock	12/15/2010
12	East	ORDER	Susquehanna	Dimock	12/15/2010
13	East	ORDER	Susquehanna	Dimock	12/15/2010
14	East	ORDER	Susquehanna	Dimock	12/15/2010
15	East	ORDER	Susquehanna	Dimock	12/15/2010
16	East	ORDER	Susquehanna	Dimock	12/15/2010
17	East	ORDER	Susquehanna	Dimock	12/15/2010
18	East	ORDER	Susquehanna	Dimock	12/15/2010
19	East	ORDER	Susquehanna	Dimock	12/15/2010
20	East	258959	Susquehanna	Lenox	5/27/2009
21	East	258960	Susquehanna	Lenox	5/27/2009

22	East	259175	Tioga	Clymer	11/12/2008
23	East	260999	Tioga	Clymer	4/28/2009
24	East	260999	Tioga	Clymer	4/28/2009
25	East	260999	Tioga	Clymer	4/28/2009
26	East	263337	Susquehanna	Springville	9/9/2009
27	East	263337	Susquehanna	Springville	9/9/2009
28	East	263337	Susquehanna	Springville	9/9/2009
29	East	265150	Lycoming	McNett	12/4/2009
30	East	265150	Lycoming	McNett	12/4/2009
31	East	268097	Susquehanna	Rush	4/23/2010
32	East	269945	Bradford	Terry	2/7/2011
33	East	272059	Bradford	West Burlington	9/16/2010
34	East	272604	Bradford	Granville	9/2/2010
35	East	273310	Bradford	Terry	10/1/2010
36	East	273310	Bradford	Terry	10/1/2010
37	East	273310	Bradford	Terry	10/1/2010
38	East	273350	Bradford	Terry	11/15/2010
39	East	273403	Bradford	Terry	11/15/2010
40	East	273463	Wyoming	Washington	4/8/2011
41	East	273868	Bradford	Orwell	8/22/2011
42	East	274088 274465	Bradford	Tuscarora	3/25/2011
43	East	274348	Bradford	Tuscarora	3/7/2011
44	East	274484	Bradford	Wilmot	11/10/2010
45	East	274484	Bradford	Wilmot	11/10/2010
46	East	274484	Bradford	Wilmot	11/17/2010
47	East	274484	Bradford	Wilmot	11/10/2010
48	East	274484	Bradford	Wilmot	11/10/2010
49	East	274484	Bradford	Wilmot	11/10/2010
50	East	274484	Bradford	Wilmot	11/10/2010
51	East	274977	Bradford	Alba Boro	12/6/2010
52	East	275203	Bradford	Alba Boro	1/3/2011
53	East	275203	Bradford	Alba Boro	1/3/2001
54	East	275524 285034	Potter	Bingham	4/20/2011
55	East	275545	Potter	Bingham	4/20/2011
56	East	275833	Bradford	Monroe	12/3/2010
57	East	275834	Bradford	Monroe	12/3/2010
58	East	275834	Bradford	Monroe	12/3/2010
59	East	275992	Bradford	Alba Boro	12/6/2010
60	East	276069	Bradford	Terry	12/7/2010
61	East	276819	Bradford	Alba Boro	1/31/2011
62	East	277315	Bradford	West Burlington	6/18/2012
63	East	277726	Bradford	Troy	8/17/2011
64	East	277775	Bradford	Wyalusing	10/24/2011
65	East	277902	Bradford	West Burlington	6/18/2012
66	East	277927	Bradford	Wyalusing	10/24/2011

67	East	278614	Tioga	Charleston	5/4/2011
68	East	279070	Bradford	Wilmot	5/16/2011
69	East	279442	Potter	Allegheny	7/14/2011
70	East	279657	Wyoming	Meshoppen	7/13/2011
71	East	279838	Lycoming	Franklin	8/2/2011
72	East	280019	Lycoming	Franklin	8/2/2011
73	East	280020	Lycoming	Moreland	3/8/2012
74	East	280200	Bradford	Smithfield	8/1/2011
75	East	280207	Bradford	Stevens	2/20/2014
76	East	280209	Bradford	Stevens	2/20/2014
77	East	280219	Lycoming	Moreland	11/4/2011
78	East	280698	Bradford	Orwell	11/7/2011
79	East	282014	Tioga	Covington	11/1/2011
80	East	282304	Lycoming	Moreland	11/4/2011
81	East	282431	Susquehanna	Lenox	9/21/2011
82	East	284149	Clinton	Grugan	1/17/2012
83	East	284589	Susquehanna	Rush	11/7/2011
84	East	285804	Bradford	Asylum	1/6/2012
85	East	286295	Lycoming	Moreland	9/5/2012
86	East	286302	Wyoming	Nicholson	3/2/2012
87	East	286302	Wyoming	Nicholson	3/2/2012
88	East	286490	Lycoming	Moreland	9/5/2012
89	East	286491	Lycoming	Moreland	9/5/2012
90	East	286551	Bradford	Wysox	8/28/2013
91	East	286642	Bradford	West Burlington	6/18/2012
92	East	286643	Bradford	West Burlington	6/18/2012
93	East	286658	Lycoming	Moreland	4/22/2013
94	East	287005	Tioga	Delmar	5/16/2012
95	East	287198	Sullivan	Elkland	9/9/2013
96	East	288376	Tioga	Shippen	11/26/2013
97	East	289614	Clearfield	Gulich	8/24/2012
98	East	289642	Bradford	Leroy	8/13/2012
99	East	290009	Bradford	Leroy	8/13/2012
100	East	290279	Bradford	Leroy	8/13/2012
101	East	290453	Susquehanna	Lenox	9/11/2012
102	East	291156	Bradford	Leroy	8/13/2012
103	East	291551	Sullivan	Forks	9/11/2013
104	East	291551	Sullivan	Forks	9/9/2013
105	East	291602	Tioga	Union	1/14/2013
106	East	291603	Tioga	Union	1/14/2013
107	East	291931	Susquehanna	Bridgewater	11/20/2012
108	East	292425	Susquehanna	Jessup	1/14/2013
109	East	292459	Sullivan	Forks	9/9/2013
110	East	292761	Bradford	Armenia	4/12/2013
111	East	292819	Bradford	Burlington	2/21/2013
112	East	293067	Lycoming	Moreland	4/22/2013
113	East	293075	Bradford	Springfield	8/4/2014

114	East	293597	Bradford	Springfield	8/4/2014
115	East	293929	Bradford	Warren	5/6/2014
116	East	294115	Bradford	Wilmot	3/25/2013
117	East	294619	Susquehanna	Dimock	10/22/2013
118	East	294741	Sullivan	Forks	9/9/2013
119	East	295774	Wyoming	Washington	8/28/2013
120	East	296362	Bradford	Franklin	3/3/2015
121	East	297823	Susquehanna	Lenox	10/11/2011
122	East	297824	Susquehanna	Lenox	11/7/2011
123	East	297825	Susquehanna	Lenox	3/2/2012
124	East	289029	Susquehanna	Dimock	9/21/2011
125	East	298064	Bradford	Springfield	8/4/2014
126	East	303704	Susquehanna	Springville	5/14/2014
127	East	300692	Bradford	Wysox	11/13/2014
128	East	301074	Susquehanna	Dimock	10/28/2014
129	East	306750	Susquehanna	Dimock	12/5/2014
130	East	308376	Susquehanna	Bridgewater	12/29/2014
131	East	308529	Lycoming	Eldred	12/12/2014
132	East	308755	Susquehanna	Hartford	11/21/2014
133	East	308786	Bradford	Herrick	2/11/2015
134	East	309245	Wyoming	Windham	1/16/2015
135	East	309261	Lycoming	Eldred	2/2/2015
136	East	310486	Wyoming	Washington	3/18/2015
137	Northwest	250746	Venango	Oakland	12/24/2007
138	Northwest	251599	Crawford	Woodcock	1/30/2008
139	Northwest	252267	Erie	Millcreek	4/11/2008
140	Northwest	252267	Erie	Millcreek	4/11/2008
141	Northwest	252818	McKean	Foster	4/4/2008
142	Northwest	253478	Forest	Hickory	4/29/2008
143	Northwest	254802	Crawford	Hayfield	5/22/2008
144	Northwest	254900	Forest	Howe	7/24/2008
145	Northwest	256043	McKean	Bradford	7/29/2008
146	Northwest	256642	Erie	Waterford	10/8/2013
147	Northwest	257185	McKean	Hamilton	9/12/2008
148	Northwest	257185	McKean	Hamilton	9/12/2008
149	Northwest	257867	Jefferson	Winslow	10/10/2008
150	Northwest	258217	Jefferson	Clover	10/28/2008
151	Northwest	258396	McKean	Hamilton	10/30/2008
152	Northwest	258396	McKean	Hamilton	10/30/2008
153	Northwest	258483	McKean	Foster	10/30/2008
154	Northwest	258484	Warren	Sheffield	11/10/2008
155	Northwest	258625	Clarion	Limestone	1/27/2009
156	Northwest	258625	Clarion	Limestone	1/27/2009
157	Northwest	259040	Elk	Jones	11/13/2008
158	Northwest	259064	Clarion	Limestone	3/26/2009
159	Northwest	260043	Warren	Sheffield	12/23/2008
160	Northwest	260496	McKean	Corydon	2/17/2009

161	Northwest	260565	Venango	Cranberry	8/13/2009
162	Northwest	260916	McKean	Foster	3/10/2009
163	Northwest	261105	Jefferson	Oliver	4/2/2009
164	Northwest	262473	Warren	Mead	8/3/2009
165	Northwest	262648	Jefferson	Knox	5/27/2009
166	Northwest	262648	Jefferson	Knox	5/27/2009
167	Northwest	262683	McKean	Foster	6/1/2009
168	Northwest	262771	Jefferson	Knox	7/13/2009
169	Northwest	263617	Warren	Glade	2/18/2010
170	Northwest	263963	McKean	Bradford	7/21/2009
171	Northwest	264898	McKean	Bradford	3/5/2010
172	Northwest	265297	Jefferson	Knox	9/11/2009
173	Northwest	265323	Clarion	Elk	9/10/2009
174	Northwest	266017	Jefferson	Warsaw	10/19/2009
175	Northwest	266591	Crawford	Oil Creek	6/24/2011
176	Northwest	267033	Clarion	Elk	1/15/2010
177	Northwest	267880	Clarion	Elk	1/20/2010
178	Northwest	267880	Clarion	Elk	1/20/2010
179	Northwest	269055	Forest	Kingsley	3/22/2010
180	Northwest	269244	Warren	Glade	9/27/2010
181	Northwest	271422	McKean	Bradford	10/19/2010
182	Northwest	271490	Warren	Sheffield	6/17/2010
183	Northwest	272189	Forest	Hickory	8/2/2010
184	Northwest	272948	McKean	Bradford	12/17/2010
185	Northwest	273024	Clarion	Madison	7/18/2014
186	Northwest	273321	Crawford	Spring	1/28/2011
187	Northwest	273460	McKean	Corydon	Oct. 2010
188	Northwest	274735	Elk	Jones	12/23/2010
189	Northwest	276220	McKean	Foster	2/9/2011
190	Northwest	276776	Forest	Hickory	3/28/2012
191	Northwest	276776	Forest	Hickory	10/20/2011
192	Northwest	276776	Forest	Hickory	3/28/2012
193	Northwest	276776	Forest	Hickory	3/28/2012
194	Northwest	276776	Forest	Hickory	3/28/2012
195	Northwest	276776	Forest	Hickory	3/28/2012
196	Northwest	276776	Forest	Hickory	3/28/2012
197	Northwest	276776	Forest	Hickory	3/28/2012
198	Northwest	276776	Forest	Hickory	3/28/2012
199	Northwest	276776	Forest	Hickory	3/28/2012
200	Northwest	276776	Forest	Hickory	3/28/2012
201	Northwest	276776	Forest	Hickory	3/28/2012
202	Northwest	276776	Forest	Hickory	5/3/2011
203	Northwest	276823	Forest	Hickory	5/4/2011
204	Northwest	277438	McKean	Bradford	7/13/2011
205	Northwest	278982	Warren	Pleasant	5/4/2012
206	Northwest	281151	Elk	Jones	8/8/2011
207	Northwest	287891	Butler	Winfield	6/4/2013

208	Northwest	289916	Clarion	Toby	11/29/2012
209	Northwest	290406	Lawrence	Pulaski	11/13/2013
210	Northwest	290406	Lawrence	Pulaski	11/19/2013
211	Northwest	290406	Lawrence	Pulaski	11/20/2013
212	Northwest	290406	Lawrence	Pulaski	10/7/2013
213	Northwest	291029	Butler	Winfield	9/7/2012
214	Northwest	292020	Warren	Sugar Grove	Sept. 2012
215	Northwest	293565	Warren	Pleasant	1/4/2013
216	Northwest	294446	Forest	Kingsley	7/19/2013
217	Northwest	294734	Warren	Pleasant	7/11/2013
218	Northwest	294947	McKean	Foster	8/28/2013
219	Northwest	296020	Butler	Forward	8/28/2013
220	Northwest	297871	Clarion	Porter	3/24/2014
221	Northwest	298337	Warren	Glade	10/1/2013
222	Northwest	300296	McKean	Lafayette	Nov. 2013
223	Northwest	259354 261083	Jefferson	Knox	3/27/2009
224	Northwest	267519 268448	McKean	Bradford	12/11/2009
225	Northwest	267519 268448	McKean	Bradford	12/11/2009
226	Northwest	305257	Butler	Connoquenessing	12/12/2014
227	Northwest	305506	Warren	Mead	7/28/2014
228	Northwest	ORDER	McKean	Bradford	2/23/2010
229	Northwest	ORDER	McKean	Bradford	2/23/2010
230	Northwest	ORDER	McKean	Bradford	2/23/2010
231	Northwest	ORDER	McKean	Bradford	2/23/2010
232	Northwest	ORDER	McKean	Bradford	2/23/2010
233	Northwest	ORDER	McKean	Bradford	2/23/2010
234	Northwest	ORDER	McKean	Bradford	2/23/2010
235	Northwest	ORDER	McKean	Bradford	2/23/2010
236	Northwest	ORDER	McKean	Bradford	2/23/2010
237	Northwest	306890	Warren	Farmington	10/28/2014
238	Northwest	307002	Venango	Cranberry	12/9/2014
239	Northwest	307679	Jefferson	Eldred	10/30/2014
240	Southwest	281911	Indiana	West Wheatfield	8/30/2013
241	Southwest	281911	Westmoreland	Donegal	12/16/2013
242	Southwest	291965	Westmoreland	Donegal	6/4/2013
243	Southwest	294666	Washington	Cross Creek	6/17/2013
244	Southwest	302442	Westmoreland	Donegal	8/25/2014
245	Southwest	306873	Westmoreland	Donegal	12/5/2014
246	Southwest	310158	Westmoreland	Donegal	3/20/2015
247	Southwest	ORDER	Indiana	East Wheatfield	9/2/2008
248	Southwest	ORDER	Indiana	East Wheatfield	9/2/2008
249	Southwest	ORDER	Indiana	East Wheatfield	9/2/2008
250	Southwest	ORDER	Indiana	East Wheatfield	9/2/2008
251	Southwest	ORDER	Indiana	East Wheatfield	9/2/2008

252	Southwest	ORDER	Indiana	West Mahoning	2/12/2008
253	Southwest	ORDER	Washington	West Pike Run	3/27/2008
254	Southwest	ORDER	Fayette	Jefferson	1/4/2008
255	Southwest	ORDER	Indiana	Cherryhill	1/15/2008
256	Southwest	ORDER	Greene	Washington	9/11/2014
3/30/2015					

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PENNSYLVANIA

Energy. Environment. Economy.

DEP publishes details on 248 cases of water damage from gas development

AUGUST 29, 2014 | 2:40 PM

BY **KATIE COLANERI**

AP PHOTO/MATT ROURKE

Ray Kemble of Dimock, Pa. displays a jug of what he identifies as his contaminated well water in this August 2013 file photo.

For the first time, Pennsylvania environmental regulators are publicly releasing documents about cases when natural gas operations have damaged private water supplies.

A list of 248 incidents is now available on the Department of Environmental Protection's website with links to the letters sent to homeowners when the agency determined their water well was impacted by gas development.

The DEP provided **an early copy of the list** to the Pittsburgh Post-Gazette in July, which showed 209 cases. The updated tally is the result of a more thorough search of paper records in regional offices, said spokesman Eric Shirk.

"As we do get more information, we will keep this list updated," he said.

DEP says incidents on the decline

Homeowners' names and addresses have been redacted, but the list shows wells were contaminated or produced less water in spots across the Marcellus Shale since late 2007. It includes impacts from both conventional and unconventional operations.

ABOUT STATEIMPACT PENNSYLVANIA

StateImpact Pennsylvania is a collaboration between **WITF** and **WHYY**. Reporters **Marie Cusick** and **Susan Phillips** cover the fiscal and environmental impact of Pennsylvania's booming energy economy, with a focus on Marcellus Shale drilling. Read their reports on this site, and hear them on public radio stations across Pennsylvania. This collaborative project is funded, in part, through grants from the Heinz Endowments and William Penn Foundation.

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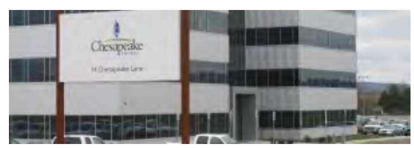
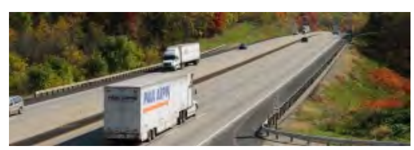


VIDEO: Fraud allegations mount against Chesapeake Energy



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A majority of the incidents occurred in the Northwest and eastern regions of Pennsylvania. The state's most-drilled county, Bradford, saw 52 incidents of degraded water supplies – more than any other county.

According to the DEP, these cases have been on the decline since a peak in 2010, and are a small number compared to the 20,000 wells that have been drilled in Pennsylvania over the last six years.

"In perspective, the percentages are good," Shirk said.

So far in 2014, the DEP has issued 11 determination letters, most recently as August 4 in Springfield Township, Bradford County. Shirk said the agency's goal is to make sure there are no future incidents.

"I think 200 or so contamination cases is pretty alarming numbers especially when you consider industry runs around saying they've not contaminated any water well supplies," said Steve Hvozdovich with Clean Water Action Pennsylvania.

The oil and gas industry has long held that their operations – specifically the process of hydraulic fracturing – do not negatively impact water supplies.

In a statement, Marcellus Shale Coalition president Dave Spigelmyer said the documents released by DEP reflect Pennsylvania's "long-standing water-related challenges."

Pennsylvania is one of two states that does not have standards for private water wells. Cases of **methane gas migrating into aquifers** have existed long before the shale boom, but faulty well casing can speed up the process.

"Our industry works closely and tirelessly with regulators and others to ensure that we protect our environment, striving for zero incidents," Spigelmyer said.

"They're playing catch-up"

Environmental groups are welcoming the release of the determination letters, but remain critical of the DEP for not providing consistent details to the public.

Hvozdovich points out that information contained in each letter varies and it is not clear whether the homeowners were satisfied by DEP's efforts to correct the problems or work with companies to replace damaged water supplies.

The release of these documents follows **a report by the state's auditor general** criticizing the DEP for mishandling complaints about water quality and drilling, including poor record-keeping.

"They're playing catch-up as fast as they can because I think frankly they're red-faced about it," said Tracy Carluccio, Deputy Director of the Delaware Riverkeeper Network.

Act 13, Pennsylvania's two-year-old oil and gas law, requires the department to to post an online list of "confirmed cases of subterranean water supply contamination that result from hydraulic fracturing."

Auditor General Eugene DePasquale said the agency has been **following the letter of the law, but not "the spirit of the law."**

Shirk said the list is part of an ongoing effort to increase transparency and respond to requests from the public and the media.

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"It's not a secret the DEP has been a paper-based agency and these records have been housed in the regions where the issues were occurring," Shirk said. "But we took the steps to manually scan in all these files and make a central repository on the Web that everybody can take a look at."

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COMMENTS

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Maggie Henry • 9 months ago

This is just the tip of the iceberg and how dare the industry do a bait and switch now! Incidence on the decline...who cares if your well is the next one contaminated by the industry? I have lived in terror of this for the last 4 years...waking up and having only contaminated water for livestock or irrigation...why should any farmer, living in an agricultural area, have to deal with this? No one has the right to poison the community!

9 • Share ›

Victoria Switzer • 9 months ago

the percentages are good if you are not one of them! I ask how many folks are not on the list because they are afraid to go public and because they get water delivered if they are good disciples!!!! If PA is willing to trade their drinking water for gas then they are off to a great start.

4 • Share ›

Maggie Henry → Victoria Switzer • 9 months ago

I'm not willing to have Pa trade my drinking water for anything. Paid thousands to drill my well and my husband's family have paid taxes for 100 years on this farm. I've been here for 35 of them...no one has the right to do what the gas industry is. Poisoning people for money. Wish I believed in hell so I could picture all of them burning in it!

4 • Share ›

JimBarth • 9 months ago

20,000 wells have been drilled in PA over the past 6 years? How many of those are high volume, slick water, multistage hydraulically frac'ed and laterally drilled into the shale? How many of those have been frac'ed, period? How many of those are in production? I have not seen a figure posted anywhere of 20,000 unconventional wells drilled, vertically or horizontally into shale, since 2004 in PA, let alone in the

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Colorado Oil and Gas Conservation Commission

Spill Analysis by Year 1999 – 4thQtr 2014

BBL = Barrels

Year	Spills	Oil Spilled (BBL)	Water Spilled (BBL)	Oil Produced (BBL)	% Produced Oil Spilled	Water Produced (BBL)	% Produced Water Spilled	Active Wells
1999	263	2,283	41,363	19,701,908	0.012%	230,156,373	0.018%	21,745
2000	254	3,579	22,540	20,021,477	0.018%	252,866,815	0.009%	22,228
2001	206	1,939	10,582	20,180,277	0.010%	266,137,265	0.004%	22,879
2002	193	3,200	57,842	20,572,273	0.016%	282,806,691	0.020%	23,711
2003	213	2,924	19,528	21,598,341	0.014%	302,791,960	0.006%	25,042
2004	222	4,005	37,095	22,570,780	0.018%	295,524,013	0.013%	26,968
2005	326	5,014	24,638	23,226,926	0.022%	347,152,092	0.007%	28,952
2006	336	2,605	33,443	24,494,593	0.011%	397,246,565	0.008%	31,096
2007	376	4,074	27,096	26,172,528	0.016%	392,829,388	0.007%	33,815
2008	408	3,195	71,959	29,926,612	0.011%	366,606,570	0.020%	39,944
2009	367	2,787	22,188	30,342,940	0.009%	359,300,950	0.006%	37,311
2010	499	3,279	33,647	32,976,407	0.010%	362,270,537	0.009%	41,010
2011	500	3,286	33,801	39,429,328	0.008%	344,478,390	0.010%	43,354
2012	405	4,503	14,389	49,429,040	0.009%	332,357,505	0.004%	46,835
2013	617	3,948	14,294	65,372,646	0.006%	326,845,429	0.004%	50,067
2014	769	2,431	16,047	95,337,373	0.003%	334,443,533	0.005%	51,737

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COLORADO TOXIC RELEASE TRACKER 2013 SUMMARY

495 Spills Were Reported To The COGCC

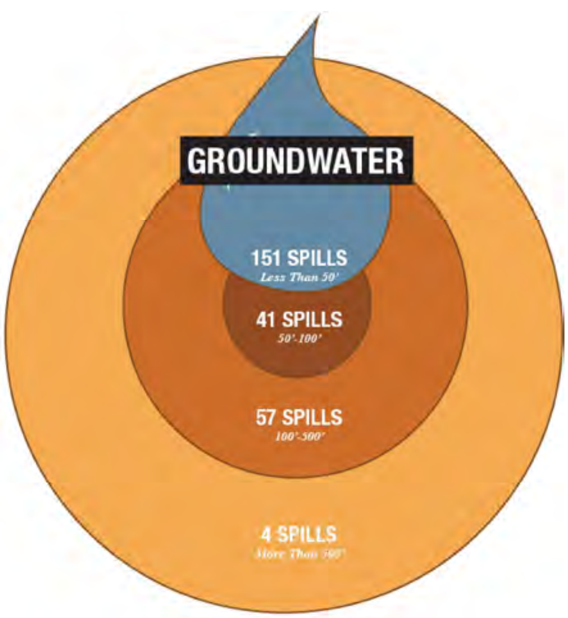
- Since January 1, 2013 oil and gas companies reported **495 spills**
- In December, 2013 oil and gas companies were responsible for **36 spills** in Colorado

22% Of Spills Resulted In Water Contamination

71 Spills Impacted Groundwater

41 Spills Impacted Surface Water

- **210 Spills** occurred within 1,000 feet of surface water
- **136 Spills** occurred within 500 feet of surface water
- **151 Spills** occurred less than 50 feet from groundwater
- **41 Spills** occurred between 50 and 100 feet from groundwater



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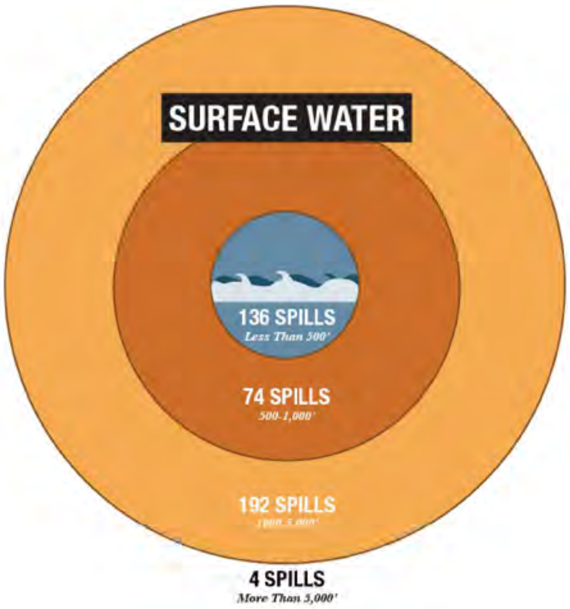

- **63 Spills** occurred in within 1,500 feet of cows, pigs, sheep, or other livestock
- **225 Spills** occurred within 1,500 feet of a building
- **65 Spills** were larger than 1,000 square feet in size
- **373 Spills** were the result of equipment failure of human error

Citation: Colorado Oil and Gas Conservation Commission, http://cogcc.state.co.us/cogis/IncidentSearch.asp

NEW MEXICO TOXIC RELEASE TRACKER 2013 SUMMARY

934 Spills Were Reported to the NMOCD in 2013

- Since January 1, 2013 oil and gas companies reported **934 spills** to the New Mexico Oil Conservation Division

What Was Spilled in 2013?

- **436** spills were reported as produced water
- **235** spills were reported as crude oil
- **166** spills were reported as methane
- **60** spills were reported as condensate
- **37** spills were other materials

Largest Spill by Material Spilled in 2013

- Produced Water: **4,257 barrels**
- Condensate: **520 barrels**
- Crude Oil: **600 barrels**
- Natural Gas: **86,184,000 cubic feet**

Common Cause of Spills in 2013

- Equipment failure was the reported cause of **391 spills**
- Corrosion was the reported cause of **195 spills**
- Normal operations were the reported cause of **84 spills**
- Human error was the reported cause of **60 spills**
- Other or not listed was the reported cause of **204 spills**

Where are Most Spills Happening?

- **592 spills** occurred in Eddy County (63 percent of all NM spills)
- **154 spills** occurred in San Juan County (16 percent of all NM spills)

Which Companies Spill the Most Often?

- COG Production and COG Operating : **123 spills**
- Burlington Resources Oil & Gas Company: **83 spills**
- Yates Petroleum: **85 spills**

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PSE Healthy Energy

SCIENCE SUMMARY

OCT 2014

Surface and groundwater contamination associated with modern natural gas development

Peer-Reviewed Literature, 2011 - 2014

Documentation of water contamination associated with modern natural gas development is a complex issue. The list of studies reported here should be seen as conservative and limited reporting of water contamination, as it only contains evidence from peer-reviewed scientific studies and does not include incidences that exist in inspection records. For instance, the Pennsylvania Department of Environmental Protection (PA DEP) released a list of 243 cases where it was determined that private water supplies were impacted by oil and gas activities[1].

Differences in local geologies and hydrologic characteristics, land-use histories, industry practices, and monitored water contaminants can complicate comparisons across studies. Baseline conditions for water quality are often unknown or may have been affected by other activities. **Nonetheless, empirical evidence of surface and groundwater contamination as a result of modern natural gas operations is documented.**

Pennsylvania (*Marcellus*). Several studies indicate degradation of ground and surface waters in dense drilling areas of Pennsylvania. Studies[2,3] found significantly **higher concentrations of thermogenic methane** in private water wells within 1 km of one or more natural gas wells (6 and 17 times on average, respectively; Fig 1).

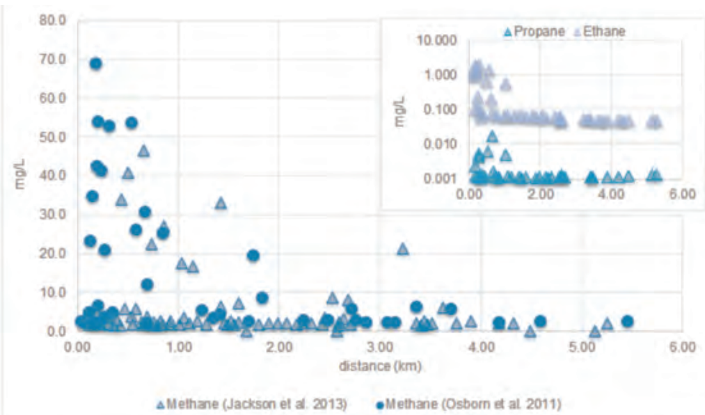

Figure 1. Hydrocarbon concentrations (mg/L) in groundwater by distance to unconventional gas wells. Private water wells within 1 km of shale gas well show higher levels of natural gas constituents (methane, ethane, propane). Isotopic analysis indicates that the hydrocarbons are thermogenic in nature (Source: Osborn et al. 2011; Jackson et al. 2013)

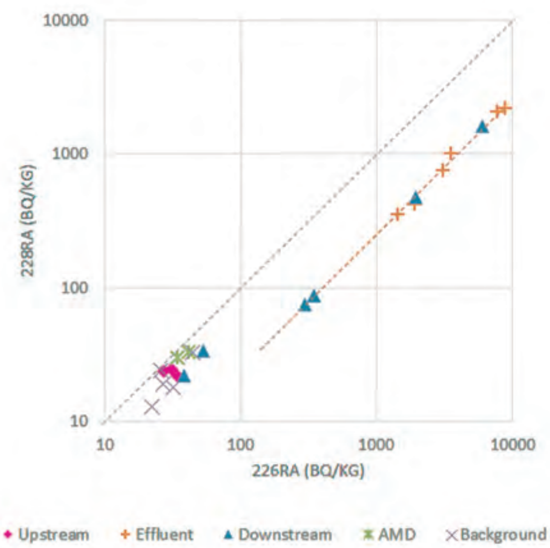

Figure 2. Activities of 228Ra/226Ra in river sediments collected upstream, adjacent, and downstream of a Marcellus shale wastewater discharge site. Despite waste treatment, downstream water quality still reflects the chemical signatures of fluids produced in natural gas extraction, as downstream ratios closely match those of untreated Marcellus brines (orange dashed line; 0.25; Source: Warner et al. 2013).

An examination of water chemistry and isoptopic signatures[4] of effluents from a brine treatment facility, stream sediments near the discharge site, and surface waters downstream and upstream of the discharge site showed **elevated levels of chloride and bromide** in downstream waters consistent (combined with isotopic data) with produced waters from Marcellus wastewaters. Radium-228/Radium-226 ratios in downstream waters and near-source sediments also closely matched ratios measured in Marcellus wastewaters (Fig 2). **Radium-226 concentrations** in near-source sediments (544-8759 Bq/kg) were found to be approximately 200 times greater than upstream and background sediments and in excess of U.S. Radioactive waste disposal threshold regulations.

A study using noble gases as tracers in areas overlying the Marcellus shale region and the Barnett shale in TX[5] found four clusters of **fugitive gas contamination** in groundwater. The data suggested the contamination most likely resulted from poor well cement casing that enabled hydrocarbon gas leaks along the well annulus.

Texas (*Barnett*). A study of groundwater quality in the Barnett shale TX[6] revealed significantly **higher levels of heavy metals** (strontium, selenium, arsenic) in private water wells located within 2 km of active gas wells relative to private water wells located further from drilling activity (Fig 3). This study was unique in that it used historical data from the region to create a baseline measure of groundwater quality before the expansion of natural gas operations. Arsenic, strontium, and selenium concentrations were also found to be significantly higher in active drilling areas relative to this historical baseline. Shallower water wells near drilling activity showed the highest levels of contamination. These findings suggest that mechanical disturbance (i.e. subsurface vibrations) of water wells, surface spills and/or faulty well casings/cement as possible causes of contamination.

Kentucky (*Appalachian*). A release of hydraulic fracturing fluids to a Knox County stream resulted in in fish stress and mortality. Water chemistry analysis[7] of the impacted stream revealed **elevated conductivity, lowered pH and alkalinity, and toxic levels of heavy metals**. Fish exposed to the contaminated water exhibited a high incidence of gill lesions consistent with impacts observed in fish exposed to low pH, dissolved heavy metals, or both. Among the species affected was the federally protected Blackside Dace.

Colorado (*Denver-Julesburg and Piceance*). An analysis of reported surface spills (Colorado Oil and Gas Conservation Commission, COGCC) within Weld County (DenverJulesburg) and groundwater monitoring data associated with each spill[8] revealed BTEX (benzene, toulene, ethylbenzene, xylene) contamination of groundwaters. During a one-year period the authors noted 77 reported surface spills impacting groundwater; 62 of these records included BTEX analytical sampling during remediation. A large percent of samples show **BTEX concentrations in excess of federal standards** (Fig 4). Another study of surface and groundwater samples from drilling-dense areas in the Piceance basin[9] showed **higher estrogenic, anti-estrogenic, or ant-androgenic activities** near gas activity relative to reference site with little or no natural gas development.

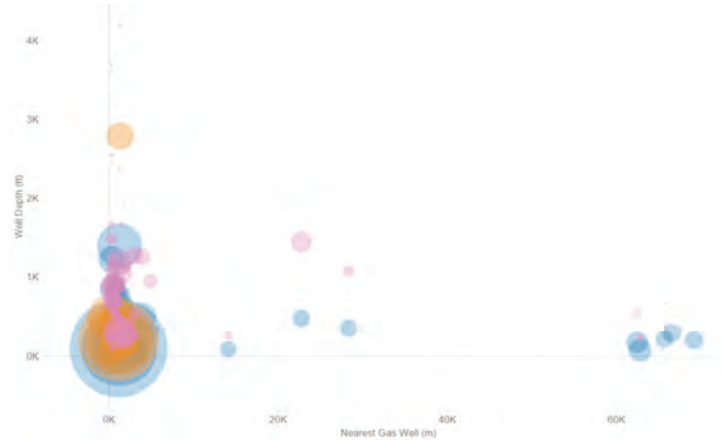

Figure 3. Arsenic (µg/L), strontium (mg/L) and selenium (µg/L) concentrations in groundwater versus distance to nearest active natural gas well and depth of water well. Circle size reflects levels of concentrations with larger circles denoting higher levels of contaminants. Risk of contamination to private water wells appears to increase with proximity to unconventional natural gas wells. Shallower water wells are particularly at risk, suggesting surface spills, mechanical disturbance of water wells, and/or faulty well casings as possible routes to contamination. (Source: Fontenot et al. 2013)

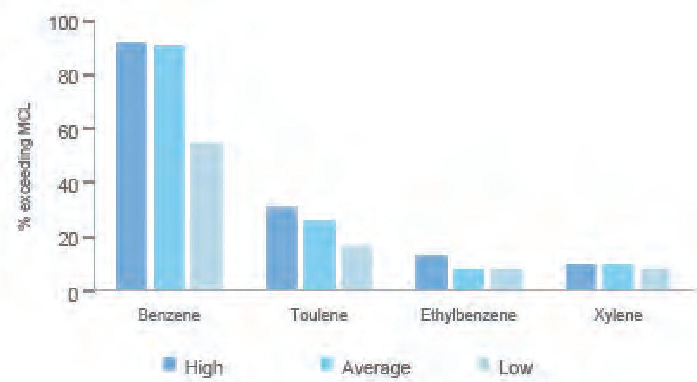

Figure 4. Percent of groundwater samples exceeding federal maximum contaminant levels (MCL) for BTEX species. Samples were taken at different stages of remediation following reported surface spills related to natural gas development. While many of the spills were effectively mitigated, >50% of samples still exceeded benzene MCLs after remediation; 16% of samples exceeded toulene MCLs post-remediation, and 8% of samples exceeded MCLs for both ethylbenzene and xylene. (Source: Gross et al. 2013)

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Working Paper

12-2014
Revision January 2015

Toward an understanding of the environmental and public health impacts of shale gas development: an analysis of the peer-reviewed scientific literature, 2009-2014

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1. Introduction

Conversations on the environmental and public health impacts of shale gas development enabled by hydraulic fracturing continue to play out in the media, in policy discussions, and among the general public. But what does the science actually say? While research continues to lag behind the rapid scaling of unconventional forms of oil and gas development, there has been a surge of peer-reviewed scientific papers published in recent years (Figure 1). In fact, of all the available literature on the impacts of shale gas development, over 75% has been published since January 1, 2013. What this tells us is that the scientific community is only now beginning to understand the environmental and public health implications. Numerous hazards and risks have been identified, but many data gaps remain. While there is now a far more substantive body of science than there was several years ago, there is still a notable dearth of quantitative epidemiology that assesses associations between risk factors and human health outcomes among populations.

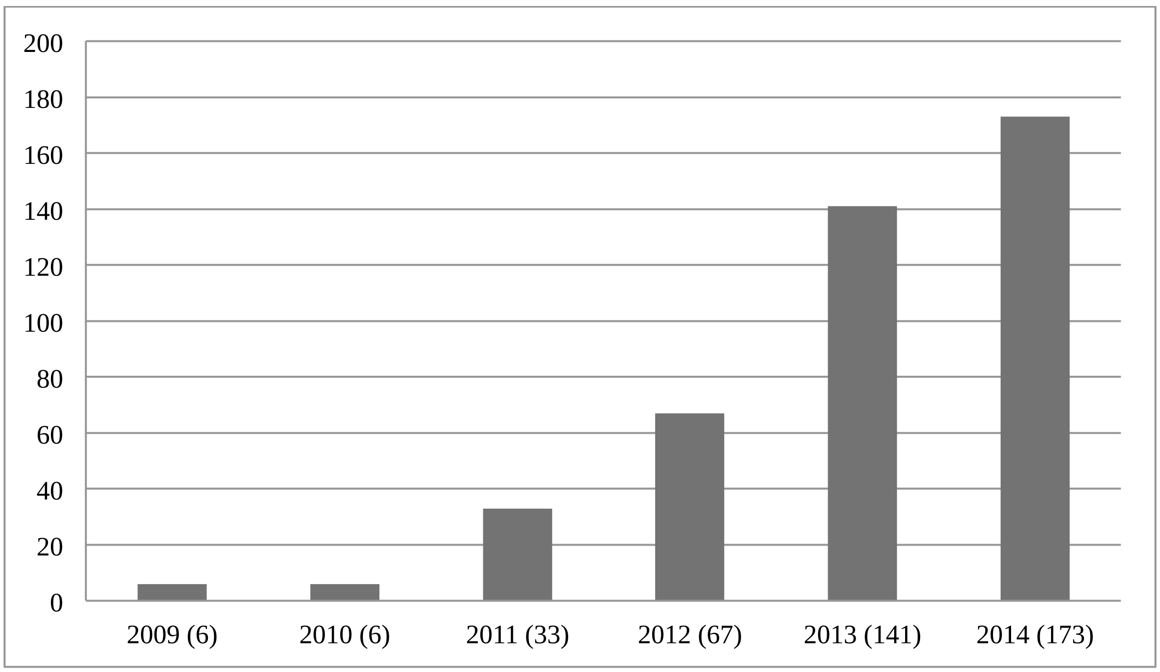

Figure 1. Number of publications that assess the impacts of shale or tight gas development by year, 2009-2014

In this analysis we provide an overview of current scientific knowledge regarding these potential impacts. We include only published peer-reviewed literature available on the subject. Specifically, we analyze studies relevant to near-term and long-term environmental public health among communities in proximity to shale gas development.

As shale gas activities continue to expand, states and countries are in a unique position to learn from experiences and scientific assessment in areas where development is already underway, including parts of Pennsylvania, Texas, and Colorado. While energy policy requires more than empirical data, legislative and regulatory bodies should account for the emerging body of science on the environmental and public health implications of shale gas development. This analysis is an attempt to summarize this emerging body of science from the available peer-reviewed literature.

There are many limitations to our analysis and it provides just a snapshot of the empirical knowledge on the public health hazards, risks, and impacts associated with shale gas development. For a more nuanced discussion please refer to our review article (Shonkoff et al. 2014) published in *Environmental Health Perspectives* (http://ehp.niehs.nih.gov/wp-content/uploads/122/8/ehp.1307866.pdf). Furthermore, as a working paper, this document is preliminary and has not yet been subjected to external peer review. Nonetheless, it provides readers with a general sense of the direction in which the existing body of scientific literature points in terms of identified and potential environmental and public health impacts.

2. Methods

A. Database assemblage and review

This analysis was conducted using the PSE Shale and Tight Gas Study Citation Database (available at: http://psehealthyenergy.org/site/view/1180). This near exhaustive collection of peer-reviewed literature on shale gas development is divided into 12 topics that attempt to organize the papers in a useful and coherent fashion. These topics include air quality, climate, community, ecology, economics, general (comment/review), health, regulation, seismicity, waste/fluids, water quality, and water usage. This study database has been assembled over several years using a number of different search strategies, including the following:

- Systematic searches in scientific databases across multiple disciplines: PubMed (http://www.ncbi.nlm.nih.gov/pubmed/), Web of Science (http://www.webofknowledge.com), and ScienceDirect (http://www.sciencedirect.com)
- Searches in existing collections of scientific literature on shale gas development, such as the Marcellus Shale Initiative Publications Database at Bucknell University (http://www.bucknell.edu/script/environmentalcenter/marcellus), complemented by Google (http://www.google.com) and Google Scholar (http://scholar.google.com)
- Manual searches (hand-searches) of references included in peer-reviewed studies that pertain directly to shale gas development.

For science literature search engines we used a combination of Medical Subject Headings

(MeSH)-based and keyword strategies, which included the following terms as well as relevant combinations thereof:

> shale gas, shale, hydraulic fracturing, fracking, drilling, natural gas, air pollution, methane, water pollution, public health, water contamination, fugitive emissions, air quality, climate, seismicity, waste, fluids, economics, ecology, water usage, regulation, community, epidemiology, Marcellus, Barnett, Denver-Julesberg Basin, unconventional gas development, and environmental pathways.

This database and subsequent analysis excluded technical papers on shale gas development not applicable to determining potential environmental and public health impacts. Examples include papers on optimal drilling strategies, reservoir evaluations, estimation algorithms of absorption capacity, patent analyses, and fracture models designed to inform stimulation techniques. Because this collection is limited to papers subjected to external peer-review in the scientific community, it does not include government reports, environmental impact statements, policy briefs, white papers, law review articles, or other grey literature. Nor does it include studies on coalbed methane, coal seam gas, tar sands or other forms of fossil fuel extraction (offshore drilling, etc.).

We have tried to include all literature that meets our criteria in our collection of the peer-reviewed science; however, it is possible that some papers may have gone undetected. Thus, we refer to the collection as *near* exhaustive. We are sure, however, that the most seminal studies on the environmental public health dimensions of shale gas development in leading scientific journals are accounted for.

The PSE Healthy Energy database has been used and reviewed by academics, experts, and government officials throughout the U.S. and internationally and has been subjected to public and professional scrutiny before and after this analysis. It represents the most comprehensive public collection of peer-reviewed scientific literature on shale and tight gas development in the world and has been accessed by thousands of people. Again, many of the publications in this database through 1 February 2014 are discussed in greater detail in Shonkoff et al. (2014).

B. Scope of analysis

1. Definitions:

There has been great confusion about the environmental dimensions of shale and tight gas development (often termed "fracking") because of the lack of uniform, well-defined terminology and boundaries of analysis. The public and the media use the term fracking as an umbrella term to refer to the entirety of shale gas development, including processes ranging from land clearing to well stimulation, to hydrocarbon development, to waste disposal. On the other hand, the oil and gas industry and many in the scientific community generally use the term as shorthand for one particular type of well stimulation method used to enhance the production of oil and natural gas – hydraulic fracturing.

The PSE Healthy Energy database and this analysis are both concerned with shale gas development in its entirety, enabled by hydraulic fracturing, and not just the method of well stimulation. Environmental and public health analyses that include only the latter should have a limited role in policy discussions. If we are to understand the social, environmental, and public health dimensions of shale gas development we must look beyond just the process of hydraulic fracturing, especially when the scientific literature indicates other aspects of the overall process warrant concern. Thus, this project should be viewed as an analysis of the scientific literature on hydraulic fracturing *and* its associated operations and ancillary infrastructure that comprise the development of shale and tight gas.

2. Inclusion and exclusion criteria:

The temporal focus of this analysis is, first and foremost, on the primary research on shale gas development published between 1 January 2009 and 31 December 2014. The reason for starting this analysis in 2009 is that research on modern, unconventional forms of natural gas development did not appear until around that time. We only include papers that evaluate environmental and public health impacts of shale gas development. As such, not all publications in the PSE Healthy Energy database were used in this analysis. We have excluded the following topics: climate, community, ecology, economics, regulation, seismicity, waste/fluids, and water usage.

We have also not included all papers that fall under the three topics (health, water quality, and air quality) used in this analysis. For instance, with the exception of public health papers, for which there has been very little primary research, we have excluded commentaries and review articles. Further, we have excluded those papers that provide baseline data or address research methods that do not assess impacts. We have also excluded letters to the editors of scientific journals that critique a particular study or the subsequent response of the author(s).

As previously mentioned, we have restricted the studies included in this analysis to those published from 2009 through 2014. There are some studies in the database on conventional forms of oil and natural gas development that are relevant to shale gas, but to maintain greater consistency we have decided to exclude those prior to 2009 from the analysis. For instance, we excluded a study published in *The Lancet* that examined the association between testicular cancer and employment in agriculture and oil and gas development published in 1986 (Sewell et al. 1986). Relatedly, some of the studies included in this analysis may be broader than shale gas development and could potentially include other forms of both conventional and unconventional oil and gas development. This is true for some of the top-down, field based air pollutant emissions studies that gauge leakage rates and emission factors in Western oil and gas fields. Where studies are not specifically related to shale gas development we included them only when the findings were both recent and substantially relevant.

Again, it is important to note that scientists are only beginning to understand the environmental and public health dimensions of these rapidly expanding industrial practices. Our analysis represents a survey of the existing science to date in an attempt to determine the direction in which scientific consensus is headed and to achieve a better understanding of the environmental and public health impacts of this form of energy development.

C. Categorical framework

We have created categories for each topic in an attempt to identify and group studies in ways that are both useful and intuitive. Clearly, there are limitations to this approach and many studies are nuanced or incommensurable in ways that may not be appropriate for this type of analysis. Further, some studies may properly belong in multiple topics. For instance, a few studies that contain data that are relevant to both air quality and public health have been included in both of these topics (Bunch et al. 2014; Colborn et al. 2014; Macey et al. 2014). Nonetheless, in order to glean some kind of emerging scientific consensus on the environmental public health dimensions of shale gas development we strived to create the most simple and accurate approach possible. Please refer to the tables included in the appendix for the citations and categorization of the studies, which are listed alphabetically by author.

Topics	Categories
Health	• Indication of potential public health risks or actual adverse health outcomes • No indication of public health risks or actual adverse health outcomes
Water Quality	• Indication of potential, positive association, or actual incidence of water contamination • Indication of minimal potential, negative association, or rare incidence of water contamination
Air Quality	• Indication of elevated air pollutant emissions and/or atmospheric concentrations • No indication of significantly elevated air pollutant emissions and/or atmospheric concentrations

1. Health

Health outcome studies and epidemiologic investigations continue to be particularly limited and most of the peer-reviewed papers to date are commentaries and reviews. Accordingly, we have also separately analyzed peer-reviewed scientific commentaries and review articles ("all papers") for this topic. Although commentaries should essentially be acknowledged as opinions, they are the opinions of experts formed from the available literature and have also been subjected to peer review.

We have included in this topic papers that consider the question of public health in the context of shale gas development. Of course, research findings in other categories such as air quality and water quality are relevant to public health, but here we only include those studies that *directly* consider the health of individuals and human populations. We only consider research to be original if it measures health outcomes or complaints (i.e., not health research that only attempts to determine public opinion or consider methods for future research agendas).

2. Water Quality

Papers on water quality are more nuanced in that some rely on empirical field measurements, while others explore mechanisms for contamination or use modeled data to determine water quality risks. Further, some of these studies explore only one aspect of shale gas development, such as the well stimulation process enabled by hydraulic fracturing. Thus, these studies do not indicate whether or not shale gas development as a whole is associated with water contamination and are therefore limited in their utility for gauging water quality impacts. Nonetheless, we have included all original research, including modeling studies. We have excluded studies that explore only evaluative methodology or baseline assessments as well papers that simply comment on or review previous studies. Here we are only concerned with actual findings in the field or modeling studies that specifically address the risk or occurrence of water contamination.

3. Air Quality

Air quality is a more complex, subjective measure that beckons comparison to other forms of energy development or industrial processes. Yet a review and analysis of the air quality data is still useful and relevant to health outcomes. Although methane is a precursor to tropospheric ozone we have excluded studies that focus exclusively on methane emissions from this topic. However, studies that address methane *and* non-methane volatile organic compound (VOC) emissions have been included, given the health-damaging dimensions of a number of VOCs (i.e., benzene, toluene, ethylbenzene, xylene, etc.) and the role of VOCs in the production of tropospheric ozone, a strong respiratory irritant. The few studies that have explored the health implications of air pollution emissions and exposure levels are included in both this category and the public health category. The papers in this topic are those that specifically address air emissions

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and air quality from well stimulation-enabled oil and gas development (i.e., unconventional oil and gas development) at either a local or regional scale. These include local and regional measurements of non-methane volatile organic compounds and tropospheric ozone.

3. Results

Health

Based on our criteria, we included 16 original research studies relevant to questions involving associations between shale gas development and public health outcomes. Of these 16 studies, 14 (87%) identified potential public health risks or actual observed poor public health outcomes and 2 (13%) found no indication of significant public health risks or actual adverse health outcomes (Figure 2). When we included commentaries and review papers in the analysis, 47 of 49 (96%) indicated potential or actual public health hazards or risks (Figure 3). The vast majority of all papers in this topic indicate the need for additional study, particularly large-scale, quantitative epidemiologic research.

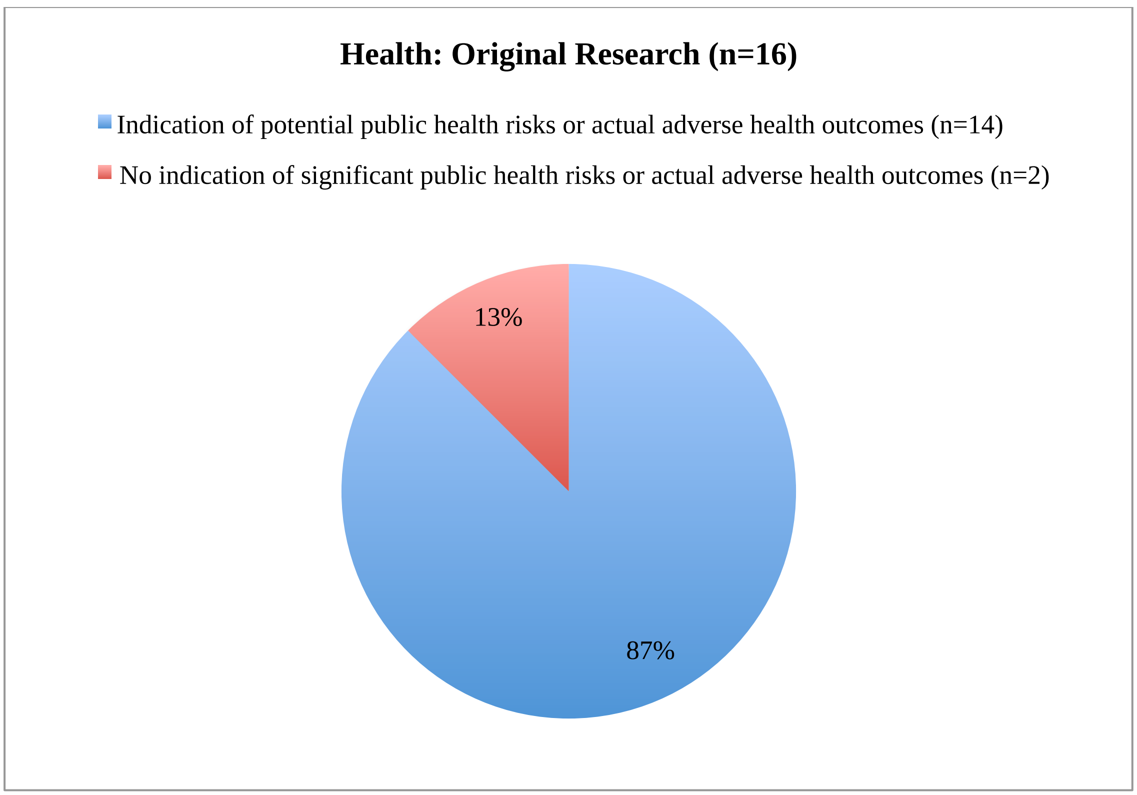

Figure 2. Peer-reviewed publications on the human health dimensions of shale gas development (original research)

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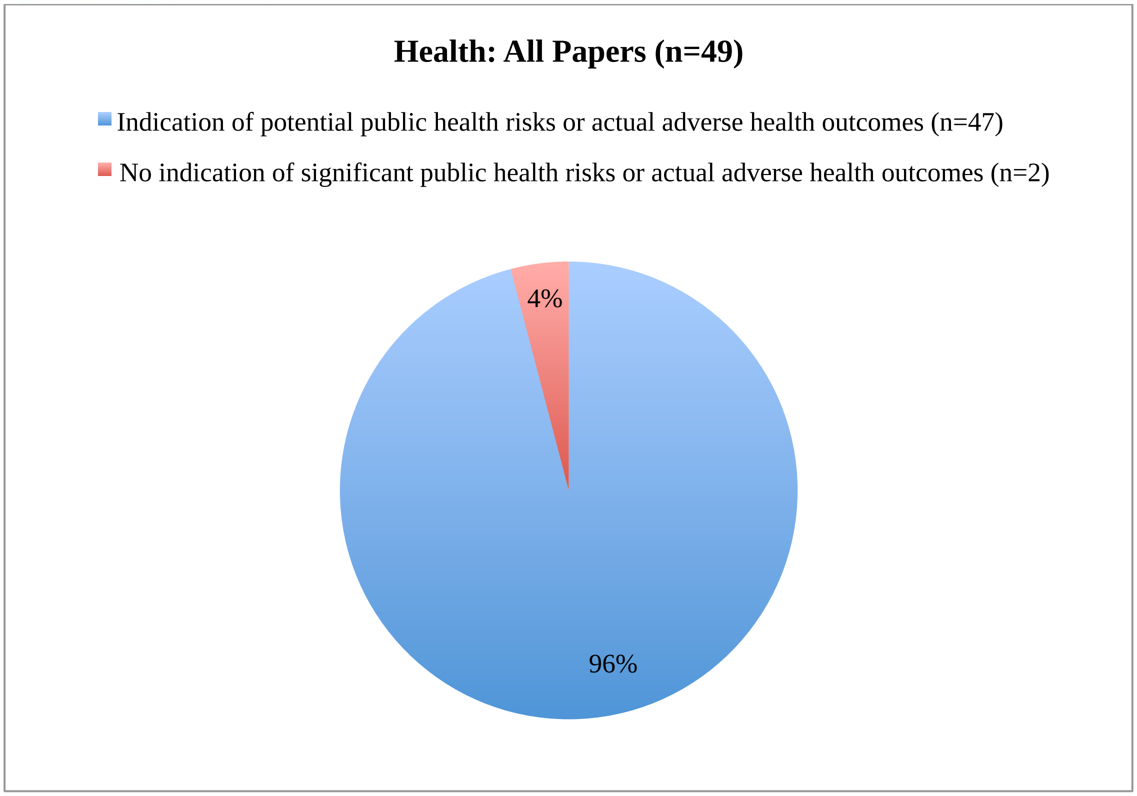

Figure 3. Peer-reviewed publications on the human health dimensions of shale gas development (original research, commentaries, and reviews)

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Water Quality

Based on our criteria, we included 30 original research studies relevant to shale gas development and water contamination. Of these 30 studies, 22 (73%) showed indication of potential, positive association, or actual incidence of water contamination associated with shale gas development, while 8 (27%) showed indication of minimal potential, negative association, or rare incidence of water contamination (Figure 4).

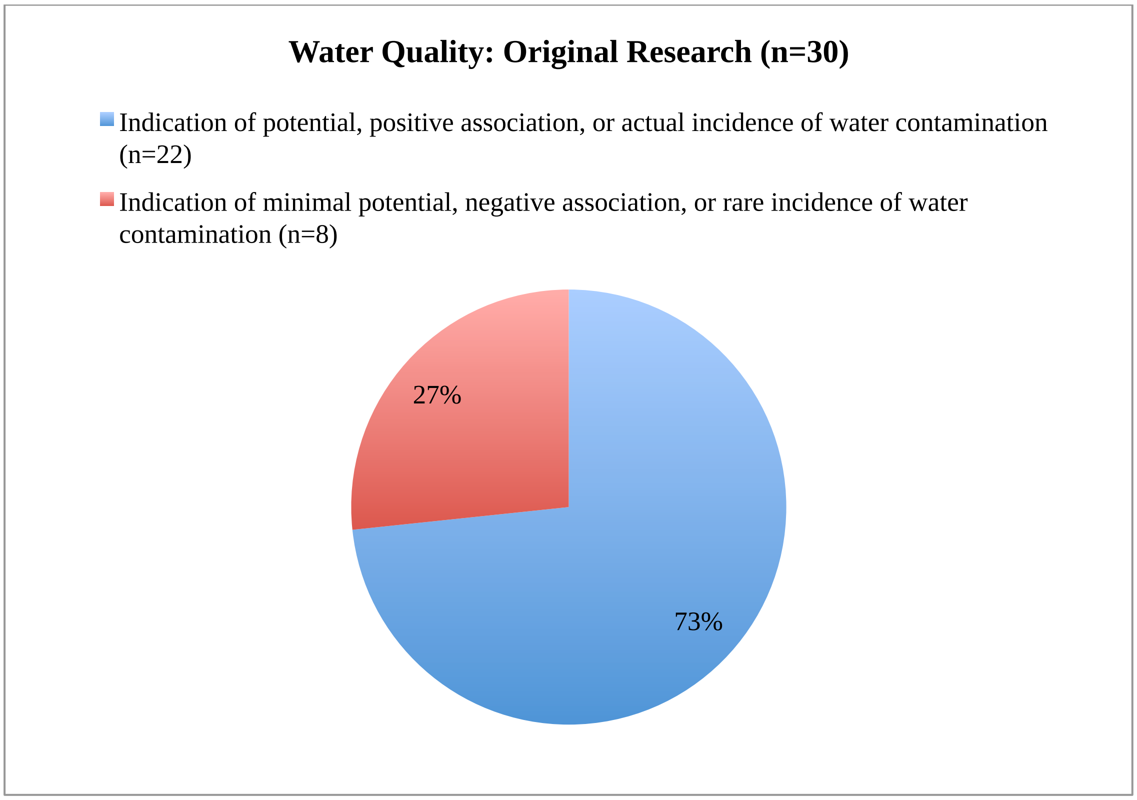

Figure 4. Peer-reviewed publications on shale gas development and water quality contamination (original research)

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Air Quality

Based on our criteria, we included 23 original research studies relevant to questions involving associations between shale and tight gas development and air pollutant emissions and atmospheric air pollutant concentrations. Of these 26 studies, 24 (92%) showed indications of elevated air pollutant emissions and/or atmospheric concentrations, while 2 (8%) of the studies showed no indication of significantly elevated air pollutant emissions and/or atmospheric concentrations (Figure 5).

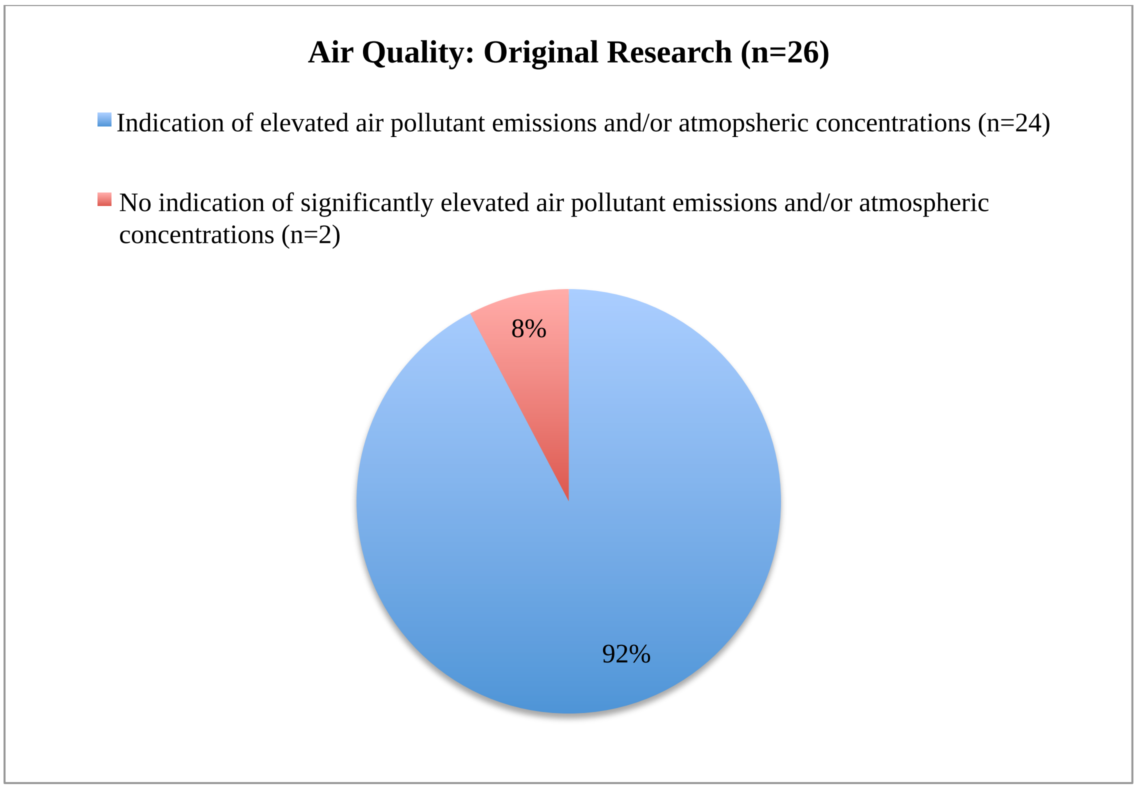

Figure 5. Peer-reviewed publications on shale and tight gas development and air pollutant emissions/air quality degradation (original research)

4. Discussion

In this analysis, we reviewed the direction of findings among papers that assessed the association between shale and tight gas development and air, water, and public health impacts. In each subject area, we found that the majority of studies indicated negative impacts of shale and/or tight gas development on the outcome of interest. Scientific consensus is not yet achievable given comparison limitations due to differences in geological, geographic, engineering, and other attributes, as well as methodological differences between studies. However, these results indicate that shale and tight gas development has known environmental and public health hazards and risks. Regulators, policy makers, and others who are charged with determining how, where, when, and if the development of shale gas should be deployed in their jurisdictional boundaries should take these findings into account.

There are clear limitations to this analysis. It provides just an overview of existing scientific studies based on the world's experience with shale gas development from 1 January 2009 to 31 December 2014. While our database is to our best estimation exhaustive, our literature search may not have captured all relevant scientific literature. Additionally, differences in geography may render some studies less relevant when interpreted across geographic and geological space.

Despite the inherent limitations, our analysis provides a general idea of the weight of the scientific evidence of possible impacts arising from shale gas development. It is important to note that this analysis only concerns itself with current empirical evidence and does not take into account developments that could potentially influence environmental and public health outcomes in positive or negative ways under different regulatory regimes. For instance, technological improvements may mitigate some existing problems, but as development continues, well pad intensities increase, and novel geologies and practices are encountered, impacts may increase.

Finally, all forms of energy production and industrial processing have environmental impacts. This report is only focused on reviewing and presenting the available science on some of the most salient environmental and public health concerns associated with shale gas development. We make no claims about the level of impacts that should be tolerated by society – these are ultimately questions of value.

Appendix

Health: Original Research (n=16)
• *Indication of potential public health risks or actual adverse health outcomes (n=14)*

1. Bamberger M, Oswald RE. 2012. Impacts of Gas Drilling on Human and Animal Health. NEW SOLUTIONS: A Journal of Environmental and Occupational Health Policy 22:51–77; doi:10.2190/NS.22.1.e.
2. Colborn T, Kwiatkowski C, Schultz K, Bachran M. 2011. Natural Gas Operations from a Public Health Perspective. Human and Ecological Risk Assessment: An International Journal 17:1039–1056; doi:10.1080/10807039.2011.605662.
3. Colborn T, Schultz K, Herrick L, Kwiatkowski C. 2014. An Exploratory Study of Air Quality near Natural Gas Operations. Human and Ecological Risk Assessment: An International Journal 0:null; doi:10.1080/10807039.2012.749447.
4. Esswein EJ, Breitenstein M, Snawder J, Kiefer M, Sieber WK. 2013. Occupational exposures to respirable crystalline silica during hydraulic fracturing. J Occup Environ Hyg 10:347–356; doi:10.1080/15459624.2013.788352.
5. Esswein EJ, Snawder J, King B, Breitenstein M, Alexander-Scott M, Kiefer M. 2014. Evaluation of Some Potential Chemical Exposure Risks During Flowback Operations in Unconventional Oil and Gas Extraction: Preliminary Results. Journal of Occupational and Environmental Hygiene 11:D174–D184; doi:10.1080/15459624.2014.933960.
6. Ferrar KJ, Kriesky J, Christen CL, Marshall LP, Malone SL, Sharma RK, et al. 2013. Assessment and longitudinal analysis of health impacts and stressors perceived to result from unconventional shale gas development in the Marcellus Shale region. International Journal of Occupational and Environmental Health 19:104–112; doi:10.1179/2049396713Y.0000000024.
7. Kassotis CD, Tillitt DE, Davis JW, Hormann AM, Nagel SC. 2013. Estrogen and Androgen Receptor Activities of Hydraulic Fracturing Chemicals and Surface and Ground Water in a Drilling-Dense Region. Endocrinology 155:897–907; doi:10.1210/en.2013-1697.
8. Macey GP, Breech R, Chernaik M, Cox C, Larson D, Thomas D, et al. 2014. Air concentrations of volatile compounds near oil and gas production: a community-based exploratory study. Environmental Health 13:82; doi:10.1186/1476-069X-13-82.
9. McKenzie LM, Guo R, Witter RZ, Savitz DA, Newman LS, Adgate JL. 2014. Birth Outcomes and Maternal Residential Proximity to Natural Gas Development in Rural Colorado. Environmental Health Perspectives 122; doi:10.1289/ehp.1306722.
10. 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. 424:79–87; doi:10.1016/j.scitotenv.2012.02.018.
11. Rabinowitz PM, Slizovskiy IB, Lamers V, Trufan SJ, Holford TR, Dziura JD, et al. 2014. Proximity to Natural Gas Wells and Reported Health Status: Results of a Household Survey in Washington County, Pennsylvania. Environmental Health Perspectives; doi:10.1289/ehp.1307732.
12. Saberi P, Propert KJ, Powers M, Emmett E, Green-McKenzie J. 2014. Field Survey of Health Perception and Complaints of Pennsylvania Residents in the Marcellus Shale Region. Int J Environ Res Public Health 11:6517–6527; doi:10.3390/ijerph110606517.
13. Steinzor N, Subra W, Sumi L. 2013. Investigating Links between Shale Gas Development and Health Impacts Through a Community Survey Project in Pennsylvania. NEW SOLUTIONS: A Journal of Environmental and Occupational Health Policy 23:55–83; doi:10.2190/NS.23.1.e.
14. Williams JF, Lundy JB, Chung KK, Chan RK, King BT, Renz EM, et al. 2014. Traumatic Injuries Incidental to Hydraulic Well Fracturing: A Case Series. Journal of Burn Care & Research 1; doi:10.1097/BCR.0000000000000219.

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• *No indication of significant public health risks or actual adverse health outcomes (n = 2)*

1. Bunch AG, Perry CS, Abraham L, Wikoff DS, Tachovsky JA, Hixon JG, et al. 2014. Evaluation of impact of shale gas operations in the Barnett Shale region on volatile organic compounds in air and potential human health risks. Science of The Total Environment 468–469:832–842; doi:10.1016/j.scitotenv.2013.08.080.
2. Fryzek J, Pastula S, Jiang X, Garabrant DH. 2013. Childhood cancer incidence in pennsylvania counties in relation to living in counties with hydraulic fracturing sites. J. Occup. Environ. Med. 55:796–801; doi:10.1097/JOM.0b013e318289ee02.

Health: All Papers (n=49)
• *Indication of potential public health risks or actual adverse health outcomes (n=47)*

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6. Colborn T, Schultz K, Herrick L, Kwiatkowski C. 2014. An Exploratory Study of Air Quality near Natural Gas Operations. Human and Ecological Risk Assessment: An International Journal 0:null; doi:10.1080/10807039.2012.749447.
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11. Ferrar KJ, Kriesky J, Christen CL, Marshall LP, Malone SL, Sharma RK, et al. 2013. Assessment and longitudinal analysis of health impacts and stressors perceived to result from unconventional shale gas development in the Marcellus Shale region. International Journal of Occupational and Environmental Health 19:104–112; doi:10.1179/2049396713Y.0000000024.

12. Finkel M, Hays J, Law A. 2013a. The Shale Gas Boom and the Need for Rational Policy. American Journal of Public Health e1–e3; doi:10.2105/AJPH.2013.301285.
13. Finkel ML, Hays J. 2013. The implications of unconventional drilling for natural gas: a global public health concern. Public Health 127:889–893; doi:10.1016/j.puhe.2013.07.005.
14. Finkel ML, Hays J, Law A. 2013b. Modern Natural Gas Development and Harm to Health: The Need for Proactive Public Health Policies. ISRN Public Health; doi:http://dx.doi.org/10.1155/2013/408658.
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17. Goldstein BD, Kriesky J, Pavliakova B. 2012. Missing from the Table: Role of the Environmental Public Health Community in Governmental Advisory Commissions Related to Marcellus Shale Drilling. Environ Health Perspect 120:483–486; doi:10.1289/ehp.1104594.
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31. McKenzie LM, Guo R, Witter RZ, Savitz DA, Newman LS, Adgate JL. 2014. Birth Outcomes and Maternal Residential Proximity to Natural Gas Development in Rural Colorado. Environmental Health Perspectives 122; doi:10.1289/ehp.1306722.
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- *No indication of significant public health risks or actual adverse health outcomes (n=2)*

1. Bunch AG, Perry CS, Abraham L, Wikoff DS, Tachovsky JA, Hixon JG, et al. 2014. Evaluation of impact of shale gas operations in the Barnett Shale region on volatile organic compounds in air and potential human health risks. Science of The Total Environment 468–469:832–842; doi:10.1016/j.scitotenv.2013.08.080.
2. Fryzek J, Pastula S, Jiang X, Garabrant DH. 2013. Childhood cancer incidence in pennsylvania counties in relation to living in counties with hydraulic fracturing sites. J. Occup. Environ. Med. 55:796–801; doi:10.1097/JOM.0b013e318289ee02.

Water Quality: Original Research (n=30)
• *Indication of potential, positive association, or actual incidence of water contamination (n=22)*

1. Darrah TH, Vengosh A, Jackson RB, Warner NR, Poreda RJ. 2014. Noble gases identify the mechanisms of fugitive gas contamination in drinking-water wells overlying the Marcellus and Barnett Shales. PNAS 201322107; doi:10.1073/pnas.1322107111.
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11. Kassotis CD, Tillitt DE, Davis JW, Hormann AM, Nagel SC. 2013. Estrogen and Androgen Receptor Activities of Hydraulic Fracturing Chemicals and Surface and Ground Water in a Drilling-Dense Region. Endocrinology 155:897–907; doi:10.1210/en.2013-1697.
12. Myers T. 2012. Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers. Ground Water 50:872–882; doi:10.1111/j.1745-6584.2012.00933.x.
13. Olmstead SM, Muehlenbachs LA, Shih J-S, Chu Z, Krupnick AJ. 2013. Shale gas development impacts on surface water quality in Pennsylvania. Proc. Natl. Acad. Sci. U.S.A. 110:4962–4967; doi:10.1073/pnas.1213871110.
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- *Indication of minimal potential, negative association, or rare incidence of water contamination (n=8)*

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Air Quality: Original Research (n=26)
• *Indication of elevated air pollutant emissions and/or atmospheric concentrations (n=24)*

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Physicians Scientists & Engineers

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APPENDIX
PART 2

APPENDIX INDEX

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NATURAL RESOURCES DEFENSE COUNCIL

September 8, 2010

By FedEx and e-mail

The Honorable Lisa Jackson
Administrator
United States Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Petition for Rulemaking Pursuant to Section 6974(a) of the Resource Conservation and Recovery Act Concerning the Regulation of Wastes Associated with the Exploration, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy.

Dear Administrator Jackson:

To best protect human health, food sources, and our environment from the toxicity of contaminants found in wastes associated with the exploration, development and production of oil, gas, and geothermal energy, we believe it is appropriate for the Environmental Protection Agency (EPA) to reconsider its 1988 Regulatory Determination and regulate these wastes under Subtitle C of the Resource Conservation and Recovery Act (RCRA). The Natural Resources Defense Council (Petitioner) is submitting the attached rulemaking petition pursuant to Section 6974(a) of RCRA, 42 U.S.C. § 6974(a). In support of this petition, we identify numerous reports and data produced since the EPA's Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development, and Production Wastes (July 6, 1988) which quantify the waste's toxicity, threats to human health and the environment, inadequate state regulatory programs, and readily available solutions.

The Natural Resources Defense Council (NRDC) is a nonprofit environmental action group established in 1970 by a group of law students and attorneys at the forefront of the environmental movement. The Natural Resources Defense Council's purpose is to safeguard the Earth: its people, its plants and animals and the natural systems on which all life depends. NRDC uses law, science and the support of 1.2 million members and online activists to protect the planet's wildlife and wild places and to ensure a safe and healthy environment for all living things. NRDC has worked for many years to ensure the proper regulation of oil and gas exploration and production operations.

Section 6974(a) of RCRA allows any person to petition the Administrator of the EPA to promulgate an environmental regulation. Within a reasonable time following receipt of such petition, the Administrator shall take action with respect to such petition and shall publish notice of such action in the Federal Register, together with the reasons therefor. This petition asks the EPA to take specific actions and directs the EPA's attention to the ample documentation in the record, which provides full support for the designation of wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy as hazardous waste under RCRA and provides a firm and compelling basis for the reconsideration of the EPA's July 1998 Regulatory Determination.

Thank you in advance for your consideration of this petition.

Respectfully submitted by:

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TABLE OF CONTENTS

I. THE EPA SHOULD REGULATE WASTE FROM THE EXPLORATION, DEVELOPMENT AND PRODUCTION OF CRUDE OIL AND NATURAL GAS UNDER SUBTITLE C OF RCRA.

We request that the U.S. Environmental Protection Agency (EPA) promulgate regulations that subject wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy to the hazardous waste provisions of Subtitle C of the Resource Conservation and Recovery Act (RCRA). We submit this petition pursuant to 42 U.S.C. § 6974(a), seeking that EPA ensure safe management of these wastes throughout their life cycle from cradle to grave, including generation, transportation, treatment, storage and disposal. Reports concerning the toxicity of exploration, development and production wastes, their release into the environment, threats to human health, the increasing amount of these types of wastes being generated, the inadequacy of existing state regulations, enforcement and oversight, and the feasibility and economic benefits of using disposal techniques that are less harmful to the environment all support regulation under Subtitle C, as described in detail below.

A. The EPA Has Authority to Reconsider Its 1988 Regulatory Determination.

Congress gave EPA the authority to prescribe necessary regulations to carry out its functions under RCRA.[1] Congress charged EPA with the task of "assuring that hazardous waste management practices are conducted in a manner which protects human health and the environment."[2] Congress ensured that the public had a way to seek additional protections from hazardous wastes by allowing "[a]ny person . . . [to] petition the Administrator for the promulgation, amendment, or repeal of any regulation under" RCRA, and by requiring that "[w]ithin a reasonable time following receipt of such petition, the Administrator shall take action with respect to such petition and shall publish notice of such action in the Federal Register, together with the reasons therefor."[3]

With these provisions, Congress expressed its intent that RCRA would adapt to changing hazardous waste management needs. Foreseeing the need to update regulations promulgated under RCRA to account for changing circumstances,[4] Congress provided the public a way to bring about EPA review of its regulations.[5] These provisions authorize EPA to reconsider its current treatment of wastes associated with the exploration, development, or production of oil and gas (E&P wastes).

[1] 42 U.S.C. § 6912(a)(1).
[2] 42 U.S.C. § 6902(a)(4).
[3] 42 U.S.C. § 6912(a)(1).
[4] 42 U.S.C. § 6912(b).
[5] 42 U.S.C. § 6912(a)(1).

Congress passed RCRA in 1976 as an amendment to the Solid Waste Disposal Act of 1965 in an effort to enact more comprehensive waste disposal standards nationwide.[6] Through RCRA, Congress declared that the "disposal of solid waste . . . without careful planning and management [was] a danger to human health and the environment."[7] Congress later amended RCRA with the Solid Waste Disposal Act Amendments of 1980.[8] One of the 1980 amendments, the so-called Bentsen Amendment, temporarily exempted "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas" from regulation under RCRA.[9]

Under the Bentsen Amendment, Congress directed EPA to conduct a study to determine whether or not E&P wastes should be regulated as hazardous wastes under RCRA.[10] EPA completed the required study and submitted a Report to Congress on the Management of Waste from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy.[11] Shortly after submitting its report to Congress, EPA issued its Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development, and Production Wastes, in which it decided that regulation of E&P wastes under Subtitle C of RCRA was unwarranted.[12]

In the more than twenty years that have passed since EPA issued its Regulatory Determination on E&P wastes, both the oil and gas industry and the risks associated with E&P wastes have expanded dramatically, making EPA's 1988 Regulatory Determination unjustified. While E&P wastes have always been hazardous to human health and the environment, the recent expansion of drilling operations to more densely populated areas places even more people at risk. EPA's reconsideration of its 1988 Regulatory Determination is especially necessary now that the basis for its Regulatory Determination no longer reflects current conditions. In its 1988 Regulatory Determination, EPA identified three factors as the basis for its decision not to regulate E&P wastes under Subtitle C. These factors included: (1) the infeasibility of implementing alternative regulations, (2) the adequacy of state regulations, and (3) the economic harm that would befall the oil and gas industry if additional regulatory controls were imposed.[13]

[6] Joseph F. Scavetta, *RCRA 101: A Course in Compliance for Colleges and Universities*, 72 NOTRE DAME L. REV. 1647 (1997).
[7] Natasha Ernst, Note, *Flow Control Ordinances in a Post-*Carbone *World*, 13 PENN ST. ENVTL. L. REV. 53 (2004) (citing 42 U.S.C §§ 6901–6992k (2003)).
[8] Pub. L. 96-482; *see also* James R. Cox, *Revisiting RCRA'S Oilfield Waste Exemption as to Certain Hazardous Oilfield Exploration and Production Wastes*, 14 VILL. ENVTL. L.J. 1, 3 (2003).
[9] 42 U.S.C. § 6921(b)(2)(A).
[10] 42 U.S.C. § 6921(b)(2)(B).
[11] EPA, REPORT TO CONGRESS, MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY, Vols. 1–3 EPA530-SW-88-003 (1987) [hereinafter REPORT TO CONGRESS].
[12] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. 25446, 25447 (July 6, 1988).
[13] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25446.

As will be discussed at greater length below, new evidence clearly demonstrates that alternative disposal practices are feasible, state regulations remain inadequate, and the oil and gas industry is unlikely to be severely harmed by the imposition of more stringent waste disposal requirements. Because this evidence shows that the assumptions on which EPA's 1988 Regulatory Determination was based are no longer correct, EPA must revisit its decision.[14]

Nothing in RCRA prevents the EPA from reconsidering its 1988 Regulatory Determination. In *American Portland Cement Alliance*,[15] the court upheld EPA's authority to reconsider regulatory determinations made pursuant to the 1980 amendments to RCRA.[16] Moreover, statements made by EPA in its 1988 Regulatory Determination indicate that EPA never intended the Regulatory Determination to be its final word on E&P waste. Instead, EPA established a three-pronged plan and intended to take further action to fill in existing gaps in the regulations governing the disposal of E&P wastes.[17] To date this three-pronged plan has not been fulfilled. Gaps in the regulatory system governing E&P wastes have grown even wider and evidence of the substantial harm E&P wastes can cause to human health and the environment has continued to accumulate. EPA must revisit its 1988 Regulatory Determination to fulfill its obligations under the 1988 Regulatory Determination and protect human health and the environment from the significant risks posed by E&P wastes.

Although the Congressional approval requirement of the Bentsen Amendment would require EPA to seek Congressional approval before any regulations take effect, it does not limit EPA's ability to review its earlier determination or to consider promulgating regulations.[18] EPA plays an important role in bringing the hazards associated with E&P wastes to Congress' attention. Unless EPA revisits its 1988 Regulatory Determination and recommends that E&P wastes be regulated under Subtitle C of RCRA, E&P wastes will continue to present substantial hazards to human health and the environment.

B. EPA Should Regulate E&P Wastes Under Subtitle C of RCRA.

In light of the documented toxicity of contaminants found in E&P waste, the failure of states to adequately regulate the disposal of E&P wastes, the dramatic increase in oil and gas production that has occurred since 1988, and the availability of safer cost-effective disposal alternatives, EPA must take action in order to prevent further harm to human health and the

[14] EPA Region 8 itself stated that "EPA may need to revisit the continued validity of the exemption in light of the advancements in practices." EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY 3-14 (Working Draft 2008).
[15] 101 F.3d 772 (D.C. Cir. 1996).
[16] *Id.*
[17] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25,447.
[18] 42 U.S.C. § 6921(b)(2)(C).

environment. EPA should reconsider its 1988 Regulatory Determination and regulate E&P wastes under Subtitle C of RCRA. Regulation under Subtitle C is not only appropriate, given that E&P wastes fall within the regulatory criteria for characteristic hazardous waste,[19] but necessary because, without such action, the oil and gas industry will lack the incentives to implement safer techniques as quickly as is necessary.[20]

1. E&P Waste Is Toxic.

E&P waste that is exempt from regulation under Subtitle C includes: drilling fluids and cuttings, produced water, used hydraulic fracturing fluids, rigwash, workover wastes, tank bottom sludge, glycol-based dehydration wastes, amine-containing sweetening wastes, hydrocarbon-bearing soil, and many other individual waste products.[21] In its 1988 Regulatory Determination, EPA admitted that E&P wastes contain toxic substances that endanger both human health and the environment.[22] Despite noting that benzene, phenanthrene, lead, arsenic, barium, antimony, fluoride, and uranium found in E&P wastes were of major concern and present at "levels that exceed 100 times EPA's health based standards,"[23] EPA declined to regulate these toxic substances under Subtitle C of RCRA. But EPA can no longer refuse to act: an ever-increasing amount of evidence demonstrates that E&P wastes are toxic, have had substantial negative effects on human health and the environment, and should be a major concern for EPA. Since 1988, numerous reports, studies, and cases have demonstrated that E&P wastes contain toxic substances that threaten both human health and the environment.

a. Contaminants Found in Different Types of E&P Wastes

E&P wastes are generally divided into three categories: produced water, drilling fluids and cuttings, and associated wastes.[24] All of these wastes contain a variety of toxic substances that present substantial risks to human health and the environment. Despite these risks, these E&P wastes are currently exempt from regulation under Subtitle C.

[19] *See* notes 282–313 *infra* and accompanying text.
[20] Closing Argument of the New Mexico Citizens for Clean Air and Water, Dec. 2007, OCD Document Image No. 14015_648_CF[1] at 9-10; *see also* AMY MALL, DRILLING DOWN: PROTECTING WESTERN COMMUNITIES FROM THE HEALTH AND ENVIRONMENTAL EFFECTS OF OIL AND GAS PRODUCTION vi (2007) [hereinafter "DRILLING DOWN"].
[21] *See* RAILROAD COMMISSION OF TEXAS, *Hazardous and Nonhazardous Oil and Gas Waste* 3–6, *in* WASTE MINIMIZATION IN THE OIL FIELD (2001).
[22] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25448.
[23] *Id.*; *see also* Cox, *supra* note 8, at 9.
[24] CLAUDIA ZAGREAN NAGY, CALIFORNIA DEP'T OF TOXIC SUBSTANCES CONTROL, OIL EXPLORATION AND PRODUCTION WASTES INITIATIVE 6 (2002).

i. Produced Water & Hydraulic Fracturing Wastewater

Produced water, also known as brine, is generally—but erroneously—considered to be "relatively clean" and contain less contaminants than other E&P waste.[25] Despite this common misconception, a study sponsored by the U.S. Department of Energy demonstrated that oil production yields "environmentally hazardous" produced water.[26] The West Virginia Department of Environmental Protection (WVDEP) found many contaminants of concern present in oil and gas wastewaters,[27] including arsenic, lead, and hexavalent chromium, while EPA Region 8 identified the presence of barium, chloride, sodium, sulfates, and other minerals,[28] and the Oklahoma Corporation Commission Oil and Gas Conservation Division stated that produced water can contain high levels of boron.[29] In 2009, the Colorado Oil and Gas Conservation Commission (COCG) documented multiple spills of produced water containing benzene levels exceeding the state's water quality standards, at least one of which was confirmed to have impacted groundwater.[30]

Knowledge of the hazardous nature of produced water is not new. In 1972, Chevron Oil Field Research Company found that "oil field produced waters contain dissolved organic compounds that are toxic to marine life."[31] More than a decade later, the U.S. General Accounting Office (GAO) acknowledged that "[b]rines associated with oil and gas production contain very high levels of chlorides . . . . Brines may also contain . . . petroleum hydrocarbons and additives, such as corrosion inhibitors, . . . and other radioactive materials."[32] EPA was aware of these hazardous constituents when it issued its 1988 Regulatory Determination. In its 1987 Report to Congress, EPA knew that "PAHs [polycyclic aromatic hydrocarbons] are a typical component of some produced waters," that "very low concentrations . . . of PAH are lethal to some forms of aquatic wildlife," and that the practice of disposing of "produced water in

[25] KELLY CORCORAN, KATHERINE JOSEPH, ELIZABETH LAPOSATA, & ERIC SCOT, UC HASTINGS COLLEGE OF THE LAW'S PUBLIC LAW RESEARCH INSTITUTE, SELECTED TOPICS IN STATE AND LOCAL REGULATION OF OIL AND GAS EXPLORATION AND PRODUCTION 31–32.
[26] C. TSOURIS, OAK RIDGE NATIONAL LABORATORY, EMERGING APPLICATIONS OF GAS HYDRATES 7.
[27] The contaminants of concern included: "sulfate, chloride, arsenic, titanium, cobalt, nickel, silver, zinc, vanadium, tin, cadmium, lead, chromium, hexavalent chromium, copper, fluoranthene, cyanide, mercury, selenium, antimony, beryllium, barium, ammonia nitrogen, fluoride, nitrite nitrogen, nitrate nitrogen, oil and grease, total suspended solids, iron, aluminum, chloroform, benzene, phthalate esters, strontium, strontium-90, boron, lithium, gross alpha radiation, gross beta radiation, radium 226+ [and] radium 228." Letter from West Virginia Department of Environmental Protection to William Goodwin, Superintendent Clarksburg Sanitary Board, July 23, 2009.
[28] EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY, WORKING DRAFT 3-11 (2008).
[29] OKLAHOMA CORPORATION COMMISSION OIL AND GAS CONSERVATION DIVISION, GUIDELINES FOR RESPONDING TO AND REMEDIATING NEW OR HISTORIC BRINE SPILLS 2 (2009).
[30] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631502, 1631508 (groundwater impact confirmed).
[31] A.H. BEYER, CHEVRON OIL FIELD RESEARCH CO., TECHNICAL MEMORANDUM, PURIFICATION OF PRODUCED WATER, PART 1—REMOVAL OF VOLATILE DISSOLVED OIL BY STRIPPING 1 (1972).
[32] U.S. GENERAL ACCOUNTING OFFICE, RCED-89-97, SAFEGUARDS ARE NOT PREVENTING CONTAMINATION FROM INJECTED OIL AND GAS WELLS 11 (1989).

unlined percolation pits [allows] PAHs and other constituents to migrate into and accumulate in soils."[33]

In addition to containing dangerous contaminants, produced water can also be radioactive. This problem first attracted national attention 1988 in southern and Gulf Coast states.[34] Shortly thereafter, GAO's 1989 report openly acknowledged the hazard.[35] A more recent analysis of normally occurring radioactive materials (NORM) levels in produced waters from the Marcellus Shale indicates that the dangers may be greater than initially thought.[36] Samples of produced water in the Marcellus Shale analyzed by the New York State Department of Environmental Conservation (NYSDEC) were reported to contain "levels of radium 226, a derivative of uranium, as high as 267 times the limit safe for people to drink."[37]

Despite knowledge of these risks, the data currently available may underestimate the actual radiation levels in produced water. A common method used by industry and EPA to measure radiation levels in produced water has been criticized because of its tendency to underestimate actual radiation levels. In the late 1980s, Exxon Mobil, along with Rogers and Associates Engineers (RAE) and the American Petroleum Institute (API), formulated correlations that could be used to estimate NORM in levels of equipment used to hold produced water.[38] The external measurement process chosen by RAE to measure the NORM levels has since been challenged as "seriously flawed" and has resulted in the reporting of a "greatly reduced radioactivity concentration of 480 pCi/gm."[39] Accurate testing could reveal that the NORM levels in produced water are even higher than currently being reported.

Wastewaters from hydraulic fracturing, largely composed of used fracturing fluids, are also toxic. Common substances found in these wastewaters include: surfactants, friction reducing chemicals, biocides, scale inhibitors, polymers, cross linkers, pH control agents, gel breakers, clay control agents and propping agents.[40] Many of these substances are possible and probable carcinogens.[41] Analysis of fracturing fluid flowback waters from Pennsylvania and West Virginia found the known carcinogen benzene present in nearly half of all fracturing fluid flowback waters at average concentrations nearly one hundred times the maximum acceptable

[33] EPA, REPORT TO CONGRESS, *supra* note 11, at II-44.
[34] Keith Schneider, *Radiation Danger Found in Oilfields Across the Nation*, N.Y. TIMES, Dec. 3, 1990, at A1.
[35] GAO, RCED-89-97, *supra* note 32.
[36] N.Y. DEP'T OF ENVTL. CONSERVATION, DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM 6-130 (2009) [hereinafter DRAFT SGEIS].
[37] Abrahm Lustgarten, ProPublica, *Natural Gas Drilling Produces Radioactive Wastewater*, SCIENTIFIC AMERICAN, Nov. 9, 2009; *see also* DRAFT SGEIS, *supra* note 36, at app. 13.
[38] Motion in Limine to Exclude Rogers and Associates Engineering Reports, Lester v. Exxon Mobil Corp., No. 630-402 (La. 24th Jud. Dist. Ct. 2009), at 6–7.
[39] *Id.* at 7-8.
[40] Wilma Subra, Louisiana Environmental Action Network, Comments on Hydraulic Fracturing to the Louisiana Senate Environmental Quality Committee, Mar. 11, 2010.
[41] *Id.*

contaminant levels established by EPA.[42] While this information demonstrates that these wastes contain toxic compounds, the true extent of the risks associated with hydraulic fracturing wastewaters is currently unknown as many of the compounds used in fracturing fluids and returned in the wastewaters are not publically disclosed.[43]

ii. Drilling Fluids and Drill Cuttings

Drilling fluids and cuttings make up two to four percent of oil and gas wastes.[44] They include rock removed during drilling (drill cuttings) and drilling muds, also known as drilling fluids, which can be either water or oil-based and often contain various additives.[45] A joint EPA/API survey found drilling fluids in reserve pits to contain "chromium, lead and pentachlorophenol at hazardous levels."[46] The survey also found that "oil-based fluids may contain benzene"[47] and that when oil-based fluids are used, "potentially toxic hydrocarbons" will be present in greater quantities.[48] Drilling muds may also contain other "potentially hazardous substances including . . . cadmium, arsenic . . . mercury, copper . . . diesel oil; grease; and various other hydrocarbons and organic compounds (e.g., methanol, chlorinated phenols, formaldehyde, benzene, toluene, ethyl benzene, xylene, and acrylamide)," as well as additives including acids and caustics, corrosion inhibitors, bactericides and biocides, surfactants, defoamers, emulsifiers, filtrater

[42] Susan Riha et al, *Comments on the Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program*, Jan. 2010, at 5; *see also* N.Y. DEP'T OF ENVTL. CONSERVATION, DRAFT SGEIS 5-104 (2009).

[43] Wilma Subra, Comments on Hydraulic Fracturing, *supra* note 40. *See also* DRAFT SGEIS, *supra* note 36, at 5-51 (stating that the fracturing fluid additives list "[c]hemical constituents are not linked to product names in Table 5.6 because a significant number of product composition and formulas have been justified as trade secrets as defined [under New York law] . . . .").

[44] U.S. CONGRESS, OFFICE OF TECHNOLOGY ASSESSMENT, MANAGING INDUSTRIAL SOLID WASTES FROM MANUFACTURING, MINING, OIL AND GAS PRODUCTION, AND UTILITY COAL COMBUSTION—BACKGROUND PAPER 67 (1992).

[45] *Id; see also* U.S. FISH & WILDLIFE SERV., REGION 6, ENVTL. CONTAMINANTS PROGRAM, RESERVE PIT MANAGEMENT: RISKS TO MIGRATORY BIRDS 4–5 (2009).

> "Water-based drilling muds can contain glycols, chromium, zinc, polypropylene glycol, and acrylamide copolymers. Synthetic-based muds contain mineral oil and oil-based muds can contain diesel oil, although diesel oil is being replaced by a palm oil derivative or hydrated caster [*sic*] oil. Other additives typically used in drilling fluids include: polymers (partially hydrolyzed polyacrylamide (PHPA) and polyanionic cellulose (PAC)); drilling detergents; and sodium carbonate (soda ash). PHPA is used to increase viscosity of fluid and inhibit clay and shale from swelling and sticking. PAC is used to increase the stability of the borehole in unconsolidated formations. Drilling detergents or surfactants are used with bentonite drilling fluids to decrease the surface tension of the drill cuttings. Soda ash is used to raise the pH of the water and precipitate calcium out of the water." *Id.* (internal citations omitted).

[46] U.S. CONGRESS, OFFICE OF TECHNOLOGY ASSESSMENT, MANAGING INDUSTRIAL SOLID WASTES FROM MANUFACTURING, MINING, OIL AND GAS PRODUCTION, AND UTILITY COAL COMBUSTION—BACKGROUND PAPER 5 (1992).

[47] *Id.*

[48] OIL & GAS ACCOUNTABILITY PROJECT, PIT POLLUTION—BACKGROUNDER ON THE ISSUES, WITH A NEW MEXICO CASE STUDY 6 (2004).

reducers, shale control inhibitors, thinners and dispersants, weighing materials, bentonite clay, and acrylamide.[49]

The use of these additives increases the risks associated with E&P waste, as many are hazardous compounds themselves.[50] EPA has already classified at least one additive, flocculant acrylamide, as a probable carcinogen.[51] Another frequently used additive, barite weighting agent, can contain cadmium and mercury.[52] When Greenpeace analyzed the heavy metal contents of one drilling fluid additive, SOLTEX® (a scale inhibitor used in both on- and off-shore drilling muds), it identified the presence of antimony, arsenic, barium, cadmium, chromium, cobalt, copper, fluoride, lead, mercury, nickel, vanadium, and zinc.[53] These reports alone create cause for concern; yet, the full extent of the risk these chemicals present is unknown, as the additives' formulas, and thus the concentrations of the various chemicals, are proprietary information and undisclosed by oil and gas companies.[54]

iii. Associated Wastes

Associated wastes include oily sludges, workover wastes, well completion and abandonment wastes and other small volume wastes associated with oil or gas production.[55] Oily sludges consist of "oily sands and untreatable emulsions segregated from the production stream, and sediment accumulated on the bottom of crude oil and water storage tanks."[56] Workover wastes include foam treatment wastes and stimulation fluids.[57] Of all the E&P wastes, associated wastes are generated in the lowest volume;[58] however, this does not mean that they are safe or that current regulations ensure they are disposed of properly. Indeed, "[a]lthough associated wastes constitute a relatively small proportion of total wastes, they are most likely to contain a range of chemicals and naturally occurring materials that are of concern to health and safety."[59] Several associated wastes identified in Colorado have the "potential to be ignitable" while others "can exhibit toxicity for heavy metals such as lead."[60]

[49] *Id.*
[50] *Id.*
[51] U.S. EPA, *Technology Transfer Air Toxics: Acrylamide*.
[52] T.A. Kassim, *Waste Minimization and Molecular Nanotechnology: Toward Total Environmental Sustainability*, *in* 3 ENVIRONMENTAL IMPACT ASSESSMENT OF RECYCLED WASTES ON SURFACE AND GROUND WATERS: ENGINEERING MODELING AND SUSTAINABILITY 191, 204 (Tarek A. Kassim ed., 2005); Texas Railroad Commission, Waste Minimization in Drilling Operations.
[53] JONATHAN WILLS, MUDDIED WATERS, A SURVEY OF OFFSHORE OILFIELD DRILLING WASTES AND DISPOSAL TECHNIQUES TO REDUCE THE ECOLOGICAL IMPACT OF SEA DUMPING (2000).
[54] OIL & GAS ACCOUNTABILITY PROJECT, *supra* note 48, at 6–7.
[55] NAGY, *supra* note 24, at 6.
[56] *Id. at* 13.
[57] *Id.* at 14.
[58] *Id. at* 6; American Petroleum Institute, Waste Management.
[59] Dara O'Rourke & Sarah Connolly, *Just Oil? The Distribution of Environmental and Social Impacts of Oil Production and Consumption*, 28 ANNUAL REV. ENVTL. RESOURCES 587, 595 (2003).
[60] Testimony of Margaret A. Ash, OGCC Envtl. Supervisor, *In the Matter of Changes to the Rules and Regulations of the Oil and Gas Conservation Commission of the State of Colorado*, at 15.

b. Contaminants Found in Specific E&P Waste Disposal Sites

The hazardous contaminants used in oil and gas exploration and production and whose presence has been identified in E&P wastes end up being disposed of in a variety of methods. Pits, burial, land application, and injection wells are the methods most frequently used to dispose of E&P wastes. Wastewater treatment facilities are also increasing in use. Studies of some of these different types of common E&P waste disposal sites provide further evidence of the toxicity of E&P wastes.

Pits are a common E&P waste disposal method used both to store drilling muds and cuttings brought to the surface in drilling operations and to hold produced water, production fluids, used hydraulic fracturing fluid, and other wastes.[61] Numerous studies have found pits to contain toxic levels of many hazardous compounds. In 2007, an industry committee of oil and gas companies in New Mexico sponsored a sampling and analysis program of waste pits in the San Juan Basin.[62] Forty-two substances, including the "BTEX" chemicals[63] (benzene, toluene, ethylbenzene, and xylene), acetone, arsenic, barium, mercury, and radium were found in the samples.[64] Eleven of the chemicals were present at concentration levels above state limits.[65] A more recent sampling of an oilfield pit in Texas identified the presence of high levels of mercury and chromium.[66] Dirt removed from a pit in Oklahoma was contaminated with "high levels of arsenic, dioxins and total petroleum hydrocarbons."[67]

Analysis of land application sites, another method for disposing of E&P wastes, provides further evidence illustrating the hazards of E&P wastes. A study of landfarms conducted by the Arkansas Department of Environmental Quality (ADEQ) found that the substances in E&P wastes that were being land applied exceeded Arkansas' acceptable limits for chloride concentrations in most of the facilities it tested.[68] In addition, "[n]ine out of eleven facilities had

[61] CORCORAN ET AL., *supra* note 25, at 20–21.
[62] The Endocrine Disruption Exchange, Potential Health Effects of Residues in 6 New Mexico Oil and Gas Drilling Reserve Pits Based on Compounds Detected in at Least One Sample, Nov. 15, 2007.
[63] SHANNON D. WILLIAMS, DAVID E. LADD & JAMES J. FARMER, U.S. GEOLOGICAL SURVEY, FATE AND TRANSPORT OF PETROLEUM HYDROCARBONS IN SOIL AND GROUND WATER AT BIG SOUTH FORK NATIONAL RIVER AND RECREATION AREA, TENNESSEE AND KENTUCKY, 2002–2003 10 (2006) ("The BTEX compounds . . . appear on The Clean Water Act Priority Pollutant list of 126 chemical substances (Office of the Federal Register, 2002)."). Testing obtained by individuals residing near the pits has also confirmed the presence of dangerous contaminants. DRILLING DOWN, *supra* note 20, at 26 n.156.
[64] The Endocrine Disruption Exchange, *supra* note 62.
[65] The Endocrine Disruption Exchange, Number of Chemicals Detected in Reserve Pits for 6 Wells in New Mexico That Appear on National Toxic Chemicals Lists: Amended Document, Nov. 15, 2007.
[66] Letter from Roy Staiger, District Office Cleanup Coordinator, Texas Railroad Commission, to Exxon Mobil Corporation, Dec. 31, 2009.
[67] OIL & GAS ACCOUNTABILITY PROJECT, SPRING/SUMMER 2006 REPORT (2006).
[68] Arkansas Dep't of Envtl. Quality, Report on Landfarms ("Four facilities had pond chlorides greater than 3,000 mg/L and the ponds were full . . . . Eight out of eleven facilities had soil concentrations greater than 1,000 mg/Kg on at least one application area. Most were several times higher than 1,000 mg/Kg . . . .").

TPH concentrations that would indicate the application of [oil-based drilling fluids] had taken place."[69] Analysis of soil samples taken from a residential property in Texas, where pit sludge had been land applied less than 300 feet from a residence, "confirmed the presence of numerous hydrocarbons identified as Recognized and Suspected human carcinogens and neurotoxins (1, 2, 4 Trimethylbenzene, 1, 3, 5 Trimethylbenzene, 4-Isopropyltoluene, Acetone, Benzene, Carbon disulfide, Ethylbenzene, Isopropylbenzene, m&m Xylene, n-Butylbenzene, n-Propylbenzene, o-Xylene, sec-Butylbenzene, tert-Butylbenzene, Toluene)."[70] The residents of this property all reported skin rashes after the waste was applied to their land.[71]

c. <u>The risks associated with these contaminants</u>

i. Substances in E&P Wastes Endanger Human Health.

Many of these substances identified in E&P wastes are known carcinogens.[72] The most prevalent contaminants found in E&P wastes are the "BTEX" chemicals:[73] benzene,[74] toluene,[75] ethylbenzene,[76] and xylene.[77] Exposure to benzene has been "associated with an increased risk of leukemia in industrial workers"[78] and other serious health conditions, exposure to toluene can cause nervous system damage,[79] while xylenes can "cause dizziness, headaches and loss of balance among other problems."[80]Many of the other chemicals found in E&P waste, including

[69] *Id.*
[70] WOLF EAGLE ENVIRONMENTAL, ENVIRONMENTAL STUDIES: FUGITIVE AIR EMISSIONS TESTING, IMPACTED SOIL TESTING, MR. AND MRS. TIMOTHY RUGGIERO (2010).
[71] Eric Griffey, *Toxic drilling waste is getting spread all over Texas farmland*, FORT WORTH WEEKLY, May 12, 2010.
[72] *See* Cox, *supra* note 8, at 4.
[73] CORCORAN ET AL., *supra* note 25, at 21.; *see also* WILLIAMS ET AL., *supra* note 63, at 10 ("The BTEX compounds . . . appear on The Clean Water Act Priority Pollutant list of 126 chemical substances (Office of the Federal Register, 2002)."); U.S.G.S., TOXIC SUBSTANCE HYDROLOGY PROGRAM: BTEX.
[74] "Benzene is a known human carcinogen and causes leukemia." DRILLING DOWN, *supra* note 20, at vi; *see also* WILLIAMS ET AL., *supra* note 63, at 26. ("Because of the high degree of toxicity and mobility of benzene (compared to other petroleum hydrocarbons), it is commonly the main ground-water contaminant of concern at petroleum release sites.").
[75] "Toluene can cause fatigue, confusion, weakness, memory loss, nausea, hearing loss, central nervous system damage, and may cause kidney damage. It is also known to cause birth defects and reproductive harm." DRILLING DOWN, *supra* note 20, at vi (footnotes omitted).
[76] "Ethylbenzene can cause dizziness, throat and eye irritation, respiratory problems, fatigue, and headaches. It has been linked to tumors and birth defects in animals, as well as to damage in the nervous system, liver, and kidneys." *Id.* (footnote omitted).
[77] "Xylene can cause headaches; dizziness; confusion; balance changes; irritation of the skin, eyes, nose and throat; breathing difficulty; memory difficulties; stomach discomfort; and possibly changes in the liver and kidneys." *Id.* (footnote omitted).
[78] N.Y. DEP'T OF ENVTL. CONSERVATION, *supra* note 36, at 5-62 (2009).
[79] CORCORAN ET AL., *supra* note 25, at 21.
[80] *Id.*

acetone,[81] arsenic,[82] barium,[83] mercury,[84] and radium,[85] all found in E&P waste samples, also raise serious concerns for human health.

The impacts of these contaminants have been documented. In a 1997 Louisiana case against U.S. Liquids & Exxon, plaintiffs reported that shortly after the dumping of more than fifty million gallons of E&P waste containing benzene, toluene, and lead occurred at a facility located less than 500 feet from the nearest resident's home, "[a] strange smell blew over the community and . . . . [m]any people in the area felt sick . . . . For nearly three weeks, most residents, including children, suffered from stomach pains, sinus problems and other ailments."[86] Other evidence demonstrates that exposure to contaminants in E&P wastes can result in delayed and long-term health effects. One study conducted in the Amazon Basin of Ecuador found that pregnant women who resided in areas where there was discharge of untreated oilfield wastes into the environment experienced higher levels of spontaneous abortion.[87] Another epidemiological study in the same area showed "significantly higher incidence of cancer for all sites combined in both men and women living in proximity to oil fields . . . . [specifically,] [s]ignificantly higher incidences were observed for cancers of the stomach, rectum skin melanoma, soft tissue and

[81] Acetone can cause nose, throat, lung and eye irritation, respiratory problems, fatigue and headaches. *See* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR ACETONE (1995); DRILLING DOWN, *supra* note 20, at vi (footnote omitted).
[82] "Chronic arsenic exposure can cause damage to blood vessels, a sensation of 'pins and needles' in hands and feet, darkening and thickening of the skin, and skin redness. It is a known human carcinogen and can cause cancer of the skin, lung, bladder, liver, kidney, and prostate." DRILLING DOWN, *supra* note 20, at vi (footnote omitted); *see also* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR ARSENIC (2007) ("Exposure to lower levels can cause nausea and vomiting, decreased production of red and white blood cells, abnormal heart rhythm . . . ."); SCIENCELAB.COM, CHEMICALS & LABORATORY EQUIPMENT, MATERIAL SAFETY DATA SHEET: ARSENIC MSDS 1 (2008), ("[Arsenic is] toxic to kidneys, lungs, the nervous system, mucous membranes.")
[83] "Ingesting drinking water containing levels of barium above the EPA drinking water guidelines for relatively short periods of time can cause gastrointestinal disturbances and muscle weakness. Ingesting high levels for a long time can damage the kidneys . . . . Some people who eat or drink amounts of barium above background levels found in food and water for a short period may experience vomiting, abdominal cramps, diarrhea, difficulties in breathing, increased or decreased blood pressure, numbness around the face, and muscle weakness. Eating or drinking very large amounts of barium compounds that easily dissolve can cause changes in heart rhythm or paralysis and possibly death. Animals that drank barium over long periods had damage to the kidneys, decreases in body weight, and some died." AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR BARIUM (2007).
[84] "Mercury can permanently damage the brain, kidneys, and developing fetus and may result in tremors, changes in vision or hearing, and memory problems. Even in low does, mercury may affect an infant's development, delaying walking and talking, shortening attention 'span,' and causing learning disabilities." DRILLING DOWN, *supra* note 20, at vi (footnote omitted).
[85] "Radium is a known human carcinogen, causing bone, liver, and breast cancer." *Id.* (footnote omitted); *see also* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR RADIUM (1999).
[86] Chris Gray, *Pits Cause Stink in Lafourche*, TIMES-PICAYUNE, July 14, 1997, at A1.
[87] Miguel San Sebastian, Ben Armstrong, & Carolyn Stephens, *Outcomes of Pregnancy among Women Living in the Proximity of Oil Fields in the Amazon Basin of Ecuador*, 8 INTL. J. OF OCCUPATIONAL AND ECON. HEALTH 312 (2002).

kidney in men and for cancers of the cervix and lymph nodes in women.[88] As reports and first-hand accounts indicate, the risks posed by the contaminants found in E&P waste are not merely speculative. And the risks will not decrease anytime soon. As many pits containing E&P wastes are buried and forgotten, the buried E&P wastes have the potential to threaten future generations who will be unaware of the hazards just below the surface.

Human health can also be harmed by exposure to radiation in NORM-contaminated E&P wastes. Exposure can occur through inhalation of radium-bearing particles, through direct contact with NORM-contaminated soils and water, or through ingestion of radium-barium particles found in plants or animals exposed to NORM-contaminated soils or water.[89] Exposure to radium can result "in an increased risk of bone, liver, and breast cancer . . . . [it] has been shown to cause effects on the blood (anemia) and eyes (cataracts). It also has been shown to affect the teeth, causing an increase in broken teeth and cavities."[90] And the risks associated with NORM-contaminated soils and waters can persist for decades. In particular, land contaminated by radium 226, such as that found in produced water from the Marcellus Shale,[91] can pose a threat to "many generations of individuals living or working on NORM-contaminated land for a period covering nearing 20,000 years."[92]

ii. Substances in E&P Wastes Endanger Wildlife and Livestock.

In addition to harming human health, exposure to contaminants in E&P waste can sicken and kill wildlife. A recent report prepared by the U.S. Fish and Wildlife Service (USFWS) indicates that pits present significant risks to wildlife. Pits can "entrap and kill migratory birds and other wildlife . . . . Birds are attracted to reserve pits by mistaking them for bodies of water. . . . The sticky nature of oil entraps birds in the pits and they die from exposure and exhaustion."[93] In 2009, ExxonMobil pled guilty to violating the Migratory Bird Treaty Act,[94] after numerous birds (including mallard ducks, grebes, white-faced ibis, gadwell ducks, owls, Wilson pharalopes, Northern Shoveler ducks, avocets, curlew, a green-winged teal, a Cassin's sparrow, a purple

[88] Anna-Karin Hurtig & Miguel San Sebastian, *Geographical Differences in Cancer Incidence in the Amazon Basin of Ecuador in Relation to Residence near Oil Fields*, 31 INT'L. J. OF EPIDEMIOLOGY 1021, 1025 (2002).
[89] Henry Spitz, Kennith Lovins & Christopher Becker, *Evaluation of Residual Soil Contamination From Commercial Oil Well Drilling Activities and Its Impact on the Naturally Occurring Background Radiation Environment*, 6 SOIL & SEDIMENT CONTAMINATION: AN INT'L J. 37, 43 (1997).
[90] AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, *supra* note 85.
[91] *See supra* note 37.
[92] Henry Spitz, Kennith Lovins & Christopher Becker, *Evaluation of Residual Soil Contamination From Commercial Oil Well Drilling Activities and Its Impact on the Naturally Occurring Background Radiation Environment*, 6 SOIL & SEDIMENT CONTAMINATION: AN INT'L J. 37, 41 (1997).
[93] U.S. FISH & WILDLIFE SERV., REGION 6, ENVTL. CONTAMINANTS PROGRAM, RESERVE PIT MANAGEMENT: RISKS TO MIGRATORY BIRDS i (2009).
[94] 16 U.S.C. §§ 703-708.

martin, and a hawk) were found sick and dead after being exposed to pit contents, including hydrocarbons, in multiple states.[95]

E&P wastes have the potential to destroy lands upon which wildlife depend, disrupt food chains, and prevent wildlife from reproducing.[96] The New Mexico Department of Game & Fish has expressed concern about the hazards of hydrocarbon toxicity to wildlife including "acute and chronic ingestion or absorption toxicity, loss of thermal stability from oiling of fur or feathers, and reproductive failure due to absorption of chemicals from the maternal bird body through the shell of eggs."[97] Other researchers are concerned about the bioaccumulation of E&P wastes in wildlife, a process that would cause their harmful effects to magnify as they progress up the food chain.[98] Wildlife habitat may also be harmed by E&P waste. The New Mexico Department of Game and Fish has stated that it "is concerned that chloride contamination of the soil vadose zone may permanently impact the ability of a closed pit location to support vegetation necessary for productive wildlife habitat."[99] Just as E&P wastes can harm humans in ways that are not immediately apparent but can cause harm to future generations, so too can they harm successive generations of wildlife.

Domesticated animals are also harmed by E&P wastes. The Pennsylvania Department of Agriculture quarantined cattle after they came into contact with hydraulic fracturing wastewater being stored in a pit that leaked into an adjacent field. The owners of the property where the pit was located noticed seepage from the pit for as long as two months prior to the leak. The Department stated that wastewater "contains dangerous chemicals and metals." Tests of the wastewater found that it contained strontium as well as other substances.[100] E&P waste is sometimes disposed of on land used for cattle grazing.[101] Residents of the Barnett Shale have reported seeing cattle drinking from sludge pits.[102] Cattle have been lost due to exposure to E&P waste in New Mexico[103] and 54 out of 56 hair samples from sick cattle analyzed by the Texas Veterinary Medical Diagnostic Laboratory contained petroleum.[104]

[95] Joint Factual Statement, U.S. v. Exxon Mobil Corp., ¶¶ 10–27 (D.Col. 2009).
[96] BRYAN M. CLARK, DIRTY DRILLING: THE THREAT OF OIL AND GAS DRILLING IN LAKE ERIE 25 (2002).
[97] Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to Florene Davidson, Commission Secretary, EMNRD Oil Conservation Division (Jan. 20, 2006); *see also* Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to Florene Davidson, Commission Secretary, EMNRD Oil Conservation Division (Mar. 7, 2006).
[98] BRYAN M. CLARK, *supra* note 96, at 25.
[99] Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to EMNRD Oil Conservation Division (Feb. 2, 2007).
[100] Press Release, Pa. Dep't of Envtl. Prot., *Cattle from Tioga County Farm Quarantined after Coming in Contact with Natural Gas Drilling Wastewater* (July 1, 2010).
[101] *See e.g.*, Amended Complaint, Sweet Lake Land and Oil Co. v. Exxon Mobil Corp., No. 209CV01100, at ¶ 32 (W.D. La. filed Sept. 14, 2009), 2009 WL 4701364.
[102] Bluedaze: Drilling Reform for Texas blog (July 25, 2008).
[103] DRILLING DOWN, *supra* note 20, at 26.
[104] Test results from Veterinary Medical Diagnostic Laboratory on July 26, 2005, August 18, 2005, and September 6, 2005; DRILLING DOWN, *supra* note 20, at 26.

In response to occurrences like these, cattle ranchers and others whose animals are at risk have sought to prevent E&P waste disposal facilities from opening near their properties.[105] Protecting cattle and other domesticated animals from exposure to E&P wastes is particularly important as the hazardous contaminants of E&P wastes have the potential to bioaccumulate in these animals and potentially make their way into the human food chain.[106]

2. Current State Regulations and Enforcement Are Inadequate and Allow E&P Waste to Be Released into the Environment.

Waste produced in E&P operations is disposed of in a variety of ways, with underground injection and burial of waste historically being the most widely used methods.[107] Wastewater treatment facilities are another growing disposal method. Even before EPA made its 1988 Regulatory Determination, data indicated that commonly used disposal practices failed to prevent E&P wastes from contaminating soil and groundwater.[108] A 1987 report documented "the migration of leachate 400 feet from reserve pits buried in . . . North Dakota and reported groundwater contamination 50 feet below the buried reserve pits."[109] Incidences of soil and groundwater contamination have continued to occur since then.

E&P wastes may leak, spill, or evaporate into the air, allowing the chemicals used in oil and gas operations to be released into the environment. These releases occur in large part because many states' regulations do not adequately account for all of these potential modes of contamination, despite the fact that releases are occurring with alarming regularity, or are not vigorously enforced. The regulations of the Railroad Commission (RRC) of Texas have been described as providing only weak assurance that the "quality of waters (and land) will not be impacted by a gas operator's activity."[110] Assurances are similarly minimal in other states where regulations provide virtually useless oversight of E&P waste disposal because they fail to "clearly indicate acceptable disposal practices for all drilling wastes."[111]

An Ohio resident with 23 years of experience in drilling oil and gas wells testified before the state legislature that existing regulations are inadequate and cannot be appropriately enforced: "… the [Ohio Department of Natural Resources] has a serious lack of ability to enforce their own regulations due to the way the current law and this bill are written."[112] A review of Tennessee oil

[105] Susan Hylton, *Drilling Waste Feud, Neighbors of Maverick Energy Services Think Water is Being Polluted*, TULSA WORLD, Mar. 21, 2010, at A11
[106] DRILLING DOWN, *supra* note 20, at 26.
[107] *See* E&P FORUM, EXPLORATION AND PRODUCTION (E&P) WASTE MANAGEMENT GUIDELINES 5 (Report No. 2.58/196, 1993).
[108] U.S. FISH & WILDLIFE SERV., *supra* note 93, at 4.
[109] *Id.*
[110] League of Women Voters of Tarrant County, Gas Drilling Waste-Water Disposal (2008).
[111] BRYAN M. CLARK, *supra* note 96, at 35.
[112] Testimony of James E. McCartney to the 128th General Assembly, Ohio Senate Environmental and Natural Resources Committee. Opponent Testimony on Senate Bill 165, Oct. 28, 2009.

and gas regulations found that the state does not have technical criteria for E&P waste management practices or any certification for E&P haulers.[113] Although all pits must be lined in Tennessee, pits are not considered or tracked through the permitting process and there are no security or wildlife protection measures.[114]

A 2009 letter from the EPA to the RRC of Texas states that the Commission should have "more rigorous evaluation" of conditions for waste disposal wells.[115] Texas also "allows companies to hire their own environmental consultants to check for contamination."[116] These regulatory failures existed when EPA issued its 1988 Regulatory Determination, and have been exacerbated in the wake of EPA's decision not to regulate E&P wastes under Subtitle C of RCRA.

a. Pits

Pit construction requirements vary greatly across the country. While a few states, such as New Mexico and Colorado, have recently adopted stricter rules governing the disposal of E&P wastes in pits, other states have minimal regulations and often do not even require the use of pit liners.[117]

The open design of pits, combined with the often minimal regulatory requirements governing their construction and use, present greater opportunities for their dangerous contents to be released into the environment. Reports indicate that the release of E&P wastes from pits is far too common.

In September 2008, New Mexico compiled its data on cases where pit substances contaminated New Mexico's groundwater.[118] The numbers were staggering: More than 700 incidents of groundwater contamination by oilfield wastes or products were documented.[119] Elsewhere, in 2001, E&P wastes from the Black Mountain disposal facility in Colorado contaminated nearby soil and groundwater when its clay lined pits began to leak.[120] Since then, many more releases of E&P wastes have occurred in Colorado. The Colorado Oil and Gas Conservation Commission (COGCC) documented several pits at the same pad site in Garfield

[113] TENNESSEE DEP'T OF ENV'T & CONSERVATION, STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., TENNESSEE STATE REVIEW 13, 19, 22, 24 (2007).
[114] *Id.* at 30.
[115] FY2008 EPA Region 6 End-of-year Evaluation of the Railroad Commission of Texas Underground Injection Control Program, with transmittal letter from Bill Luthans, Acting Director, Water Quality Protection Division, Region 6 to Tommie Seitz, Director, Oil and Gas Division (June 19, 2009).
[116] Joe Carroll, *Exxon's Oozing Texas Oil Pits Haunt Residents as XTO Deal Nears*, Bloomberg Businessweek, April 16, 2010.
[117] *See infra* notes 146–160 and accompanying text; *see also* OKLA. ADMIN. CODE § 165:10-7-16(b)(1)(B)(iii), (2)(b).
[118] NEW MEXICO ENERGY, MINERALS AND NATURAL RES. DEP'T, OIL CONSERVATION DIV., CASES WHERE PIT SUBSTANCES CONTAMINATED NEW MEXICO'S GROUND WATER (2008).
[119] Oil & Gas Accountability Project, Groundwater Contamination.
[120] Kim Weber, Regarding Support of HB 1414—Evaporative Waste Facilities Regulations.

County whose liners had torn and allowed wastes to be released on multiple occasions between April and August 2008.[121] The reports indicated that the pits were located on rocky terrain and that some of the liners had been torn by rocks on the site.[122] In total, more than 6,000 barrels of pit contents escaped the pits because of the tears.[123] In La Plata County, a landowner reported the possible contamination of his well by an unlined reserve pit located a mere 350 feet uphill from his well.[124] The COGCC eventually concluded that "it appear[ed] that fluids from the unlined reserve pit infiltrated into the shallow groundwater, flowed downhill and impacted the Thomson water well."[125] The COGCC has documented numerous other incidents where pits have leaked,[126] overflowed, [127] or been unlined,[128] thereby allowing their contents to be absorbed by unprotected ground.

In May, 2008, a Colorado citizen drank water from his spring and fell ill. The COGCC found benzene in the groundwater that exceeded standards by 32 times and benzene in faucet water that exceeded standards by 13 times, as well as elevated levels of toluene and xylenes. Although the COGCC began investigating this complaint in June, 2008, it wasn't until October, 2008, that the operator stated that it became aware that the production pit was never permitted. The state appears to have been unaware that the pit was never permitted even though it was investigating the pit as a possible source of groundwater contamination. In July, 2010, the COGCC found that the operator failed to properly permit, construct, maintain, and repair the pit, leading to a release or releases of E&P waste that impacted groundwater. The agency found that the liner had been stretched over rocks and had improperly sealed seams.[129]

In addition to the reports from New Mexico and Colorado, there have been many complaints by citizens of contamination reportedly caused by E&P wastes in other states. NYSDEC has received numerous reports of E&P waste releases, many of which have contaminated soil and

[121] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630424, 1630426, 1630427, 1630428, 1630429, 1630430.
[122] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NO. 1630428.
[123] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630424 (714 bbls), 1630426 (2000 bbls), 1630427 (500 bbls), 1630428 (1250 bbls), 1630429 (204 bbls), 1630430 (2017 bbls).
[124] Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development, Maralex Drilling Fluids in Drinking Water; COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORT, DOC. NO. 1953000.
[125] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, NOAV REPORT, DOC. NO. 200085988; *see also* Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development, Maralex Drilling Fluids in Drinking Water.
[126] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631518, 1631599, 2605176, 2605847.
[127] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 200225543, 200225547, 200225546.
[128] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NO.1632846.
[129] Colorado Oil and Gas Conservation Commission, Cause No. 1V, Order No. 1V, Docket No. 1008-OV-06

groundwater.[130] In June 1987, in West Seneca, N.Y., product from an open pit containing oil and other solvents was found running from the pit towards a nearby creek.[131] In November 1996, in Reading, N.Y., a produced water pit overflowed and spilled approximately two hundred gallons of produced water into a creek feeding into Seneca Lake.[132] NYSDEC determined that no cleanup was possible.[133] When a property owner in Bolivar, N.Y., called in June 2002 to report leaking oil wells, NYSDEC inspectors also found unlined leaking containment ponds.[134]

E&P wastes in pits have been released into the environment in other states as well. Pennsylvania's Department of Environmental Protection (PADEP) has documented several incidents of dangerous E&P waste releases into the environment. Notably, at two of Atlas Resources LLC's well sites in Pennsylvania, "compromised" pit liners allowed fracturing flowback fluids to escape.[135] In Ohio, a fracturing flowback pit was cut with a track hoe in 2010, causing more than 1.5 million gallons of fluid were spilled into the environment.[136] In 2008, the back wall of a pit in Ohio gave way, causing pit contents to spill and flow towards a creek.[137]

In addition to releases caused by torn liners and overflows, pits allow the hazardous contaminants in E&P wastes to be released into the environment through evaporation into the air. E&P wastes such as produced water stored in open pits can "release methane, toxic volatile organic chemicals and sulfur based compounds into the air."[138] Rocky Mountain Clean Air Action collected data showing that wastewater evaporation pits in Garfield County, Colorado are "major sources of air pollution and pose greater threats to human health than previously reported."[139] The data indicated that high levels of hydrocarbons and other hazardous air pollutants were being released into the air. [140] Also in Garfield County, beginning in October 2005, a resident repeatedly notified the COGCC that severe odors were emanating from an E&P waste pit located close to her home.[141] In early December 2005, the resident reported smelling "a different sort of stench . . . the 'Benzene smell'" to the COGCC and requested that the agency

[130] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST (2009).
[131] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 37 (2009) (Spill Number: 8702469).
[132] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 53 (2009) (Spill Number: 9610217).
[133] *Id.*
[134] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 124-25 (2009) (Spill Number: 0275147).
[135] Consent Assessment of Civil Penalty, In re Atlas Resources LLC, Dancho-Brown 4, ¶¶ AV–AZ, Groves 8, ¶¶ BA–BE.
[136] Ohio Department of Natural Resources, Notice of Violation No. 1278508985, June 21, 2010.
[137] Ohio Department of Natural Resources, Notice of Violation No. 2016754140, May 16, 2008.
[138] Subra, *supra* note 43.
[139] Phillip Yates, *Clean Air Group Contends Evaporation Ponds in Garfield County More Dangerous than Previously Believed*, POST INDEPENDENT, Jan. 9, 2008.
[140] *Id.*
[141] Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development.

install full-time air monitoring equipment.[142] At the end of the month, the resident learned that sampling of the air fairly close to the pit "showed that benzene and xylenes exceeded the [EPA's] 'non-cancer risk levels' for these compounds – at 67 µg/m3, benzene was present at more than double the risk level. Other detectable compounds included acetone, toluene and ethylbenzene."[143]

While some incidents are effectively reported and prosecuted by state authorities, many more incidents occur that are not addressed adequately by state officials. In these cases, the citizens affected by such releases into the environment have instead turned to the judicial system in order to hold the oil and gas companies accountable. John Preston Stephenson, Jr. sued Chevron U.S.A alleging that waste from Chevron oil pits contaminated his property with "hazardous toxic and carcinogenic chemicals."[144] Similarly, the Sweet Lake Land and Oil Company sued multiple defendants, including Exxon, Noble Energy, Inc., and Texas Eastern Skyline Oil Company, for contamination of "the soil and groundwater with produced water, oil, drilling muds, technologically enhanced naturally occurring radioactive materials (sometimes referred to as 'TENORM'), hydrocarbons, metals, and other toxic and/or hazardous substances, wastes and pollutants," claiming that the defendants knew the pits contents would contaminate the plaintiff's surface and subsurface soil and water.[145] Sweet Lake Land and Oil Company further alleged that "[t]he presence of the pits, substances and scrap on and under the Property constitutes a nuisance."[146] These claims are only a handful of many more by citizens who have been harmed by E&P wastes released from pits.[147]

These reports of contamination are at least partially attributable to inadequate state efforts to regulate E&P waste disposal in pits. Despite the fact that pit contents have been found to contain hazardous contaminants,[148] many states fail to require operators to use the most basic of precautions. Tennessee, for example, does not even take pits into account in its permitting process, thereby "making their management and disposal difficult to track" and increasing the

[142] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, COMPLAINT REPORT, DOC. NO. 200081602.
[143] Oil &Gas Accountability Project, *supra* note 141.
[144] Amended Complaint at ¶ 9, Stephenson v. Chevron U.S.A, Inc., No. 209CV01454, (W.D. La. filed Sept. 11, 2009), 2009 WL 4701406.
[145] Sweet Lake Land and Oil Co. v. Exxon Mobil Corp., *supra* note 101, at ¶ 10.
[146] *Id.* at ¶ 27.
[147] *See also* Petition for Damages, Brownell Land Corp., LLC v. Honey Well Int'l., No. 08CV04988, ¶¶ 11-12 (E.D. La. filed Nov. 21, 2008), 2008 WL 5366168; Rice Agricult. Corp., Inc., v. HEC Petroleum Inc., 2006 WL 2032688 (E.D. La); Petition for Damages, Tensas Poppadoc, Inc. v. Chevron U.S.A., Inc., No. 040769, ¶ 8 (7th Judicial Court La. filed Sept. 21, 2005), 2005 WL 6289654; Petition for Damages to School Lands, Louisiana v. Shell Oil Co., No. CV04-2224 L-O, (W.D. La. filed Oct. 29, 2004), 2004 WL 2891505 (where the State of Louisiana and the Vermilion Parish School Board made similar allegations against Shell Oil, claiming they had contaminated school property. In July 2006, the case was remanded to state court).
[148] *See* notes 62–67 *supra*.

likelihood that the locations of the wastes will be forgotten in the future.[149] In addition, Tennessee has no freeboard or liner integrity requirements,[150] does not require testing or tracking of pit wastes,[151] and fails to require oil to be removed from pits.[152] Kentucky similarly turns a blind eye to the risks E&P wastes present to the public through its failure to require testing of E&P waste characteristics and its treatment of all E&P wastes except production brines and drilling muds as solid wastes, subject to less stringent disposal requirements "irrespective of the risk posed to human health or the environment from the waste."[153]

States also fail to take other simple steps that would dramatically decrease the likelihood of E&P wastes being released into the environment, for example, requiring pits to be lined with impermeable barriers. In Oklahoma, neither emergency pits nor pits holding water-based drilling fluids are required to have any lining.[154] This failure to require the use of a liner in pits holding water-based drilling fluids increases the risk that the "barite, clays, lignosulfonate, lignite, caustic soda and other specialty additives" found in water-based muds will contaminate the environment.[155] Kentucky's liner requirements are also inadequate. Kentucky does not require the use of liners in drilling pits that are used for less than thirty day storage and has "minimal liner requirements for holding pits" for storage over thirty days.[156]

Wildlife protection devices are another important and too often underused safety measure. Tennessee,[157] Louisiana,[158] and Kentucky all fail to require any "fencing, flagging or netting of pits," thereby increasing the risks the pits present to wildlife and domestic animals.[159] And according to a recent report prepared by Region 6 of the U.S. Fish & Wildlife Service, these three states are not alone.[160] As reported by Region 6, only thirteen states require pits or open tanks to be screened or netted to prevent wildlife from coming into contact with E&P wastes.[161] The failure to require pit operators to use even the most basic protection devices such as fencing or netting greatly increases the likelihood that wildlife will come into contact with E&P waste and suffer significant harm.

[149] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 30.
[150] *Id.*
[151] *Id.* at 32.
[152] *Id.* at 31.
[153] STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., KENTUCKY STATE REVIEW 50–51 (2006).
[154] OKLA. ADMIN. CODE § 165:10-7-16(b)(1)(B)(iii), (2)(b).
[155] CORCORAN ET AL., *supra* note 25, at 20; *see also* U.S. FISH & WILDLIFE SERV., *supra* note 93, at 4–5 ("Water-based drilling muds can contain glycols, chromium, zinc, polypropylene glycol, and acrylamide copolymers.").
[156] KENTUCKY STATE REVIEW, *supra* note 153, at 54.
[157] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 30.
[158] STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., LOUISIANA STATE REVIEW 29 (2004).
[159] *Id.*
[160] U.S. FISH & WILDLIFE SERVICE, *supra* note 93, at 13 fig. 15.
[161] *Id.*

States also fail to regulate where pits may be located, allowing them to be placed near residences, schools, and other areas frequently used by the public. In some cases, homes are located so close to pits that residents have been forced indoors because of the foul odors and health symptoms emanating from the pits. One Pennsylvania family reported severe headaches caused by fumes from a pit less than 200 feet from their home.[162] As of 2005, when STRONGER, Inc. conducted a review of Indiana's E&P waste disposal practices and regulations, Indiana regulations had no requirements regarding "specifications for the location, orientation and construction of drilling pits. There [were] no required setbacks of minimum distances from buildings, homes or other structures for drilling pits." Since then, although Indiana has adopted a new rule requiring pits to be located at least one hundred feet from streams, rivers, lakes and drainage ways, it still does not specifically require pits to be setback from other structures.[163] By allowing pits to be sited close to where people live and children attend school, state regulators are bringing health risks literally closer to the citizens across the country.

b. Land application

EPA has stated that hazards also exist with land application of E&P wastes, finding that hydrocarbons, salts, and metals can all cause contamination when E&P wastes are land applied.[164] The Oil Industry International Exploration and Production Forum (E&P Forum), an international industry association, has also issued warnings, stating that land application may result in contaminants accumulating "in the soil [at] a level that renders the land unfit for further use."[165] New York State allows waste to be disposed of in municipal landfills.[166] Land where only oil and gas waste is applied is often called a "landfarm." Studies of landfarm conditions confirm that these hazards are real. When the Arkansas Department of Environmental Quality conducted a study of landfarms in Arkansas, it found that "all 11 sites that land applied fluids at some point had improperly discharged the fluids so as to cause runoff into the waters of the state."[167]

Land application sites outside of Arkansas are sources of similar concerns. Near Holdenville, Oklahoma, residents protested the opening of a landfarm because they were worried about

[162] Christie Campbell, *Foul Odor from Impoundment Upsets Hopewell Woman*, OBSERVER-REPORTER, Apr. 14, 2010. June Chappel, who lives near a pit, stated that the odor "reminded her of a hair perm. It smelled like ammonia . . . [and] 'took your breath away.'" *Id.* Other times the fumes have smelled like gasoline, diesel fuel, and sewage. *Id.*
[163] 312 IND. ADMIN. CODE 16-5-13 (2010).
[164] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 49 (2000).
[165] E&P FORUM, *supra* note 107, at 17.
[166] Letter from Gary M. Maslanka, New York State Division of Solid & Hazardous Materials, to Joseph Boyles, Casella (April 27, 2010).
[167] Press Release, Arkansas Dep't of Envtl. Quality, ADEQ Releases Landfarm Study Report (Apr. 20, 2009).

potential "water contamination and land spoilage."[168] After the residents lost two appeals in which they tried to prevent its opening, the landfarm finally began operations and made the residents' fears a reality. Claudia Olivo, who owns a cattle ranch adjacent to the landfarm, filed a complaint with EPA after she noticed "strange glistening spots in the water" on her property.[169] In response, EPA issued a cease-and-desist order against the landfarm after finding that it had made unauthorized discharges of drilling mud into a creek that ran through Olivo's property, in violation of the Clean Water Act.[170] The Crouch Mesa landfarm in Aztec, New Mexico, is located directly across the street from a residential area and is the source of considerable visible dust observed blowing toward homes.[171]

Despite these risks, many states inadequately regulate land application. In Oklahoma, one-time land applications may occur as close as one hundred feet from any perennial stream, freshwater pond, lake or wetland.[172] Tennessee regulations fail to provide any explicit guidance regarding the use of land applications.[173] Meanwhile, Kentucky has no siting criteria for land application specific to E&P wastes.[174]

These lax regulations result in E&P wastes being land applied near, and in some cases, on residential property, increasing the likelihood that humans will be exposed to E&P waste's toxic compounds.[175] In Martha, Kentucky, produced water and tank bottoms were land applied on farmland near where a family of two adults and two children lived.[176] The family grew the majority of the vegetables and meat they consumed on the farm,[177] and the portion of the family's land used for storing E&P waste disposal was located a mere 100 feet from a small creek which "drains into a marsh, which then drains into a larger creek" from which the farm's cattle drank.[178] The family no longer drinks from its well, which has been contaminated with benzene.[179] Lead and arsenic were found in soil samples.[180] In addition, areas of the farm where E&P wastes had been disposed were found to be NORM-contaminated sites which "will remain radioactive for many thousands of years," "creating many opportunities for radium to enter the soil and be taken up by plants or cattle grazing on the land," and threatening "[f]uture inhabitants or workers on the NORM-contaminated land [who] may also be directly exposed to ionizing

[168] Susan Hylton, *supra* note 105, at A11.
[169] *Id.*
[170] *Id.*
[171] DRILLING DOWN, *supra* note 20, at 22.
[172] OKLA. ADMIN. CODE § 165:10-7-26(c)(6) (2009).
[173] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 32.
[174] KENTUCKY STATE REVIEW, *supra* note 153, at 50.
[175] *See* WOLF EAGLE ENVIRONMENTAL, *supra* note 70.
[176] Spitz et al., *supra* note 92, at, 45.
[177] *Id.* at 46.
[178] *Id.* at 45.
[179] *Id.*
[180] *Id.* at 55.

radiation or inhale radium-bearing particles."[181] As demonstrated by the contamination that occurred in Martha, Kentucky, inadequate state regulations too frequently fail to protect the public and the environment from the hazards associated with land application of E&P wastes.

A Texas resident lives fifty feet away from a 100-acre land farm, where the Texas Railroad Commission issued 22 minor permits for 22 different operations that are all located on one property. A second land farm is located just down the road.[182]

c. Injection Wells

Underground injection, the most widely used disposal method,[183] also poses concerns. If the formation into which E&P wastes are injected does not meet certain levels of permeability, porosity, and low reservoir pressure, the formations can form a poor seal around the E&P wastes and threaten nearby aquifers.[184] Under the Underground Injection Control (UIC) Program, E&P wastes may be injected in Class II wells, while wastes designated as hazardous under RCRA can only be disposed of in the more strictly regulated Class I wells.[185]

The lower standards applicable to Class II wells have proven inadequate to prevent E&P wastes from contaminating groundwater. In 1988, GAO released a report, *Safeguards Are Not Preventing Contamination from Injected Oil and Gas Wells,* which examined the effectiveness of EPA's UIC program.[186] Although GAO speculated that it was likely that more incidents had occurred, it reported that the EPA was aware of at least 23 cases across the country where Class II injection wells had contaminated drinking water supplies.[187] Since then more incidences of concern have occurred.

In September 2007, a state inspector in Texas inspected an underground injection disposal well site outside of Fort Worth and found no problems. Yet a resident complained of "spilled oil, overflowing dikes and green-colored fluid in standing puddles." Inspectors returned and found that "oil-stained soil" had seeped several inches into the ground, that the "containment dike will not hold estimated capacity," and that standing water had oil in it. State records showed that the well site was not being used, when in fact it was actively being injected with oil and gas waste.[188]

[181] *Id.* at 57.
[182] *See* Griffey, *supra* note 71
[183] M.G. PUDER & J.A. VEIL, ARGONNE NATIONAL LABORATORY, OFFSITE COMMERCIAL DISPOSAL OF OIL AND GAS EXPLORATION AND PRODUCTION WASTE: AVAILABILITY, OPTIONS, AND COSTS, S-2 (2006) ("By far, the most common commercial disposal method for produced water is injection.").
[184] *See* E&P FORUM, *supra* note 107, at 15.
[185] DRILLING DOWN, *supra* note 20, at 17; *see also* 42 U.S.C § 300h-4; 42 U.S.C § 300h(b); 42 U.S.C. § 300(h)-1(c).
[186] U.S. GENERAL ACCOUNTING OFFICE, *supra* note 32, at 2.
[187] *Id.* at 3.
[188] Abrahm Lustgarten, *State Oil and Gas Regulators Are Spread Too Thin to Do Their Jobs,* ProPublica, December 30, 2009.

Residents in DeBerry, Panola County, Texas, first began complaining that their groundwater was contaminated in 1996.[189] An underground injection disposal facility began operations one-eighth of a mile away from the community in 1987, injecting produced water into the ground at depths between 1,080 and 1,110 feet.[190] In 1996, while the well was still in operation, DeBerry residents told an EPA Region 6 employee that their water was discolored, was staining their kitchen and bath fixtures, and that they were experiencing gastrointestinal problems.[191] The residents of DeBerry ultimately stopped using their drinking water and instead began to obtain water from other sources.[192] No government agency tested DeBerry's drinking water for several years after residents first complained. Not until 2002 did the site operator of the injection wells in DeBerry, Basic Energy, sample the drinking water.[193] When it did, the residents' suspicions were confirmed. The results showed the presence of contaminants above the EPA's maximum contaminant levels.[194] In 2003, the Texas RRC found benzene, barium, arsenic, cadmium, lead and mercury in wells at levels exceeding the state's drinking water standards.[195] Because the Texas RRC never completed a full assessment of the contamination, the source of the contamination is not definitively known; however, residents strongly believe the injection wells were the cause of the contamination, and EPA has been unable to rule this possibility out conclusively.[196]

Also in Texas, an underground injection disposal facility in Daisetta is linked to contamination of a fresh water aquifer. The EPA found a lack of compliance reviews, inappropriate monitoring, and incomplete record-keeping, as well as a lack of evidence that all problems were ever remedied. This problematic facility led to a surface collapse and a large sinkhole.[197]

The likelihood that similar incidents will continue to occur exists as long as underground injection associated with oil and gas exploration, production, and development only has to meet the requirements for Class II wells and states fail to require better monitoring.

In addition, a vast amount of E&P waste is being injected underground without any UIC regulation whatsoever. Used hydraulic fracturing fluid—perhaps millions of gallons per each

[189] EPA OFFICE OF THE INSPECTOR GENERAL, COMPLETE ASSESSMENT NEEDED TO ENSURE RURAL TEXAS COMMUNITY HAS SAFE DRINKING WATER, NO. 2007-P-00034 2 (2007).
[190] *Id.* at 3.
[191] *Id.* at 2.
[192] *Id.*
[193] *Id.*
[194] *Id.*
[195] *Hearing Before the Subcomm. on Superfund and Environmental Health of the S. Comm. on Environment and Public Works* 12–13 (2007) (statement of Robert D. Bullard, Dir. Environmental Justice Resource Center).
[196] EPA, OFFICE OF THE INSPECTOR GENERAL, *supra* note 189, at 3.
[197] EPA, *supra* note 115.

well—remain underground permanently. It has been estimated that up to 90% of hydraulic fracturing fluids used in the Marcellus shale formation remain underground.[198] Yet this waste disposal and storage activity is not subject to any federal underground injection regulations.

d. Wastewater Treatment Facilities

In regions where underground injection is not readily available, hydraulic fracturing wastewater and produced water may be sent to wastewater treatment plants prior to release to surface water. The plants may be publicly owned treatment works (POTWs) that typically process municipal sewage or centralized wastewater treatment (CWT) facilities that process industrial wastes. None of the POTWs and few of the CWT plants currently in operation have the capacity to reduce to safe levels all of the chemical contaminants commonly found in E&P waste. As a result, toxins are released to surface water, with adverse impacts on drinking water quality. The very high concentrations of total dissolved solids (TDS)—principally salts—that are common in hydraulic fracturing wastewater and produced water present a particular problem for wastewater treatment facilities.

Without adequate pretreatment, pollutants in oil and gas waste will pass through a POTW into the receiving stream, and they may interfere with ordinary sewage treatment systems.[199] Even with pretreatment, POTWs are not effective in removing salts from those wastes.[200] The use of POTWs for treatment of E&P waste in western Pennsylvania produced TDS levels in the Monongahela River in excess of drinking water standards, forcing the Commonwealth to limit the waste to one percent of influent at nine plants along the river.[201] Unauthorized discharges of pollutants, including fecal matter, from a POTW into the Susquehanna River were attributed to the plant's acceptance of oil and gas wastes.[202] Even CWT plants rarely have the evaporation and crystallization technologies needed to reduce extremely high levels of TDS in hydraulic fracturing wastewater and produced water (up to 300,000 mg/l) to levels consistent with water quality standards (500 mg/l). There is not a single CWT facility with that capacity in all of New York or Pennsylvania.[203]

[198] ProChemTech International, Inc., Marcellus Gas Well Hydrofracture Wastewater Disposal by Recycle Treatment Process.
[199] N.Y. State Water Res. Inst., *Waste Management of Cuttings, Drilling Fluids, Hydrofrack Water and Produced Water*; Oh. Envtl. Prot. Agency, *Marcellus Shale Gas Well Production Wastewater*.
[200] *Id.*
[201] Joaquin Sapien, *With Natural Gas Drilling Boom, Pennsylvania Faces an Onslaught of Wastewater*, ProPublica, Oct. 4, 2009; *Municipal Authorities' Perspective: Marcellus Shale Natural Gas Wastewater Treatment, Hearing Before the S. Comm. on Envtl. Res. & Energy* (Pa. 2010) (statement of Peter Slack, Pennsylvania Municipal Authorities Ass'n).
[202] Press Release, Pa. Dep't Envtl. Prot., DEP Says Jersey Shore Borough Exceeds Wastewater Permit Limits (June 23, 2009).
[203] N.Y. State Water Res. Inst., *supra* note 199; Joaquin Sapien, *supra* note 201.

e. Other spills, leaks, and intentional dumping

In addition to those releases that commonly occur when these common E&P waste disposal methods are being used properly, many other spills and releases occur before E&P wastes reach these storage or disposal sites. These other releases can be the result of equipment failure, accidents, negligence, or intentional dumping. Consistent federal regulations for waste management, storage and disposal would help prevent them in the future.

For example, in Pennsylvania, Atlas Resources LLC "discharged residual and industrial waste, including diesel and production fluids, onto the ground at seven of the 13 well sites."[204] At three of the wells Atlas allowed produced water to be released into the environment.[205] Pennsylvania records also show that pipes used to transport waste, sometimes for miles, have leaked. In October, 2009, a pipe carrying diluted wastewater spilled about 10,500 gallons into a high-quality stream, killing about 170 small fish and salamanders. In December, 2009, a pipe failed in five places, spilling an estimated 67,000 total gallons of fluid, tests of which found elevated levels of salts, barium and strontium.[206]

NYSDEC has documented numerous other examples of releases. In October 1997, a produced water tank in Willing, New York, containing produced water from natural gas extraction overflowed and contaminated the surrounding soil and a nearby creek from which cows drank with fifteen thousand gallons of produced water.[207] The produced water killed vegetation in its path.[208] More recently, in September 2005, eight hundred gallons of production brine from another tank in Pine City, New York, overflowed when it was not emptied on schedule, causing an impact on nearby streams.[209] In July 1996, crude oil tank bottoms were dumped into a pit and set on fire.[210] In March 2003, a property owner in Ithaca, New York, called to report that a driller was dumping mud on his property.[211] In May 2007, NYSDEC received an anonymous tip indicating that produced water from a natural gas well was being

[204] Press Release, Pa. Dep't Envtl. Prot., DEP Fines Atlas $85,000 for Violations at 13 Well Sites, Jan. 7, 2010.
[205] Consent Assessment of Civil Penalty, *In re Atlas Resources LLC*, Pevarnik 8, ¶¶ Z–AD, Willis 18, ¶¶ AE–AI, Thompson 33 ¶¶ AP–AU.
[206] Laura Legere, *Massive Use of Water in Gas Drilling Presents Myriad Chances for Pollution*, SCRANTON TIMES-TRIBUNE, June 22, 2010.
[207] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 3 (2009) (Spill Number: 9707892).
[208] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 4 (2009) (Spill Number: 9707892).
[209] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 8 (2009) (Spill Number: 0507041).
[210] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 23 (2009) (Spill Number: 9604701).
[211] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 68 (2009) (Spill Number: 0212276).

dumped on the ground near Cayuga Creek in Sheldon, New York.[212] In May 2009, eight hundred gallons of produced water contaminated soils in Westfield, New York, after equipment failed and allowed the fluids to be released into the environment a mere 1200 yards away from nearby homes.[213]

The COGCC has also documented incidents where tanks have been improperly sealed[214] or allowed to overflow,[215] where corroded equipment allowed produced water to contaminate the ground,[216] and where equipment failure has allowed produced water to escape from underground injection wells.[217] Between June 2002 and June 2006, 555 produced water spills were reported to the COGCC.[218]

In Texas, between 2001 and 2006, thirty percent of spill complaints were inspected "either late or not at all."[219] Most recently in the Texas town of Flower Mound, the Texas RRC sent out a notification stating that approximately 3,000 gallons of "flowback water containing fracturing fluid and associated additives" spilled out of gas well pad site.[220] To date, the RRC has not publically released either the cause of the spill or the exact contents of the flowback water.[221]

The mayor of West Union, West Virginia, wrote a letter to the WVDEP in October 2009 to express his concern over WVDEP's failure to notify the town until two months after a spill occurred.[222] The mayor was even more concerned about WVDEP's failure to have any emergency notification system in place, stating that the continued failure to establish such a system "will only result in less time for the water system to react [to future spills] and [result in] a greater chance of catastrophe."[223] Elsewhere in West Virginia, Luanne McConnell Fatora reported a release of between fifty and seventy barrels of some type of oil and gas waste in a

[212] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 159 (2009) (Spill Number: 0750225).
[213] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 143 (2009) (Spill Number: 0902327).
[214] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORT, DOC. NO. 1630697.
[215] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631155, 1631831, 1631794, 1632853.
[216] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630885, 1631496, 1631519, 1632057, 2605191, 1632995.
[217] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 200226284, 200225725, 2605709.
[218] OIL & GAS ACCOUNTABILITY PROJECT, COLORADO OIL AND GAS INDUSTRY SPILLS: A REVIEW OF COGCC DATA (JUNE 2002-JUNE 2006) 1-2 (2006).
[219] Lustgarten, *supra* note 188.
[220] *Frac Fluid Spill Reported in Flower Mound*, CROSS TIMBERS GAZETTE, Mar. 17, 2010.
[221] *Id.*
[222] Letter from Robert F. Fetty, Mayor, Town of West Union, to Barbara Taylor, Director, WVBPH/Office of Environmental Health Services, Oct. 28, 2009.
[223] *Id.*

stream in Doddridge County.[224] Fatora's son discovered the spill when he tried to go fishing in the stream in late August 2009 and found the water to be "acrid" and covered with a "red/orange gel" that had an oily smell which got on his hands and did not "go away for some time despite repeated washing."[225] Although the Chief of the West Virginia Oil and Gas Office stated that the fluids were consistent with oil and gas waste, more than a month after the spill the WVDEP remained uncertain about what caused the release.[226]

These releases, and the undoubtedly numerous other unreported incidents, demonstrate that current regulations and regulatory enforcement is inadequate to prevent E&P wastes from being released into the environment.

3. Oil & Gas Production Has Increased Dramatically Since 1988.

When EPA released its 1988 Regulatory Determination, the domestic oil and natural gas industry was struggling. Since then, oil and natural gas production in the United States has increased dramatically. Tens of thousands of new oil wells have been drilled. According to the U.S. Energy Information Administration (US EIA), between 1989 and 2008 the number of producing gas wells nationwide almost doubled, increasing from roughly 262,000 to 479,000 wells.[227]

Bureau of Land Management (BLM) statistics also demonstrate the growth in oil and gas operations under its jurisdiction. In most years during the 1990s, there were less than four thousand applications for permits to drill (APDs) filed with the BLM.[228] BLM has stated that "[s]ince 1996, the number of new APDs has risen dramatically."[229] BLM received more than ten thousand APDs in 2006.[230] Although BLM projects that the number of APDs will decline by 2010,[231] BLM still expects to receive a staggering number, approximately 7,000, of APDs in 2010. Furthermore, BLM attributes this projected decrease to the fact that a larger percentage of proposed drilling is expected to occur on existing leases and not to a decrease in drilling.[232]

State agency statistics also demonstrate an increase in the amount of domestic drilling: one example is Texas, where the number of permits issued by the RRC for drilling in the Barnett

[224] Ken Ward Jr., *What Caused Big Fracking Fluid Spill in Doddridge County?*, SUSTAINED OUTRAGE: A GAZETTE WATCHDOG BLOG (Oct. 2, 2009); *see also* Letter from Louanne McConnell Fatora to Gov. Manchin, West Highlands Conservancy (Aug. 30, 2009).
[225] Letter from Louanne McConnell Fatora to Gov. Manchin, (Aug. 30, 2009).
[226] Ward Jr., *supra* note 224.
[227] U.S. ENERGY INFO. ADMIN., NUMBER OF PRODUCING GAS WELLS (2009).
[228] BUREAU OF LAND MGT., BLM FY 2010 BUDGET JUSTIFICATIONS III-120 (2010).
[229] *Id.* at III-119.
[230] *Id.* at III-120.
[231] *Id.*
[232] *Id.* at III-122.

Shale increased from 273 in 2000 to 3,653 in 2007,[233] and 4,145 in 2008.[234] Industry-wide, API statistics confirm that these increases are not isolated incidents. The API reported that 2006 was a record year for gas drilling, in which more than 29,000 new wells were drilled.[235] The API expected that this trend would continue and it did: a new 21-year record was reached when 11,771 wells were drilled in the first-quarter of 2007.[236]

Along with this increase in drilling, there has been an associated increase in the amount of E&P waste produced. In Utah's Uintah County the amount of produced water generated from oil and gas operations increased from approximately 800,000 barrels per month in January 1999 to over 1,600,000 barrels per month in January 2007.[237] Even though some techniques have been implemented to reduce the amount of produced water generated from oil and gas extraction activities, EPA's Region 8 noted an overall two percent increase in the amount of produced water generated from 2002 to 2008.[238] The increases in both drilling and E&P waste that have occurred since 1988 indicate that the risks associated with E&P wastes have become even more substantial and that EPA must revisit its Regulatory Determination in light of these developments.

4. Regulation Under Subtitle C of RCRA Would Not Harm the Oil & Gas Industry.

In its 1988 Regulatory Determination, EPA placed significant weight on the potential harm that increased regulation of E&P waste could cause the oil and natural gas industry in making its determination not to regulate E&P wastes under Subtitle C of RCRA. EPA claimed that regulating E&P wastes under Subtitle C would be "extremely costly" for industry.[239] EPA also asserted that "[a]ny program to improve management of oil and gas wastes in the near term will be based largely on technologies and practices in current use."[240] While in 1988 EPA did not believe that the oil and gas industry would develop new waste management technologies, its belief has proved to be incorrect.

[233] Hannah Wiseman, *Untested Waters: The Rise of Hydraulic Fracturing in Oil and Gas Production and the Need to Revisit Regulation*, 20 FORDHAM ENVTL. L. REV. 115, 124 (2009) (citing Texas Railroad Commission, Newark, East (Barnett Shale), Drilling Permits Issued (1993–2007)).
[234] Texas Railroad Commission, Newark, East (Barnett Shale) Field, Drilling Permits Issued (1993–2009).
[235] Daniel Cusick, *Industry Sets Record for Drilling, Well Completions*, LAND LETTER, Jan. 18, 2007.
[236] Am. Petroleum Inst., "U.S. Q1 drilling & completion estimates at 21-year high—API," Apr. 26, 2007.
[237] DIV. OF OIL, GAS AND MINING, UTAH DEP'T OF NATURAL RES., PRODUCED WATER DISPOSAL, graph slide 6 (2007).
[238] EPA REGION 8, *supra* note 28, at fig. 3-9.
[239] 53 FED. REG. at 25446-01, 25456.
[240] *Id.* at 25,451. EPA's Report to Congress indicates that EPA did not truly believe this assertion that it made in the 1988 Regulatory Determination: "Long-term improvements in waste management need not rely, however, purely on increasing the use of better existing technology. The Agency does foresee the possibility of significant technical improvements in future technologies and practices." EPA, REPORT TO CONGRESS, MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY III-2 (1987)

Evidence since 1988 demonstrates that new technologies and practices are available and that the use of these safer practices often results in significant cost savings. In 2008, EPA itself stated that "It has been 20 years since the RCRA exemption for oil and gas exploration and production was implemented, and many practices and chemicals used have changed during that time,"[241] and has noted that many safer drilling fluids have been developed[242] and the use of alternatives to pits has become increasingly practical.[243] In addition to the savings that can result from the use of these new disposal methods, companies using safer disposal practices also obtain cost benefits by preventing pollution in the first place, as opposed to being allowed to use "cheaper" practices and later required to clean up the damage they create.[244] The State of New Mexico found that drilling activity more than doubled in the year immediately following establishment of more protective rules for oil and gas waste pits.[245]

It is time for EPA to require oil and gas companies to use these new, safer technologies.

a. New Waste Disposal Technologies

Safer disposal methods for E&P wastes have been developed since 1988. Although EPA acknowledged that such developments were likely in its 1987 Report to Congress, it chose not to require the use of then-emerging safer technologies because it believed that requiring their use would be prohibitively expensive for the oil and gas industry. Recent cost analyses indicate that those fears were unfounded; in many instances, the use of more environmentally sound disposal practices actually saves oil and gas companies money. For example, a study conducted in New Mexico found that eliminating pits, traditionally considered the cheapest disposal method, is actually more cost-effective than their continued use.[246]

[241] EPA REGION 8, *supra* note 28, at 3–13.
[242] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 29 (2000).
[243] EPA, REGION 8, OIL AND GAS ENVIRONMENTAL ASSESSMENT REPORT 1996–2002 13 (2003).
[244]

> [W]e've had testimony through here that the costs of remediation are, you know, in the hundreds of thousands to, typically millions of dollars. And there's a huge cost benefit to business to prevent pollution versus us allowing them to pollute water and then come back and require them to clean it up. I think that's really a disservice to industry, not to help them prevent that from occurring.

Statement of Commissioner William Olson before the New Mexico Oil Conservation Division, Apr. 16, 2008, OCD Document Image 14015_657_CF[1] at 30.
[245] Press Release, State of New Mexico, Governor Bill Richardson Announces Oil and Gas Drilling Activity in New Mexico Is Strong: Environmental regulations are not driving business away (May 19, 2010).
[246] DORSEY ROGERS, GARY FOUT & WILLIAM A. PIPER, NEW INNOVATIVE PROCESS ALLOWS DRILLING WITHOUT PITS IN NEW MEXICO (2006).

An Oil and Gas Accountability Project (OGAP) analysis demonstrates that closed-loop drilling systems, which use storage tanks and other equipment instead of pits, are cost-effective and can save money compared to conventional waste management with pits.[247] Mary Ellen Denomy, an expert in petroleum accounting, testified before the New Mexico Oil Conservation Division and reported her findings that the costs associated with a typical closed loop drilling system, also known as a pitless drilling system, are only 3.58% of total drilling costs, a significant reduction from the costs associated with typical on-site pit burial (6.58% of total drilling costs) and digging up and hauling wastes to a centralized facility (9.38% of total drilling costs).[248] While initial costs may be higher, closed-loop drilling systems create long-term savings because there is no need to construct pits, drilling waste can be dramatically reduced, water use can be reduced by as much as eighty percent, truck traffic is reduced by as much as seventy-five percent, and tanks can be reused.[249] Comparisons have found closed-loop drilling can result in a cost savings of up to $180,000 per pit,[250] and a project in New Mexico found that:

> [T]he average cost of using a pit and hauling the waste elsewhere for disposal is about 45% more compared to following the same process without a reserve pit. Moreover, the analysis showed that burying the waste on-site costs about 24% more when using a reserve pit as opposed to employing the closed-loop system.[251]

Individual case studies provide further support for these conclusions. A survey of Prima Energy Corporation's closed-loop system in Colorado indicated that closed-loop drilling could be more cost effective than conventional rotary drilling with reserve pits.[252] Prima Energy Corporation drilled over 68 wells in Colorado using closed-loop systems and compared their costs to the costs of using conventional rotary drilling with reserve pits.[253] The closed-loop drilling systems' average cost was $15,600 compared to conventional rotary drilling's cost of $17,020.[254] The study further demonstrated that closed-loop drilling systems result in significant waste minimization. Conventional rotary drilling was found to generate 5,200 barrels more barrels of produced water than closed-loop drilling.[255]

[247] Oil & Gas Accountability Project, Alternatives to Pits.
[248] Oil & Gas Accountability Project, Closing Argument and Proposed Changes to Proposed Rule 50, *Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, Dec. 10, 2007, at 10.
[249] Oil & Gas Accountability Project, *supra* note 247.
[250] *Id; see also* ROGERS ET AL., *supra* note 246, at 4–5.
[251] Dorsey Rogers, Dee Smith, Gary Fout & Will Marchbanks, *Closed-loop drilling system: A Viable Alternative to Reserve Waste Pits*, WORLD OIL, Dec. 2008, at 46.
[252] *See* Oil & Gas Accountability Project, *supra* note 247.
[253] Exhibit 8, Closed-Loop Drilling Case Studies, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, OCD Document Image No. 14015_637_[CF]1.
[254] *Id.*
[255] *Id.*

Similarly a study of two wells drilled two hundred feet apart in Matagorda County, Texas provides further support for assertions that closed-loop drilling systems can provide cost savings.[256] In Matagorda County, two wells were drilled two hundred feet apart "through the same formations, using the same rig crew, mud company and bit program."[257] One well used a closed-loop system while the other used traditional solids-control equipment. The closed-loop system "resulted in some significant savings" including: a forty-three percent savings in drilling fluid costs, twenty-three percent fewer rotating hours, fewer days to drill the wells to comparable depths, a thirty-seven percent reduction in bits used, and up to thirty-nine percent improvement in penetration rates.[258]

EPA's own studies confirm that closed-loop drilling systems are a safer and cost-saving waste disposal process.[259] Because of these types of findings, EPA has promoted the use of closed-loop drilling systems in Region 8.[260] The RRC of Texas has confirmed that closed-loop systems can result in significant cost savings;[261] and many other government agencies also support the use of closed-loop drilling systems.[262] In addition to the already demonstrated economic advantages of closed-loop systems, there is a great likelihood that the costs of constructing closed-loop systems will decrease even more in the future "as economies of scale and innovations in operations" continue to occur.[263] If these systems are manufactured in the United States, they add the benefit of new job creation in addition to lower environmental risk.

Although safer and economical, even closed loop systems can leak or spill. Strong regulations are required to govern the storage and transport of toxic waste. In some cases, waste may be transported via pipeline to storage or disposal sites. Yet in Texas, State officials declared at a public meeting that the state has no "rule-making authority" over such pipelines.[264]

[256] *Id.*
[257] *Id.*
[258] *Id.*
[259] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 69 (2000).
[260] EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY 4-4 (Working Draft 2008).
[261] Abrahm Lustgarten, *Underused Drilling Practices Could Avoid Pollution*, PROPUBLICA, Dec. 14, 2009.
[262] U.S. Fish & Wildlife Serv., *Wildlife Mortality Risk in Oil Field Waste Pits*, U.S. FWS CONTAMINANTS INFORMATION BULLETIN (2000) (recommending the use of closed loop containment systems and elimination of open pits and ponds); BUREAU OF LAND MGT, THE GOLD BOOK: SURFACE OPERATING STANDARDS AND GUIDELINES FOR OIL AND GAS EXPLORATION AND DEVELOPMENT (4th ed. 2007). "To prevent contamination of ground water and soils . . . it is recommended that operators use a closed-loop drilling system or line reserve pits with an impermeable liner." *Id.* at 17.
[263] Controlled Recovery Inc.'s Written Closing Argument, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc*., Dec. 10, 2007, at 3.
[264] Lowell Brown, *Officials Give Few Answers to Argyle*, DENTON RECORD-CHRONICLE, Jan. 30, 2010.

b. Waste Minimization, Reuse, and Recycling Techniques

Waste minimization, reuse and recycling techniques also can be economical for companies. According to the RRC of Texas, "[w]aste minimization has been proven to be an effective and beneficial operating procedure," while recycling "is becoming a big business and more recycling options are available every day." [265] Both serve to reduce the total amount of E&P wastes that must be disposed and thereby decrease the risks associated with E&P wastes. In its manual *Waste Minimization in the Oilfield*, the RRC of Texas offers oil and gas companies more than one hundred ways to minimize wastes.[266] This manual, along with reports from individual companies implementing various waste minimization and recycling techniques, demonstrates that improved practices are possible.

Studies by the E&P Forum attest to the benefits of waste recycling[267] and identify several ways industry can reduce waste, "through process and procedure modifications . . . [For example,] improved solids control equipment and new technology can reduce the volumes [of drilling fluids] discharged to the environment, . . . more effective drillbits can reduce the need for chemical additions, [and] gravel packs and screens may reduce the volume of formation solids/sludge produced."[268] An analysis by OGAP found that the use of closed-loop drilling systems, in addition to providing cost benefits, maximizes the ability to reuse and recycle drilling fluids.[269] And waste reduction is not just beneficial from an environmental perspective. It can provide further opportunities for the oil and gas industry to save money. A study on land owned by the U.S. Army Corps of Engineers in Oklahoma found that a reduction in "wastes by close to 1.5 million pounds" resulted in "[a] material and disposal cost savings of $12,700."[270]

Both the government and industry are aware of the cost saving opportunities associated with the use of waste minimizing technologies and recycling and reuse projects. For example, STW Resources has developed a technology for use in the Barnett Shale that can reclaim approximately seventy percent of the flowback water produced by hydraulic fracturing operations in the region and thereby reduce the total amount of waste associated with hydraulic fracturing while also enabling the wastes to be reused.[271] And in July of 2008, the RRC of Texas approved Devon Energy's "third pilot program to treat and reuse frac fluid . . . . As a result of its water recycling efforts, Devon is the industry leader in water recycling and now used recycled

[265] Railroad Commission of Texas, *supra* note 52.
[266] DRILLING DOWN, *supra* note 20, at 29.
[267] E&P FORUM, *supra* note 107, at14 ("There are potential benefits in the sale of recovered hydrocarbons. All hydrocarbon wastes should be returned to the production stream where possible.").
[268] UNEP E&P FORUM, ENVIRONMENTAL MANAGEMENT IN OIL AND GAS EXPLORATION AND PRODUCTION: AN OVERVIEW OF ISSUES AND MANAGEMENT APPROACHES 54 (1997).
[269] Oil & Gas Accountability Project, *supra* note 247.
[270] Exhibit 8, Closed-Loop Drilling Case Studies, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, OCD Document Image No. 14015_637_[CF]1.
[271] STW RES., INC., CONTAMINATED WASTE WATER RECLAMATION OPPORTUNITIES 2–3.

frac water at one out of every 10 frac jobs in its Barnett Shale operations."[272] Devon's wastewater recycling program "is projected to produce 75 percent reusable fracture fluid and 25 percent high concentrate and solids. The concentrate will be used as a drilling fluid or disposed of in an authorized facility."[273] Devon Energy Production Central Division's vice president estimated that "[a]t full treatment capacity, up to 85 percent of [the] water [Devon] recover[s] from fracture completions in the Barnett Shale could be reused." [274] And Devon Energy is not alone: Fountain Quail Water Management, DTE Gas Resources Inc., Burlington Resources, and Stroud Energy have all engaged in reuse and recycling efforts.[275]

New projects are underway at the national level: the U.S. Department of Energy's National Energy Technology Laboratory launched nine new projects in October 2009 focused on developing new technologies "to improve management of water resources, water usage, and water disposal."[276] These projects add to the fifteen already underway that are focused on "assess[ing] options and technologies for handling, cleaning, and reuse of produced and flowback water" in the Barnett and Appalachian shale plays.[277] When combined with pitless drilling through a closed-loop system, recycling of waste is clearly an effective, available, and economical way to manage E&P waste more safely and allow for compliance with stronger regulations.

c. <u>New Substitutes for Toxic Materials</u>

Studies indicate that the use of less toxic drilling and hydraulic fracturing fluids can both reduce the risks associated with E&P wastes and also reduce oil and gas companies' liability, thus potentially saving them money in the long run.[278] Other agencies confirm EPA's findings on the benefits of using safer cost effective alternatives. Numerous agencies encourage operators "to substitute less toxic, yet equally effective products for conventional drilling products."[279] And most recently, ExxonMobil announced that it "'supports the disclosure of the identity of the ingredients being used in fracturing fluids.'"[280] OGAP sees ExxonMobil's statement as a "significant step" and believes that "[o]nce the chemicals are widely known . . . companies will

[272] News Release, Railroad Commission of Texas, Commissioners Approve of Devon Water Recycling Project for the Barnett Shale, July 29, 2008.
[273] *Id.*
[274] *Energy Companies Strive to Reuse Water*, WEATHERFORD TELEGRAM, July 25, 2007, at 3C.
[275] *Id.*
[276] U.S. Dep't of Energy, National Energy Technology Lab, *Nine New Projects*, OIL & GAS PROGRAM NEWSLETTER (Dep't), Winter 2009, at 8.
[277] *Id.* at 6.
[278] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006 (2000).
[279] BUREAU OF LAND MGT, THE GOLD BOOK: SURFACE OPERATING STANDARDS AND GUIDELINES FOR OIL AND GAS EXPLORATION AND DEVELOPMENT, at 39 (4th ed. 2007).
[280] Katie Burford, *ExxonMobil Favors Fracing Disclosure, Environmental Group Welcomes Position from Oil Industry Giant*, DURANGO HERALD, Apr. 19, 2010.

be more likely to use green alternatives" which will result in "a lessening of the toxicity of the fluids" over time.[281]

In addition, the search for chemicals with lower potential environmental impacts has "result[ed] in the generation of less toxic wastes . . . . [For] example . . . mud and additives that do not contain significant levels of biologically available heavy metals or toxic compounds."[282] These types of new synthetic drilling fluids already have been developed and are less toxic, "free of polynuclear aromatic hydrocarbons and have . . . faster biodegradability and lower bioaccumulation potential."[283] Safer alternatives to current drilling fluids are available—all that remains is for the oil and gas industry to adopt widespread use of them.

Industry has already proven itself to be capable of switching to less hazardous compounds in the past. In the 1990s many drilling companies voluntarily phased out the use of benzene in their operations.[284] EnCana stopped using a chemical, 2-Butoxyethanol, linked with reproductive problems in animals, while BJ Services, "one of the largest fracturing service providers in the world, has discontinued the use of fluorocarbons, a family of compounds that are persistent environmental pollutants." [285] Schlumberger has developed "GreenSlurry," which the company claims is "earth-friendly."[286] Antero Resources Corporation pledged to use only "green frac" materials in the communities of Rifle, Silt and New Castle in western Colorado.[287] Yet these reported less toxic fluids are not used everywhere. While the oil and gas industry clearly has the capability to adapt its operations to safer technologies, most companies have been reluctant to make such changes. EPA should thus act and require the oil and gas industry to expand the use of the safer, less toxic drilling fluids that are currently available.

5. Oil and Gas Waste Meets the Statutory and Regulatory Criteria for Hazardous Waste.

Absent their special exclusion from RCRA, E&P wastes would properly be regulated under Subtitle C of RCRA. Congress defined hazardous wastes under RCRA as:

> [A] solid waste, or combination of solid wastes, which because of its quantity, concentration, or physical, chemical or infectious characteristic may—

[281] *Id.*
[282] E&P FORUM, *supra* note 107, at12-23.
[283] Drilling Waste Management Information System, Drilling Waste Management Fact Sheet: Using Muds and Additives with Lower Environmental Impacts.
[284] Susan Riha et al., *supra* note 42, at 6.
[285] Lustgarten, *supra* note 261.
[286] Schlumberger, "Earth-friendly GreenSlurry system for uniform marine performance," March, 2003.
[287] The Rifle, Silt, New Castle Community Development Plan, Jan. 1, 2006.

> (A) cause, or significantly contribute to an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness; or
> (B) pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed.[288]

Under RCRA, Congress instructed EPA to "define hazardous waste using two different mechanisms: by listing certain specific solid wastes as hazardous . . . and by identifying characteristics . . . which, when exhibited by a solid waste, make it hazardous."[289] Under RCRA, "[c]haracteristic wastes are wastes that exhibit measurable properties which indicate that a waste poses enough of a threat to warrant regulation as a hazardous waste."[290] The four technical criteria EPA uses to determine if a waste is a characteristic waste include:[291] ignitability, corrosivity, reactivity, and toxicity.[292] Waste will be considered hazardous if it exhibits *any* of the four characteristics.[293] Because various types of E&P wastes exhibit several of these characteristics, E&P wastes should properly be regulated under Subtitle C of RCRA as characteristic hazardous wastes.

a. Ignitability

Ignitability is a criterion used to identify wastes that "can readily catch fire and sustain combustion."[294] A substance's flashpoint is indicative of its ignitability.[295] A waste's flash point is "the lowest temperature at which the fumes above a waste will ignite when exposed to flame."[296] Eleven percent of oily sludges sampled in California had a flash point exceeding the regulatory threshold.[297]

The risks associated with E&P wastes having hazardous flashpoints under RCRA's criteria have been demonstrated in the past decade. In January 2003, a fire occurred when hydrocarbon vapor from basic sediment and water, a type of E&P waste, ignited at a Texas open area collection pit.[298] Three people were killed in the fire and four others were severely burned.[299] In

[288] 42 U.S.C. § 6903(5).
[289] EPA, RCRA ORIENTATION MANUAL, CHAPTER III: RCRA SUBTITLE C—MANAGING HAZARDOUS WASTE, at III-17.
[290] *Id.* at III-22.
[291] Hazardous Waste Treatment Council v. U.S. EPA, 861 F.2d 277, 279 (D.C. Cir. 1988).
[292] *See* 40 CFR § 261.20 et seq.
[293] *Id.*
[294] EPA, *supra* note 2899, at III-22.
[295] NAGY, *supra* note 24, at 36.
[296] EPA, *supra* note 2899, at III-23.
[297] NAGY, *supra* note 24, at 31.
[298] U.S. Dep't. of Labor, Occupational Safety & Health Admin., Potential Flammability Hazard Associated with Bulk Transportation of Oilfield Exploration and Production (E&P) Waste Liquids, SHIB-03-24-2008.
[299] *Id.*

May 2006, a natural gas condensate tank and pit caught on fire in Colorado.[300] Nearby residents were described as "'terrified' by the 200-foot flames."[301] Residents were also concerned because they were not able to learn what potential health impacts they were exposed to from the burning waste "since neither the company nor local or state authorities bothered taking air quality samples during the blaze."[302]

More recently, a wastewater impoundment pond in Washington County, Pennsylvania caught fire.[303] George Zimmerman reported seeing "flames shooting 100 feet in the air" at the fire that occurred at the hydraulic fracturing site located on his property.[304] A state police fire marshal determined that the fire was an accident caused by "a malfunction [that] ignited fumes [most likely in the frac tank] and caused $375,000 in damages."[305] The fire also "badly damaged" the frac pit liner, causing a spokeswoman from the Pennsylvania DEP to be concerned that the pit's contents might escape.[306] Instances such as these fires and the sampling data from California indicate that E&P wastes are ignitable, and that this characteristic of E&P wastes has resulted in serious harm. E&P wastes with these flash points would appropriately be regulated as characteristic hazardous wastes under Subtitle C of RCRA. Such regulation is necessary to prevent future incidents similar to the January 2003 and March 2010 fires.

b. <u>Corrosivity</u>

Waste is corrosive if "it is acqueous and has a pH less than or equal to 2 or greater than or equal to 12.5" or if "[i]t is a liquid and corrodes steel . . . at a rate greater than 6.35 mm per year."[307] Drilling wastes sampled in California had elevated pH levels approaching the 12.5 regulatory limit.[308] In addition, corrosive chemicals are frequently found in E&P wastes. For example, hydrogen sulfide is a corrosive and "toxic gas occurring naturally in some oil and gas reservoirs."[309] The corrosive characteristics of E&P wastes have already been responsible for many incidents where E&P wastes have been improperly released. On numerous occasions, spills of E&P wastes have been reported as originating from corroded equipment that had begun to leak because of corrosion attributed to the substances the equipment contained.[310] Again, because a waste is properly regulated under Subtitle C of RCRA when it exhibits *any* of the four

[300] OIL & GAS ACCOUNTABILITY PROJECT, SPRING/SUMMER 2006 REPORT (2006).
[301] *Id.*
[302] *Id.*
[303] Janice Crompton, *Residents Reported Gas Odors Before Explosion*, PITTSBURGH POST-GAZETTE, Apr. 1, 2010, at B-1.
[304] Kathie O. Warco, *Fumes Ignite at Gas Well*, OBSERVER-REPORTER, Apr. 1, 2010.
[305] *Id.*
[306] *Id.*
[307] 40 CFR § 261.22.
[308] NAGY, *supra* note 24, at 37.
[309] E&P FORUM, *supra* note 107, at28.
[310] *See supra* note 216 and accompanying text.

criteria of characteristic hazardous wastes, corrosive E&P wastes should be regulated under Subtitle C.

c. Reactivity

A waste is reactive if "(1) it is normally unstable and readily undergoes violent change without detonating, (2) [i]t reacts violently with water, (3) [i]t forms potentially explosive mixtures with water, (4) [w]hen mixed with water, it generates toxic gases, vapors or fumes in a quantity sufficient to present a danger to human health or the environment, (5) [i]t is a cyanide or sulfide bearing waste which, when exposed to pH conditions between 2 and 12.5, can generate toxic gases, vapors or fumes in a quantity sufficient to present a danger to human health or the environment, (6) [i]t is capable of detonation or explosive reaction if it is subjected to a strong initiating source or if heated under confinement, (7) [i]t is readily capable of detonation or explosive decomposition or reaction at standard temperature and pressure, [or] (8) [i]t is a forbidden explosive . . . ."[311]

Out of the four criteria for determining characteristic hazardous wastes, reactivity is the most difficult to test: "In many cases, there is no reliable test method to evaluate a waste's potential to explode, react violently, or release toxic gas under common waste handling conditions."[312] In some cases, a waste's reactivity can be evaluated by a releasable sulfide test.[313] Although no regulatory threshold valuable for releasable sulfides has been established, EPA established an interim guidance value.[314] Testing of E&P wastes in California found samples of sludge and tank bottoms exceeding EPA's interim guidance value.[315]

d. Toxicity

The Code of Federal Regulations describes the specific levels/concentrations at which various chemicals will be considered toxic for the purposes of RCRA. To determine whether a chemical meets the required level, EPA uses the Toxicity Characteristic Leaching Procedure (TCLP). Many E&P wastes would be considered toxic under this test. The New Mexico Oil Conservation Division (OCD) found that several samples taken from E&P waste disposal pits in the state contained levels of chemicals that failed the TCLP test.[316] Specifically, the OCD found pits that contained levels of arsenic, lead, mercury, 2,4-Dinitrotoluene, and 2-Methylnaphthalene that exceeded TCLP levels.[317] Its report indicated that the levels of lead they found alone would have allowed the wastes to be considered characteristically hazardous if not for the RCRA

[311] 40 CFR § 261.23.
[312] EPA, *supra* note 2899, at III-23.
[313] NAGY, *supra* note 24, at 38.
[314] *Id.*
[315] *Id.* at 38–39.
[316] *See* Earthworks, OCD's 2007 Pit Sampling Program: What Is in that Pit?, at 31.
[317] *Id.* at 34.

exemption.[318] Analysis of E&P waste in California determined that both produced water and oily sludge met the federal toxicity characteristic and would be considered hazardous, again, if not for the RCRA exemption.[319] Because of this evidence, and the multitude of evidence discussed above indicating that E&P wastes have caused, and present substantial risk of continuing to cause, hazards to human health and the environment, EPA should reconsider its 1988 Regulatory Determination and regulate E&P wastes under Subtitle C of RCRA, as would be proper given the fact that they frequently exhibit the same traits as characteristic hazardous wastes.

II. REQUEST FOR PROMULGATION OF REGULATIONS

The Petitioner, the Natural Resources Defense Council, respectfully requests that the EPA promulgate regulations classifying wastes from the exploration, development and production of oil and natural gas as hazardous waste subject to provisions of Subtitle C of RCRA. This request is based on overwhelming evidence that waste from the exploration, development and production of oil and natural gas is hazardous, taking into account its toxicity, corrosivity, and ignitability, that it is released into the environment where it can cause harm, that state regulations are inadequate, and that there are numerous methods available to manage it as hazardous waste. As set forth in this Petition, evidence exists for EPA to document that, because of its quantity, concentration, and chemical characteristics, E&P waste may cause or significantly contribute to an increase in mortality and serious incapacitating illness and that it may pose a substantial present or potential hazard to wildlife and the environment when improperly treated, transported or disposed of, or otherwise managed, as is occurring throughout the U.S. in the absence of sufficient mandatory federal oversight. *See* 42 U.S.C. § 6902(4)-(5).

The Petitioner requests that the EPA consider the relevant statutory and regulatory factors, as well as the factors set forth in the July 1988 Regulatory Determination, and promulgate regulations applying to wastes from the exploration, development and production of oil and natural gas under Subtitle C of RCRA.

Respectfully submitted this 8th day of September, 2010.

[318] *Id.* at 35.
[319] NAGY, *supra* note 24, at 40.

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APPENDIX PART 3

APPENDIX INDEX

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Fears of tainted water well up in western Colorado

By Nancy Lofholm
***Denver Post Staff Writer* (mailto:nlofholm@denverpost.com?subject=The Denver Post:)**

POSTED: 10/11/2009 01:00:00 AM MDT | 28 COMMENTS (HTTP://WWW.DENVERPOST.COM/CI_13535728#DISQUS_THREAD)
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Outfitter Ned Prather, left, with his brother Dick, smells a cup of water from his spring northeast of DeBeque that is contaminated with toxins found in oil and gas production. (William Woody, Special to The Denver Post)

LOGAN MOUNTAIN — Ned Prather can't forget that awful drink of water.

He was thirsty the afternoon of May 30, 2008, after he and his wife, Dollie, drove up the dusty, steeply kinked road to their cabin an hour northeast of DeBeque. He went to the sink and filled a glass with water.

"I tipped it up just like this and just started guzzling — like an idiot. I didn't know it was bad until I drank two- thirds of the cup," said the 61-year-old outfitter as he retraced his actions that day.

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His throat burned. His head pounded. His stomach hurt. He felt like he was going to suffocate.

Tests would show the water from a spring he has drank from for decades was heavily contaminated with a carcinogenic and nervous system-damaging chemical stew known as BTEX — benzene, toluene, ethylbenzine and xylene. BTEX and other volatile organic compounds come to the surface in the production water from oil and gas wells.

Prather may be the only victim of oil-and-gas-field contamination to guzzle a glass of toxin-laced water. But last year, there were 206 spills in Colorado connected to or suspected in 48 cases of water contamination. Since 2003, there have been around 300 cases.

State records show BTEX has seeped into water wells when the casings designed to keep oil and gas wells from contaminating groundwater have given way. Methane, the most common contaminant found in water wells, has blown a pump house off its foundation, forced the evacuation of homes and turned tap water flammable. In Prather's part of the country, a Garfield County hydrogeologic study shows chloride is rising in many springs besides his, indicating they are being affected by drilling.

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The Colorado Oil and Gas Conservation Commission investigates each contamination [illegible] nated water wells, and in the past, h[illegible] gas well [illegible] pits, tanks and pipelines. But finding the source of contamination can be time-consuming and complicated, particularly in Prather's case.

Eighteen wells are located within 3,000 feet of Prather's spring. An abandoned pit of reeking production water sits on one hill above the cabin. Another pit was quickly reclaimed in the days after his drink.

Nearly 8,000 gallons of diesel were spilled on one hill when a spigot was accidentally left open the winter before Prather's spring went bad. Pipelines — some more than 30 years old — snake over the hillsides nearby.

"It's a terrible situation," said Dave Neslin, director of the oil and gas commission. "This one is more complicated."

Prather hasn't talked publicly until now about his nasty drink or his frustration in getting the problem solved. He has always been a supporter of the energy industry. In fact, he and his three brothers used to work for Occidental Petroleum, a company under notice for allegedly contaminating a spring that runs on the other side of his cabin.

But 16 months after his nasty drink, no source has been pinned down for the contamination. The spring water still reeks with an odor somewhere between diesel fuel and permanent- wave solution.

And Prather has had enough.

"I've always stuck up for oil and gas, but now when we need them to stand up and do what's right, they won't," Prather said. "If I was asked what has made me the maddest in all this, it's the oil and gas commission not doing what they are supposed to do."

Three companies operating in the area — Marathon Oil Co., Petroleum Development Corp. and Nonsuch Natural Gas — have been released from notices of alleged violation. Williams Production has been released from a notice on one drill site but is still being investigated on another site above the Prathers' place.

The oil and gas commission has spent $129,000 on the services of four environmental contractors and two chemistry laboratories and a still untallied amount on hundreds of hours of staff time and travel.

The commission also ordered the oil and gas companies to provide alternative drinking water for the Prathers' cabin and to put up a fence between the spring and the cabin. The commission had the companies locate a new spring to supply the cabin, but the Prathers are afraid to drink the water from it.

The four companies initially suspected in the contamination of Prather's drinking water formed a group to investigate the problem. They installed 44 groundwater monitoring wells and 37 soil gas probes.

As he stood out in the middle of the monitoring pipes that bristle up the draw from the Prathers' spring, attorney Richard Djokic, who represents the Prathers, called the commission's actions thus far "enforcement by negotiation" and likened the self-investigation to a bungled crime scene.

"Imagine you have a body on the ground here, and we're all standing around holding guns. A cop comes and says, 'Figure out amongst yourselves who did this and let me know.' "

Neslin argued with that analogy. He said the commission staff reviews all the companies' studies and raw data.

The companies doing the studies aren't admitting blame.

Williams Production issued a prepared statement saying, "None of the data we have collected and analyzed indicates the condensate is coming from Williams Production or its facilities."

Djokic said legal action on the matter has not been ruled out.

There is still the unknown issue of effects on Prather's health. And there is a given: Bad water has decimated his outfitting business. Hunters don't want to stay in a cabin with suspect water or to harvest deer and elk they fear could be drinking contaminated water.

Prather said in the past several years he has taken in more than $100,000 in the outfitting business he built up over 40 years. This year he had to borrow money to return deposits from hunters who changed their minds.

And his children and grandchildren no longer want to come to the cabin.

"This is the thing," Prather said, "Me and [illegible] were going to leave this to our gran[illegible]y."

When it comes to his own health, Prather has no idea what to expect.

"Not that many people have turned up a glass and drank that much benzene at one time," he said.

Prather said after he drank the water, he hopped on a four-wheeler and took a bottle of the stuff to a nearby well where he asked workers, "what did I just drink?" They didn't know, but they sniffed it and took pity on him. They gave him bottled water to ease his burning throat.

Prather's wife drove him to St. Mary's Hospital in Grand Junction. Doctors took multiple blood samples and did an EKG to test his heart.

He wouldn't know for 18 days, after the oil and gas commission tested the water, what he drank. The sample from the spring contained 100 micrograms per liter of BTEX. Five micrograms is the safety threshold for groundwater. A toxicologist with the oil and gas commission told him to get continued blood tests to check for liver or kidney damage.

So far, the tests show no damage. But Prather has suffered unexplained health problems dating back before the drink. His hands and head shake. The tremors have worsened lately.

While Prather worries about that, Neslin said the commission is trying to wrap up the investigation. His staff has narrowed potential sources and concluded the contamination on the Prathers' spring came from a release of condensate on the east side of the drainage, likely from a leaking pipe, pit or tank belonging to Williams.

Prather isn't satisfied. He still suspects Marathon's large diesel spill and the fracking that occurred before the spring went bad. When wells are fracked, liquids containing chemicals are forced into deep rock formations to break up the rock and allow gas to escape.

Prather's spring has now turned into a political issue. State Sen. Josh Penry, who has made criticism of the new oil and gas rules part of his gubernatorial campaign, wrote to Neslin on Prather's behalf two weeks ago. His letter stated that a commission with the time to "promulgate a raft of new rules and paperwork requirements" should have time to enforce longstanding groundwater protection rules.

Neslin replied with an outline of what has been done.

"The Prathers experience provides an example of why the COGCC developed and implemented new requirements and procedures to attempt to prevent such incidents from occurring," he wrote.

Prather agrees but said he sees few oil and gas field problems being stopped.

"I don't see anybody up there preventing anything," he said. "I think they are getting away with murder."

Nancy Lofholm: 970-256-1957 or nlofholm@denverpost.com (mailto:nlofholm@denverpost.com)

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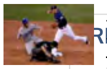
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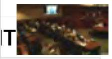
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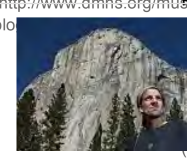


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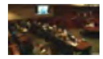
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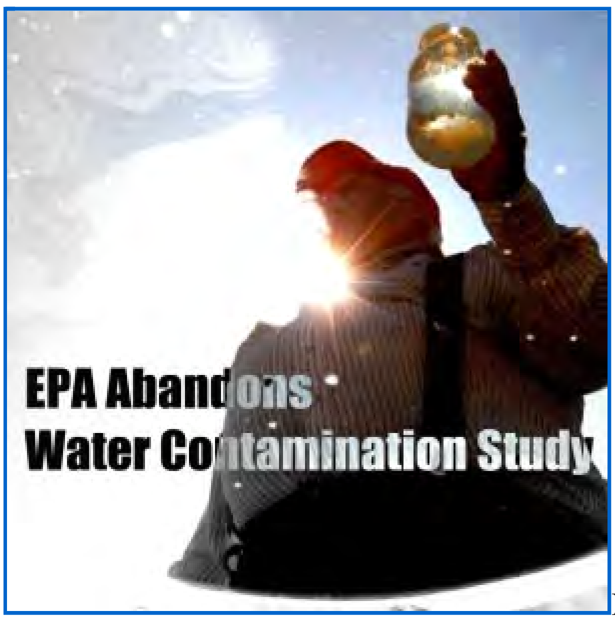
A Closer Look: The EPA's Abandoned Pavillion, WY Investigation

September 13, 2013 by Kendall Gurule 1 comment



In 2011, the EPA issued a draft water contamination study with a groundbreaking assertion—fracking fluid has contaminated drinking water in Wyoming[1]. The study represented the first time that such a claim had been made publicly by the EPA and the first time that such contamination had been scientifically proven. By all estimates, these findings were about to revolutionize the fracking debate. Two years later, the study has been largely discredited, ignored by the media, and was recently completely abandoned by the EPA. So what happened? What's the story with water contamination in Wyoming?

EPA investigates fracking and water contamination in Wyoming

Over the course of the four year study, a total of 5 test wells were drilled by the EPA after an initial round of testing showed the presence of methane and other hydrocarbons in several municipal and domestic water wells[1]. As these substances can sometimes find their way into water wells through natural causes, EPA investigators installed three shallow and two deep monitoring wells to determine if nearby drilling was actually causing the contamination. So what did they find?

In the three shallow test wells drilled near drilling wastewater disposal pits, testing revealed elevated levels of BTEX chemicals, gasoline and diesel range compounds, and other hydrocarbons, indicating that groundwater near these pits was being contaminated by improper disposal of drilling waste products[1]. But was *hydraulic fracturing* actually causing pollution of drinking water deep underground?

Analysis of results from the 2 deep monitoring wells was more complex. Testing of water samples from these wells showed elevated pH levels indicative of drilling activity[1]. Chemicals present in drilling and fracking fluids such as potassium, chloride, synthetic organics, BTEX and other oil and gas compounds were also found in samples taken from the two deep test wells[1]. This evidence, combined with the fact that logs from nearby oil and gas wells showed casing flaws, led investigators to conclude that hydraulic fracturing in the area had indeed led to deep groundwater pollution in the area[1]. A thorough draft of the study was published and awaited peer review. However, the wait began to extend longer and longer…and eventually the agency announced that the study would not be released for peer review at all[3]. So what happened? Why hold back such an apparently groundbreaking investigation?

Did the EPA frack up?

As it turns out the EPA may have been concerned that their results would not hold up under peer review. In 2013, following public hearings and analysis by fellow government agencies such as the US Geological Survey, the US Bureau of Land Management, and the State of Wyoming, it became apparent that the EPA themselves had made some of the same drilling mistakes that they were trying to prevent in industry.

For example, according to the Wyoming Department of Environmental Quality (DEQ), the EPA did not case their monitoring wells correctly[2]. In a contradiction of their own regulatory requirements, EPA drillers did not line their two deep test wells with stainless steel casing[2]. Because the casing was carbon steel rather than stainless steel, it was susceptible to corrosion and thereby to affecting the chemical content of groundwater and fluids in the well. According to the EPA's own publication "Handbook of Suggested Practices for the Design and Installation of Ground-Water Monitoring Wells",

> 'the use of carbon steel, low-carbon steel and galvanized steel in monitoring well construction is not considered prudent in most natural geochemical environments…The presence of corrosion products represents a high potential for the alteration of ground-water sample chemical quality.

The surfaces on which corrosion occurs also present potential sites for a variety of chemical reactions and adsorption. These surface interactions can cause significant changes in dissolved metal or organic compounds in ground water samples …'[2]

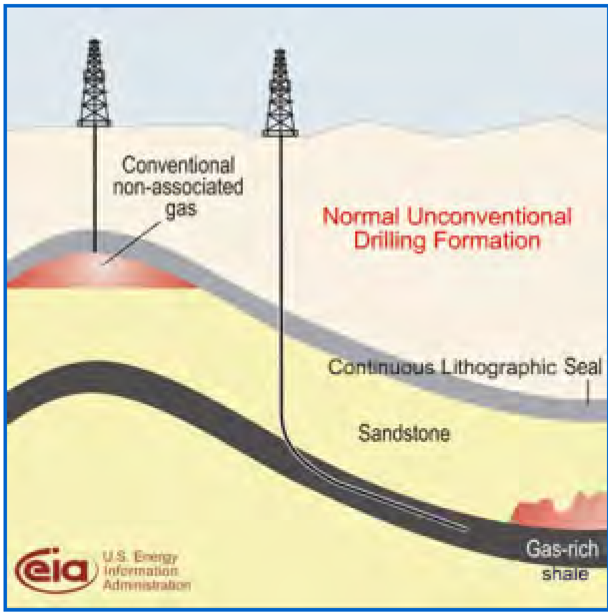
Drilling mud and cuttings from an EPA monitoring well.

Furthermore, the EPA failed to clear drilling mud and cuttings from the bottom of their wells, instead leaving debris behind to contaminate water samples with drilling related chemicals[2]. Consequentially, these combined missteps made it difficult to scientifically prove a link between deep groundwater contamination and fracking. In mid-2013, under pressure from critics, the EPA abandoned the study altogether, handing it over to the State of Wyoming[3]. However, not all of the EPA's findings have been debunked.

Did drilling companies frack up?

While the EPA's methods in drilling the two deep test wells were indeed flawed, their remaining valid results have all but been forgotten under the cloud of skepticism. In addition to its deep water testing, the study also found pollution of shallow groundwater with oil and gas compounds near wastewater disposal pits[1].

According to all current reports, these results are based on reliable test methods and indicate a need for safer and more effective waste disposal methods by drilling companies.



Futhermore, both the well casings and local geology made for risky drilling. As mentioned previously, logs and completion reports for local wells showed sporadic bonding in intervals of casing. Casings were also extremely shallow, with some extending as little as 110 meters underground—actually shallower than some local domestic wells.

Fracking also occurred at unusually shallow depths. To compound the issue, there is little vertical continuity of a lithographic layer in the Wind River Formation[1]. A lithographic layer is a layer of dense shale rock that fluids and gases cannot flow through. Normally, this layer forms a continuous "cap" over an underground fracking location, preventing contaminants from flowing out and into groundwater. Because the composition of the Wind River Formation is so laterally variable, there is no such "cap".

Combined, all these factors make for a high risk situation for water contamination to occur. However, due to their drilling faux pas, the EPA's study does not actually constitute proof.

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In Pavillion, Wyoming Water Contamination Case, Questions Continue To Swirl About Oil and Gas Industry's Role

Sharon Kelly (/user/8003) | February 6, 2014

A funny thing happened when Idaho Dept. of Lands Oil and Gas Program Manager Robert Johnson stepped to the microphone at a public hearing this past fall. He said something that many have long suspected, but few officials have actually been willing to say bluntly and publicly.

He said that the oil and gas industry was responsible for the contaminated groundwater in Pavillion, Wyoming — referring to a high-profile case (http://www2.epa.gov/region8/pavillion) where environmentalists have alleged oil and gas drilling and fracking caused a town's water supplies to go bad.

"Everybody's heard of Pavillion, Wyoming," Mr. Johnson said. "OK. Pavillion was a leaking above ground pit that was not lined."

"Did the industry cause it?" Mr. Johnson said. "Yes they did."

Later in his talk, Mr. Johnson also pointed to a faulty cement casing in a natural gas well as another factor in the case, describing EPA data showing pollution was caused "by a bad cement job on an Encana well that was drilled in 1985."

His statement is noteworthy because, before coming to Idaho, Mr. Johnson was directly involved with the Pavillion investigation. He worked for (http://idahobusinessreview.com/2013/09/20/bobby-johnson-is-oil-and-gas-program-manager-for-idaho-department-of-lands/) the groundwater division of the Wyoming State Engineer's Office, which has taken the lead role in the contamination investigation.

The comments, which were recorded (http://www.co.gem.id.us/development-services/Active%20Public%20Hearings/default.htm) by county officials and distributed by anti-drilling advocates, were also significant because they were so candid and because the state of Wyoming maintains that more study is needed before blame can be assigned. The state is currently investigating the Pavillion incident and expects to publish (http://yosemite.epa.gov/opa/admpress.nsf/0/DC7DCDB471DCFE1785257B90007377BF) a report in September of this year.

Asked about the comments, Idaho state officials said that the remarks about wastewater pits were intended "to illustrate that the State of Idaho requires lined pits to avoid surface contamination," adding that Mr. Johnson, an Idaho official, was not speaking on behalf of the State of Wyoming. Mr. Johnson worked for the oil and gas industry (http://www.pasonusa.com/index.php?option=com_content&view=article&id=13&Itemid=23) before joining (http://http://idahobusinessreview.com/2013/09/20/bobby-johnson-is-oil-and-gas-program-manager-for-idaho-department-of-lands/) the Wyoming State Engineer's Office.

His allegation directly contradicts the position of oil and gas company, Encana, which still maintains on its website (http://www.encana.com/news-stories/news-releases/details.html?release=632327) that tests show "no impacts from oil and gas development" on Pavillion's groundwater. This fall, Encana, which drilled the oil and gas wells that locals suspect caused the pollution, made a $1.5 million grant (http://yosemite.epa.gov/opa/admpress.nsf/0/DC7DCDB471DCFE1785257B90007377BF) to Wyoming to help fund the state report, which left environmentalists crying foul (http://www.warws.com/documents/conservationgroupcallsfortransparencypeerreviewinpavillionareagroundwaterstudy.pdf) over the potential for the funding to undermine the investigation's independence and influence results.

It is the latest development in an ongoing and embarrassing drama that has left locals reliant on water cisterns (http://kgab.com/state-continues-to-work-with-pavillion-residents-on-drinking-water/) for their drinking water while state, federal and industry experts battle over the causes and public relations executives attempt to gin up doubts about the oil and gas industry's role.

In June, the EPA announced (http://yosemite.epa.gov/opa/admpress.nsf/0/DC7DCDB471DCFE1785257B90007377BF)it was pulling out of Pavillion, amid concerns about the expense of the investigation and allegations from drilling advocates that its 2011 draft report (http://www2.epa.gov/region8/draft-investigation-ground-water-contamination-near-pavillion-wyoming) on Pavillion would not survive peer review. The 2011 EPA report made headlines because its data suggested that contamination was linked to fracking, contradicting industry claims that the process had never contaminated groundwater.

Such claims have been widely (http://scienceblogs.com/significantfigures/index.php/2013/06/27/the-growing-evidence-of-the-threat-of-f[illegible]g-to-the-nations-groundwater/) debunked (http://www.nytimes.com/interactive/us/drilling-down-documents-7.html?_r=0#document/p1/a27935) since then. But the industry still often repeats (http://www.api.org/~/media/Files/Policy/Exploration/HYDRAULIC_FRACTURING_PRIMER.ashx) them.

While the oil and gas industry asserted that the natural gas found in the water had formed naturally in the aquifer's shallow rock layers (so-called biogenic gas), the EPA tests showed the gas bore the distinct signature of gas formed far below the surface (thermogenic gas). The discovery of thermogenic gas, along with chemicals associated with fracking, was strong evidence that fracking could have contaminated the town's water.

Mr. Johnson's description of the EPA's 2011 findings highlight a key issue with the onshore drilling boom that's swept across the U.S. Lost in the debate over fracking's hazards are the hazards of other stages of extracting the oil and gas.

Well integrity, many experts say, is a key issue. Industry studies have found that over a 30 year period, between 2 and 60 percent of wells suffer (http://frackwire.com/well-casing-failure/)from faulty casings — a major problem even at the lowest end of the spectrum, because over a million (http://online.wsj.com/news/articles/SB10001424052702303672404579149432365326304) new oil and gas wells are expected to be drilled in the U.S. over the next few decades.

The EPA's 2011 data showing contamination surrounding the oil and gas industry's wastewater pits and the potential problems with gas well casings, layers of cement and steel that are supposed to keep oil and gas isolated, drew far less attention than the report's implications surrounding the hydraulic fracturing process.

The unfolding story of the Pavillion investigation highlights the hazards not only of the onshore drilling rush, but also the political hazards of using fracking as the exclusive focus of the debate over the risks.

In 2009, Pavillion residents first contacted the EPA to ask the agency to investigate what had gone wrong with their water, which had suddenly turned brown, fizzed, and smelled like an oily puddle on pavement. Pavillion residents like John Fenton and Louis Meeks (http://www.propublica.org/article/hydrofracked-one-mans-mystery-leads-to-a-backlash-against-natural-gas-drill/single) were interviewed in the documentary Gasland, helping to draw national attention to their situation.

In December, 2011, the EPA published a draft report that suggested (http://www.npr.org/blogs/thetwo-way/2011/12/08/143381365/epa-report-links-fracking-to-water-pollution) fracking was responsible for the water contamination — and all hell broke loose.

The agency's draft came under fire (http://www.forbes.com/sites/christopherhelman/2011/12/09/questions-emerge-on-epas-wyoming-fracking-study/) from oil and gas companies who claimed that EPA had bungled the investigation and made numerous technical mistakes. They argued that EPA had used a sample size that was too small and potentially even caused the contamination they found themselves when they were drilling test wells.

"The Agency has failed to address significant concerns raised with the process and conclusions of the draft report, including ... the use of a very limited and incomplete data sets to draw technically inadequate conclusions," wrote Senators David Vitter and James Inhofe in a Jan. 17, 2013 letter (http://www.inhofe.senate.gov/download/?id=049c1852-326e-4774-91de-755adba5951d&download=1)to the EPA questioning the draft report in detail.

The EPA, which had pointed to the costs of drilling the test wells as their primary constraints in the investigation, found itself under fire — and also under fiscal pressure. Sequestration (http://www.bna.com/largest-epa-sequester-n17179872605/) hit. The agency's budget was threatened (http://www.politico.com/story/2013/07/epa-budget-cuts-94632.html) by fiscal conservatives and from drilling proponents in Congress alike.

So this summer, the EPA announced (http://http://yosemite.epa.gov/opa/admpress.nsf/20ed1dfa1751192c8525735900400c30/dc7dcdb471dcfe1785257b90007377bf!OpenDocument) that it was pulling out of the Pavillion case, leaving a cloud of suspicion around its 2011 report's conclusions.

Industry public relations experts made the most of the EPA's retreat. "If the EPA had any confidence in its draft report, which has been intensely criticized by state regulators and other federal agencies, it would proceed with the peer review process," Energy In Depth spokesman Steve Everley told reporters (http://www.eenews.net/stories/1059983265).

But lost in the hullabaloo was the fact that EPA still backed the data in the 2011 report, and it extracted promises from Wyoming officials to incorporate that data in the state's investigation.

The Pavillion withdrawal was part of a wave (http://www.propublica.org/article/epas-abandoned-wyoming-fracking-study-one-retreat-of-many) of abandoned EPA fracking investigations. The agency backed away (http://ecowatch.com/2013/08/13/dimock-residents-demand-epa-reopen-fracking-water-study/) from its investigation into Dimock, PA (http://www.desmogblog.com/2013/08/05/censored-epa-pennsylvania-fracking-water-contamination-presentation-published-first-time) and into allegations that Range Rources polluted Steve Lipsky's water well in Texas. Drilling supporters suggested that the investigations had been a politically-motivated witch-hunt, unsupported by science.

Within the past month, however, new life has been breathed into the investigation in Texas (http://www.desmogblog.com/2014/01/09/steve-lipsky-responds-report-clearing-epa-wrongdoing-fracking-study), after the EPA's internal watchdog found that the agency had solid reasons to pursue its investigation. And the EPA never concluded that the industry hadn't contaminated Dimock, Pennsylvania's water, it simply said (http://switchboard.nrdc.org/blogs/ksinding/epa_still_burying_head_in_sand.html) that it wasn't worth spending the money to pursue the investigation because affected residents now had or expected to arrange for access to clean drinking water.

The long back and forth over these high profile cases also brings into stark relief a major problem with policing the oil and gas industry: figuring out exactly how companies caused pollution isn't just technically challenging, it's expensive. The EPA's draft report may have suffered technical flaws or it may have been sound – without a peer review process, we'll never know. But the agency was already operating on a budget that limited its ability to conduct a full investigation.

So if the deba[...]racking unfolds by the industry's terms, pollution only "counts" if it was directly caused by the fracking process itself — spills and other leaks, they ar[...]'t relevant to whether fracking itself is risky.

(http://www.facebook.com/sharer/sharer.php?u=www.desmogblog.com%2F2014%2F02%2F06%2Fpavillion-wyoming-water-contamination-case-questions-continue-swirl-about-oil-and-gas-industry-s-role&title=In Pavillion, Wyoming Water Contamination Case, Questions

But then, spending money to conclusively and indisputably prove that fracking caused contamintion is costly — too expensive, in fact, for the federal government to undertake. And without proof that fracking caused harm, they argue, the process should remain unregulated.

All this, of course, brings us back to Mr. Johnson. If he is correct, the oil and gas industry destroyed much of the town of Pavillion's drinking water supplies, and the industry arguments about the threats and true costs of drilling need to be reconsidered.

With more than 15 million people (http://online.wsj.com/news/articles/SB10001424052702303672404579149432365326304) already living near a new oil and gas well, and millions more expected as the onshore drilling rush progresses, what happened in Pavillion — both to the town and to the EPA's investigation — is a cautionary tale for us all.

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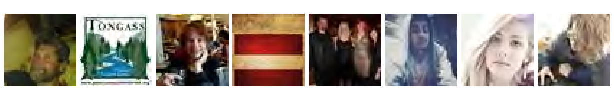

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Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing

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Directional drilling and hydraulic-fracturing technologies are dramatically increasing natural-gas extraction. In aquifers overlying the Marcellus and Utica shale formations of northeastern Pennsylvania and upstate New York, we document systematic evidence for methane contamination of drinking water associated with shale-gas extraction. In active gas-extraction areas (one or more gas wells within 1 km), average and maximum methane concentrations in drinking-water wells increased with proximity to the nearest gas well and were 19.2 and 64 mg CH_4 L^{-1} ($n = 26$), a potential explosion hazard; in contrast, dissolved methane samples in neighboring nonextraction sites (no gas wells within 1 km) within similar geologic formations and hydrogeologic regimes averaged only 1.1 mg L^{-1} ($P < 0.05$; $n = 34$). Average $\delta^{13}C$-CH_4 values of dissolved methane in shallow groundwater were significantly less negative for active than for nonactive sites (-37 ± 7‰ and -54 ± 11‰, respectively; $P < 0.0001$). These $\delta^{13}C$-CH_4 data, coupled with the ratios of methane-to-higher-chain hydrocarbons, and δ^2H-CH_4 values, are consistent with deeper thermogenic methane sources such as the Marcellus and Utica shales at the active sites and matched gas geochemistry from gas wells nearby. In contrast, lower-concentration samples from shallow groundwater at nonactive sites had isotopic signatures reflecting a more biogenic or mixed biogenic/thermogenic methane source. We found no evidence for contamination of drinking-water samples with deep saline brines or fracturing fluids. We conclude that greater stewardship, data, and—possibly—regulation are needed to ensure the sustainable future of shale-gas extraction and to improve public confidence in its use.

groundwater | organic-rich shale | isotopes | formation waters | water chemistry

Increases in natural-gas extraction are being driven by rising energy demands, mandates for cleaner burning fuels, and the economics of energy use (1–5). Directional drilling and hydraulic-fracturing technologies are allowing expanded natural-gas extraction from organic-rich shales in the United States and elsewhere (2, 3). Accompanying the benefits of such extraction (6, 7) are public concerns about drinking-water contamination from drilling and hydraulic fracturing that are ubiquitous but lack a strong scientific foundation. In this paper, we evaluate the potential impacts associated with gas-well drilling and fracturing on shallow groundwater systems of the Catskill and Lockhaven formations that overlie the Marcellus Shale in Pennsylvania and the Genesee Group that overlies the Utica Shale in New York (Figs. 1 and 2 and Fig. S1). Our results show evidence for methane contamination of shallow drinking-water systems in at least three areas of the region and suggest important environmental risks accompanying shale-gas exploration worldwide.

The drilling of organic-rich shales, typically of Upper Devonian to Ordovician age, in Pennsylvania, New York, and elsewhere in the Appalachian Basin is spreading rapidly, raising concerns for impacts on water resources (8, 9). In Susquehanna County, Pennsylvania alone, approved gas-well permits in the Marcellus formation increased 27-fold from 2007 to 2009 (10).

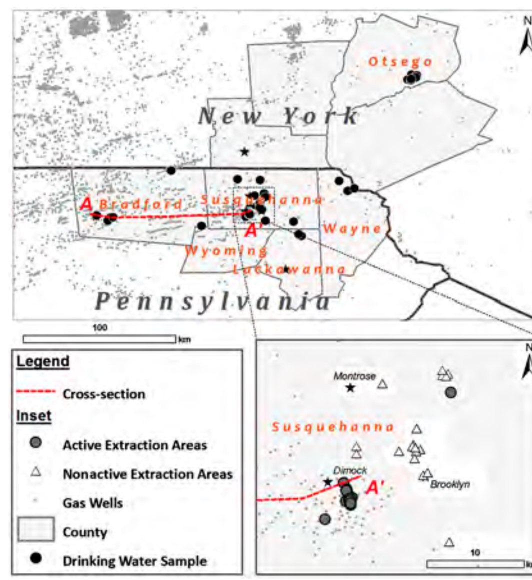

Fig. 1. Map of drilling operations and well-water sampling locations in Pennsylvania and New York. The star represents the location of Binghamton, New York. (*Inset*) A close-up in Susquehanna County, Pennsylvania, showing areas of active (closed circles) or nonactive (open triangles) extraction. A drinking-water well is classified as being in an active extraction area if a gas well is within 1 km (see *Methods*). Note that drilling has already spread to the area around Brooklyn, Pennsylvania, primarily a nonactive location at the time of our sampling (see inset). The stars in the inset represent the towns of Dimock, Brooklyn, and Montrose, Pennsylvania.

Concerns for impacts to groundwater resources are based on (*i*) fluid (water and gas) flow and discharge to shallow aquifers due to the high pressure of the injected fracturing fluids in the gas wells (10); (*ii*) the toxicity and radioactivity of produced water from a mixture of fracturing fluids and deep saline formation waters that may discharge to the environment (11); (*iii*) the potential explosion and asphyxiation hazard of natural gas; and (*iv*) the large number of private wells in rural areas that rely on shallow groundwater for household and agricultural use—up to one million wells in Pennsylvania alone—that are typically unregulated and untested (8, 9, 12). In this study, we analyzed groundwater from 68 private water wells from 36- to 190-m deep in

Author contributions: S.G.O., A.V., and R.B.J. designed research; S.G.O. and N.R.W. performed research; A.V. contributed new reagents/analytic tools; S.G.O., A.V., N.R.W., and R.B.J. analyzed data; and S.G.O., A.V., N.R.W., and R.B.J. wrote the paper.

The authors declare no conflict of interest.

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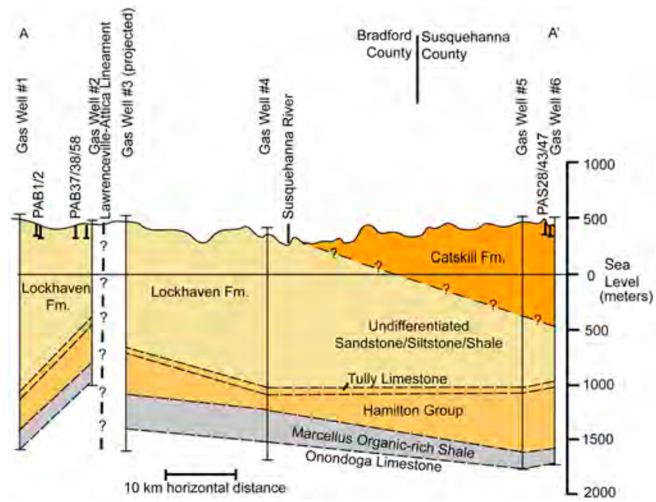

Fig. 2. Geologic cross-section of Bradford and western Susquehanna Counties created from gas-well log data provided by the Pennsylvania Department of Conservation and Natural Resources. The approximate location of the Lawrenceville-Attica Lineament is taken from Alexander et al. (34). The Ordovician Utica organic-rich shale (not depicted in the figure) underlies the Middle Devonian Marcellus at approximately 3,500 m below the ground surface.

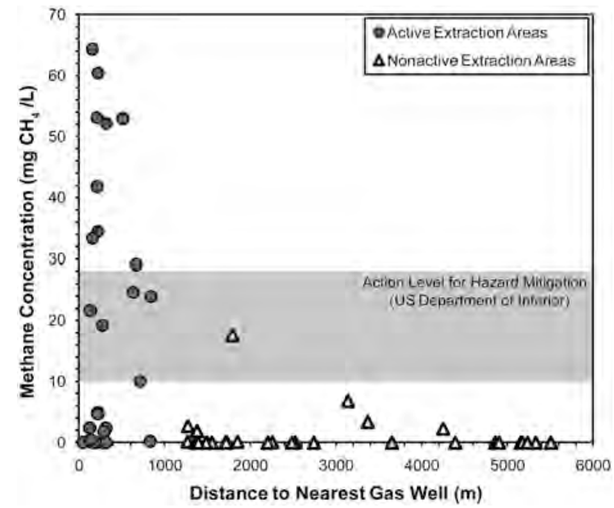

Fig. 3. Methane concentrations (milligrams of CH_4 L^{-1}) as a function of distance to the nearest gas well from active (closed circles) and nonactive (open triangles) drilling areas. Note that the distance estimate is an upper limit and does not take into account the direction or extent of horizontal drilling underground, which would decrease the estimated distances to some extraction activities. The precise locations of natural-gas wells were obtained from the Pennsylvania Department of Environmental Protection and Pennsylvania Spatial Data Access databases (ref. 35; accessed Sept. 24, 2010).

northeast Pennsylvania (Catskill and Lockhaven formations) and upstate New York (Genesee formation) (see Figs. 1 and 2 and *SI Text*), including measurements of dissolved salts, water isotopes (^{18}O and ^{2}H), and isotopes of dissolved constituents (carbon, boron, and radium). Of the 68 wells, 60 were also analyzed for dissolved-gas concentrations of methane and higher-chain hydrocarbons and for carbon and hydrogen isotope ratios of methane. Although dissolved methane in drinking water is not currently classified as a health hazard for ingestion, it is an asphyxiant in enclosed spaces and an explosion and fire hazard (8). This study seeks to evaluate the potential impact of gas drilling and hydraulic fracturing on shallow groundwater quality by comparing areas that are currently exploited for gas (defined as active—one or more gas wells within 1 km) to those that are not currently associated with gas drilling (nonactive; no gas wells within 1 km), many of which are slated for drilling in the near future.

Results and Discussion

Methane concentrations were detected generally in 51 of 60 drinking-water wells (85%) across the region, regardless of gas industry operations, but concentrations were substantially higher closer to natural-gas wells (Fig. 3). Methane concentrations were 17-times higher on average (19.2 mg CH_4 L^{-1}) in shallow wells from active drilling and extraction areas than in wells from nonactive areas (1.1 mg L^{-1} on average; $P < 0.05$; Fig. 3 and Table 1). The *average* methane concentration in shallow groundwater in active drilling areas fell within the defined action level (10–28 mg L^{-1}) for hazard mitigation recommended by the US Office of the Interior (13), and our maximum observed value of 64 mg L^{-1} is well above this hazard level (Fig. 3). Understanding the origin of this methane, whether it is shallower biogenic or deeper thermogenic gas, is therefore important for identifying the source of contamination in shallow groundwater systems.

The $\delta^{13}C$-CH_4 and $\delta^{2}H$-CH_4 values and the ratio of methane to higher-chain hydrocarbons (ethane, propane, and butane) can typically be used to differentiate shallower, biologically derived methane from deeper physically derived thermogenic methane (14). Values of $\delta^{13}C$-CH_4 less negative than approximately −50‰ are indicative of deeper thermogenic methane, whereas values more negative than −64‰ are strongly indicative of microbial methane (14). Likewise, $\delta^{2}H$-CH_4 values more negative than about −175‰, particularly when combined with low $\delta^{13}C$-CH_4 values, often represent a purer biogenic methane origin (14).

The average $\delta^{13}C$-CH_4 value in shallow groundwater in active drilling areas was -37 ± 7‰, consistent with a deeper thermogenic methane source. In contrast, groundwater from nonactive areas in the same aquifers had much lower methane concentrations and significantly lower $\delta^{13}C$-CH_4 values (average of -54 ± 11‰; $P < 0.0001$; Fig. 4 and Table 1). Both our $\delta^{13}C$-CH_4 data and $\delta^{2}H$-CH_4 data (see Fig. S2) are consistent with a deeper thermogenic methane source at the active sites and a more biogenic or mixed methane source for the lower-concentration samples from nonactive sites (based on the definition of Schoell, ref. 14).

Because ethane and propane are generally not coproduced during microbial methanogenesis, the presence of higher-chain hydrocarbons at relatively low methane-to-ethane ratios (less than approximately 100) is often used as another indicator of deeper thermogenic gas (14, 15). Ethane and other higher-chain hydrocarbons were detected in only 3 of 34 drinking-water wells from nonactive drilling sites. In contrast, ethane was detected in 21 of 26 drinking-water wells in active drilling sites. Additionally, propane and butane were detected (>0.001 mol %) in eight and two well samples, respectively, from active drilling areas but in no wells from nonactive areas.

Further evidence for the difference between methane from water wells near active drilling sites and neighboring nonactive sites is the relationship of methane concentration to $\delta^{13}C$-CH_4 values (Fig. 4*A*) and the ratios of methane to higher-chain hydro-

Table 1. Mean values ± standard deviation **of methane concentrations (as milligrams of CH_4 L^{-1}) and carbon isotope composition in methane in shallow groundwater $\delta^{13}C$-CH_4 sorted by aquifers and proximity to gas wells (active vs. nonactive)**

Water source, *n*	milligrams CH_4 L^{-1}	$\delta^{13}C$-CH_4, ‰
Nonactive Catskill, 5	1.9 ± 6.3	−52.5 ± 7.5
Active Catskill, 13	26.8 ± 30.3	−33.5 ± 3.5
Nonactive Genesee, 8	1.5 ± 3.0	−57.5 ± 9.5
Active Genesee, 1	0.3	−34.1
Active Lockhaven, 7	50.4 ± 36.1	−40.7 ± 6.7
Total active wells, 21	19.2	−37 ± 7
Total nonactive wells, 13	1.1	−54 ± 11

The variable *n* refers to the number of samples.

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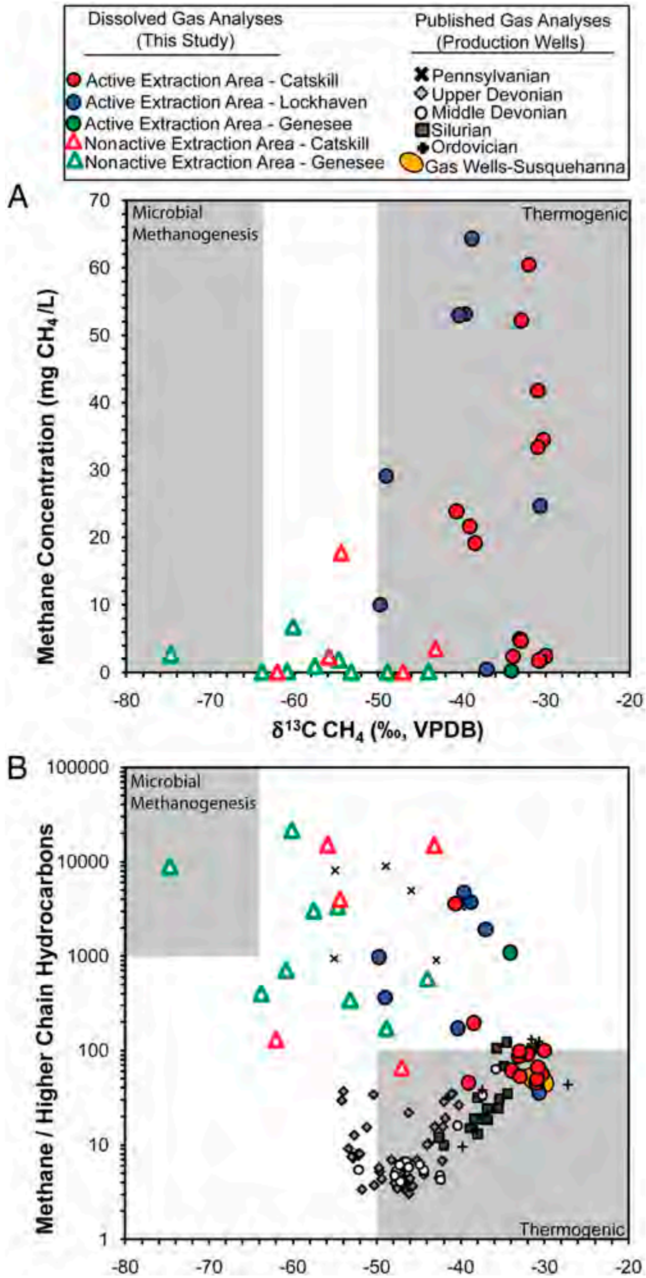

Fig. 4. (*A*) Methane concentrations in groundwater versus the carbon isotope values of methane. The nonactive and active data depicted in Fig. 3 are subdivided based on the host aquifer to illustrate that the methane concentrations and $\delta^{13}C$ values increase with proximity to natural-gas well drilling regardless of aquifer formation. Gray areas represent the typical range of thermogenic and biogenic methane taken from Osborn and Mcintosh (18). VPDB, Vienna Pee Dee belemnite. (*B*) Bernard plot (15) of the ratio of methane to higher-chain hydrocarbons versus the $\delta^{13}C$ of methane. The smaller symbols in grayscale are from published gas-well samples from gas production across the region (16–18). These data generally plot along a trajectory related to reservoir age and thermal maturity (Upper Devonian through Ordovician; see text for additional details). The gas-well data in the orange ovals are from gas wells in our study area in Susquehanna County, Pennsylvania (data from Pennsylvania Department of Environmental Protection). Gray areas represent typical ranges of thermogenic and biogenic methane (data from Osborn and McIntosh, ref. 18).

carbons versus $\delta^{13}C\text{-}CH_4$ (Fig. 4*B*). Methane concentrations not only increased in proximity to gas wells (Fig. 3), the accompanying $\delta^{13}C\text{-}CH_4$ values also reflected an increasingly thermogenic methane source (Fig. 4*A*).

Using a Bernard plot (15) for analysis (Fig. 4*B*), the enriched $\delta^{13}C\text{-}CH_4$ (approximately $> -50‰$) values accompanied by low ratios of methane to higher-chain hydrocarbons (less than approximately 100) in drinking-water wells also suggest that dissolved gas is more thermogenic at active than at nonactive sites (Fig. 4*B*). For instance, 12 dissolved-gas samples at active drilling sites fell along a regional gas trajectory that increases with reservoir age and thermal maturity of organic matter, with samples from Susquehanna County, Pennsylvania specifically matching natural-gas geochemistry from local gas wells (Fig. 4*B*, orange oval). These 12 samples and local natural-gas samples are consistent with gas sourced from thermally mature organic matter of Middle Devonian and older depositional ages often found in Marcellus Shale from approximately 2,000 m below the surface in the northern Appalachian Basin (14–19) (Fig. 4*B*). In contrast, none of the methane samples from nonactive drilling areas fell upon this trajectory (Fig. 4*B*); eight dissolved-gas samples in Fig. 4*B* from active drilling areas and all of the values from nonactive areas may instead be interpreted as mixed biogenic/thermogenic gas (18) or, as Laughrey and Baldassare (17) proposed for their Pennsylvanian gas data (Fig. 4*B*), the early migration of wet thermogenic gases with low-$\delta^{13}C\text{-}CH_4$ values and high methane-to-higher-chain hydrocarbon ratios. One data point from a nonactive area in New York fell squarely in the parameters of a strictly biogenic source as defined by Schoell (14) (Fig. 4*B*, upper-left corner).

Carbon isotopes of dissolved inorganic carbon ($\delta^{13}C\text{-DIC} > +10‰$) and the positive correlation of δ^2H of water and δ^2H of methane have been used as strong indicators of microbial methane, further constraining the source of methane in shallow groundwater (depth less than 550 m) (18, 20). Our $\delta^{13}C$-DIC values were fairly negative and show no association with the $\delta^{13}C\text{-}CH_4$ values (Fig. S3), which is not what would be expected if methanogenesis were occurring locally in the shallow aquifers. Instead, the $\delta^{13}C$-DIC values from the shallow aquifers plot within a narrow range typical for shallow recharge waters, with the dissolution of CO_2 produced by respiration as water passes downward through the soil critical zone. Importantly, these values do not indicate extensive microbial methanogenesis or sulfate reduction. The data do suggest gas-phase transport of methane upward to the shallow groundwater zones sampled for this study (<190 m) and dissolution into shallow recharge waters locally. Additionally, there was no positive correlation between the δ^2H values of methane and δ^2H of water (Fig. S4), indicating that microbial methane derived in this shallow zone is negligible. Overall, the combined gas and formation-water results indicate that thermogenic gas from thermally mature organic matter of Middle Devonian and older depositional ages is the most likely source of the high methane concentrations observed in the shallow water wells from active extraction sites.

A different potential source of shallow groundwater contamination associated with gas drilling and hydraulic fracturing is the introduction of hypersaline formation brines and/or fracturing fluids. The average depth range of drinking-water wells in northeastern Pennsylvania is from 60 to 90 m (12), making the average vertical separation between drinking-water wells and the Marcellus Shale in our study area between approximately 900 and 1,800 m (Fig. 2). The research area, however, is located in tectonically active areas with mapped faults, earthquakes, and lineament features (Fig. 2 and Fig. S1). The Marcellus formation also contains two major sets of joints (21) that could be conduits for directed pressurized fluid flow. Typical fracturing activities in the Marcellus involve the injection of approximately 13–19 million liters of water per well (22) at pressures of up to 69,000 kPa. The majority of this fracturing water typically stays underground and could in principle displace deep formation water upward into shallow aquifers. Such deep formation waters often have high concentrations of total dissolved solids >250,000 mg L^{-1}, trace toxic elements, (18), and naturally occurring radioactive materials, with activities as high as 16,000 picocuries per liter (1 pCi L^{-1} = 0.037 becquerels per liter) for ^{226}Ra compared to a drinking-water standard of 5 pCi L^{-1} for combined ^{226}Ra and ^{226}Ra (23).

We evaluated the hydrochemistry of our 68 drinking-water wells and compared these data to historical data of 124 wells in the Catskill and Lockhaven aquifers (24, 25). We used three types of indicators for potential mixing with brines and/or saline fracturing fluids: (*i*) major inorganic chemicals; (*ii*) stable isotope signatures of water ($\delta^{18}O$, δ^2H); and (*iii*) isotopes of dissolved constituents (δ^{13}C-DIC, $\delta^{11}B$, and ^{226}Ra). Based on our data (Table 2), we found no evidence for contamination of the shallow wells near active drilling sites from deep brines and/or fracturing fluids. All of the Na^+, Cl^-, Ca^{2+}, and DIC concentrations in wells from active drilling areas were consistent with the baseline historical data, and none of the shallow wells from active drilling areas had either chloride concentrations >60 mg L^{-1} or Na-Ca-Cl compositions that mirrored deeper formation waters (Table 2). Furthermore, the mean isotopic values of $\delta^{18}O$, δ^2H, δ^{13}C-DIC, $\delta^{11}B$, and ^{226}Ra in active and nonactive areas were indistinguishable. The ^{226}Ra values were consistent with available historical data (25), and the composition of $\delta^{18}O$ and δ^2H in the well-water appeared to be of modern meteoric origin for Pennsylvania (26) (Table 2 and Fig. S5). In sum, the geochemical and isotopic features for water we measured in the shallow wells from both active and nonactive areas are consistent with historical data and inconsistent with contamination from mixing Marcellus Shale formation water or saline fracturing fluids (Table 2).

There are at least three possible mechanisms for fluid migration into the shallow drinking-water aquifers that could help explain the increased methane concentrations we observed near gas wells (Fig. 3). The first is physical displacement of gas-rich deep solutions from the target formation. Given the lithostatic and hydrostatic pressures for 1–2 km of overlying geological strata, and our results that appear to rule out the rapid movement of deep brines to near the surface, we believe that this mechanism is unlikely. A second mechanism is leaky gas-well casings (e.g., refs. 27 and 28). Such leaks could occur at hundreds of meters underground, with methane passing laterally and vertically through fracture systems. The third mechanism is that the process of hydraulic fracturing generates new fractures or enlarges existing ones above the target shale formation, increasing the connectivity of the fracture system. The reduced pressure following the fracturing activities could release methane in solution, leading to methane exsolving rapidly from solution (29), allowing methane gas to potentially migrate upward through the fracture system.

Methane migration through the 1- to 2-km-thick geological formations that overlie the Marcellus and Utica shales is less likely as a mechanism for methane contamination than leaky well casings, but might be possible due to both the extensive fracture systems reported for these formations and the many older, uncased wells drilled and abandoned over the last century and a half in Pennsylvania and New York. The hydraulic conductivity in the overlying Catskill and Lockhaven aquifers is controlled by a secondary fracture system (30), with several major faults and lineaments in the research area (Fig. 2 and Fig. S1). Consequently, the high methane concentrations with distinct positive $\delta^{13}C$-CH_4 and δ^2H-CH_4 values in the shallow groundwater from active areas could in principle reflect the transport of a deep methane source associated with gas drilling and hydraulic-fracturing activities. In contrast, the low-level methane migration to the surface groundwater aquifers, as observed in the nonactive areas, is likely a natural phenomenon (e.g., ref. 31). Previous studies have shown that naturally occurring methane in shallow aquifers is typically associated with a relatively strong biogenic signature indicated by depleted $\delta^{13}C$-CH_4 and δ^2H-CH_4 compositions (32) coupled with high ratios of methane to higher-chain hydrocarbons (33), as we observed in Fig. 4*B*. Several models have been developed to explain the relatively common phenomenon of rapid vertical transport of gases (Rn, CH_4, and CO_2) from depth to the surface (e.g., ref. 31), including pressure-driven continuous gas-phase flow through dry or water-saturated fractures and density-driven buoyancy of gas microbubbles in aquifers and water-filled fractures (31). More research is needed across this and other regions to determine the mechanism(s) controlling the higher methane concentrations we observed.

Based on our groundwater results and the litigious nature of shale-gas extraction, we believe that long-term, coordinated sampling and monitoring of industry and private homeowners is needed. Compared to other forms of fossil-fuel extraction, hydraulic fracturing is relatively poorly regulated at the federal level. Fracturing wastes are not regulated as a hazardous waste under the Resource Conservation and Recovery Act, fracturing wells are not covered under the Safe Drinking Water Act, and only recently has the Environmental Protection Agency asked fracturing

Table 2. Comparisons of selected major ions and isotopic results in drinking-water wells from this study to data available on the same formations (Catskill and Lockhaven) in previous studies (24, 25) and to underlying brines throughout the Appalachian Basin (18)

	Active		Nonactive		Previous studies (background)		
	Lockhaven formation $N = 8$	Catskill formation $N = 25$	Catskill formation $N = 22$	Genesee group $N = 12$	Lockhaven formation (25) $N = 45$	Catskill formation (24) $N = 79$	Appalachian brines (18, 23) $N = 21$
Alkalinity as HCO_3^-,							
mg L^{-1}	285 ± 36	157 ± 56	127 ± 53	158 ± 56	209 ± 77	133 ± 61	150 ± 171
mM	[4.7 ± 0.6]	[2.6 ± 0.9]	[2.1 ± 0.9]	[2.6 ± 0.9]	[3.4 ± 1.3]	[2.2 ± 1.0]	[2.5 ± 2.8]
Sodium, mg L^{-1}	87 ± 22	23 ± 30	17 ± 25	29 ± 23	100 ± 312	21 ± 37	33,000 ± 11,000
Chloride, mg L^{-1}	25 ± 17	11 ± 12	17 ± 40	9 ± 19	132 ± 550	13 ± 42	92,000 ± 32,000
Calcium, mg L^{-1}	22 ± 12	31 ± 13	27 ± 9	26 ± 5	49 ± 39	29 ± 11	16,000 ± 7,000
Boron, μg L^{-1}	412 ± 156	93 ± 167	42 ± 93	200 ± 130	NA	NA	3,700 ± 3,500
$\delta^{11}B$ ‰	27 ± 4	22 ± 6	23 ± 6	26 ± 6	NA	NA	39 ± 6
^{226}Ra, pCi L^{-1}	0.24 ± 0.2	0.16 ± 0.15	0.17 ± 0.14	0.2 ± 0.15	0.56 ± 0.74	NA	6,600 ± 5,600
δ^2H, ‰, VSMOW	−66 ± 5	−64 ± 3	−68 ± 6	−76 ± 5	NA	NA	−41 ± 6
$\delta^{18}O$, ‰, VSMOW	−10 ± 1	−10 ± 0.5	−11 ± 1	−12 ± 1	NA	NA	−5 ± 1

Some data for the active Genesee Group and nonactive Lockhaven Formation are not included because of insufficient sample sizes (NA). Values represent means ±1 standard deviation. NA, not available.

N values for $\delta^{11}B$ ‰ analysis are 8, 10, 3, 6, and 5 for active Lockhaven, active Catskill, nonactive Genesee, nonactive Catskill, and brine, respectively. *N* values for ^{226}Ra are 6, 7, 3, 10, 5, and 13 for active Lockhaven, active Catskill, nonactive Genesee, nonactive Catskill, background Lockhaven, and brine, respectively. $\delta^{11}B$ ‰ normalized to National Institute of Standards and Technology Standard Reference Material 951. δ^2H and $\delta^{18}O$ normalized to Vienna Standard Mean Ocean Water (VSMOW).

firms to voluntarily report a list of the constituents in the fracturing fluids based on the Emergency Planning and Community Right-to-Know Act. More research is also needed on the mechanism of methane contamination, the potential health consequences of methane, and establishment of baseline methane data in other locations. We believe that systematic and independent data on groundwater quality, including dissolved-gas concentrations and isotopic compositions, should be collected before drilling operations begin in a region, as is already done in some states. Ideally, these data should be made available for public analysis, recognizing the privacy concerns that accompany this issue. Such baseline data would improve environmental safety, scientific knowledge, and public confidence. Similarly, long-term monitoring of groundwater and surface methane emissions during and after extraction would clarify the extent of problems and help identify the mechanisms behind them. Greater stewardship, knowledge, and—possibly—regulation are needed to ensure the sustainable future of shale-gas extraction.

Methods

A total of 68 drinking-water samples were collected in Pennsylvania and New York from bedrock aquifers (Lockhaven, 8; Catskill, 47; and Genesee, 13) that overlie the Marcellus or Utica shale formations (Fig. S1). Wells were purged to remove stagnant water, then monitored for pH, electrical conductance, and temperature until stable values were recorded. Samples were collected "upstream" of any treatment systems, as close to the water well as possible, and preserved in accordance with procedures detailed in *SI Methods*. Dissolved-gas samples were analyzed at Isotech Laboratories and water chemical and isotope (O, H, B, C, Ra) compositions were measured at Duke University (see *SI Methods* for analytical details).

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Proximity to Natural Gas Wells and Reported Health Status: Results of a Household Survey in Washington County, Pennsylvania

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Background: Little is known about the environmental and public health impact of unconventional natural gas extraction activities, including hydraulic fracturing, that occur near residential areas.

Objectives: Our aim was to assess the relationship between household proximity to natural gas wells and reported health symptoms.

Methods: We conducted a hypothesis-generating health symptom survey of 492 persons in 180 randomly selected households with ground-fed wells in an area of active natural gas drilling. Gas well proximity for each household was compared with the prevalence and frequency of reported dermal, respiratory, gastrointestinal, cardiovascular, and neurological symptoms.

Results: The number of reported health symptoms per person was higher among residents living < 1 km (mean ± SD, 3.27 ± 3.72) compared with > 2 km from the nearest gas well (mean ± SD, 1.60 ± 2.14; $p = 0.0002$). In a model that adjusted for age, sex, household education, smoking, awareness of environmental risk, work type, and animals in house, reported skin conditions were more common in households < 1 km compared with > 2 km from the nearest gas well (odds ratio = 4.1; 95% CI: 1.4, 12.3; $p = 0.01$). Upper respiratory symptoms were also more frequently reported in persons living in households < 1 km from gas wells (39%) compared with households 1–2 km or > 2 km from the nearest well (31 and 18%, respectively) ($p = 0.004$). No equivalent correlation was found between well proximity and other reported groups of respiratory, neurological, cardiovascular, or gastrointestinal conditions.

Conclusion: Although these results should be viewed as hypothesis generating, and the population studied was limited to households with a ground-fed water supply, proximity of natural gas wells may be associated with the prevalence of health symptoms including dermal and respiratory conditions in residents living near natural gas extraction activities. Further study of these associations, including the role of specific air and water exposures, is warranted.

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Introduction

Unconventional methods of natural gas extraction, including directional drilling and hydraulic fracturing (also known as "fracking"), have made it possible to reach natural gas reserves in shale deposits thousands of feet underground (Myers 2012). Increased drilling activity in a number of locations in the United States has led to growing concern that natural gas extraction activities could contaminate water supplies and ambient air, resulting in unforeseen adverse public health effects (Goldstein et al. 2012). At the same time, there is little peer-reviewed evidence regarding the public health risks of natural gas drilling activities (Kovats et al. 2014; McDermott-Levy and Kaktins 2012; Mitka 2012), including a lack of systematic surveys of human health effects.

The process of natural gas extraction. Natural gas extraction of shale gas reserves may involve multiple activities occurring over a period of months. These include drilling and casing of deep wells that contain both vertical and horizontal components as well as placement of underground explosives and transport and injection of millions of gallons of water containing sand and a number of chemical additives into the wells at high pressures to extract gas from the shale deposits (hydraulic fracturing) (Jackson RE et al. 2013). Chemicals used in the hydraulic fracturing process can include inorganic acids, polymers, petroleum distillates, anti-scaling compounds, microbicides, and surfactants (Vidic et al. 2013). Although some of these fluids are recovered during the fracking process as "flowback" or "produced" water, a significant amount (as much as 90%) (Vidic et al. 2013) may remain underground. The recovered flowback water—which may contain chemicals added to the fracking fluid as well as naturally occurring chemicals such as salts, arsenic, and barium and naturally occurring radioactive material originating in the geological formations—may be stored in holding ponds or transported offsite for disposal and/or wastewater treatment elsewhere.

Potential water exposures. Although much of the hydraulic fracturing process takes place deep underground, there are a number of potential mechanisms for chemicals used in the fracturing process as well as naturally occurring minerals, petroleum compounds (including volatile organic compounds; VOCs), and other substances of flowback water (Chapman et al. 2012) to enter drinking-water supplies. These include spills during transport of chemicals and flowback water, leaks of a well casing (Kovats et al. 2014), leaks through underground fissures in rock formations, runoff from drilling sites, and disposal of fracking flowback water (Rozell and Reaven 2012). Studies have reported increased levels of methane in drinking water wells located < 1 km from natural gas drilling, suggesting contamination of water wells from hydraulic

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P.M.R. and J.D.D. had full access to all the data in the study and take responsibility for the integrity of the data and the accuracy of the data analysis.

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fracturing activities (Jackson RB et al. 2013; Osborn et al. 2011), although natural movement of methane and brine from shale deposits into aquifers has also been suggested (Warner et al. 2012). If contaminants from hydraulic fracturing activities were able to enter drinking water supplies or surface water bodies, humans could be exposed to such contaminants through drinking, cooking, showering, and swimming.

Potential air exposures. The drilling and completion of natural gas wells, as well as the storage of waste fluids in containment ponds, may release chemicals into the atmosphere through evaporation and off-gassing. In Pennsylvania, flowback fluids are not usually disposed of in deep injection wells; therefore surface ponds containing flowback fluids are relatively common and could be sources of air contamination through evaporation. Flaring of gas wells, operation of diesel equipment and vehicles, and other point sources for air quality contamination around drilling activities may also pose a risk of respiratory exposures to nitrogen oxides, VOCs, and particulate matter. Release of ozone precursors into the environment by natural gas production activities may lead to increases in local ozone levels (Olaguer 2012). Well completion and gas transport may cause leakage of methane and other greenhouse gases into the environment (Allen 2014). Studies in Colorado have reported elevated air levels of VOCs including trimethylbenzenes, xylenes, and aliphatic hydrocarbons related to well drilling activities (McKenzie et al. 2012).

Human health impact. Concerns about the impact of natural gas extraction on the health of nearby communities have included exposures to contaminants in water and air described above as well as noise and social disruption (Witter et al. 2013). A published case series cited the occurrence of respiratory, skin, neurological, and gastrointestinal symptoms in humans living near gas wells (Bamberger and Oswald 2012). A convenience sample survey of 108 individuals in 55 households across 14 counties in Pennsylvania who were concerned about health effects from natural gas facilities found that a number of self-reported symptoms were more common in individuals living near gas facilities, including throat and nasal irritation, eye burning, sinus problems, headaches, skin problems, loss of smell, cough, nosebleeds, and painful joints (Steinzor et al. 2013). Similarly, a convenience sample survey of 53 community members living near Marcellus Shale development found that respondents attributed a number of health impacts and stressors to the development. Stress was the symptom reported most frequently (Ferrar et al. 2013).

Here we report on the analysis of a cross-sectional, random-sample survey of the health of residents who had ground-fed water wells in the vicinity of natural gas extraction wells to determine whether proximity to gas wells was associated with reported respiratory, dermal, neurological, or gastrointestinal symptoms.

Methods

Selection of study area. The Marcellus formation, a principal source of shale-based natural gas in the United States, is a Middle Devonian–age black, low-density, organically rich shale that has been predominantly horizontally drilled for gas extraction in the southwestern portion of Pennsylvania since 2003 [Pennsylvania Spatial Data Access (PASDA) 2013]. In this study we focused on Washington County in southwestern Pennsylvania, an area of active natural gas drilling (Carter et al. 2011). At the time of the administration of the household survey during summer 2012, there were, according to the Pennsylvania Department of Environmental Protection, 624 active natural gas wells in Washington County. Of these natural gas wells, 95% were horizontally drilled (Pennsylvania Department of Environmental Protection 2012). The county has a highly rural classification with nearly 40% of the land devoted to agriculture (U.S. Department of Agriculture 2007). Washington County has a population of approximately 200,000 persons with 94% self-identified as white, 90% having at least a high school diploma, and a 2012 median household income of $53,545 (Center for Rural Pennsylvania 2014). We selected a contiguous set of 38 rural townships within the center of Washington County as our study site in order to avoid urban areas bordering Pittsburgh, which would be unlikely to have ground-fed water wells, and areas near the Pennsylvania border, which might be influenced by gas wells in other states (Figure 1).

Survey instrument. We designed a community environmental health assessment of reported health symptoms and health status based on questions drawn from publicly available surveys. Symptom questions, covering a range of organ systems that had been mentioned in published reports (Bamberger and Oswald 2012; Steinzor et al. 2013), asked respondents whether they or any household members had experienced each condition during the past year (see Supplemental Material, "Questionnaire"). The health assessment also asked a number

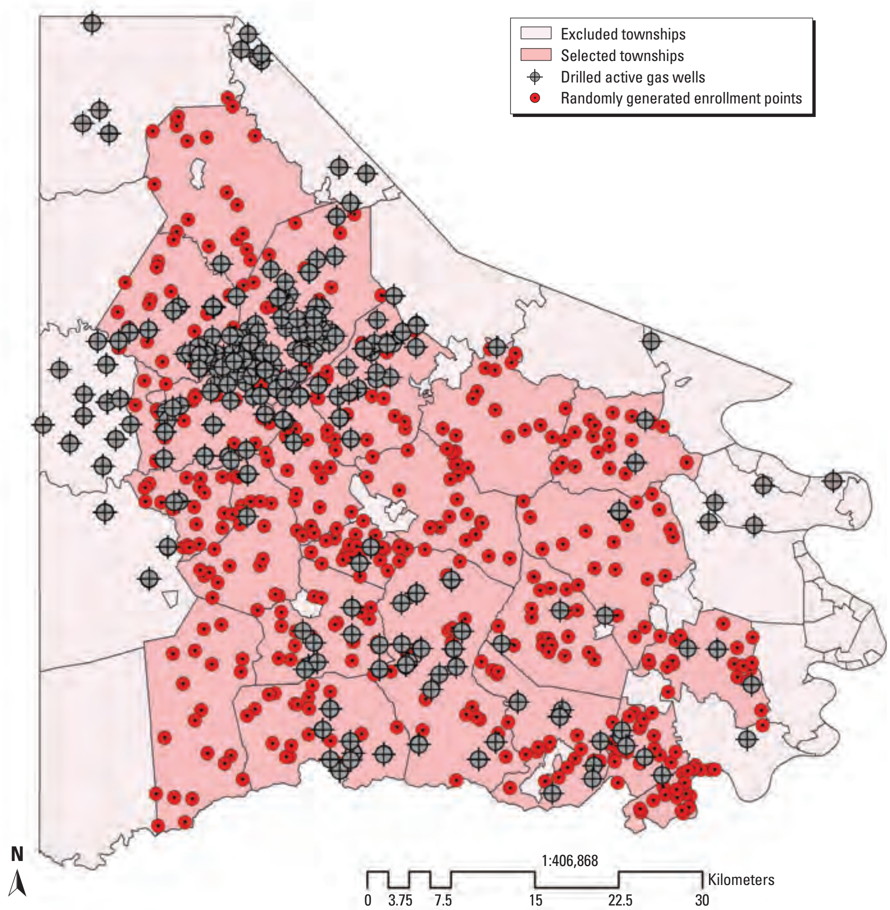

Figure 1. Distribution of drilled active Marcellus Shale natural gas wells (n = 624) and randomly generated sampling sites (n = 760) for eligible municipalities of Washington County, Pennsylvania.

of general yes/no questions about concerns of environmental hazards in the community, such as whether respondents were satisfied with air quality, water quality, soil quality, environmental noise and odors, and traffic, but did not specifically mention natural gas wells or hydraulic fracturing or other natural gas extraction activities. The survey was pretested with focus groups in the study area in collaboration with a community based group and revised to ensure comprehensibility of questions.

Selection and recruitment of households. Using ArcGIS Desktop 10.0 software (ESRI, Inc., Redlands, CA), we randomly selected 20 geographic points from each of 38 contiguous townships in the study county (Figure 1). We identified an eligible home nearest to each randomly generated sampling point, and visited each home to determine which households were occupied and had ground-fed water wells. We selected households with ground-fed water wells to assess possible health effects related to water contamination. From the original 760 points identified (i.e., 20 points in each of the 38 townships), we excluded 12 duplicate points and 64 points found not to correspond to a house structure (see Supplemental Material, Figure S1). After site visits by the study team who spoke to residents or neighbors, we excluded house locations determined not to have a ground-fed well or spring. Additional points were excluded if the structure was not occupied ($n = 5$) or inaccessible from the road ($n = 4$). During visits to eligible households, a study member invited a responding adult at least 18 years of age to participate in the survey, described as a survey of community environmental health that considered a number of environmental health factors. Three households were excluded when the respondent was unable to answer the questionnaire due to language or health problems. Eligible households were offered a small cash stipend for participation.

The Yale University School of Medicine Human Research Protection Program determined the study to be exempt from Human Subjects review. Respondents provided oral consent but were not asked to sign consent forms; their names were not recorded.

Of the 255 eligible households, respondents refused to complete the survey in 47 households, and we were not able to contact residents in another 26 households. Reasons for refusal included "not interested" ($n = 8$), "no time/too busy" ($n = 3$), "afraid" ($n = 1$), and 35 gave no reason. The rate of refusal varied by distance category, with 12 of 74 (16%) of households < 1 km from a gas well, 10 of 67 (15%) of households 1–2 km from wells, and 25 of 86 (25%) of eligible households > 2 km from a gas well refusing to participate, but the differences were not statistically significant. At the consenting 180 households (71% of eligible households), an adult respondent completed the survey covering the health status of the 492 individuals living in these households.

Administration of survey at residence. Trained study personnel administered the survey in English. The responding adult at the participating household reported on the health status of all persons in the household over the past year. A study team member recorded the global positioning system (GPS) coordinates of the household using a Garmin GPSMAP® 62S Series handheld GPS device (Garmin International, Inc., Olathe, KS). Survey personnel were not aware of the mapping results for gas well proximity to the households being surveyed.

Household proximity to nearest active gas well and age of wells. A map of 624 active natural gas wells in the study area, and their age and type, was created by utilizing gas well permit data publicly available at the PASDA (2013). Ninety five percent of the gas wells had "spud dates" (first date of drilling) between 2008 and 2012, with more than half of spud dates occurring in 2010 and 2011. We used ArcGIS to calculate the distance between each household location (as defined by the GPS reading taken during the site visit) and each natural gas well in the study area. We then classified households according to their distance from the nearest gas well with distance categories of < 1 km, 1–2 km, or > 2 km. We used 1 km as the initial cut point for distance to a nearest gas well because of the reported association of higher methane levels in drinking-water wells located < 1 km from natural gas wells (Osborn et al. 2011), and 2 km as the second cut point because it was close to the mean of the distances between households and nearest gas wells. The mean and median distance between a household and the nearest natural gas well were 2.0 km and 1.4 km, respectively. We classified the age of each gas well as the time interval between spud date and the date that the household survey was conducted during summer, 2012.

Statistical analysis. Demographic variables were analyzed for differences among individuals between distance categories using chi-square, analysis of variance, or generalized linear mixed-model statistics as appropriate. Reported occupation was classified as either blue collar, office sales and service, management/professional, or not working, using classifications of the U.S. Bureau of Labor Statistics (2014).

The prevalence of each outcome and the number of symptoms reported for each household member included in the study were calculated according to the distance of each household (< 1, 1–2, or > 2 km) from the nearest gas well. To test the association between household distance from a well and the overall number of symptoms as well as the presence or absence of each of six groups of health conditions (dermal, upper respiratory, lower respiratory, gastrointestinal, neurological, and cardiovascular), we used SAS 9.3 in a generalized linear mixed model (GLMM) analysis (SAS Institute Inc., Cary, NC). The analysis used maximum likelihood estimation with adaptive quadrature methods (Schabenberger 2007) including a random effect for household to account for the clustering of individuals within a household. The model was adjusted for age of individual (continuous), sex (binary), average adult household education (continuous), smoker present in household (yes/no), awareness of environmental hazard nearby (yes/no), employment type (four categories), and whether animals were present in the home or backyard (yes/no). Given the exploratory nature of this study, no adjustments were made for multiple comparisons and significance was established at the two-sided 0.05 level. Statistical analyses were conducted using SAS 9.3.

Results

Demographics. Individuals living in households < 1 km from gas wells were older (mean, 46.9 ± 21.9) compared with individuals in households > 2 km from a gas well (mean, 40.0 ± 23.5 years, $p = 0.03$) (Table 1). There was a higher proportion of children in the households > 2 km from a gas well compared with those < 1 km from a gas well (27% vs. 14%, $p = 0.008$). Families had lived in their homes an average of 22.8 ± 17.2 years at the time of the interview. Thirty-four percent of individuals had blue-collar jobs and 38% of the subjects were nonworkers (e.g., unemployed, students). Sixty-six percent reported using their ground-fed water (well or natural spring) for drinking water, and 84% reported using it for other activities such as bathing. The age of the nearest gas well was significantly greater for households < 1 km from a gas well (mean, 2.3 ± 1.6) compared with those 1–2 km or > 2 km from a well (1.5 ± 1.3 and 1.1 ± 0.9, respectively, $p < 0.05$). Reported smoking was less common in households near gas wells, whereas reported respondent awareness regarding environmental health risks was higher, although these differences were not statistically significant.

Reported health symptoms. The average number of reported symptoms per person in residents of households < 1 km from a gas well (3.27 ± 3.72) was greater compared with those living > 2 km from gas wells (1.60 ± 2.14, $p = 0.0002$).

Individuals living in households < 1 km from natural gas wells were more likely to report having any of the queried skin conditions over the past year (13%) than residents of households > 2 km from a well (3%; χ^2 = 13.8, p = 0.001) (Table 2). Reported upper respiratory symptoms were also more frequent among households < 1 km (39%) compared with households > 2 km from gas wells (18%; χ^2 = 17.9, p = 0.0001).

In a hierarchical model that adjusted for age, sex, household education level, smokers in household, job type, animals in household, and awareness of environmental risk (Table 3), household proximity to natural gas wells remained associated with number of symptoms reported per person < 1 km (p = 0.002) and 1–2 km (p = 0.05) compared with > 2 km from gas wells, respectively. In similar models, living in a household < 1 km from the nearest gas well remained associated with increased reporting of skin conditions [odds ratio (OR) = 4.13; 95% confidence interval (CI): 1.38, 12.3] and upper respiratory symptoms (OR = 3.10; 95% CI: 1.45, 6.65) compared with households > 2 km from the nearest gas well.

For the other grouped symptom complexes examined, there was not a significant relationship in our adjusted model between the prevalence of symptom reports and proximity to nearest gas well. In the multivariate model, however, environmental risk awareness was significantly associated with report of all groups of symptoms.

Age of the nearest gas well was found to be negatively correlated with distance (r = –0.325; p < 0.0001): Gas wells < 1 km from households tended to be older than the nearest wells in other distance categories. When age of wells was added to the multivariate model, proximity to gas wells remained significantly associated with respiratory symptoms, but the association between proximity and dermal symptoms lost statistical significance.

Discussion

This spatially random health survey of households with ground-fed water supply in a region with a large number of active natural gas wells is to our knowledge the largest study to date of the association of reported symptoms and natural gas drilling activities. We found an increased frequency of reported symptoms over the past year in households in closer proximity to active gas wells compared with households farther from gas wells. This association was also seen for certain categories of symptoms, including skin conditions and upper respiratory symptoms. This association persisted even after adjusting for age, sex, smokers in household, presence of animals in the household, education level, work type, and awareness of environmental risks. Other groups of reported symptoms, including cardiac, neurological, or gastrointestinal symptoms, did not show a similar association with gas well proximity. These results support the need for further investigation of whether natural gas extraction activities are associated with community health impacts.

These findings are consistent with earlier reports of respiratory and dermal conditions in persons living near natural gas wells (Bamberger and Oswald 2012; Steinzor et al. 2013). Strengths of the study included the larger sample size compared with previously published surveys, and the random method of selecting households using geographic information system methodology, which reduces the possibility of selection bias (although only a subset of households, those with ground-fed water supply, were sampled).

A limitation of the study was the reliance on self-report of health symptoms. On one hand, symptoms in other household members may have been underreported by the household respondent; on the other hand, awareness bias in individuals concerned about the presence of an environmental health hazard would be more likely to increase reporting of illness symptoms, leading to recall bias of the results. We did not collect data on whether individuals were receiving financial compensation for gas well drilling on their property, which could have affected their willingness to report symptoms. It is possible that differential refusal to participate could have introduced potential for selection bias; for example, individuals who were receiving compensation for gas drilling on their property might be less willing to participate in the survey. We found instead that the refusal rate, though < 25% overall, was higher among households farther from gas wells, suggesting that such households may have been less interested in participating because they had less awareness of hazards. The study questionnaire did not include questions about natural gas extraction activities, in order to reduce awareness bias. At the same time, it is likely that household residents were aware of gas drilling activities in the vicinity of households; and the fact that reported environmental awareness by respondents was associated with the prevalence of all groups of reported health symptoms suggests a correlation between heightened awareness of health risks and reported health conditions. Nevertheless, the observed association between gas well proximity and reported dermal and upper respiratory symptoms persisted in the multivariate model even after adjusting for environmental awareness. Future studies should attempt to medically confirm particular diagnoses and further assess and control for the effect of awareness on reported health status.

Table 1. Demographics and household characteristics by proximity to the nearest natural gas well.

Characteristic	< 1 km	1–2 km	> 2 km	All
Individuals				
n	150	150	192	492
Sex				
Male	80 (53)	78 (52)	92 (48)	250 (51)
Female	70 (47)	72 (48)	100 (52)	242 (49)
Children	21 (14)*	27 (18)	52 (27)	100 (20)
Education (years)	13.4 ± 2.0	13.5 ± 1.9	13.3 ± 2.0	13.4 ± 1.9
Age (years)	46.9 ± 21.9**	45.5 ± 22.7	40.0 ± 23.5	43.8 ± 23.0
Occupation[a]				
M/P	29 (19)	34 (23)	33 (17)	96 (19)
O/S	17 (11)	11 (7)	14 (7)	42 (9)
BC	60 (40)	51 (34)	56 (29)	167 (34)
NW	44 (29)	54 (36)	89 (46)	187 (38)
Households				
n	62	57	61	180
Smoking[b]	7 (11)	12 (21)	14 (23)	33 (18)
Years in household (*n*)	23.7 ± 16.6	23.5 ± 16.4	21.2 ± 18.6	22.8 ± 17.2
Body mass index (kg/m^2)	27.9 ± 5.1	27.5 ± 5.4	27.9 ± 6.1	27.8 ± 5.5
Use ground-fed water				
Drinking	39 (63)	41 (72)	38 (62)	118 (66)
Other	54 (87)	51 (89)	46 (75)	151 (84)
Water has unnatural appearance	13 (21)	7 (12)	6 (10)	26 (14)
Taste/odor prevents water use	14 (23)	10 (18)	19 (31)	43 (24)
Dissatisfied with odor in environment	7 (11)	1 (2)	1 (2)	9 (5)
Environmental risk awareness[c]	16 (25)	16 (28)	9 (15)	41 (23)
Years since spud date of closest well (years)	2.3 ± 1.6[#]	1.5 ± 1.3	1.1 ± 0.9	1.6 ± 1.4

Values are *n* (%) or mean ± SD.
[a]Participant occupation was categorized into six main industries according to the U.S. Bureau of Labor Statistics (2014), and presented here in four main groups: M/P, management or professional; O/S, office, sales, or service; BC, blue collar (fishing, farming, and forestry; construction, extraction, maintenance, production, transportation, and material moving); NW, nonworker (student, disabled, retired, or unemployed). [b]Household smoking was determined when respondents were asked if they or at least one member of their household smoked cigarettes in the house at the time of the survey. [c]Household respondents were asked if they were aware of any environmental health risks near their residence (yes/no), to approximate potential sources of expectation or awareness bias. *p = 0.008 compared with > 2 km households. **p = 0.03 compared with > 2 km households. [#]p < 0.05 compared with 1–2 km and > 2 km households.

A further study limitation was the fact that our analysis includes multiple comparisons between groups of households, and the consequent possibility that random error could account for some of our findings. We limited such comparisons by grouping individual symptoms into organ system clusters. However, we acknowledge that the multiple comparisons used in the methodology mean that any such particular findings should be viewed as preliminary and hypothesis generating.

Our use of gas well proximity as a measure of exposure was an indirect measure of potential water or airborne exposures. More precise data could come from direct monitoring and modeling of air and water contaminants, and correlating such measured exposures with confirmed health effects should be a focus of future study. Biomonitoring of individuals living near natural gas wells could provide additional information about the role and extent of particular chemical exposures.

There are several potential explanations for the finding of increased skin conditions among inhabitants living near gas wells. One is that natural gas extraction wells could have caused contamination of well water through breaks in the gas well casing or other underground communication between ground water supplies and fracking activities. The geographic area studied has experienced petroleum and coal exploration and extraction activities in the past century, and such activities may increase the risk of chemicals in fracking fluid or flowback water entering ground water and contaminating wells. If such contamination did occur, several types of chemicals in fracking fluid have irritant properties and could potentially cause skin rashes or burning sensation through exposure during showers or baths. There are published reports of associations between the prevalence of eczema and other skin conditions with exposure to drinking water polluted with chemicals including VOCs (Chaumont et al. 2012; Lampi et al. 2000; Yorifuji et al. 2012) as well as changes in water hardness (Chaumont et al. 2012; McNally et al. 1998).

A second possible explanation for the skin symptoms could be exposure to air pollutants including VOCs, particulates, and ozone from upwind sources, such as flaring of gas wells (McKenzie et al. 2012) and exhaust from vehicles and heavy machinery.

A third possibility to explain the clustering of skin and other symptoms would be that they could be related to stress or anxiety that was greater for households living near gas wells. In this study, awareness of environmental risk was independently associated with overall reporting of symptoms as well as reporting of skin problems. However, in multivariate models, proximity to gas wells remained a significant predictor of symptoms even when adjusting for such awareness. These results argue for possible air or water contaminant exposures, in addition to stress, contributing to the observed patterns of increased health symptoms in households near gas wells. A fourth possibility would be the role of allergens or irritant chemicals not related to natural gas drilling activities, such as exposure to agricultural chemicals or household animals. We did not see a correlation between skin conditions and either the presence of an animal in the household or agricultural occupation, making this association less likely. At the same time, it is possible that other confounding could be present but not accounted for in our models.

Table 2. Prevalence of selected health conditions reported by individuals by proximity to the nearest gas well (2011–2012).[a]

Symptoms	< 1 km (*n* = 150)	1–2 km (*n* = 150)	> 2 km (*n* = 192)
Total number of symptoms per individual	3.27 ± 3.72	2.56 ± 3.26	1.60 ± 2.14
Dermal [*n* (%)]	19 (13)	7 (5)	6 (3)
Rashes/skin problems	10 (7)	7 (5)	6 (3)
Dermatitis	6 (4)	5 (3)	2 (1)
Irritation	6 (4)	2 (1)	1 (1)
Burning	8 (5)	4 (3)	1 (1)
Itching	9 (6)	5 (3)	2 (1)
Hair loss	2 (1)	0 (0)	1 (1)
Upper respiratory [*n* (%)]	58 (39)	46 (31)	35 (18)
Allergies/sinus problems	35 (23)	27 (18)	27 (14)
Cough/sore throat	10 (7)	3 (2)	2 (1)
Itchy eyes	19 (13)	22 (15)	10 (5)
Nose bleeds	13 (9)	8 (5)	4 (2)
Stuffy nose	16 (11)	8 (5)	4 (2)
Lower respiratory [*n* (%)]	29 (19)	29 (19)	27 (14)
Asthma/COPD	16 (11)	21 (14)	15 (8)
Chronic bronchitis	8 (5)	2 (1)	2 (1)
Chest wheeze/whistling	6 (4)	9 (6)	7 (4)
Shortness of breath	8 (5)	7 (5)	8 (4)
Chest tightness	4 (3)	6 (4)	5 (3)
Cardiac [*n* (%)]	46 (31)	39 (26)	37 (19)
High blood pressure	38 (25)	33 (22)	29 (15)
Chest pain	8 (5)	5 (3)	6 (3)
Heart palpitations	10 (7)	7 (5)	4 (2)
Ankle swelling	11 (7)	5 (3)	5 (3)
Gastrointestinal [*n* (%)]	15 (10)	13 (9)	11 (6)
Ulcers/stomach problems	11 (7)	7 (5)	8 (4)
Liver problems	4 (3)	0 (0)	1 (0.5)
Nausea/vomiting	1 (1)	3 (2)	1 (0.5)
Abdominal pain	4 (3)	2 (1)	2 (1)
Diarrhea	5 (3)	2 (1)	2 (1)
Bleeding	4 (3)	4 (3)	0 (0)
Neurologic [*n* (%)]	48 (32)	37 (25)	39 (20)
Neurologic problems	1 (0.7)	5 (3)	0 (0)
Severe headache/migraine	24 (16)	14 (9)	18 (9)
Dizziness/balance problems	11 (7)	12 (8)	11 (6)
Depression	4 (3)	3 (2)	2 (1)
Difficulty concentrating/remembering	9 (6)	9 (6)	6 (3)
Difficulty sleeping/insomnia	18 (12)	19 (13)	10 (5)
Anxiety/nervousness	11 (7)	4 (3)	11 (6)
Seizures	2 (1)	2 (1)	1 (0.5)

COPD, chronic obstructive pulmonary disease.
[a]Six categories representing major health conditions of *a priori* interest chosen to ascertain symptom prevalence among individuals living in proximity to the nearest gas well in 2011–2012.

Table 3. Associations of nearest gas well proximity and symptoms.

	< 1 km		1–2 km		
Outcome	OR (95% CI)	*p*-Value	OR (95% CI)	*p*-Value	> 2 km
Dermal	4.13 (1.38, 12.3)	0.011	1.44 (0.42, 4.9)	0.563	Ref
Upper respiratory	3.10 (1.45, 6.65)	0.004	1.76 (0.81, 3.76)	0.148	Ref
Lower respiratory	1.45 (0.67, 3.14)	0.339	1.40 (0.65, 3.03)	0.387	Ref
Cardiac	1.67 (0.85, 3.26)	0.135	1.28 (0.65, 2.52)	0.473	Ref
Gastrointestinal	2.01 (0.49, 8.18)	0.328	1.79 (0.43, 7.41)	0.417	Ref
Neurological	1.53 (0.89, 2.63)	0.123	1.04 (0.59, 1.82)	0.885	Ref

Ref, reference. Results are from hierarchical logistic regression that adjusted for age, household education level, sex, smokers in household, job type, animals in household, and awareness of environmental risk.

Our findings of increased reporting of upper respiratory symptoms among persons living < 1 km from a natural gas well suggests that airborne irritant exposures related to natural gas extraction activities could be playing a role. Such irritant exposures could result from a number of activities related to natural gas drilling, including flaring of gas wells and exhaust from diesel equipment. Because other studies have suggested that airborne exposures could be a significant consequence of natural gas drilling activity, further investigation of the impact of such activities on respiratory health of nearby communities should be investigated. Future studies should collect such data.

Since most of the gas wells in the study area had been drilled in the past 5–6 years, one would not yet expect to see associations with diseases with long latency, such as cancer. Furthermore, if some of the impact of natural gas extraction on ground water happens over a number of years, this initial survey could have failed to detect health consequences of delayed contamination. However, if the finding of skin and respiratory conditions near gas wells indicates significant exposure to either fracking fluids and chemicals or airborne contaminants from natural gas wells, studies looking at such long-term health effects in chronically exposed populations would be indicated.

Conclusions

The results of this study suggest that natural gas drilling activities could be associated with increased reports of dermal and upper respiratory symptoms in nearby communities; these results support the need for further research into health effects of natural gas extraction activities. Such research could include longitudinal assessment of the health of individuals living in proximity to natural gas drilling activities, medical confirmation of health conditions, and more precise assessment of contaminant exposures.

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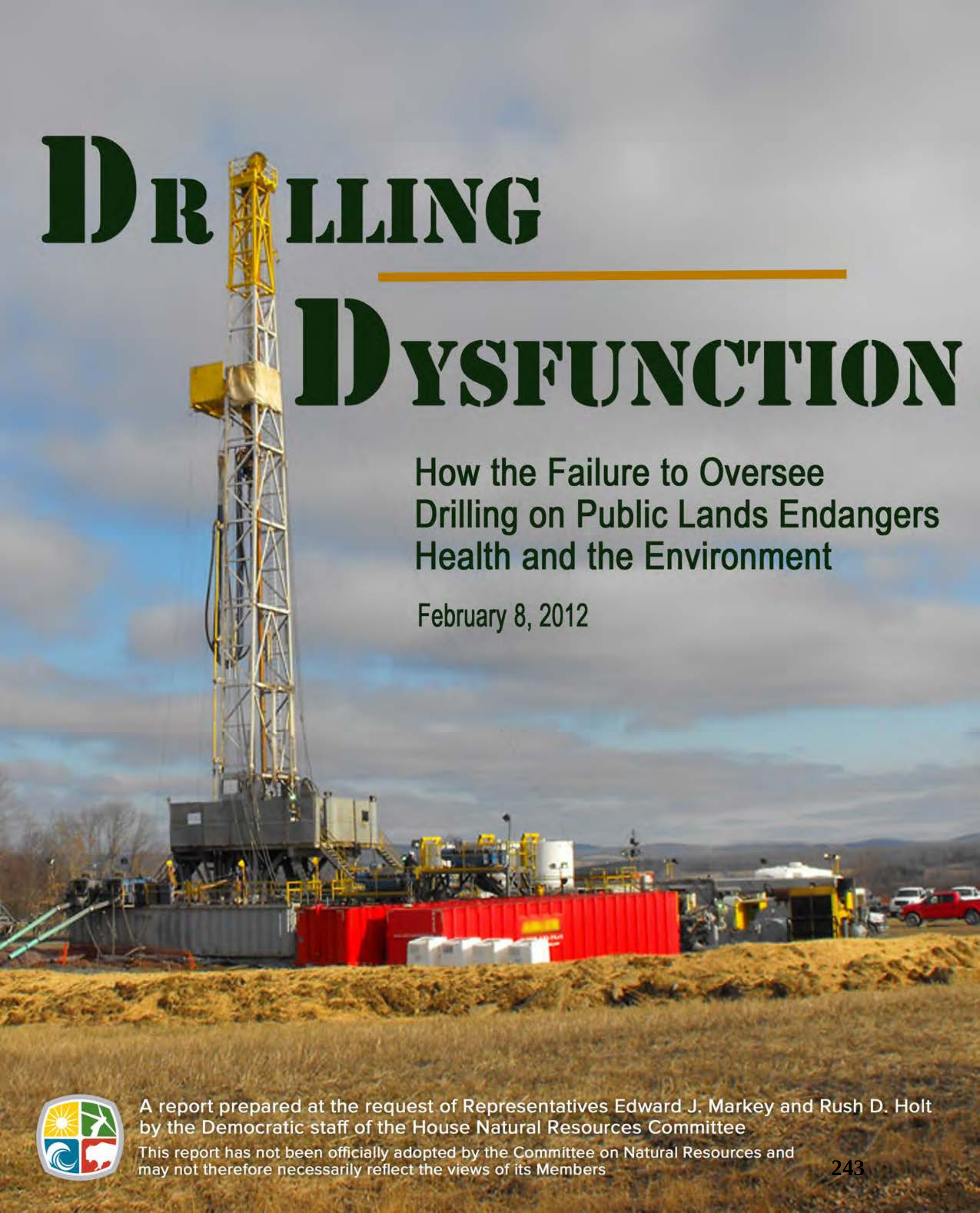

Drilling Dysfunction

How the Failure to Oversee Drilling on Public Lands Endangers Health and the Environment

February 8, 2012

A report prepared at the request of Representatives Edward J. Markey and Rush D. Holt by the Democratic staff of the House Natural Resources Committee

Table of Contents

Executive Summary

Hydraulic fracturing has helped to expand natural gas production in the United States, unlocking natural gas supplies in shale and other unconventional formations across the country. As a result of developments in this technology and the rapid expansion of its use, natural gas production in the Unites States has reached levels not seen in decades.[1] In the last 5 years, more than 90 percent of the natural gas wells drilled on federal lands were accessed using hydraulic fracturing. This technology has helped natural gas production on federal lands to more than double in the last 20 years. Onshore oil production on federal lands also continues to increase and currently accounts for approximately 6 percent of total domestic production.

As the use of hydraulic fracturing has grown, so have concerns about its environmental and public health impacts. One concern is that hydraulic fracturing fluids used to fracture formations contain numerous chemicals that could harm human health and the environment, especially if they enter drinking water supplies. According to the Department of Interior (DOI), approximately one-third of a random sample chosen to represent gas wells on federal lands was hydraulically fractured in, near or below an underground source of drinking water.

In February 2011, Rep. Edward J. Markey (D-Mass.), Ranking Democrat on the Natural Resources Committee, and Rep. Rush D. Holt (D-N.J.), Ranking Democrat on the Energy and Mineral Resources Subcommittee, launched an investigation to examine the practice and oversight of oil and gas drilling on federal lands. As a part of that inquiry, the lawmakers asked the DOI for information regarding safety or drilling violations that have occurred on federal lands over the last ten years. Over several months, the Department provided Committee staff with data responsive to the Markey-Holt request. This report summarizes and analyzes the information provided to the Democratic committee staff.

Short of shutting down a well's operation, the Interior Department's strongest enforcement tool against companies that fail to comply with the rules and regulations of drilling on federal lands is to levy monetary fines. However, in order for these fines to serve as a deterrent for noncompliance they must be: 1) issued consistently to all companies on all federal land, 2) large enough to incentivize compliance, and 3) based on accurate and complete information regarding oil and gas activities occurring on federal lands.

The Democratic Committee staff's analysis shows that only a very small percentage of violations result in fines and that the fines that are levied amount to nothing more than pocket change for billion-dollar oil and gas companies. The majority of the major safety violations stem from the failure of a blowout preventer or casing and cementing of the well, which all became visible deficiencies in offshore oil drilling following the Deepwater Horizon oil spill. This analysis also exposes the fact that oil and gas companies have on dozens of occasions initiated drilling on federal lands before they have received formal approval to do so. Furthermore, many violations were issued because companies failed to keep proper records and conduct routine safety tests, which could potentially conceal

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[1] Natural gas production in the U.S. in 2010 reached 21,577 billion cubic feet. Energy Information Administration (EIA), *Natural Gas Monthly (Mar. 2011)*. See: www.eia.gov/dnav/ng/hist/n9070us1A.htm

significant safety issues, and makes it more difficult for the Department of Interior to conduct effective oversight on drilling operations. Astonishingly, monetary fines issued for all drilling violations occurring on all federal lands, over the decade covered in this report amounted to a total of just $273,875.

One challenge for assessing fines lies in the outdated structure for monetary fines and civil penalties, which was first set in the early 1980s and has never been revised. Nearly 30 years later, these low monetary penalties can be far below a company's daily operating costs and, accordingly, inconsequential to many operators. As a result, oil and gas drillers that pollute groundwater, spill toxic chemicals or break other rules have little to fear from inspectors.

These types of monetary penalties and the inconsistent way in which they are levied do little to ensure accountability and protection of the surface and subsurface environment. As the rapid expansion of natural gas drilling continues, the DOI must revise its drilling and safety regulations to account for more widespread use of technologies like hydraulic fracturing and significantly revise its inspection and enforcement strategies to ensure that extraction of natural gas from deep below the earth's surface does not do irreversible harm to the environment and public health.

Results in Brief

- <u>There were a total of 2,025 safety and drilling violations that were issued to 335 companies drilling in seventeen states between February 1998 and February 2011.</u> Of these, 27 percent were classified by Committee staff as a major environmental or safety violation, 20 percent as a minor safety violation and 53 percent as a minor drilling or operational violation.

- <u>Oil and gas drilling activities on public lands may endanger drinking water.</u> Approximately one-third of a random sample chosen by the DOI to represent oil and gas wells on federal lands was hydraulically fractured in, near or below an underground source of drinking water. The widespread use of this drilling practice at such locations underscores the importance of ensuring that hydraulic fracturing operations be conducted in a fashion which will not threaten drinking water supplies. Anecdotally, and through a casual conversation that occurred with the operator after the well had already been fractured, the DOI was made aware of one case in which diesel fluid was used during hydraulic fracturing in a well in Wyoming that was completed in 2008, without a permit, without prior knowledge of the agency and in potential violation of the Safe Drinking Water Act.

- <u>There were many violations that could endanger health and safety of workers and the environment</u>. An evaluation of the data found many examples of major environmental or safety violations reported during this period, including a 2008 blowout of a well in North Dakota that was not immediately reported to the DOI; an operator in Mississippi that did not install a blowout preventer or any other safety equipment to control the well in the event of a blowout; and an improper casing and cement job in Wyoming that led to leaks of water and gas through the cement of the well.

- There were 549 violations classified as "major" by Committee staff, 53 percent of which (293 violations) were related to non-functional blowout preventers. In addition, 25 percent of what were classified as minor safety violations (104 out of 410 violations) were issued because of minor problems with the blowout preventer or other device that could impact well control. In all, problems with blowout preventers or other devices responsible for well control constituted 20 percent (397 out of 2,025 violations) of all violations.

- Some operators fail to get approval from DOI prior to drilling on federal lands. In fifty-four instances, operators were given written citations for violations related to drilling on federal lands before they received the appropriate approval. In many instances, according to DOI staff, these violations were given because an operator began drilling on federal lands before the permit to drill was fully processed and approved by the DOI.

- More than one-fifth of major violations involved a compromise of vital casing and cementing. Twenty-one percent of the 549 major cited environmental or safety violations were issued because of deficiencies in casing and cementing programs. Appropriate casing and cementing is the first line of defense in protecting underground sources of drinking water.

- Operators frequently violate safety testing, record-keeping and notification requirements. The majority (628 out of 1,066 total or 60 percent) of the minor drilling or operational violations were issued for safety testing, record-keeping and notification violations. These included written violations for failing to comply with requirements to keep records of operations and to notify the Department of significant activities. Failure to keep such records or reports when required to do so could potentially conceal significant safety issues, and makes it more difficult for the agency to conduct effective oversight on drilling operations occurring on federal lands.

- Monetary penalties are almost never issued and when issued amount to very little. Despite the fact that many of these violations were issued for serious safety and environmental reasons, only 125 (six percent) of all the violations were levied a monetary fine. Although the violations that occurred were spread across 17 states, eight states (AK, AR, LA, ND, NV, OH, SD, and WV) never issued a monetary fine of any amount during the entire period examined. Additionally, only 64 out of the 335 operators with violations were ever levied a monetary fine. The fines that were levied also amounted to very little. In fact, fines issued on all federal lands for violations dating from February 1998-February 2011 amounted to a total of just $273,875. For example, in 2003 an operator was found to be discharging fluids directly from the rig into the Washita River in Oklahoma. As a penalty for this, the operator was issued a monetary assessment of only $2,500, which is less than what some of the largest oil and gas companies can earn in a minute.[2]

[2] In its 2011 3rd quarter financial report the 3 top U.S. Oil and Gas Companies (Exxon Mobil, ConocoPhillips and Chevron Corporation) each reported earnings of over $7 billion. See for example: http://www.chevron.com/chevron/pressreleases/article/10282011_chevronreportsthirdquarternetincomeof78billionupfrom38billioninthirdquarter2010.news

- The issuance of monetary fines is inconsistent. There were frequent incidences in which a specific activity led inspectors to issue a monetary penalty against one operator, but not against another, when the second operator was found to have committed the identical violation. This occurred even within the same state, even though each state presumably has uniform inspection and enforcement processes and protocols. Even among those operators that were frequent repeat violators, there were four companies that never once received a fine, despite the fact that companies with even fewer violations did receive a fine. This lack of consistency in the issuance of monetary penalties calls into question the adequacy and effectiveness of the oversight of onshore oil and gas drilling operations and the ability of the DOI to ensure safety and environmental performance of hydraulic fracturing as this practice expands on federal lands.

Background

The Bureau of Land Management (BLM) within the Department of Interior (DOI) oversees approximately 700 million acres of sub-surface mineral estate throughout the nation and issues leases for natural gas development on federal lands.[3] In the last 20 years, natural gas development on federal lands has more than doubled, from 1.2 trillion cubic feet (Tcf) in fiscal year 1991 to nearly 3.0 Tcf in fiscal year 2010.[4] In fiscal year 2010, about 14 percent of domestically produced natural gas and about 6 percent of domestically produced oil came from onshore public lands.[5] Much of the increase in natural gas production comes from increased accessibility to unconventional sources of natural gas, including tight sands, coalbed methane and shale rock. This accessibility is largely credited to advances in drilling technologies, including horizontal drilling and hydraulic fracturing (sometimes referred to as “fracking”). The combined use of these technologies have made vast reserves of natural gas economically recoverable, triggering a wave of new production activities across the United States and an increase in gas production on federal lands.

Hydraulic Fracturing

Hydraulic fracturing is a well stimulation technique used to maximize production of oil and gas in unconventional reservoirs. In order to create additional permeability in the producing oil or gas formation, hydraulic fracturing is used to create spaces (or fractures) in the rock pores enabling the oil or gas to flow more freely to producing wells. To create these fractures, the process of hydraulic fracturing involves pumping millions of gallons of water combined with sand and often-unidentified chemical agents (collectively known as fracturing fluids) down the well bore at extremely high pressures. More recently, this same drilling technique has been used to produce oil from low permeability shale deposits in the United States. According to the BLM, over the last decade, leasing and exploration activities on BLM-managed public lands has focused mainly on the development of natural gas resources. Professional estimates from BLM field offices projected that 90 - 95 percent of gas exploration and development on federal lands over the last five years was accessed using hydraulic fracturing.[6] There has also been an increase in hydraulic fracturing used to access oil deposits. According to the National Petroleum Council hydraulic fracturing accounts for approximately 43 percent of total U.S. oil production.[7]

With increased use of this technology, there has been an increase in public concern about the impacts of hydraulic fracturing on water quality, water quantity, public health, and the environment. Many of the concerns have centered on contamination of drinking water, if fracturing fluids were to seep into groundwater or surface water during the process of hydraulic fracturing. Oil and gas companies use a variety of additives and chemicals in their fracturing fluid with the goal of widening and extending the length of the fractures and transporting large

[3] http://democrats.naturalresources.house.gov/content/files/2011-06-03_LTR_DOIResponseTo2011-02-28Lttr.pdf
[4] http://www.blm.gov/wo/st/en/info/newsroom/Energy_Facts_07.html
[5] http://www.standard.net/topics/business/2011/04/01/blm-hold-forums-natural-gas-fracturing
[6] http://democrats.naturalresources.house.gov/content/files/2011-11-17_LTR_DOIResponseREUSDW.pdf
[7] Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources (2011). National Petroleum Council.

amounts of material to "prop open" the fractures. While some of these chemicals are generally harmless, such as sand and salt, an investigation by the House Energy and Commerce Committee Democratic staff released by Reps. Henry A. Waxman (D-Calif.), Edward J. Markey (D-Mass.) and Diana DeGette (D-Colo.) found that between 2005 and 2009, 14 leading oil and gas companies used more than 780 million gallons of hydraulic fracturing products containing 750 different chemicals, including carcinogenic and other toxic components such as lead and benzene.[8] In fact, these companies used 29 distinct chemicals that are known or possible human carcinogens, regulated under the Safe Drinking Water Act (SDWA) for their risks to human health, or listed as hazardous air pollutants under the Clean Air Act. The investigation also found that 12 of the 14 companies used more than 32 million gallons of diesel fuel ─ which often contains benzene, toluene, ethylbenzene and xylenes (the BTEX compounds) ─ chemicals known for their toxicity and adverse health impacts in 20 states.[9]

In a 2004 report, the Environmental Protection Agency (EPA) stated that the "use of diesel fuel in fracturing fluids poses the greatest threat" to underground sources of drinking water.[10] The Energy and Commerce Committee investigation found that the utilization of diesel by these companies in fracturing fluids occurred without knowledge of the state and federal regulators, a direct violation of the 2005 Energy Policy Act. The law includes a provision that exempts hydraulic fracturing operations from the permit requirements of the Safe Drinking Water Act unless diesel fluid is being used.[11] Whenever diesel fluid is being used in hydraulic fracturing operations, the operators are required to receive prior authorization from state or federal regulators.[12] The EPA recently found chemicals commonly used in hydraulic fracturing in a drinking water aquifer in Pavilion, Wyoming. Through monitoring wells, EPA found several synthetic cancer causing compounds, including 2-butoxyethanol, glycols, naphthalene, toluene as well as benzene, which was found at a concentration 50 times the federal Safe Drinking Water standard.[13] According to an EPA report published in 1987, this was not the first incidence in which drinking water was found contaminated with fracturing fluids. A West Virginia drinking water well was found to be contaminated with fracturing fluids and natural gas from nearby drilling operations in 1984.[14] The EPA also recently began sampling water from approximately sixty homes in Dimock, Pennsylvania after residents raised concerns that their water was contaminated with hazardous substances from nearby drilling activities.[15] The EPA is currently conducting a national study on the impacts of hydraulic fracturing on drinking water resources. Initial results from that study are expected at the end of 2012, with a final report expected in 2014.

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[8] http://democrats.energycommerce.house.gov/index.php?q=news/committee-democrats-release-new-report-detailing-hydraulic-fracturing-products

[9] http://democrats.energycommerce.house.gov/index.php?q=news/reps-waxman-markey-and-degette-report-updated-hydraulic-fracturing-statistics-to-epa

[10] U.S. Environmental Protection Agency, Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coal bed Methane Reservoirs (June 2004) (EPA816-R-04-003) at 4-11.

[11] 42 U.S.C. § 300h(d)

[12] While the SDWA excludes hydraulic fracturing from underground injection control (UIC) regulation, the use of diesel fuel during hydraulic fracturing is still regulated by the UIC program.
See: http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydroreg.cfm

[13] See for example: http://www.nytimes.com/2011/12/09/us/epa-says-hydraulic-fracturing-likely-marred-wyoming-water.html

[14] "A tainted Water Well, and Concern There May Be More" *The New York Times,* August 3, 2011

[15] http://yosemite.epa.gov/opa/admpress.nsf/0/8eb78248ce13d9dc8525798a0070f991?OpenDocument

Disposal of hydraulic fracturing wastewater is another public health and environmental concern. As much as 80 percent of the fluids injected for hydraulic fracturing returns to the surface as "flowback," which can be contaminated with tens of thousands of pounds of chemicals, naturally occurring radioactive material, salt and sand. A deep horizontal shale well can use anywhere from 2 to 10 million gallons of water to fracture a single well.[16] While the percentage of chemical additives in hydraulic fracturing fluid is typically small,[17] the quantity of fluid used in the fracturing process is so large that the United States Geological Survey estimates that three million gallons of fracturing fluid would yield about 15,000 gallons of chemicals in the waste.[18] Earlier this year, The New York Times released results of an investigation[19] that indicated that the recovered fracturing fluid, which flows back up the well after drilling, is loaded with naturally occurring radioactive elements associated with the shale formations. The investigation suggested that millions of gallons of drilling wastewater contaminated with radioactive radium, at levels that far exceed the safe drinking water standards, were dumped into rivers and other U.S. waterways. In several cases, fracturing wastewater was sent to treatment facilities that could not adequately treat it. The New York Times investigation also found that natural gas from hydraulic fracturing operations had seeped into underground drinking water supplies in at least five states, including Colorado, Ohio, Pennsylvania, Texas and West Virginia. Wastewater pumped into disposal wells has also been implicated in small earthquakes in Texas, Arkansas and Ohio.[20] The most recent of this seismic activity, which occurred on December 31, 2011 in Youngstown Ohio, led officials to halt all underground injection of wastewater until further assessment of the earthquakes could be performed.

Proper well construction and operation are necessary for the safe production of oil and natural gas. There have been several notable cases in which hydraulically fractured wells have blown out, due to faulty construction, cementing or defective equipment, spilling large quantities of fracturing fluids and natural gas and causing the evacuation of multiple households.[21] One such event occurred in April 2011 when equipment failure at a well in Pennsylvania that was in the process of being hydraulically fractured, caused tens of thousands of gallons of chemical-laced water to spew out of the well and into a nearby creek, causing evacuation of homes and temporary suspension of drilling activities at nearby sites.[22] These events have highlighted the need for a more holistic approach in determining the environmental impacts of natural gas drilling, an approach that focuses not just on the process of hydraulic fracturing itself, but the entire drilling process from exploration to reclamation.

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[16] Kargbo, D. et al. Natural Gas Plays in the Marcellus Shale: Challenges and Potential Opportunities. *Environ. Sci. Technol.*, 2010, 44 (15), pp 5679–5684

[17] Estimates range between 0.5 and 2% of the total volume of fracturing fluid.
See for example: http://www.gwpc.org/e-library/documents/general/State%20Oil%20and%20Gas%20Regulations%20Designed%20to%20Protect%20Water%20Resources.pdf

[18] http://pubs.usgs.gov/fs/2009/3032/pdf/FS2009-3032.pdf

[19] "Regulation Lax as Gas Wells' Tainted Water Hits River" *The New York Times*, February 26, 2011

[20] See: http://mobile.bloomberg.com/news/2012-01-03/ohio-halts-wells-after-quake-won-t-stop-natural-gas-drilling?category=%2Fnews%2Fenvironment%2F

[21] See for example: http://news.yahoo.com/s/ap/20110305/ap_on_re_us/us_onshore_well_blowouts

[22] http://www.reuters.com/article/2011/04/21/us-chesapeake-blowout-idUSTRE73K5OH20110421

Management of Federal Mineral Resources

The Bureau of Land Management has leased approximately 42 million acres for oil and gas development,[23] essentially six percent of the entire federal onshore mineral estate. Of these 42 million acres, about 12.2 million acres are currently in production with an estimate of an additional one million acres that will come into production during the next ten years.[24]

Section 604 of the Energy Policy and Conservation Act (EPCA) of 2000, as amended by Section 364 of the Energy Policy Act of 2005, required an inventory report of all onshore Federal lands to identify estimates of the oil and gas resources underlying these lands.[25] The most recent of these reports issued in 2008, demonstrates that 34 percent of the technically recoverable[26] onshore oil resources and 35 percent of the technically recoverable natural gas resources within the United States are on federal lands. This translates to an estimated 30.6 billion barrels of oil and 231 trillion cubic feet of natural gas that are technically recoverable from the federal onshore mineral estate.

Currently, natural gas operations on federal lands are primarily governed by what is known as the Onshore Oil and Gas Order No. 1 and No. 2 (43 CFR 3160). Onshore Order No. 1 (amended in 2007) contains the information an operator must submit to the BLM for the approval of proposed gas exploration and development on federal lands. These submittal requirements include items such as design of casing strings, cementing programs for the casing strings and the type of well control equipment proposed to be used by the operator. Onshore Order No.2 sets the minimal requirements for well design, construction and well control, including minimum casing and cementing requirements. However, Onshore Order No. 2 has not been updated since 1988 and reflects neither the significant technological advances of hydraulic fracturing and associated technologies nor the tremendous growth in its use.

While an operator is mandated to get an approved permit for drilling on federal lands, BLM's current regulations do not require an operator to get additional approvals to undertake hydraulic fracturing operations nor do they contain provisions that would mandate that an operator disclose the chemical components or volumes of fracturing fluids used in wells on public lands. As a result, important information about drilling operations on federal lands is not required to be disclosed by operators. In fact, when asked if BLM was ever aware of an instance in which diesel fluid was used on federal lands as a part of hydraulic fracturing operation, BLM responded that an operator in Wyoming utilized diesel in hydraulic fracturing activities without a permit. BLM only found out about the use of diesel through a casual conversation with the operator after the well had already been hydraulically fractured. This well was completed in 2008 and further details or documentation of the use of diesel on this well was not available. Additionally, in 2001, BLM received a Notice of Intent for the hydraulic fracturing of a well in Anchorage, Alaska. The submitted proposal stated that diesel would be used and provided an initial estimate of 700 barrels of diesel. This procedure was approved by BLM and the well was subsequently

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[23] Oil and gas development are not tracked separately and are often produced from the same lease
[24] http://democrats.naturalresources.house.gov/content/files/2011-06-03_LTR_DOIResponseTo2011-02-28Lttr.pdf
[25] http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/EPCA_III.html
[26] Technically recoverable resources are resources that are recoverable using current exploration and production technology without regard to cost or profitability.

stimulated. Information regarding the actual final volume of diesel used or whether the well was in or near an underground source of drinking water was not available.

In response to escalating public concerns and the anticipated growth of oil and natural gas exploration and production, the DOI began hosting a series of public forums in 2010 to discuss hydraulic fracturing techniques and examine best practices that should be put in place to ensure that development of natural gas on public lands proceeds in a responsible and environmentally sustainable manner.[27] As a part of this process, the BLM also held three regional public meetings in Colorado, North Dakota, and Arkansas ─ states that have experienced significant increases in natural gas development.[28]

In August 2011, the Secretary of Energy Advisory Board (SEAB) issued a report with recommendations for improving the safety and environmental performance of natural gas hydraulic fracturing from shale formations. The report included 20 recommendations in four key areas: 1) public accessibility to information about gas production, 2) short term and long-term actions to protect air and water quality, 3) systemic approach to development of best operating practices, and 4) research and development to improve safety and environmental performance.[29] Among the recommendations included in the report are:

- disclosure of all chemicals used in fracturing fluid at each well;
- using a life-cycle approach to managing and tracking water and wastewater, including developing best practices for casing and cementing;
- extensive testing, monitoring, and disclosure of air pollution associated with gas development;
- reduction in diesel use;
- improving communication among state and federal regulators; and
- further study of the climate change impacts posed by natural gas development.

In this report, the SEAB also highlighted DOI's unique position to address cumulative impacts of shale gas drilling and cautioned that if concerted and sustained action is not taken "there is a real risk of serious environmental consequences and a loss of public confidence."[30] Secretary of Interior Ken Salazar has also stated "BLM is considering revisions to its current regulations to address disclosure of chemicals used in fracturing fluids."[31] During a meeting of the SEAB, David Hayes, Deputy Secretary of the DOI spoke about the department proposing new rules that would among other things focus on "extending existing well-bore integrity standards to the hydraulic fracturing phase of development" to protect against leaks.[32] Recently, a draft of BLM proposed regulations for hydraulic fracturing on federal lands leaked to the press.[33] In response, DOI stated that the proposed rules seek to ensure disclosure of hydraulic fracturing fluids, improve assurances on well-bore integrity and ensure companies have water

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[27] See: http://www.blm.gov/co/st/en/BLM_Information/newsroom/2011/april/blm_to_hold_regional.html
[28] http://www.bismarcktribune.com/news/state-and-regional/article_341d8db6-5ce5-11e0-bf59-001cc4c03286.html
[29] http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf
[30] http://www.shalegas.energy.gov/resources/111011_press_release.pdf
[31] Ken Salazar (Secretary of Interior). Quote from: U.S. Congress. Hearing of the House Natural Resources Committee. "The Future of U.S. Oil and Natural Gas Development on Federal Lands and Waters" (Date: 11/16/2011)
[32] http://origin-www.bloomberg.com/apps/news?pid=conewsstory&tkr=APC:US&sid=aO0BaKF5YtlA
[33] "Exclusive: First glimpse of fracking rules" *PoliticoPro Energy*. February 2, 2012

management plans for fluids that flow back to the surface. The department has no projected date for the draft's official release or finalization of the proposed rules and will continue to gather public input in developing final rules.

Bureau of Land Management Enforcement and Inspections

The mission of BLM's Oil and Gas Inspection and Enforcement Program (I&E Program) is to ensure full compliance with the laws and regulations governing oil and gas companies operating on federal and Indian lands. BLM's Washington, D.C. office headquarters, state offices and field offices design and implement annual inspection strategies. The Washington, D.C. office prescribes guidelines, policies, and procedures for inspections conducted during the year by state and field offices. Inspectors operate out of 32 BLM field offices, located primarily in California, Colorado, Montana, New Mexico, Oklahoma, Utah and Wyoming.[34]

Inspections play an important role in protecting public lands from environmental degradation and help to ensure that oil and gas operations on federal and Indian lands are prudently conducted in a manner that minimizes waste, protects surface and subsurface environment and ensures general public safety. Environmental inspections may be completed in all phases of a well's life cycle, from site construction to final reclamation. If regulatory violations are uncovered, field inspectors issue a notice of Incident of Noncompliance (INC) or a written violation notice, which may include an immediate monetary assessment and can be issued for both major and minor regulatory violations. An example of a major violation may be failure to install the appropriate well control equipment, while a minor violation may include issues such as inadequate fencing around disposal pits or a missing well identification sign. Monetary assessments are fixed at $250 for a minor violation and $500 per day for a major violation. In addition to assessments, BLM inspectors also have authority to issue civil penalties, which involve varying daily dollar fines that are calculated according to the severity of the violation. Civil penalties range from $500 to $10,000 per day depending upon how long the infraction(s) have continued uncorrected. As a last resort, BLM can choose to cancel the operator's lease if an operator fails to comply with previous enforcement actions. However, to date, BLM has never cancelled a lease because of noncompliance.

[34] U.S. Department of the Interior, Office of Inspector General. Evaluation Report: Bureau of Land Management's Oil and Gas Inspection and Enforcement Program. December 2010.

Investigation

In February 2011, Reps. Markey and Holt queried the Department of Interior DOI Secretary Ken Salazar for more information about the practice and oversight of oil and gas drilling activities on federal lands.[35] In response to this inquiry, the Department of Interior (DOI) provided a listing of all oil and gas operators that have received an incident of noncompliance or violation for safety or drilling reasons in the last decade – a total of 2,025 individual violations. The information supplied by the DOI provided the location, operator, date and nature of the violation as well as information about any monetary penalties levied against the operators of a noncompliant well. The DOI provided information for violations covering fiscal year 2000 through March 2011 – spanning 11 years and 5 months. Because some of these violations were not immediately resolved, the actual violations in this report date from February 1998 through February 2011.What follows is the Democratic Committee staff's analysis of the enforcement data provided.

Methodology

Using the data provided by the Department of Interior which catalogued oil and gas operators that have received an incident of noncompliance for safety or drilling reasons and the nature of the violation, Natural Resources Democratic Committee staff classified each of the violations into three main categories: (1) major environmental or safety violations (2) minor safety violations and (3) minor drilling or operational violations.

The classification was made based on an evaluation of the nature of the violation as described by BLM officials at the time the violation was discovered. If the nature of the violation posed an immediate threat to the health and safety of the public (workers on the site) or endangered the surface or subsurface environment, it was classified as a major environmental or safety violation by the Committee staff. If the nature of the violation described did not rise to the level of a major violation, but nonetheless had the potential to impact the safety of the workers or integrity of the well, it was classified as a minor safety violation. The violation was classified as a minor drilling or operational violation if the violation detailed did not threaten worker safety or the environment and dealt primarily with the day-to-day operation of a drill site. Each of these three main categories were further subdivided and grouped into subcategories of violations to reflect the more specific type of violation that occurred. For an explanation of the subcategories used by the Committee staff to analyze the data, see Appendix A.

In some cases there were so few of a particular type of violation or the description of the violation was too cryptic to place into one of the specific subcategories. In these instances the violation was placed into a generic "other" category. Because inconsistent and incomplete descriptions of violations were sometimes used by inspectors, it is possible that some violations were inconsistently or imprecisely categorized by the Committee staff. Additionally, the duration of the violation was not consistently noted by the inspectors in the description of the violation and therefore duration was not used by the Committee staff in classifying a violation. While

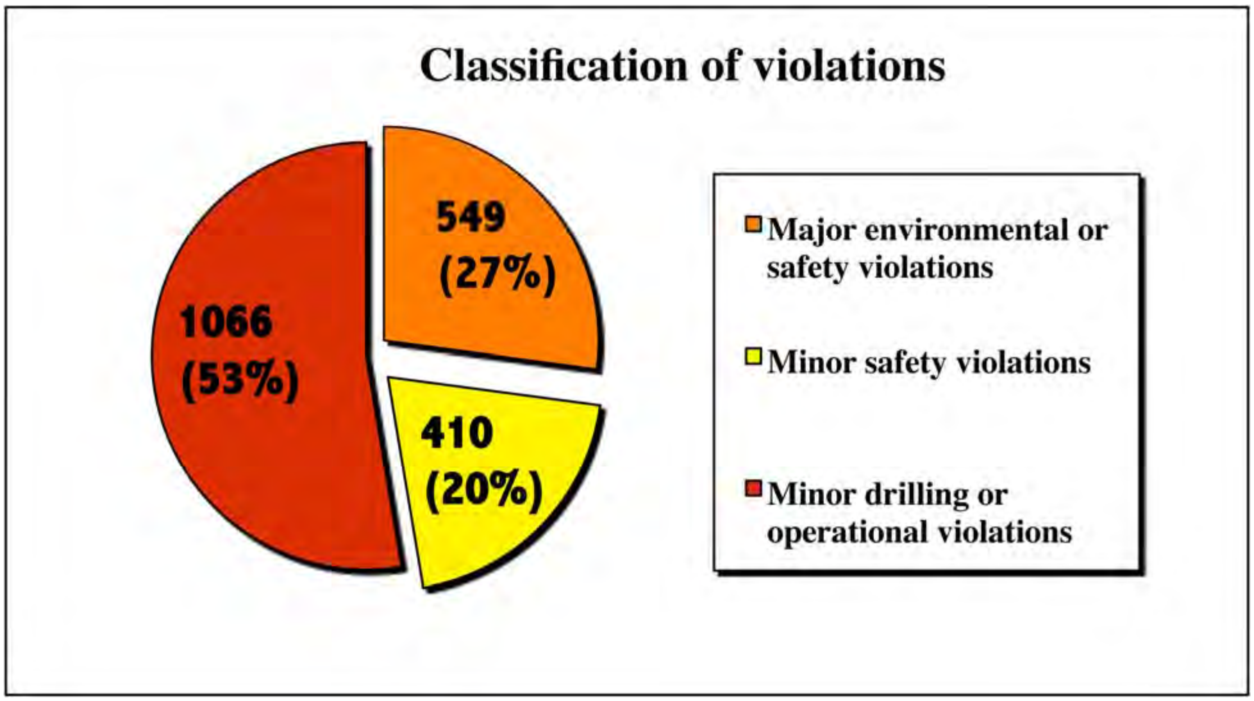
[35] http://democrats.naturalresources.house.gov/pr@id=0018.html

Committee staff attempted to utilize inspectors' own classification of whether a violation was considered a major or minor incident of noncompliance, a review of the data found identical violations that were classified differently by BLM field offices, making the inspectors' classifications of this information inadequate for purposes of our analysis. Addressing these inconsistencies in data entry and the interpretation and classification of violations would be an important step for DOI to take in order to improve its oversight and enforcement of drilling activities.

Findings

There were a total of 2,025 violations for safety and drilling violations issued to 335 companies drilling in seventeen states dating from February 1998 through February 2011. Of these, 27 percent were classified by the Committee staff as a major environmental or safety violation, 20 percent as a minor safety violation and 53 percent as a minor drilling or operational violation.

Figure 1: Classification of Violations



Oil and gas wells on public lands may endanger drinking water

In response to Representatives Markey and Holt's query about the relationship between hydraulic fracturing on public lands and underground sources of drinking water, the BLM conducted a review of 706 randomly-selected wells. This sample was chosen to reflect the more than 86,000 wells present on federal lands and provide a statistical confidence rate of 95 percent.[36] Information was provided as to whether wells in this sample were hydraulically fractured and if so, if they were located within, near, or below an underground source of drinking water (i.e. aquifer).[37] The BLM does not specifically track the co-occurrence of oil and gas with underground sources of drinking water. However, the BLM does evaluate the potential for groundwater occurrences during the permitting process.[38] In response to Reps. Markey and Holt's inquiry the BLM was able to retrospectively review a sample of randomly selected oil and gas wells to determine if drilling occurred in, near or below an underground source of drinking water.[39] Wells drilled in coalbed formations are of particular concern, since these formations typically contain shallow aquifers that could be used for drinking water. Wells drilled in coal bed formations were considered by BLM to have occurred in an underground source of drinking water.

In total, 210 out of the random sample of 706 oil and gas wells (30 percent) were hydraulically fractured in, near or below an underground source of drinking water. The information provided indicates that 49 out of 706 wells (7 percent) were drilled in an underground source of drinking water[40] and 100 percent of these 49 wells were gas wells stimulated by hydraulic fracturing. Additionally, 113 natural gas wells (16 percent of the sample) and 43 oil wells (6 percent of the sample) were hydraulically fractured below an underground source of drinking water. An additional five hydraulically fractured natural gas wells were located within one-quarter of a mile of an aquifer, an area considered close enough to endanger underground water resources.[41] There were a total of 337 wells (115 oil wells and 222 gas wells) that were hydraulically fractured, but were not located in, near or below an underground source of drinking water.[42] Out of the sample of 706 wells, 158 (22 percent) were not hydraulically fractured. The proximity of these wells to an underground source of drinking water was not provided by BLM.

Information provided by BLM indicated that there were at least two instances in which diesel fuel was used in hydraulic fracturing of a well. One of these instances occurred in Wyoming, where an operator used diesel in the hydraulic fracturing fluid of a well without a permit and without the BLM's knowledge—a potential violation of the Safe Drinking Water Act. It was only after completion of this well in 2008, that BLM learned of the use of diesel through a casual conversation with the operator of this well. Because of this, it is unknown whether this well was in, near or below an underground source of drinking water. Diesel was also used in a well in Anchorage, Alaska in 2001. In this case BLM did know that diesel was being used, since it was noted in the submitted drilling procedure, but information regarding the actual final volume of diesel used or whether the drilling occurred in, near or below a drinking water source

[36] http://democrats.naturalresources.house.gov/content/files/2011-11-17_LTR_DOIResponseREUSDW.pdf
[37] An underground source of drinking water is an aquifer or part of an aquifer which supplies water for human consumption.
[38] Operators are required in an Application for Permit to Drill (APD) to identify all usable water zones.
[39] Coal bed natural gas produced from coal seams containing underground sources for drinking water (USDW) were used as a proxy for determining if drilling occurred in a USDW. Near an USDW was defined as within a fixed radius of not less than one-quarter of a mile.
[40] Coal bed natural gas produced from coal seams containing an underground source of drinking water were used to determine if fracturing occurred in a underground source of drinking water.
[41] The zone of endangering influence is the distance from a well in which the pressures in the injection zone may cause the migration of drilling /fracturing fluid into an underground source of drinking water.
[42] Defined by BLM to mean wells fractured in an area that does not supply a public water system or; in an area that may have sufficient water to supply a public water system but does not currently supply water for human consumption or; does not supply water that is less than 10,000 mg/l total dissolved solids.

is unknown. Under the 2005 Energy Policy Act, any company that performs hydraulic fracturing using diesel fuel must receive a permit to be in compliance with the Safe Drinking Water Act.

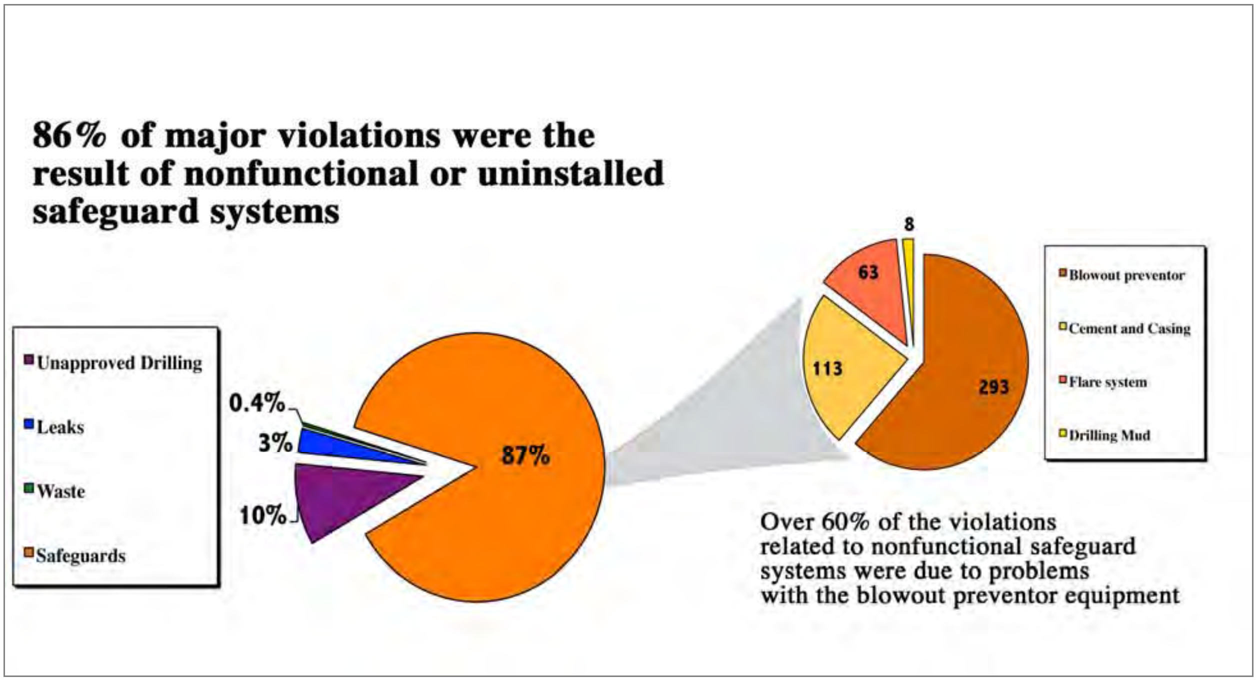
To protect underground water sources, BLM requires operators to develop casing and cementing plans to isolate the injection of hydraulic fracturing fluids and makes it a priority to witness the process to ensure that it occurs in a manner that will not compromise these water supplies. However, as is discussed below, casing and cementing procedures are frequently not followed and operators regularly fail to notify BLM as to when these procedures will occur. As a result, casing and cementing activities are often performed without a BLM witness present to ensure it happens in a manner that would protect water sources.

Many major violations related to non-functional blowout preventers

The blowout preventer (BOP) is a large valve that can be operated remotely to shut down the well if necessary, for example when encountering unexpected flow or erratic pressure. The system is a critically important feature to the safety of the crew, the drilling rig and the wellbore itself. The essential role of the BOP in safeguard drilling operations was dramatically underscored when the failure of the BOP at the Macondo well site in the Gulf of Mexico led to the BP Deepwater Horizon disaster, our nation’s worst offshore oil spill.

Of the major environmental or safety violations 477 out of 549 (87 percent) were issued because safeguard systems were not installed or functional. These safeguards were related to drilling mud (used to control pressure in the well), the flare system (used to eliminate waste gas), cementing and casing (used to isolate water zones) and well control equipment, including blowout preventers. For example, in 2009 an operator in Colorado was found to be missing a well control device “that is capable of complete closure of the well bore,” according to the BLM violation information provided. Additionally, in 2009 another operator in Mississippi was found operating a well without a blowout preventer or other equivalent well control equipment.

Figure 2: Breakdown of Major Environmental or Safety Violations



Fifty-three percent of the major environmental or safety violations were issued because the blowout preventer (BOP) and related equipment was not installed in a manner that would ensure well control in the event of a blowout. For example, in 2010 an inspector in New Mexico found that one of the valves in the BOP responsible for mitigating excessive pressure and stopping flow was leaking and needed immediate replacement. There are several instances in which operators were drilling thousands of feet below the earth's surface without any method of well control. This often wasn't discovered until after the well had already been completed. In 2008, a well in North Dakota experienced a blowout that was never reported to BLM. As a result, BLM had to issue a request to the operator to find out details about the nature of the blowout and the plans the operator has for future operation on the leased land.

Vital casing and cementing procedures are commonly compromised

Another vital part of the drilling, hydraulic fracturing (stimulation) and well completion process is ensuring adequate casing and cementing. Well casing consists of a series of metal tubes installed in the freshly drilled hole that are cemented into place to create a barrier between the underground water supplies and the well bore. Casing strengthens the sides of the well hole, ensures that no oil or natural gas seeps out of the well hole as it is brought to the surface and keeps other fluids or gases from seeping into the formation through the well. Casing and cementing is the first line of defense in protecting underground sources of drinking water. If done incorrectly, contamination of water sources could occur.

Of the major environmental or safety violations, 21 percent (113 violations out of 549 major violations) were citations that deal with deficiencies in casing and cementing programs. These include failing to follow the DOI's Oil and Gas Order No. 2, which contains minimal basic requirements for casing and cementing quality to protect and isolate usable water zones. In at least one instance in Wyoming, an improper casing and cement job led to water and gas leaking through the cement. In another 2010 case occurring in Colorado, an operator was given a written notice of noncompliance because they were conducting hydraulic fracturing operations too close to the top of the cement, an activity that put natural resources and environmental quality at risk.

Some operators fail to get approval prior to drilling on federal lands

In 54 instances, operators were given written notices of noncompliance for drilling on federal lands without first getting approval to do so. These types of violations were the ones that were most likely (65 percent) to be assessed a monetary penalty. These penalties ranged from $500 to $20,000, depending on the length of time the well was in operation prior to being discovered. In some instances fines were issued for physically locating a rig and drilling on federal lands before the BLM had received proper documentation to fully process and approve a permit, while other instances involved operators who were approved to drill only vertically, but instead dilled a horizontal well without approval from the BLM. In two instances, an operator was found to have drilled a water well to collect water for use in drilling and completion operations without approval from the BLM. In another case, an operator installed a pipeline without approval. In a few instances, these violations were issued because operators were told by the BLM to suspend drilling activity for a specified period of time, usually to protect wildlife, and operators violated this mandate.

Problems with power supply and well control equipment are common

Of the 410 violations that committee staff classified as minor safety violations, 25 percent were issued because of problems with the BOP or other well control device configuration that could impact well control. These violations were typically issued for infractions relating to the set up or assembly of the BOP-related equipment. This included violations for missing bolts on the wellhead equipment, valves that were not properly installed or plugged, or drilling pipes that were not correctly positioned.

Improper air supply or inoperable backup power systems were responsible for 31 percent of the 410 violations in this category. These systems are used to operate the blowout preventer and if not properly supplied could result in a BOP never being activated when needed.

Problems with storage and disposal of drilling fluids are occasionally found

Forty out of the 410 minor safety violations (10 percent) were because the storage containment vessels for chemicals, drilling fluids or waste were not designed or constructed properly to ensure environmental protection. In some cases the storage vessels were not of adequate size or located to close to the well bore, while in other cases the vessels were not adequately lined to protect surface and subsurface resources in the event of a leak.

In a few instances (19 out of 410 minor safety violations), operators were issued a written notice for soil contamination with hydrocarbons, diesel or other chemicals, likely occurring from a leak from one of the storage vessels or from otherwise sloppy rig operations.

Operators frequently violate safety testing, record-keeping and notification requirements

As a part of onshore oil and gas operations, the operator must supply certain written requirements to BLM. Once approved, BLM issues the operator an approved permit to drill (APD) which specifies the drilling plan (as required in Onshore Order No. 1) and certain Conditions of Approval (COA). The operator of a lease is required to comply with any orders and instructions contained within the COA. These conditions include requirements for operators to keep certain records of operations and to notify BLM of certain operational activities in a timely fashion. Failure to keep such records or reports when required to do so could potentially conceal significant safety issues, and makes it more difficult for the agency to conduct effective oversight on drilling operations occurring on federal lands. Additionally, failure to notify BLM of activity that requires a federal official to witness keeps the BLM in the dark about drilling operations. The majority (628 out of 1,066 total or 60 percent) of the minor drilling or operational violations were issued for various safety testing, record-keeping and notification violations. These included written violations for lack of or incorrect well signs, failing to record or perform routine safety and equipment tests, not supplying BLM with required reports or not notifying BLM prior to changing elements of the approved permit or prior to conducting an activity in which a BLM inspector was to be present.

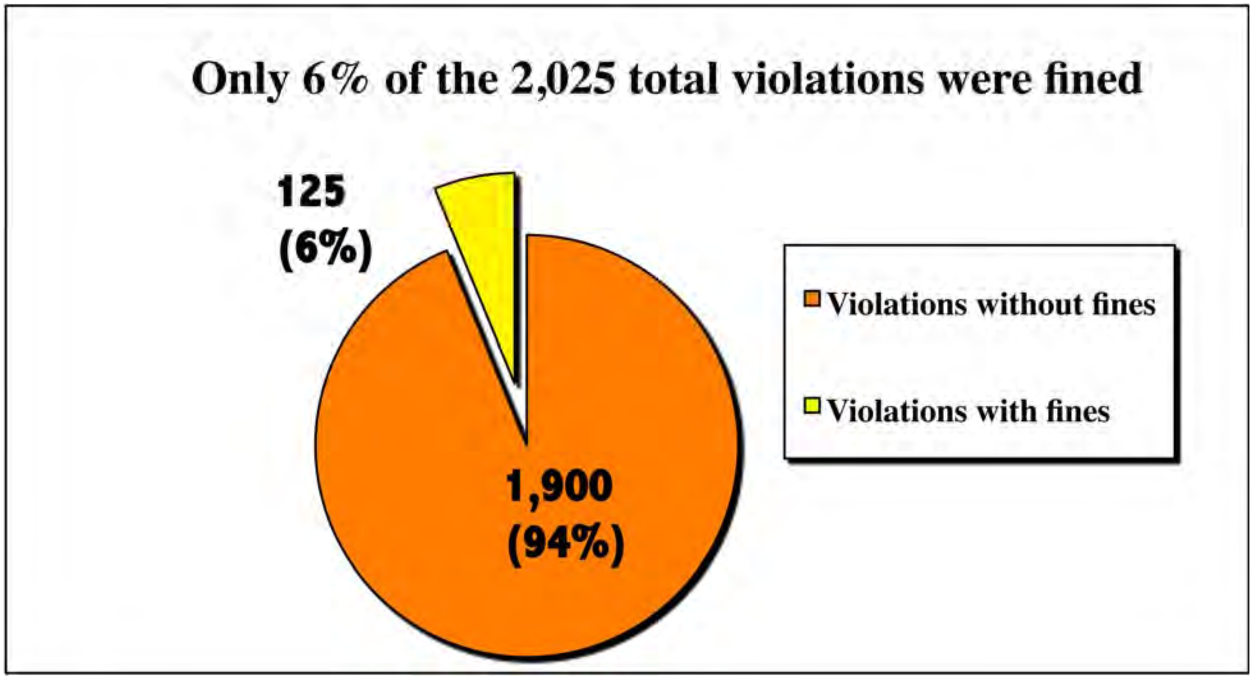
For example, it is a BLM priority to witness casing and cementing activities to verify that the process happens adequately enough to isolate any underground water sources. However, 184 of the 628 violations (29 percent), classified here as record-keeping issues were because the operator never told BLM that they were about to undertake a procedure in which a BLM representative was required to be present. Furthermore, there are other instances in which an operator changed the approved casing or cementing design without ever notifying the BLM. When and if this is discovered, BLM field officers will typically request that the operator provide additional technical information regarding the cementing and casing protocol that was utilized.

The remaining 438 drilling or operational violations (out of total 1,066, or 41 percent) were given because of excess surface disturbance (62 violations), inadequate fencing, netting or other security measures (193 violations), disturbing wildlife or archeological habitats (19 violations), improperly disposing of trash (66 violations), failing to conduct a mechanical integrity test (24 violations), inadequate warning signs or measurements for excessive hydrogen sulfide vapors (67 violations) and other minor drilling or operational violations (7 violations).

Monetary penalties are almost never issued and when issued are inconsistently applied

Of all the violations that were issued over the last decade only six percent (125 out of 2,025) issued to sixty-four companies were ever assessed a monetary fine in conjunction with the written incidence of noncompliance. The majority of the fines that were levied were because of a major safety or environmental violation (60 percent), while the remaining forty percent of monetary assessments were split between minor safety violations (18 percent) and minor drilling or operational violations (22 percent).

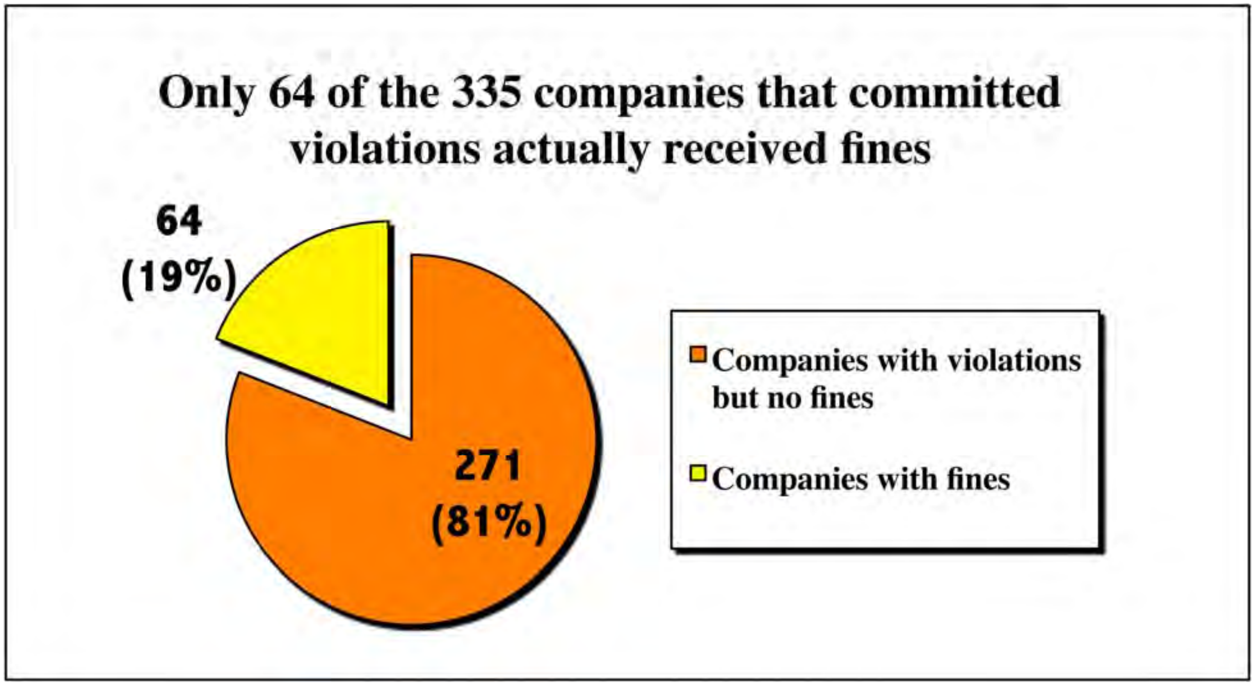
Figure 3: Percentage of Violations that Incurred Fines



Monetary fines were levied on just 64 of the 335 companies responsible for violations occurring on federal lands in the last decade and ranged in cost from $125 to $20,000 (average penalty of $2,191). There were only two violations that incurred $20,000 penalties and both were because the companies drilled into federal estate without first getting an approved permit from the BLM. While one may reasonably assume that companies with repeated incidences of noncompliance were more likely to receive a monetary penalty, this did not in fact hold true. The issuance of a monetary fine or amount of the monetary fine was not correlated to companies who were frequent violators. Five out of the twenty-one companies (24 percent) that were repeat offenders (defined by Committee staff as companies with 20 or more violations[43]) never once received a monetary penalty – despite the fact that companies with even fewer violations did receive a fine. For more information about the companies issued written violations and fines, see Appendix B.

[43] Companies with 20 or more violations in the years covered by this report include: Anadarko, Ballard Petroleum Holding, Bill Barrett Corp, BP America Production, Burlington Resources, Cabot Oil and Gas Corp, Chesapeake Operating, COG Operating, Devon Energy Production, Encana Oil and Gas, Energen Resources Corp, EOG Resources, Laramie Energy, Nearburg Producing, Newfield Exploration, Noble Energy, North Finn, Questar Exploration and Production, Ultra Resources, Williams Production RMT, XTO Energy, and Yates Petroleum Corporation.

Figure 4: Percentage of Companies that Received Fines

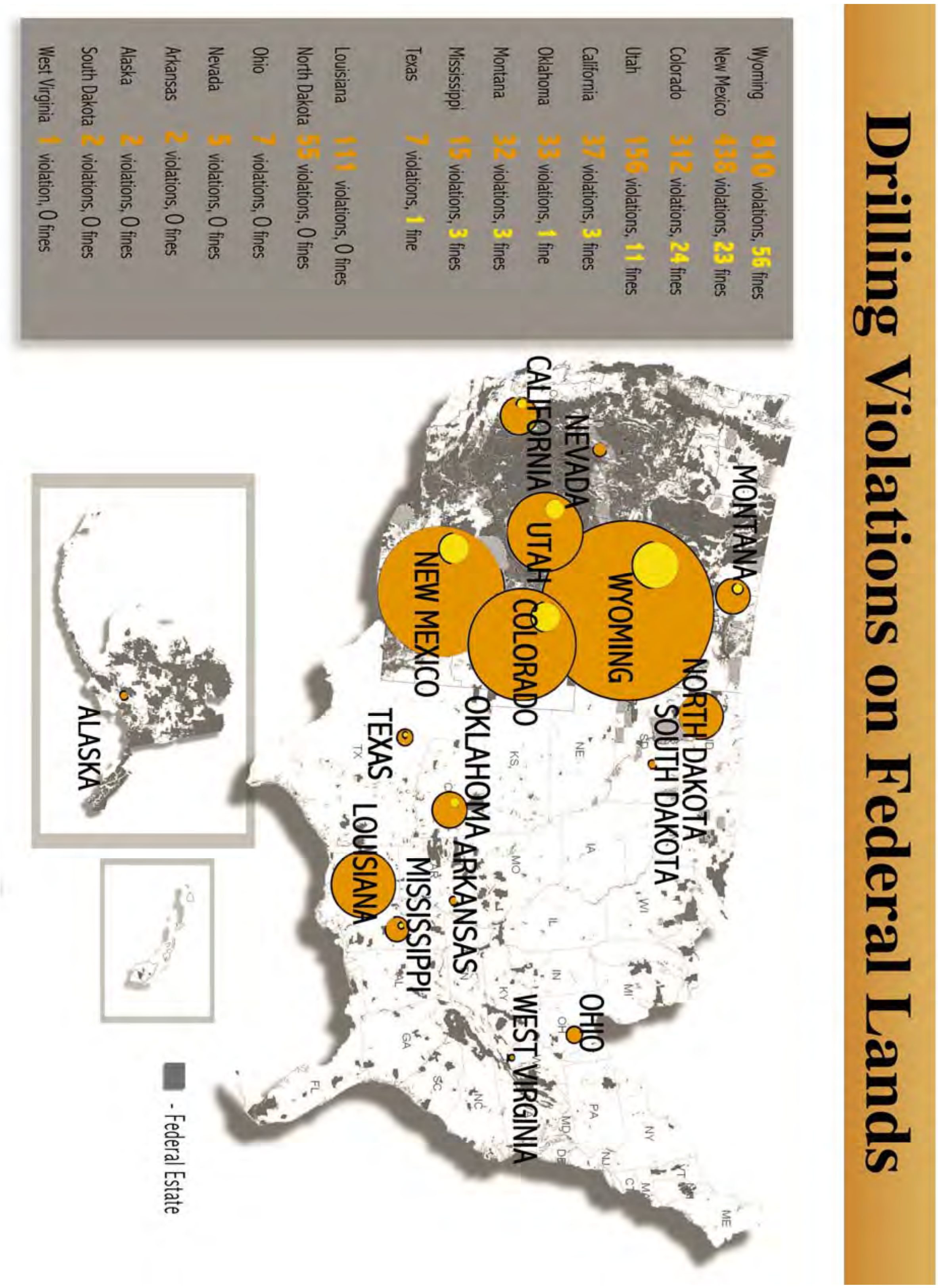


Although the violations that occurred were spread across 17 states, eight states (AK, AR, LA, ND, NV, OH, SD, and WV) never issued a monetary fine at all, despite the fact that these states cumulatively accounted for 9 percent of all the violations that were issued. Wyoming, the state in which the most fines were issued for drilling activities on federal lands (810 violations), collected monetary fines over the entire ten year period that amounted to a total of just $120,500. In fact, collectively, fines issued on federal lands in all states for violations dating from February 1998 - February 2011 amounted to just $273,875.

There were frequent incidences in which a specific violation led inspectors to issue a monetary penalty against one operator, but not against another, when the second operator was found to have committed the identical violation. There was no apparent consistency in the BLM's issuance of monetary penalties throughout its jurisdiction, calling into question the adequacy and effectiveness of the BLM's oversight of onshore oil and gas drilling operations and the ability of the BLM to ensure safety and environmental performance of hydraulic fracturing as this practice expands on federal lands. In one of the most egregious environmental violations, an operator was cited in 2003 for discharging fluid from the drilling rig directly into the Washita River in Oklahoma and was ordered to pay a fine of only $2,500.

Even within the same state, which presumably has uniform inspection and enforcement processes, there was no consistency as to whether a particular violation received a monetary assessment or not. For instance, a violation issued in New Mexico for a failure to install the appropriate pressure gauge for well control elicited a $1,500 fine for one operator, but a different operator in the same state, with the identical violation occurring just a week prior received nothing more than a written notice of violation.

Figure 5: Violations and Fines by State



Appendix A: Explanation and Breakdown of Violations

Major Environmental or Safety Violations (549 Violations = 27% of Total)			
Code	**Description of Violation**	**Number of Violations**	**Percentage within Category***
FA	Failure to get approval for drilling or other significant activity	54	10%
LK	Gas leaks, well head leaks, blowouts	16	3%
SG	Safeguard measures not in place	477	87%
SG/BOP	Related to the blowout preventer (BOP) system	*293*	*53%*
SG/CM	Related to well cement and/or casing	*113*	*21%*
SG/FS	Related to flare system used to eliminate waste gas	*63*	*11%*
SG/MD	Related to mud weight or mud flow	*8*	*2%*
WM	Waste material from drilling operations not disposed of properly	2	0.4%

Minor Safety Violations (410 Violations = 20% of Total)			
Code	**Description of Violation**	**Number of Violations**	**Percentage within Category***
AS	Air supply to pumps, pressure accumulator or backup power systems missing, inoperable or improperly maintained	129	31%
CT	Soil/area contamination with oil, chemicals or cuttings	19	5%
PG	Pressure gauge, leak detector or mud gauge/monitoring equipment is not installed or is improperly maintained	33	8%
PT	Pit/storage unit not constructed to sufficient volume, improper location, or failure to maintain adequate empty space in the unit	40	10%
WC	Minor well containment issue (ie: missing bolts, problems with BOP assembly/ configuration or missing handles)	104	25%
WD	Wind direction socks or indicators not in place or inoperable	85	21%

**Percentages were rounded to the nearest whole number*

Appendix A: Explanation and Breakdown of Violations

Minor Drilling or Operational Violations (1066 Violations = 53% of Total)			
Code	**Description of Violation**	**Number of Violations**	**Percentage within Category***
RK	Record-keeping violations	628	60%
RK/SN	Signs, markers or permit not present/visible in location required	*208*	*20%*
RK/NT	Failure to submit test results, reports or provide sufficient notification to BLM regarding upcoming activity	*184*	*17%*
RK/SD	Change in sundry conditions or operations without notifying and receiving approval from BLM	*52*	*5%*
RK/RC	Failure to perform routine tests or to record test results	*177*	*17%*
RK/OT	Other type of record-keeping violation	*7*	*0.7%*
HS	Hydrogen sulfide sign, testing, or calculations needed	67	6%
MIT	Mechanical Integrity Test on equipment in the well is required to be performed	24	2%
RD	Excess surface disturbance or roads/pad not constructed as approved	62	6%
SV	Fencing, netting, belt guards, protective weather, or other security and safety violations	193	18%
TS	Improper disposal of trash, construction, septic or other waste or improper handling of weed infestation	66	6%
WL	Failure to avoid disruptive activity in certain prescribed time frames to comply with wildlife or archaeological conditions	19	2%
OT	Other minor drilling or operational violation	7	0.7%

**Percentages were rounded to the nearest whole number*

Appendix B: List of Companies with Violations and Fines

Companies with Violations	Number of Violations	Number of Fines
Aera Energy LLC	2	0
Agate Petroleum Incorporated	1	0
Amoco Production Co.	1	0
Amtex Energy Incorporated	1	0
Anadarko E & P Company LP	61	1
Anchor Bay Corp	1	0
Anschutz Exploration Corp	9	1
Antero Resources Piceane Corp	7	0
Apache Corporation	8	3
Apollo Energy L P	1	0
Area Energy LLC	1	0
Asher Associates Inc.	1	0
Aspen Operating LLC	4	1
Aurora Gas LLC	2	0
Autry C Stephens	1	0
Ballard Petroleum Holding LLC	21	3
Basin Resources Corporation	2	0
Bass Enterprises Production Co	3	0
Beartooth Oil & Gas Company	2	0
Becker Clyde M	1	0
Bellevue Resources Inc	1	0
Benson Montin Geer Drilling Corp	4	0
BEPCO LP	1	1
Berry Petroleum Company	14	1
Bill Barrett Corporation	45	0
Billy B Oil Company	1	0
Black Bear Oil Corporation	2	0
Black Diamond Energy Inc	17	0
BOPCO LP	3	0
BP America Production Co.	30	1
Breitburn Energy Company LLC	2	0
Brigham Oil & Gas LP	2	0
Brothers Production Co Inc	1	0
BTA Oil Producers	2	0
Burlington Resources O&G Co LP	34	0
Burnett Oil Company Inc	4	1
Burr Oil & Gas Inc.	1	0
C & H Well Servicing Inc	1	0
Cabal Energy Corporation	1	0
Cabot Oil & Gas Corporation	25	2
Campbell & Hedrick	2	0
Camwest II LP	1	0
Carl H Nordstrand	1	0
Case Sales Company Inc.	1	0
CBS Operating Corporation	1	0
Central Resources Inc	11	0
CH4 Energy LLC	15	0
Chesapeake Operating Inc	57	2
Chevron USA Incorporated	3	0
Chi Operating Incorporated	13	0
Chisos Ltd	1	0
Chizum Oil LLC	2	0

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Choctaw II Oil & Gas Ltd	1	0
Cimarex Energy Co	7	0
Citation Oil & Gas corporation	12	0
Coastal Oil & Gas Corp	11	0
Cog Operating LLC	25	3
Coleman Oil & Gas Incorporated	6	0
Combined Resources Corporation	1	0
Comet Energy Services LLC	1	0
Concho Oil & Gas Corporation	6	0
ConocoPhillips Company	17	0
Continental Resources Inc	18	1
Cook Oil Co.	1	0
Crawley Petroleum Corp	2	0
Davis Petroleum Corporation	2	0
Decker Operating Company LLC	1	0
Delong Oil & Gas Co	1	0
Delta Petroleum Corporation	6	0
Denbury Onshore LLC	1	0
Derrick Petroleum	1	0
Devon Energy Production Co L P	54	3
Diversified Operating Corp.	1	0
Dominion Expl & Production Inc	5	0
Doral Energy Corp	1	0
Double Eagle Petroleum	4	0
Dudley & Associates LLC	2	0
Dugan Production Corporation	8	0
Duke Oil & Gas Inc	1	0
Duncan Oil INC	2	0
Eagle Operating Incorporated	6	0
East Resources Incorporated	1	0
Edge Petroleum Operating Co, Inc	1	0
Edward H Everett Co	1	0
EGL Resources Inc	2	0
El Paso E&P Co LP	19	0
Ellora Operating LP	4	0
Elm Ridge Resources Inc	9	0
Emerald Operating Company	8	0
Emergent Value Group LLC	2	0
Encana Oil & Gas Inc	63	4
Encore Operating LP	5	0
Endeavor Energy Resources LP	1	0
Enduring Resources LLC	6	1
Energen Resources Corporation	20	1
Energytec Inc	3	0
Enervest Operating LLC	8	0
Entek GRB LLC	1	0
EOG Resources Incorporated	51	3
Equity Oil Co	2	0
Exxon Mobil Corp	10	5
F & M Oil & Gas Company	1	0
Fairway Resources	1	0
Fancher Oil LLC	1	0

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Fasken Oil & Ranch Ltd	1	0
Ferry Lake Oil Co LLC	5	0
FH Petroleum Corp	3	0
Fidelity Expl & Prod Co	3	0
FIML Natural Resources, LLC	3	0
Flying J Oil & Gas Inc	1	0
Forest Oil Corporation	3	0
Fossil Energy Group, LLC	7	2
Frank Eblen Syndicate Inc	1	0
Fredonia Resources Inc	2	0
G & H Production Co, LLC	1	0
G R Contractors	1	0
Gasco Energy Inc	4	1
Genesis Gas & Oil, LLC	4	3
Gilbreath Norman L	3	0
Glen Plemons	1	0
GMT Exploration Company LLC	3	0
GPE Energy Inc	2	0
Gruy Petroleum Management Co	2	0
Grynberg Jack J	10	2
Guadalupe Operating LLP	2	0
H C M	1	0
Hart Oil & Gas Inc	1	0
Harvey E Yates Co	1	0
Headington Oil, LP	4	1
Hegco Canada Inc	1	0
Heinrich Carl	1	0
High Plains Petroleum Corp	1	0
Howell Petroleum Corporation	2	0
HRM Resources LLC	1	0
Hunt Petroleum Corporation	9	0
Infinity Oil & Gas of Wyoming	1	0
Inland Production Company	2	0
Integrated Energy LLC	2	0
Ivanhoe Energy USA Inc	1	1
J & J Jackson O & G Inc	1	0
J & J SERVICES INC	1	0
Jed Oil (USA) Inc.	2	0
Jehovah Jireh Oil Co	3	0
JM Huber Corp	8	0
JN Expl & Prod Ltd Ptnrship	2	0
Joe Melton Drilling Co, Inc	1	0
JP Oil Company Incorporated	1	0
Julander Energy Company	1	0
Justin Energy LLC	1	0
J-W Operating Company	12	0
K2 America Corporation	1	0
Kennedy Oil	18	2
Kerr-McGee Oil & Gas Onshore L P	9	2
KLT Gas Inc	3	0
Koch Exploration Company	1	0
KWB Oil Property Management	1	0

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L & J Operating Incorporated	5	0
Lance Oil + Gas Co Inc	19	0
Laramie Energy LLC	20	0
Latigo Petroleum Inc	2	0
Limark Corporation	3	0
Louis Dreyfus Natural Gas Corp	1	0
Lowry Exploration Inc	1	0
M & K Oil Company Incorporated	1	0
Mack Energy Corporation	12	0
MacPherson Oil Company	7	0
Mak-J Energy Wyoming LLC	5	0
Manzano Oil Corp	3	0
Mar Oil & Gas Corporation	1	0
Maralex Resources Incorporated	6	0
Marathon Oil Company	6	0
Marbob Energy Corporation	7	0
Marion Energy Incorporated	8	0
Marks & Garner Production Co	1	0
Markus Production Inc	2	0
Marmac Petroleum Co	2	0
Matador Resources Company	2	0
Matrix Energy LLC	2	1
McAdamas J F	1	0
McElvain Oil & Gas Prop Inc	1	0
McKay Oil Corporation	3	0
McMurry Oil LLC	6	0
Medallion Exploration	5	0
Medicine Bow Operating Co	18	8
Merit Energy Company	17	0
Meritage Energy Partners LLC	1	0
Mewbourne Oil Company	6	0
Midland Operating Inc	1	0
Momentum Operating Co Inc	1	0
Mont Rouge Inc	1	0
Mountain States Petro Corp	4	0
MTG Operating Co	2	0
Murchison Oil& Gas Inc	1	0
Murphy Exploration & Prod Co	2	0
Nadel & Gussman	9	0
Nance Petroleum Corporation	11	2
National Pride Oper Co Inc	1	0
NBI Services Inc	2	0
Nearburg Producing Company	2	0
Newfield Exploration Company	21	5
Noble Energy Inc	32	0
Nordstrand Engineering Inc	2	0
North Flinn LLC	21	2
Northern Lights Oil Co LC	1	0
Northwood Energy Corp	1	0
Nuevo Energy Company	1	0
O'Brien Energy Resources Corp.	6	0
Occidental Elk Hills Inc	1	0

Companies with Violations	Number of Violations	Number of Fines
Ohio Valley Energy Sys Corp	1	0
Oilfield Salvage	1	0
Osborn Heirs CO	4	1
Oxy USA Incorporated	11	1
Pannonian Energy Inc	3	0
Parawon Operating LLC	1	0
Patina Oil and Gas Vcorp	1	0
Paul B Rankin Inc	3	0
Penn Virginia MC Energy LLC	5	0
Pennaco Energy Inc	3	0
Petco Petroleum Corporation	2	0
Petro Mex LLC	7	0
Petro-Canada Res(USA) Inc	14	1
Petroglyph Operating Co Inc	1	0
Petrogulf Corporation	9	0
Petrohunt LLC	1	0
Petrol Industries Inc	3	0
Petroleum Development Corp	9	1
Petrox Resources Inc	11	0
Phillips Petroleum Co	1	0
Phoenix Production Company	1	0
Pinnacle Gas Resources, Inc	12	2
Pioneer Natural Resources USA	3	0
Plains Expl & Prod Company	8	0
Plantation Operating LLC	1	1
Pogo Producing Company	4	0
Prairie Energy Inc	1	0
Premier Oil & Gas Incorporated	5	2
Pride Energy Company	2	0
Prima Oil & Gas Co	2	0
Primary Natural Resources INC	5	1
Probity Operating LLC	2	0
QEP Energy Company	1	0
QEP Uinta Basin Inc	1	0
Questar Expl & Prod Co PNDL	27	1
R C Taylor Companies Inc	1	0
Rancher Energy Corporation	1	0
Ranken Energy Corporation	2	0
Read & Stevens Incorporated	5	0
Remuda Operating CO	2	0
Retamco Operating Incorporated	1	1
RHCJ Enterprises LLC	1	0
Riata Energy Incorporated	2	1
Richardson Operating Company	7	2
RIM Offshore Inc	3	0
RKI Exploration and Production	5	2
RME Petroleum Company	5	0
Robert L Bayless Producer LLC	4	2
Roddy Production Company Inc	1	0
RSC Resources Limited	1	0
Ryder Oil & Gas LLC	2	1
S G Interests I LTD	3	0

Appendix B: List of Companies with Violations and Fines

Companies with Violations	Number of Violations	Number of Fines
Saga Petroleum	3	0
Sam Enterprises Inc	2	0
Samedan Oil Corp	1	1
Samson Resources Company	18	0
Sannes Ronald M & Margaret A	1	0
SDX Resources Incorporated	3	0
Shackelford Oil Co	3	0
Shenandoah Energy Inc	14	2
Sitta R E	1	0
Slawson Exploration Co Inc	13	1
Snow Operating Company Inc	2	0
Sonoma Energy Corporation	1	0
Southern States Oil Prod LLC	12	0
Southwest Energy Production	2	0
Southwest Royalties Inc	3	0
Southwestern Production Corp	2	0
Spence Energy CO	2	1
St. Mary Land & Exploration Co	2	0
Staghorn Resources LLC	1	0
Stephens & Johnson Oper Co	1	0
Stocker Resources INC	7	0
Stone Energy LLC	2	0
Summit Resources INC	1	0
SWEPI LP	8	0
Synergy Operating LLC	1	0
Tandem Energy Corp	3	0
Texaco Exploration & Production Inc	4	0
The Houston Exploration Company	3	1
The Termo Company	3	0
Thomas Operating Company, Inc	3	0
Thompson J Cleo	11	1
Thorofare Resources Inc	1	0
Threshold Development Company	1	0
Timberline Production Company	1	0
Titan Resources Corporation	2	0
Tom Brown Inc	12	0
Torch E&P Company	1	0
Trend Exploration I, LLC	8	0
Tripperary Oil & Gas Corp	2	0
True Oil Company	12	3
Twin Arrow Incorporated	3	0
U S OIL GAS INC	1	0
Ultra Resources Inc	52	0
United Energy Incorportated	6	2
Ursa Major (Crow OG) LLC	1	0
Vantage Energy Uinta LLC	1	0
Venture Oil and Gas Inc	14	3
Viking Resources Corp	1	0
Vintage Drilling, LLC	3	0
Wagner & Brown Limited	2	0
Walsh & Watts Inc	1	0
Ward Williston Company	3	0

Appendix B: List of Companies with Violations and Fines

Companies with Violations	Number of Violations	Number of Fines
Warren American Oil Company	1	0
Warren E&P, Incorporated	6	0
Wascana Oil and Gas Inc	1	0
Webb Oil Company	1	0
Wellstar Corporation	1	0
Westall Ray	4	0
Western Natural Gas Inc	2	1
Western Operating Co	1	0
Westport Oil & Gas Company LP	10	0
Wexpro Company	7	0
Whiting Oil & Gas Corporation	8	0
Whitmar Exploration Company	1	1
Wildfire Partners INC	3	0
Williams Production RMT Co	98	7
Williamson J C	3	1
Windsor Energy Group LLC	4	1
Wold Oil Properties, Inc	4	1
Wolverine Gas & Oil CO of UT	2	0
XTO Energy Co.	47	3
Yarhola Production Co	1	0
Yates Petroleum Corporation	39	5
Zenergy Inc	1	0
ZIA Energy INC	1	0
TOTAL (335 companies)	2025	125

APPENDIX
PART 4

APPENDIX INDEX

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Geochemical evidence for possible natural migration of Marcellus Formation brine to shallow aquifers in Pennsylvania

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The debate surrounding the safety of shale gas development in the Appalachian Basin has generated increased awareness of drinking water quality in rural communities. Concerns include the potential for migration of stray gas, metal-rich formation brines, and hydraulic fracturing and/or flowback fluids to drinking water aquifers. A critical question common to these environmental risks is the hydraulic connectivity between the shale gas formations and the overlying shallow drinking water aquifers. We present geochemical evidence from northeastern Pennsylvania showing that pathways, unrelated to recent drilling activities, exist in some locations between deep underlying formations and shallow drinking water aquifers. Integration of chemical data (Br, Cl, Na, Ba, Sr, and Li) and isotopic ratios ($^{87}Sr/^{86}Sr$, $^{2}H/H$, $^{18}O/^{16}O$, and $^{228}Ra/^{226}Ra$) from this and previous studies in 426 shallow groundwater samples and 83 northern Appalachian brine samples suggest that mixing relationships between shallow ground water and a deep formation brine causes groundwater salinization in some locations. The strong geochemical fingerprint in the salinized (Cl > 20 mg/L) groundwater sampled from the Alluvium, Catskill, and Lock Haven aquifers suggests possible migration of Marcellus brine through naturally occurring pathways. The occurrences of saline water do not correlate with the location of shale-gas wells and are consistent with reported data before rapid shale-gas development in the region; however, the presence of these fluids suggests conductive pathways and specific geostructural and/or hydrodynamic regimes in northeastern Pennsylvania that are at increased risk for contamination of shallow drinking water resources, particularly by fugitive gases, because of natural hydraulic connections to deeper formations.

formation water | isotopes | Marcellus Shale | water chemistry

The extraction of natural gas resources from the Marcellus Shale in the Appalachian Basin of the northeastern United States (1, 2) has increased awareness of potential contamination in shallow aquifers routinely used for drinking water. The current debate surrounding the safety of shale gas extraction (3) has focused on stray gas migration to shallow groundwater (4) and the atmosphere (5) as well as the potential for contamination from toxic substances in hydraulic fracturing fluid and/or produced brines during drilling, transport, and disposal (6–9).

The potential for shallow groundwater contamination caused by natural gas drilling is often dismissed because of the large vertical separation between the shallow drinking water wells and shale gas formations and the relatively narrow zone (up to 300 m) of seismic activity reported during the deep hydraulic fracturing of shale gas wells (10, 11). Recent findings in northeastern Pennsylvania (NE PA) demonstrated that shallow water wells in close proximity to natural gas wells (i.e., <1 km) yielded, on average, higher concentrations of methane, ethane, and propane with thermogenic isotopic signature. By comparison, water wells farther away from natural gas development had lower combustible gas concentrations and an isotopic signature consistent with a mixture between thermogenic and biogenic components (4). In contrast, when inorganic water geochemistry from active drilling areas was compared to nonactive areas and historical background values, no statistically significant differences were observed (4). Increasing reports of changes in drinking water quality have nevertheless been blamed on the accelerated rate of shale gas development.

The study area in NE PA consists of six counties (Fig. 1) that lie within the Appalachian Plateaus physiographic province in the structurally and tectonically complex transition between the highly deformed Valley and Ridge Province and the less deformed Appalachian Plateau (12, 13). The geologic setting and shallow aquifer characteristics are described and mapped in greater detail in multiple sources (4, 14–19) and in *SI Methods*. The study area contains a surficial cover composed of a mix of unconsolidated glacial till, outwash, alluvium and deltaic sediments, and postglacial deposits (the Alluvium aquifer) that are thicker in the valleys (17–19) (Fig. S1). These sediments are underlain by Upper Devonian through Pennsylvanian age sedimentary sequences that are gently folded and dip shallowly (1–3°) to the east and south (Fig. S2). The gentle folding creates alternating exposure of synclines and anticlines at the surface that are offset surface expressions of deeper deformation (12, 20). The two major bedrock aquifers are the Upper Devonian Catskill and the underlying Lock Haven Formations (14, 15, 18, 19). The average depth of drinking water wells in the study area is between 60 and 90 m (Table S1). The underlying geological formations, including the Marcellus Shale (at a depth of 1,200–2,500 m below the surface) are presented in Fig. 2, Fig. S2 *A* and *B*, and *SI Methods*.

In this study, we analyze the geochemistry of 109 newly-collected water samples and 49 wells from our previous study (4) from the three principal aquifers, Alluvium (n = 11), Catskill (n = 102), and Lock Haven (n = 45), categorizing these waters into four types based on their salinity and chemical constituents (Figs. 1 and 2, and *S1 Text*). We combine these data with 268 previously-published data for wells in the Alluvium (n = 57), Catskill (n = 147), and Lock Haven (n = 64) aquifers (18, 19) for a total of 426 shallow groundwater samples. We analyzed major and trace element geochemistry and a broad spectrum of isotopic tracers ($\delta^{18}O$, $\delta^{2}H$, $^{87}Sr/^{86}Sr$, $^{228}Ra/^{226}Ra$) in shallow

ENVIRONMENTAL SCIENCES

Author contributions: N.R.W., R.B.J., and A.V. designed research; N.R.W., R.B.J., S.G.O., A.D., A.W., and A.V. performed research; N.R.W., R.B.J., T.H.D., K.Z., and A.V. analyzed data; and N.R.W., R.B.J., T.H.D., and A.V. wrote the paper.

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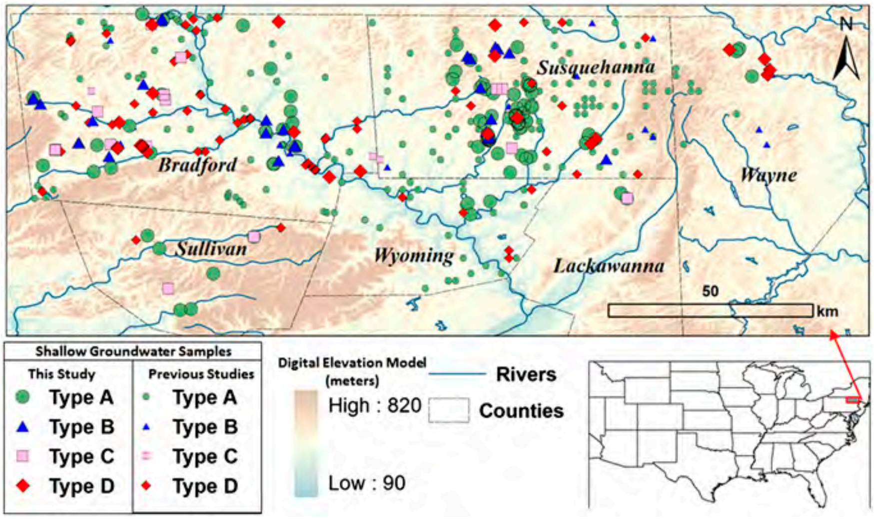

Fig. 1. Digital elevation model (DEM) map of northeastern PA. Shaded brown areas indicate higher elevations and blue-green shaded areas indicate lower elevations (valleys). The distribution of shallow (<90 m) groundwater samples from this study and previous studies (18, 19) are labeled based on water type. Two low salinity (Cl < 20 mg/L) water types dominated by Ca-HCO_3 (type A = green circles) or Na-HCO_3 (type B = blue triangles) were the most common, and two higher salinity (Cl > 20 mg/L) water types were also observed: Br/Cl < 0.001 (type C = pink squares) and brine-type groundwater Br/Cl > 0.001 (type D = red diamonds). Type D groundwater samples appear associated with valleys (Table S1) and are sourced from conservative mixing between a brine and fresh meteoric water. The DEM data were obtained from NASA' Shuttle Radar Topography Mission http://srtm.usgs.gov/.

ground water and compared these to published (6, 21, 22) and new data of 83 samples from underlying Appalachian brines in deeper formations from the region (Table S2) to examine the possibility of fluid migration between the hydrocarbon producing Marcellus Formation and shallow aquifers in NE PA. We hypothesize that integration of these geochemical tracers could delineate possible mixing between the Appalachian brines and shallow groundwater.

Results and Discussion

The water chemistry data from the Alluvial, Catskill, and Lock Haven shallow aquifers (Table S1) reveal a wide range of solute concentrations from dilute groundwater with total dissolved solids (TDS) <500 mg/L and Cl < 20 mg/L to highly saline water (e.g., a salt spring with TDS of 7,800 mg/L and Cl approximately 4,000). Based on these characteristics, we divide the water samples into four types of ground water (Fig. 1). Two groundwater types (A and B; n = 118 of 158 samples from this and our previous study (4) are characterized by low salinity and high Na/Cl and Br/Cl (all ratios reported as molar) ratios (Table S1). The two elevated salinity (Cl > 20 mg/L) water types (C and D) were divided based on their Br/Cl ratios. Type (C) (n = 13 of 158) has a distinctive low (<0.001) Br/Cl ratio (Fig. 3) and higher NO_3^- concentrations that we attribute to salinization from domestic sources such as wastewater and/or road salt that have typically low Br/Cl ratios. The fourth subset of shallow groundwater (type D) (n = 27 of 158) was identified with a relatively high Br/Cl ratio (>0.001) and low Na/Cl ratio (Na/Cl < 5) with a statistically significant difference in water chemistry from types A–C (Table S3).

A geochemical analysis of published data collected in the 1980s (18, 19) revealed similar shallow salinized groundwater with a distinctive higher Cl (>20 mg/L) and low Na/Cl ratio. The saline groundwater mimics type D water with statistically indis-

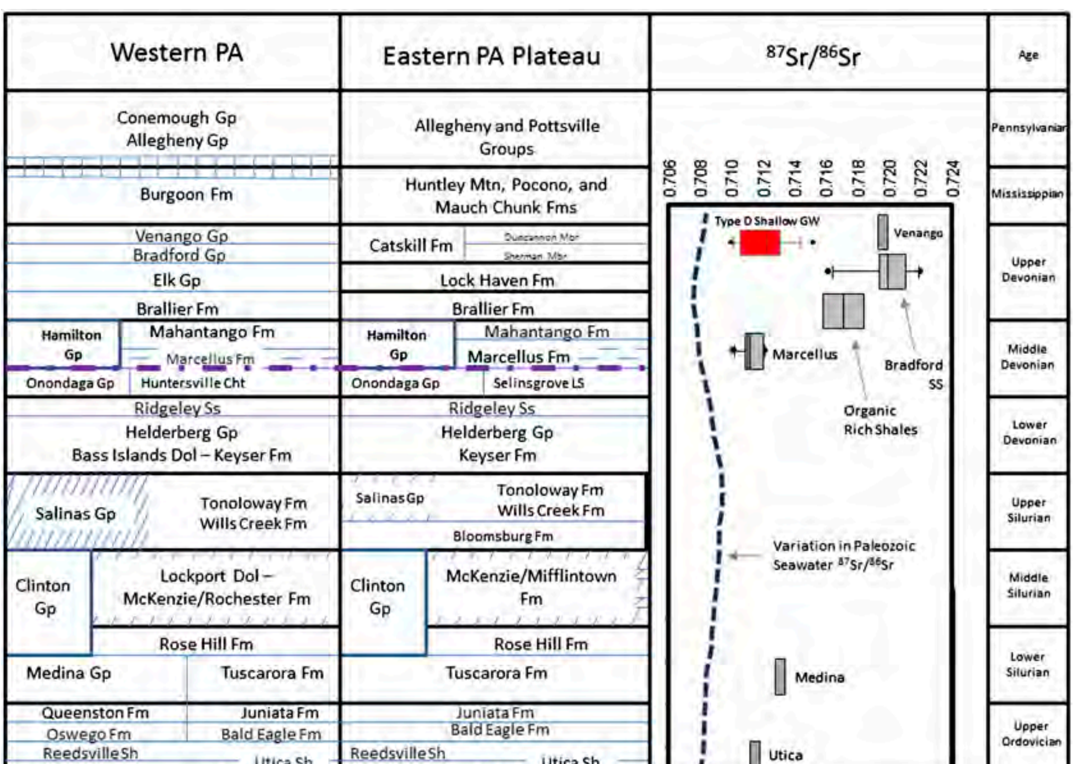

Fig. 2. Generalized stratigraphic section in the subsurface of western and eastern PA plateau adapted from (14, 15, 18, 19) and Sr isotope data of Appalachian brines and type D saline groundwater. Variations of $^{87}Sr/^{86}Sr$ ratios in Appalachian Brine and type-D groundwater samples show enrichment compared to the Paleozoic secular seawater curve (dashed grey line) (49). Note the overlap in values of type-D shallow ground water with $^{87}Sr/^{86}Sr$ values in Marcellus brines or older formations (21, 22, 24) but no overlap with the Upper Devonian brines in stratigraphically equivalent formations (Table S2) (21, 24).

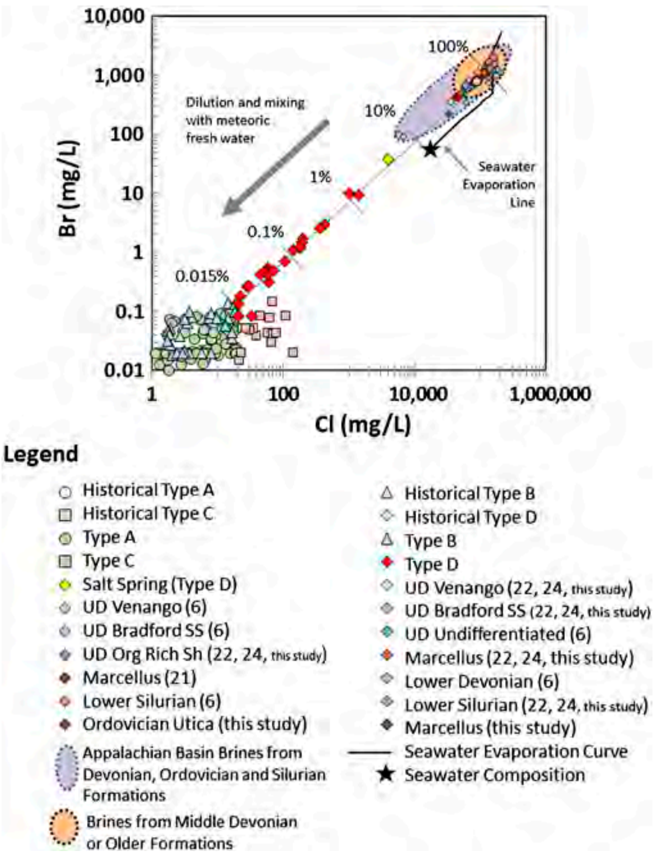

Fig. 3. Bromide vs. chloride concentrations (log-log scale) in shallow groundwater in NE PA and Appalachian brines from this and previous studies (18, 19). The linear relationship (type D: $r^2 = 0.99$, $p < 1 \times 10^{-5}$; sample types A–C: $r^2 = 0.14$) between the conservative elements Br and Cl demonstrates that the majority of the higher salinity samples of type D are derived from dilution of Appalachian brines that originated from evaporated seawater. Even with a large dilution of the original brine, the geochemical signature of type-D waters are still discernable in shallow groundwater from other high salinity (Cl > 20 mg/L) groundwater with low Br/Cl ratios (type C). Type C water likely originated from shallow sources such as septic systems or road deicing. Seawater evaporation line is from (25).

tinguishable (Table S3) concentrations of major cations and anions (Fig. 4 *A* and *B*); however, bromide concentrations were not available in the historical data set. Nonetheless, we designated historical samples with high Cl (>20 mg/L) and low Na/Cl ratio (Na/Cl < 5) as possible type D (n = 56 of 268). The remaining historical samples with Cl concentrations (>20 mg/L) were designated as type C. All water types (A–D) were statistically indistinguishable from their respective historical types (A–D) (Table S3).

Type D saline waters are characterized by a Na-Ca-Cl composition with Na/Cl, Sr/Cl, Ba/Cl, Li/Cl, and Br/Cl ratios similar to brines found in deeper Appalachian formations (e.g., the Marcellus brine) (4, 6, 21, 22) (Table S2). This suggests mixing of shallow modern water with deep formation brines. Furthermore, the linear correlations observed for Br, Na, Sr, Li, and Ba with chloride (Fig. 3 and Fig. S3 *A–F*) demonstrate the relatively conservative and nonreactive behavior of these constituents and that the salinity in these shallow aquifers is most likely derived from mixing of deeper formation brines.

The stable isotopes ($\delta^{18}O = -8$ to -11‰; $\delta^2H = -53$ to -74‰) of all shallow groundwater types (A–D) are indistinguishable ($p > 0.231$) and fall along the local meteoric water line (LMWL) (23) (Fig. 5). The similarity of the stable isotopic compositions to the modern LMWL likely indicate dilution with modern (post-glacial) meteoric water. Shallow groundwater isotopic compositions do not show any positive $\delta^{18}O$ shifts towards the seawater evaporation isotopic signature (i.e., higher $\delta^{18}O$ relative to δ^2H) as observed in the Appalachian brines (Fig. 5 and Table S2). Because of the large difference in concentrations between the brines and fresh water, very small contributions of brine have a large and measureable effect on the geochemistry and isotopes of dissolved salts (Fig. 3) but limited effect on $\delta^{18}O$ and δ^2H. Mass-balance calculations indicate that only a brine fraction of higher than approximately 20% would change the $\delta^{18}O$ and δ^2H of salinized groundwater measurably. Oxygen and hydrogen isotopes are, therefore, not sensitive tracers for the mixing of the Appalachian brines and shallow groundwater because of the large percentage of the fresh water component in the mixing blend. For example, the salt spring at Salt Springs State Park with the highest salinity among shallow groundwater samples is calculated to contain <7% brine.

The discrete areas of type D water have lower average elevations and closer distances to valley centers but do not correlate with distance to the nearest shale gas wells (Fig. 1 and Fig. S1 and Table S1). The lack of geospatial association with shale-gas wells and the occurrence of this type of saline water prior to shale gas development in the study area (14, 15, 18, 19) (see distribution in Fig. 4 *A* and *B*) suggests that it is unlikely that hydraulic fracturing for shale gas caused this salinization and that it is instead a naturally occurring phenomenon that occurs over longer timescales.

Distinguishing the ultimate source of the salinized water in NE PA requires an evaluation of the geochemical signatures of underlying brines in the Appalachian Basin. The data presented

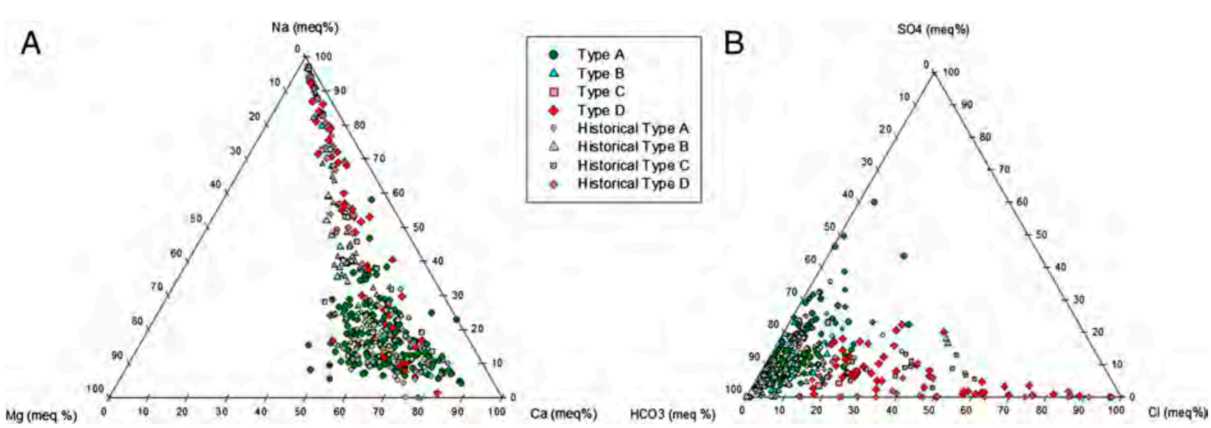

Fig. 4. Ternary diagrams that display the relative percent of the major cations (*A*) and anions (*B*) in shallow groundwater samples from this and previous studies (18, 19). The overlap indicates that Na-Ca-Cl type saline water was present prior to the recent shale-gas development in the region and could be from natural mixing.

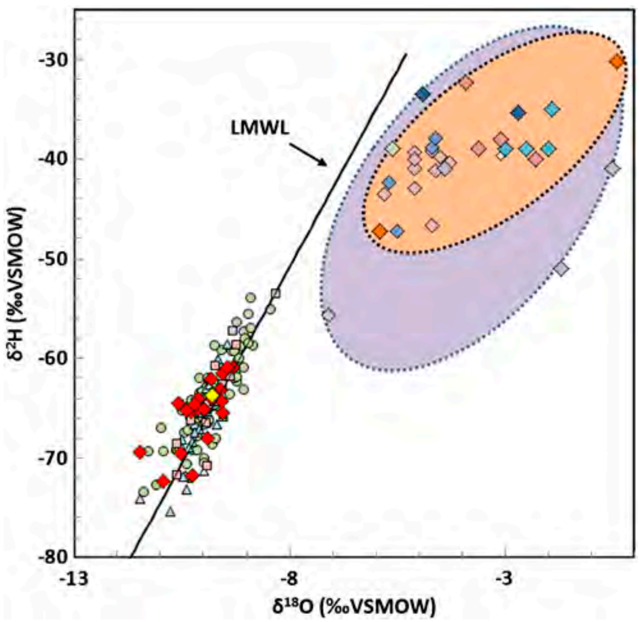

Fig. 5. δ^2H vs. δ^{18}O in shallow groundwater from this study and Appalachian brines. The water isotope composition of the shallow groundwater samples including the Salt Spring appear indistinguishable from each other and the local meteoric water line (LMWL) (23) and do not show any apparent trends toward the stable isotope ratios of the Appalachian brines (6, 22). The data indicate that dilution of the type-D waters likely occurred on modern (post-glacial) time scales. Symbol legend is provided in Fig. 3.

in this study (Figs. 2 and 3, and Fig. S3 *A–F* and Table S2) and previous studies (4, 6, 22, 24), suggest that the Appalachian brines evolved by evaporation from a common seawater origin but underwent varying stages of alteration. The first stage of evolution common to all of the brines is the evaporation of seawater beyond halite saturation resulting in brines with high Br/Cl and low Na/Cl ratios relative to seawater (6). The degree of evaporation that is computed based on the Br/Cl ratio in the Appalachian brines ($4\text{–}7 \cdot 10^{-3}$)(Fig. 3) as compared to the evaporated sea water curve (25) is equivalent to 20–40-fold, though mixing between brines of different evaporation stages cannot be excluded. The brines then likely underwent dolomitization with carbonate rocks that enriched Ca and depleted Mg in the brine relative to the seawater evaporation curve (6) (Fig. S3 *B* and *C*) and sulfate reduction that removed all sulfate. In addition, the composition of each respective hypersaline Ca-Cl Appalachian brine (i.e., Salina and/or Marcellus) was differentially altered by interactions with the host aquifer rocks presumably under tectonically-induced thermal conditions (26) that resulted in resolvable variations in Sr/Ca, Ba/Sr, and ^{87}Sr/^{86}Sr ratios. The final stage of brine alteration that accounts for the observed brine compositions is dilution (6).

The net results of these processes generated large variations in brine salinity (TDS of 10–343 g/L), relatively homogeneous elevated Br/Cl ratios (range of $2.4 \cdot 10^{-3}$ to $7.6 \cdot 10^{-3}$) and enriched δ^{18}O (0‰ to −7‰) and δ^2H (−33‰ to −45‰) in all Appalachian brines. The remnant geochemical signatures (i.e., Sr/Ca, Ba/Sr, and ^{87}Sr/^{86}Sr) of formation specific brine-rock interactions provide the most suitable basis for differentiating the Appalachian brines. The Sr/Ca ratios (0.03–0.17) of the produced waters from Marcellus wells are significantly higher than brines evolved through calcite ($0.4\text{–}1.6 \cdot 10^{-3}$) or aragonite ($1.5\text{–}2.2 \cdot 10^{-2}$) dolomitization but are consistent with equilibrium with other minerals such as gypsum or celestite (27). Similarly, the Ba/Sr (0.01–1.78) ratios range up to values observed for typical upper continental crust (Ba/Sr = 1.3–1.7) (28).

New and compiled data presented in Table S2 show distinctive geochemical fingerprints (Sr/Ca, Ba/Sr, Sr/Cl, Ba/Cl, Li/Cl, and ^{87}Sr/^{86}Sr) among the Appalachian brines in the different formations. We, therefore, used these variables as independent tracers to differentiate possible brine sources for the shallow type D groundwater. Brines from the Marcellus Formation show systematically low (less radiogenic) ^{87}Sr/^{86}Sr (0.71000–0.71212; n = 50) and high Sr/Ca (0.03–0.17) ratios compared to the more radiogenic Upper Devonian brines (^{87}Sr/^{86}Sr ratio = 0.71580–0.72200; n = 12; Fig. 6) and low Sr/Ca (0.002–0.08)(Fig. S4). Because of the relatively high Sr concentration and diagnostic Sr/Ca, Ba/Sr, and ^{87}Sr/^{86}Sr ratios, this geochemical proxy has the potential to elucidate regional flow paths, salinity sources, and the specific source of the Appalachian brines (21, 24) (Fig. 6). The ^{87}Sr/^{86}Sr ratios (0.71030–0.71725 ± 0.000003 SE) of low-saline groundwater (type A and B) vary widely in the shallow aquifers, but the overwhelming majority are distinctly different from values of produced water brines from Upper Devonian (0.71580–0.72200) (24) (Table S2) and Middle Devonian Marcellus Formation (0.71000–0.71212) (21) (Fig. 6). Conversely, the type D shallow groundwater data show a linear correlation between Sr and Cl (i.e., conservative behavior of Sr) (Fig. S3*D*) and a decrease of ^{87}Sr/^{86}Sr from 0.71453–0.70960 with increasing Sr concentrations and salinity confirming that the resulting salinity is likely derived from mixing with Marcellus Formation brine (Fig. 6). Our data also display a strong association between ^{87}Sr/^{86}Sr and Sr/Ca ratios (Fig. S4), a relationship suggested as a sensitive indicator of Marcellus brines because of the unique combination of low ^{87}Sr/^{86}Sr ratios and high Sr/Ca ratios reported for brines from the Marcellus Formation (21).

The saline waters in the eastern portion of the study area follow the expected Sr-isotope mixing trend hypothesized from new and published data on produced water from the Marcellus Formation (Fig. 6). In contrast, the saline waters from the western portion of our study area show systematic mixing with an end

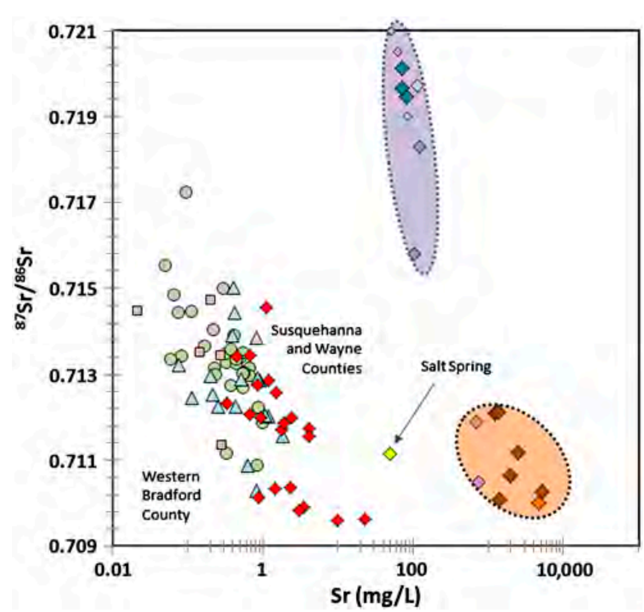

Fig. 6. ^{87}Sr/^{86}Sr vs. Sr concentrations (log scale) of Appalachian Brines (21, 24) and shallow groundwater samples in the study area. The shallow groundwater samples are divided in the figure based on water types. Increased concentrations of Sr in the shallow aquifers are likely derived from two component mixing: (*i*) A low salinity, radiogenic ^{87}Sr/^{86}Sr groundwater sourced from local aquifer reactions; and (*ii*) A high salinity, less radiogenic ^{87}Sr/^{86}Sr water consistent with Marcellus Formation brine. The Marcellus Formation ^{87}Sr/^{86}Sr appears lower in western Bradford than in Susquehanna and Wayne counties. Other brine sources such as the Upper Devonian formations have a more radiogenic ^{87}Sr/^{86}Sr ratio that does not appear to show any relationship to the salinized shallow groundwater. Symbol legend is provided in Fig. 3.

member of a slightly lower $^{87}Sr/^{86}Sr$ ratio (0.70960). This lower ratio could reflect provenance variations within the formation (e.g., lower siliclastic detrital component away from the Acadian clastic source) in the region (21). In sum, whereas the high Br/Cl ratio in type D saline groundwater reflects mixing with underlying Appalachian brines from a common evaporated seawater origin, the $^{87}Sr/^{86}Sr$ ratios indicate mixing with brines with lower $^{87}Sr/^{86}Sr$ fingerprints of approximately 0.7096–0.7110 that cannot be accounted for by Upper Devonian formations but are similar to the underlying Marcellus Formation brines.

Other features that characterize the produced waters from the Marcellus Formation are the high activities of naturally occurring nuclides of ^{226}Ra and ^{228}Ra and low $^{228}Ra/^{226}Ra$ ratios (7). ^{226}Ra and ^{228}Ra are the disintegration products of ^{238}U and ^{232}Th, respectively, and are generated in groundwater from alpha recoil, desorption from sediments, and dissolution of aquifer material (7, 29). In most of the shallow groundwater we sampled (Table S1), combined Ra activities were low (<5 pCi/L). In contrast, reported activities of Ra in Marcellus brines from the study area were high (1,500–3,100 pCi/L) (Fig. S5) with low $^{228}Ra/^{226}Ra$ ratios (0.12–0.73) (7). The highest Ra activities that we measured were in type D waters, and the range (0.4 to 28 pCi/L) is consistent with our calculated mixing range of approximately 0.01–7% based on chloride and bromide mass-balance calculations (Fig. 3), though some interaction such as adsorption with the aquifer rocks (29) is likely. In addition, the $^{228}Ra/^{226}Ra$ ratio in the salinized groundwater (mean = 0.56) is higher than that of the majority of the Marcellus produced waters from the study area (mean = 0.33) (7) (Table S2) indicating that the dissolved Ra in the shallow groundwater is likely derived from a combination of local water-rock interactions and conservative mixing.

Methane data from our previous studies (4, 30) can be examined based on the four water types (A–D) we found in this study. The highest average methane concentrations were observed in type D waters throughout the dataset, followed by type B and A. In locations >1 km away from shale gas drilling sites only one sample, a type B water, out of total of 41 samples contained elevated methane concentrations (>10 mg/L). One newly sampled type D water from the spring at Salt Springs State Park (30) also had concentrations >10 mg/L. Within 1 km of a natural gas well, three type A, three type B, and five type D samples had methane concentrations >10 mg/L. In three type D groundwater samples that were located in the lowland valleys >1 km from shale gas drilling sites, methane concentrations were 2–4 mg/L for the two previously sampled shallow ground waters and 26 mg/L for the newly sampled salt spring. In contrast, type A groundwater >1 km away from drilling sites had methane concentrations <0.01 mg/L in all samples (n = 14). This could suggest that methane in type D water >1 km away from drilling sites could be derived from natural seepage (31) but at concentrations much lower than those observed near drilling (4).

Cross-formational pathways allowing deeper saline water to migrate into shallower, fresher aquifers have been documented in numerous study areas including western Texas (32, 33), Michigan Basin (34, 35), Jordan Rift Valley (36), Appalachian Basin (26), and Alberta, Canada (37). In the Michigan Basin, upward migration of saline fluid into the overlying glacial sediments (34, 35) was interpreted to reflect isostatic rebound following the retreat of glaciers, leading to fracture intensification and increased permeability (34). Alternatively, vertical migration of over-pressured hydrocarbons has been proposed for the Appalachian Basin in response to tectonic deformation and catagensis (i.e., natural gas induced fracturing) during the Alleghenian Orogeny (38–40). This deformation resulted in joints that cut across formations (J_2) in Middle and Upper Devonian formations (39). In addition, the lithostatic and isostatic rebound following glacial retreat significantly increased fracture intensification and permeability in the Upper Devonian aquifers within our study area.

We hypothesize that regions with the combination of deep high hydrodynamic pressure and enhanced natural flow paths (i.e., fracture zones) (39, 41, 42) could induce steep hydraulic gradients and allow the flow of deeper fluids to zones of lower hydrodynamic pressure (43, 44). The higher frequency of the saline type D water occurrence in valleys (Table S1) is consistent with hydrogeological modeling of regional discharge to lower hydrodynamic pressure in the valleys with greater connectivity to the deep subsurface (43–45).

The possibility of drilling and hydraulic fracturing causing rapid flow of brine to shallow groundwater in lower hydrodynamic pressure zones is unlikely but still unknown. By contrast, the time scale for fugitive gas contamination of shallow aquifers can be decoupled from natural brine movement specifically when gas concentrations exceed solubility (approximately 30 cc/kg) and forms mobile free phase gases (i.e., bubbles). In western PA, on the Appalachian Plateau, contamination of shallow aquifers has been described as leakage of highly pressurized gas through the over-pressurized annulus of gas wells and into the overlying freshwater aquifers via fractures and faults (43, 44). The faults are often connected to local and regional discharge areas (i.e., valleys) where the methane contamination is observed (43). Buoyant flow of methane gas bubbles through these fractures is far more rapid than head-driven flow of dense brine, occurring on time scales of less than a year (46).

This study shows that some areas of elevated salinity with type D composition in NE PA were present prior to shale-gas development and most likely are unrelated to the most recent shale gas drilling; however, the coincidence of elevated salinity in shallow groundwater with a geochemical signature similar to produced water from the Marcellus Formation suggests that these areas could be at greater risk of contamination from shale gas development because of a preexisting network of cross-formational pathways that has enhanced hydraulic connectivity to deeper geological formations (43). Future research should focus on systematically monitoring these areas to test potential mechanisms of enhanced hydraulic connectivity to deeper formations, confirm the brine source, and determine the timescales for possible brine migration.

Methods

Drinking water wells were purged until pH, electrical conductance, and temperature were stabilized. Samples were collected prior to any treatment systems and filtered/preserved following USGS protocols (47). All major element and isotopic chemistry analyses were conducted at Duke University. Major anions were determined by ion chromatography, major cations by direct current plasma optical emission spectrometry, and trace metals by VG PlasmaQuad-3 inductively coupled plasma mass-spectrometry. Alkalinity was determined by titration with HCl to pH 4.5. Stable isotopes were determined by continuous flow isotope ratio mass spectrometry using a Thermo-Finnigan TCEA and Delta + XL mass spectrometer at the Duke Environmental Isotope Laboratory (DEVIL). Analytical precisions for $\delta^{18}O$ and $\delta^{2}H$ were estimated as ±0.1‰ and ±1.5‰, respectively. Radium isotope analyses (^{226}Ra and ^{228}Ra) were measured at the Laboratory for Environmental Analysis of RadioNuclides (LEARN) using a Durridge RAD7 radon-in-air monitor (^{226}Ra) and Canberra DSA2000BEGe gamma detector (^{228}Ra) following methods described in (29) and (48). Strontium isotopes were analyzed by a thermal ionization mass spectrometer on a ThermoFisher Triton. The mean $^{87}Sr/^{86}Sr$ of the Standard Reference Material-987 standard was 0.710266 ± 0.000005 (SD).

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AN E&E SPECIAL REPORT

HYDRAULIC FRACTURING:

When 2 wells meet, spills can often follow

Gayathri Vaidyanathan, E&E reporter

EnergyWire: Monday, August 5, 2013

When a geyser of oil and fracking fluid spewed out of an oil well on a farmer's field in Innisfail, Alberta, it coated 100 trees with a fine mist. About 20,000 gallons of oil and fluid collected on a snow-covered field and had to be cleaned up.

The spill was caused by hydraulic fracturing -- not the activities surrounding drilling. A series of similar incidents are being reported across the United States and Canada.

Drillers call it a "frack hit" or "downhole communication," and it could also contaminate groundwater aquifers.

SPECIAL SERIES

There are thousands of oil spills at the nation's onshore oil and gas well sites every year. But the data are scattered amid databases, websites and even file drawers of state agencies across the country. *EnergyWire* spent four months mining the data for the most comprehensive report available on the spills that result from the nation's booming oil and gas industry. **Click here** to view the report.

A basic review by *EnergyWire* of oil spill reports from various states, as well as phone interviews with regulators, revealed more than 10 cases of frack hits that have resulted in spills ranging from 300 gallons to 25,700 gallons. The events were recorded in states from Montana to Texas.

The incidents are called frack hits because they happen when the fractures of two wells intersect. The communicating wells have, in cases, been as far apart as 1.8 miles, though it is more common for the wells to be less than 3,000 feet apart. That is too close for comfort because most states allow adjacent horizontal well bores to be about 600 feet from each other.

"Our concern is where the communication results in a loss of well control," said Ron Gusek, vice president of an Alberta-based oil and gas company and chairman of an Alberta industry task force set up to examine frack hits. "In other words, there's a fluid spill on the surface or loss of well control underground that could lead to contamination of a water aquifer."

The incidents generally go unrecorded by state regulators, but traces are found in oil spill databases as instances where operators report an overflowing production tank that spilled a few barrels into the environment.

Frack hits will be more common in the future as companies drill multiple wells in close proximity on each well pad.

They are a result of technological advancements in the industry since companies began combining directional drilling and fracking to split apart shale rock and extract oil and gas. The oil and gas development brought concerns about groundwater, set off by "Gasland," a documentary that showed water from a tap being set on fire due to the presence of methane. Since then, contamination worries have surfaced in Pavillion, Wyo., where U.S. EPA and the U.S. Geological Survey have found propane, methane and ethane -- all components of natural gas -- in groundwater aquifers.

Industry has argued that fracking is not a threat to groundwater resources and that there is no path for methane or fracking fluid in formations deep underground to contaminate groundwater aquifers. And surface spills are generally tied to human carelessness rather than drilling.

Frack hits could be a path of contamination, particularly in cases where the cementing is below standards.

In New Mexico on Feb. 9, 2012, Devon Energy Corp. was fracking a well when an older producing well 600

Some frack hits

New Mexico: A horizontal well being fracked communicated downhole with an older producing well on Feb. 22, 2012, leading to a spill of 9,000 gallons of oil. The wells were separated by 600 feet. The spill was cleaned up.

New Mexico: Two vertical wells, both fracked, communicated across a distance of 2,000 feet on July 7, 2010, causing a spill of 19,000 gallons of produced water. The spill was cleaned up.

feet away started spouting 7,000 gallons of oil and wastewater. The fracks had hit the older well and pushed fluids out.

If the well had not been properly cemented -- a possibility with older wells -- the fluids could have migrated outside the well bore and directly entered groundwater aquifers.

"Everyone thinks cement is this magic; it's not," said Michael Beck, president of Surface Solutions Inc. and a consultant for the oil and gas industry in Canada who is helping companies including Encana Corp. deal with downhole communication issues. "Cement is not 100 percent perfect, it cracks."

The mechanism

Fracking involves pumping water, sand and chemicals into the well bore at high pressures to fracture shale. The well bores are horizontal, extending thousands of feet at times, and fractures extend a few hundred feet into the surrounding rock, like cracks embedded in an ice cube. That's the assumption, at least.

Oklahoma: A well being fracked communicated with a neighboring well on Oct. 10, 2012, spilling 420 gallons of oil. The spill was cleaned up.

Oklahoma: A well being fracked communicated with a neighboring well on June 7, 2012, spilling 714 gallons of oil and produced water. The spill was cleaned up.

Arkansas: A well being fracked hit another well on Nov. 2, 2012, spilling 3,300 gallons of produced water. The spill was contained in the berm and cleaned up.

Montana: Two wells communicated during fracking on Jan 3, 2012, spilling about 35,000 gallons of oil and water. The spill was cleaned up.

West Virginia: Two frack hits have come to the attention of the DEP since 2011: one where a company was fracking in the Marcellus Shale and communicated with producing wells, and another where a company was fracking in the Berea sandstone formation and communicated with an abandoned well.

-- Gayathri Vaidyanathan

The truth can be messier. Some fractures get away from the drillers, extending even as far as adjacent formations. Using microseismic technology, researchers in Pennsylvania recently found one extending as far away as 1,800 feet, as reported by the Associated Press.

In the case of the Alberta spill, regulators found that an oil well 3,000 feet away was being fracked, and it had communicated with the well that lost control. About 20,000 gallons of fracking fluid and oil had to be cleaned up.

The fractures move toward the regions of lowest pressure, which can be a nearby well bore. Once a channel is established, the pressures of around 10,000 pounds per square inch travel rapidly across the formation to the older well. It pushes fracking fluid and whatever is at the bottom of the producing well -- oil, gas and produced water -- up the old well bore, which is not equipped to handle high pressures.

"The frack fluid crosses the path of least resistance," said James Amos, supervisory environmental protection specialist with the Bureau of Land Management in New Mexico. It runs up the well bore and can cause the production tank that's collecting the oil to overflow.

To the lay observer, it appears to be a surface spill. But in reality, such spills are caused by fracking hundreds or even thousands of feet away.

Communication between wells is not always bad. Sometimes companies want the fracks to communicate to effectively stimulate the rock. But problems arise when the communication is unintended and unexpected.

The worst-case scenario is when the fluids, propelled by high pressure, travel outside the steel pipe casing the producing well, through a bad cement job, and the brine enters groundwater aquifers. The risk is high when the frack hits communicate with older producing wells or abandoned wells.

In the New York State Department of Environmental Conservation alone, there are 4,000 unreported or abandoned wells to be plugged and 35,000 wells for which there are no records.

"If it doesn't get inside the well bore, it can migrate up the outside of the well bore; there are water aquifers up there," Beck said. He described aging cement as a layer of bubble gum wrapped around the steel pipe casing a well. It separates from the well bore with time, especially in areas where the geology is sandy or swampy, and provides a path to the groundwater aquifer.

How probable is it?

EnergyWire documented more than 10 cases of frack hits that resulted in blowouts or spills since 2010, and most state regulators said they are rare but would be more common in the future as additional wells get drilled.

"We've drilled 4,500 wells in our particular area, the wells are all closely spaced, you are drilling in areas where there are pre-intersecting fractures in the rock; I wouldn't expect it not to happen," said Lawrence Bengal, director of the Arkansas Oil and Gas Commission.

In the Montney Formation of Alberta, about 30 percent of the well bores that are up to 1,500 feet apart experience frack hits, Beck said. The Montney is similar in geology to the Bakken Shale of North Dakota.

The hits are common enough on New Mexico federal lands that some operators are temporarily shutting down their producing wells while new wells are being fracked, Amos said. They install cast-iron plugs downhole to prevent the fracking fluid from shooting up the well bore and damaging the producing well, he added.

Predicting frack hits

Industry is getting better at predicting the behavior of fractures underground, but the challenge will only increase as more wells get drilled, Pat Handren, an engineer with Denbury Resources Inc., wrote in a brief to EPA, which is conducting a study on fracking.

"As well density increases, it becomes increasingly probable that wells will communicate either through previously created fractures or through adjacent wellbores and then into previously created fractures," he wrote.

Anthony Ingraffea, an engineering professor at Cornell University and a critic of the oil and gas industry, described communication, and any resulting environmental impact, as a matter of probability.

"The industry can say there is less than a 1 percent probability this is going to happen," he said over the phone. "If you roll the dice 100 times, it is going to happen once. If you roll the dice 1,000 times, it is going to happen more than once."

Regulation

Frack hits are usually not reported to state regulators unless there is a spill of fracking fluid from the producing well.

In such cases, the incidents masquerade in state databases as production tank overflows due to an unexpected increase in pressure -- a "kick." That seems innocuous until one pauses to examine why, exactly, a producing well that should experience stable pressures would experience a kick.

"They [frack hits] periodically occur, but they don't necessarily put down the exact or the surmised cause. Most of the time we'll just get a spill report that says all of a sudden we overran the tanks 100 barrels to the bermed area," said Steve Sasaki, chief field inspector at the Montana Board of Oil and Gas.

State regulators disagree on whether a frack hit is a significant problem. Most, such as Bengal of the Arkansas Oil and Gas Commission, believe they are an issue for companies to resolve among themselves because it affects production. If there is a surface spill, it will be cleaned up and contained, he said. Additional regulation is not necessary, especially because wells are cased and cemented very stringently in his state, he added.

He acknowledged there could be a problem with fracks communicating with older wells.

Other regulators, such as Amos with the BLM in New Mexico, see all spills, including ones that can be contained at the surface, as a problem.

In Canada, the industry has put together a set of best practices to deal with the problem before it gets more prevalent.

"We just want to make sure that people have taken steps to ensure that they eliminate the risk of anything happening," said Gusek of the Alberta task force. "We saw that it has a potential to be a high-consequence event when and if it happened."

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Approved Applications for Permit to Drill - Not Drilled
September 30, 2014

State	Field Office	Federal	Indian	Total AAPDs
Alaska	Statewide	6	0	5
Alaska Total		**6**	**0**	**6**
California	Bakersfield	97	0	97
California Total		**97**	**0**	**97**
	Canon City	67	0	67
	Craig	28	0	28
	Durango	13	21	34
	Glenwood Springs	214	0	214
	Grand Junction	31	0	31
	Meeker	261	0	261
Colorado Total		**614**	**21**	**635**
Eastern States	Jackson	12	0	12
	Milwaukee	0	0	0
Eastern States Total		**12**	**0**	**12**
Montana	Great Falls	1	3	4
	Miles City	26	5	31
	North Dakota	169	187	356
Montana Total		**196**	**195**	**391**
Nevada	Statewide	17	0	17
Nevada Total		**17**	**0**	**17**
New Mexico	Carlsbad	545	0	545
	Farmington	195	22	217
	Hobbs	264	0	264
	Rio Puerco	4	43	47
	Roswell	25	0	25
	Tulsa	40	82	122
New Mexico Total		**1,073**	**147**	**1,220**
Utah	Moab	11	0	11
	Price	141	0	141
	Salt Lake	0	0	0
	Vernal	835	557	1,392
Utah Total		**987**	**557**	**1,544**
Wyoming	Buffalo	1,101	0	1,101
	Casper	182	0	182
	Kemmerer	21	0	21
	Lander	25	11	36
	Newcastle	39	0	39
	Pinedale	211	0	211
	Rawlins	271	0	271
	Rock Springs	121	0	121
	Worland	15	0	15
Wyoming Total		**1,986**	**11**	**1,997**
Grand Total		**4,988**	**931**	**5,919**

AAPD = Approved Applications for Permit to Drill
Note: Approved Applications for Permit to Drill expire after 2 years
with one extension of an additional 2 years for a total of 4 years

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Scientific Solutions

IMPACTS OF GAS DRILLING ON HUMAN AND ANIMAL HEALTH

MICHELLE BAMBERGER
ROBERT E. OSWALD

ABSTRACT

Environmental concerns surrounding drilling for gas are intense due to expansion of shale gas drilling operations. Controversy surrounding the impact of drilling on air and water quality has pitted industry and lease-holders against individuals and groups concerned with environmental protection and public health. Because animals often are exposed continually to air, soil, and groundwater and have more frequent reproductive cycles, animals can be used as sentinels to monitor impacts to human health. This study involved interviews with animal owners who live near gas drilling operations. The findings illustrate which aspects of the drilling process may lead to health problems and suggest modifications that would lessen but not eliminate impacts. Complete evidence regarding health impacts of gas drilling cannot be obtained due to incomplete testing and disclosure of chemicals, and nondisclosure agreements. Without rigorous scientific studies, the gas drilling boom sweeping the world will remain an uncontrolled health experiment on an enormous scale.

Keywords: hydraulic fracturing, shale gas drilling, veterinary medicine, environmental toxicology

> At what point does preliminary evidence of harm become definitive evidence of harm? When someone says, "We were not aware of the dangers of these chemicals back then," whom do they mean by *we*?
>
> —Sandra Steingraber, *Living Downstream* (Da Capo Press, 2010)

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U.S. DEPARTMENT OF THE INTERIOR **BUREAU OF LAND MANAGEMENT**

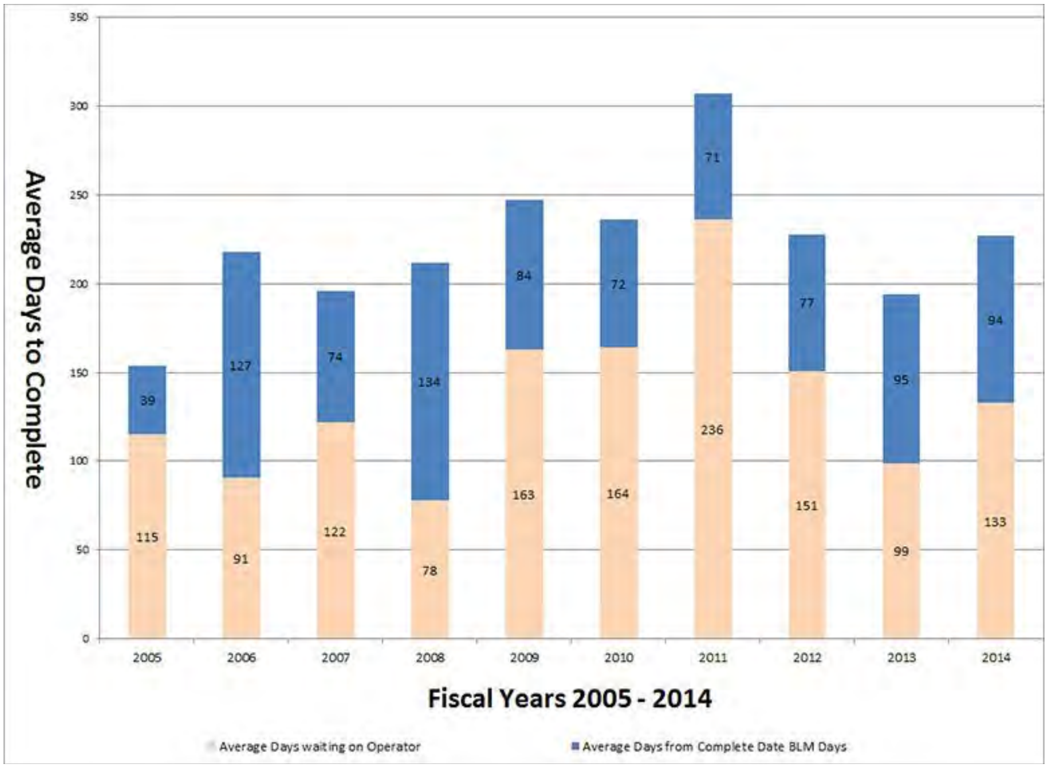
Print Page

Average Application for Permit to Drill (APD) Approval Timeframes: FY2005 - FY2014

This chart illustrates the average number of days to process an APD, broken out as follows:

- Average number of days after initial submission that industry takes to resolve any deficiencies in an APD
- Average number of days for the BLM to process the complete APD

Return to Main Oil and Gas Statistics Page »



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STATE OF COLORADO
OIL & GAS
CONSERVATION COMMISSION

DEPARTMENT OF NATURAL RESOURCES
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To: Colorado Oil and Gas Conservation Commissioners

From: Colorado Oil and Gas Conservation Commission Staff

Dated: February 18, 2011

Re: Use of Diesel Fuel for Hydraulic Fracturing in Colorado

This memorandum reports on our investigation to date into the use of diesel fuel for hydraulic fracturing in Colorado.

On January 31, 2011, the House of Representatives Committee on Energy and Commerce notified the Environmental Protection Agency that 12 oil and gas service companies had used about 32.2 million gallons of diesel fuel or fluids containing diesel fuel for hydraulic fracturing during the period from 2005 through 2009 and that about 1.3 million gallons of such fuel or fluids had been used in Colorado. The Committee further reported that these companies had not obtained permits under the Safe Drinking Water Act authorizing the injection of diesel fuel. The Committee stated that it could not determine whether these activities had adversely affected drinking water supplies because it lacked the information to do so.

We are currently reviewing our records to investigate the use of diesel fuel for hydraulic fracturing in Colorado. Our regulations do not require operators to report the constituents of their fracturing fluids unless requested under Rule 205. Rule 308B, however, requires operators to submit a Completed Interval Report, Form 5A, within 30 days after completing a formation. These reports include summary information on the formation treatment, which may include hydraulic fracturing as well as certain types of well maintenance. In their summaries, some operators have reported the use of diesel alone or in combination with other substances. The staff's review of these reports is ongoing, but reports for 65 wells refer to the use of diesel for formation treatments generally. Five of these wells were treated in the 1950s, thirteen in the 1960s, six in the 1970s, twenty-nine in the 1980s, four in the 1990s, seven in the 2000s, and one in 2010. The treatment in 2010 did not involve hydraulic fracturing. None of the treatments involved wells completed in coal bed methane formations, which are generally shallower and therefore might pose a greater risk to drinking water.

With respect to the period from 2005 through 2009 that the Committee investigated, the reports indicate that diesel fuel or fluids containing diesel fuel were used to hydraulically fracture or otherwise treat four wells: two in 2005, and two in 2007. By way of comparison, our records indicate that more than 10,000 wells were hydraulically fractured during this period. However, we emphasize that many operators did not include fracturing fluid constituents in their completed interval reports because they were not required to do so; therefore, the reports do not provide complete information on this subject as reflected in the difference in fluid volumes between the reports (66,000 gallons) and the Committee's investigation (1.3 million gallons).

To obtain additional information, we asked the Committee to provide us with the data it compiled for Colorado, but it has declined to do so because of confidentiality constraints. Therefore, we are requesting this information from the service companies and operators themselves. For this purpose, we have contacted all 13 service companies who could have provided information to the Committee regarding Colorado as well as 15 of the largest operators in Colorado. Our expectation is that the service companies will provide us with the Colorado information that they previously reported to the Committee and that the operators will provide us with additional information that we can use to verify and cross-check the information that we receive from the service companies. We have already received a number of responses, and our collection and review of this information is ongoing. This should help us to determine the extent to which diesel fuel and fluids containing diesel fuel were used for hydraulic fracturing in Colorado during the period from 2005 through 2009, including the volumes of such fluids used and when and where such use occurred.

This information should help us to assess whether this activity had any effect upon drinking water supplies by allowing us to identify and investigate nearby water wells. For some water wells, we may already have collected water quality data that addresses possible diesel contamination; for other water wells, we can seek to obtain such data at a relatively modest cost. If no diesel contamination is identified, then this would indicate that the hydraulic fracturing of the oil and gas well in question did not impact drinking water supplies. If diesel contamination is identified, then this could indicate that hydraulic fracturing of the oil and gas well did impact drinking water supplies and we can seek remediation of such contamination and take further action to ensure that it does not recur. It is important to remember that we have previously investigated numerous complaints alleging impacts to water wells and ground water resources from hydraulic fracturing and other oil and gas operations. Staff believes that if such impacts had occurred, whether due to the use of diesel fuel or other substances, then they would have been identified during our investigations.

As a general matter, we believe that the Commission's regulations should have prevented the contamination of drinking water supplies from the use of diesel fuel or other substances for hydraulic fracturing in Colorado. The fracturing fluids would have been injected into hydrocarbon-bearing formations at depths that often approach 8,000 feet or more, while most drinking water supplies are less than 1,000 feet deep. Rule 317 required the wells to be cased with steel pipe and the casing to be cemented to create a hydraulic seal. This should have ensured that any fluids or hydrocarbons flowing back up the well bore did not come into contact with the shallower aquifers. Other regulations and Commission orders imposed further operational and monitoring requirements, and the 2008 rulemaking mandated additional protections, including cement bond logs, bradenhead monitoring, public water system setbacks, and water well sampling.

After consulting with the Attorney General's Office, we also believe that the mere use of diesel fuel for hydraulic fracturing, in and of itself, would not have violated our regulations. Although Rule 325 required persons to obtain an underground injection formation permit before constructing or operating a Class II well for the underground disposal of fluids, the Commission staff did not construe this requirement to apply to hydraulic fracturing. Nor did the Environmental Protection Agency, which administers the Safe Drinking Water Act, advise the Commission that it should require such a permit for hydraulic fracturing involving diesel fuel. A violation of Rule 324A would, however, have occurred if this activity resulted in a significant adverse environmental impact to water, soil, or biological resources.

FRED UPTON, MICHIGAN
CHAIRMAN

HENRY A. WAXMAN, CALIFORNIA
RANKING MEMBER

ONE HUNDRED TWELFTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON ENERGY AND COMMERCE
2125 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515–6115

Majority (202) 225-2927
Minority (202) 225-3641

January 31, 2011

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

Dear Administrator Jackson:

We have been investigating the practice of hydraulic fracturing and its potential impact on water quality in the United States. Because EPA is also examining this issue, we are writing to share our findings regarding the use of diesel fuel in hydraulic fracturing fluids.

In 2003, EPA signed a memorandum of agreement with the three largest providers of hydraulic fracturing to eliminate the use of diesel fuel in coalbed methane formations in underground sources of drinking water. Two years later, Congress exempted hydraulic fracturing from the Safe Drinking Water Act except when the fracturing fluids contain diesel. As a result, many assumed that the industry stopped using diesel fuel altogether in hydraulic fracturing.

Our investigation has found that this is not the case. 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. Halliburton injected more than 7 million gallons of diesel fuel or fluids containing diesel; BJ Services injected even more, 11.5 million gallons.

According to EPA, any company that performs hydraulic fracturing using diesel fuel must receive a permit under the Safe Drinking Water Act. We learned 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. This appears to be a violation of the Safe Drinking Water Act. It also means that the companies injecting diesel fuel have not performed the environmental reviews required by the law.

A key question is whether the unauthorized injection of hydraulic fracturing fluids containing diesel fuel is adversely affecting drinking water supplies. None of the oil and gas service companies could provide data on whether they performed hydraulic fracturing in or near underground sources of drinking water, telling us that the well operators, not the service companies, track that information. We also asked about diesel fuel use in coalbed methane formations, which tend to be shallower and closer to drinking water sources. The three largest companies—Halliburton, BJ Services, and Schlumberger—told us they have stopped using diesel fuel in coalbed methane formations located in underground sources of drinking water. Three smaller companies reported using a limited volume of products containing diesel in coalbed methane wells but did not provide information on the proximity of these wells to drinking water sources.

Background

The oil and gas industry uses hydraulic fracturing to force fluids and propping agents into oil and gas production wells at extremely high pressure, cracking the oil or gas seams and allowing trapped natural gas and oil to escape. In many instances, the fluids used in this process are water-based. There are some formations, however, that are not fractured effectively by water-based fluids because clay or other substances in the rock absorb water. In these formations, diesel fuel or other hydrocarbons may replace water as the primary carrier fluid to transport sand and other proppants into the fractures created by the hydraulic fracturing process.

EPA has raised concerns about the potential public health risks posed by diesel fuel used in hydraulic fracturing fluids. In a 2004 report, EPA stated that the "use of diesel fuel in fracturing fluids poses the greatest threat" to underground sources of drinking water.[1] Diesel fuel contains toxic constituents, including benzene, toluene, ethylbenzene, and xylenes (collectively known as "BTEX" compounds). The Department of Health and Human Services, the International Agency for Research on Cancer, and EPA have determined that benzene is a human carcinogen.[2] Chronic exposure to toluene, ethylbenzene, or xylenes also can damage the central nervous system, liver, and kidneys.[3]

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[1] U.S. Environmental Protection Agency, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* (June 2004) (EPA 816-R-04-003) at 4-11.

[2] U.S. Department of Health and Human Services, Agency for Toxic Substances and Disease Registry, *Public Health Statement for Benzene* (Aug. 2007).

[3] U.S. Environmental Protection Agency, *Basic Information about Toluene in Drinking Water*, *Basic Information about Ethylbenzene in Drinking Water*, and *Basic Information about*

In December 2003, EPA entered into a voluntary memorandum of agreement (MOA) with the three largest hydraulic fracturing companies, Halliburton, BJ Services, and Schlumberger, to "eliminate diesel fuel in hydraulic fracturing fluids injected into coalbed methane production wells in underground sources of drinking water."[4] The MOA focused on coalbed methane wells because they tend to be shallower and closer to underground sources of drinking water than other oil and gas production wells. The MOA did not address hydraulic fracturing in other formations.

In 2005, Congress passed the Energy Policy Act, which contained a provision addressing the application of Safe Drinking Water Act (SDWA) to hydraulic fracturing. Congress modified the definition of "underground injection" to exclude "the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities."[5]

The effect of this law is to exempt hydraulic fracturing from the underground injection control (UIC) permit requirements unless the fluid being injected is diesel fuel. As EPA states on its website:

> While the SDWA specifically excludes hydraulic fracturing from UIC regulation under SDWA § 1421 (d)(1), the use of diesel fuel during hydraulic fracturing is still regulated by the UIC program. Any service company that performs hydraulic fracturing using diesel fuel must receive prior authorization from the UIC program.[6]

Perhaps as a result of the actions of EPA and Congress, some have assumed that the oil and gas industry has stopped using diesel in hydraulic fracturing. EPA staff told the Committee that the agency assumed that the MOA had eliminated most diesel use.[7] In a 2004 letter to

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Xylenes in Drinking Water (online at http://water.epa.gov/drink/contaminants/basicinformation/index.cfm) (accessed Jan. 21, 2011).

[4] Memorandum of Agreement between the U.S. Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation (Dec. 12, 2003).

[5] 42 U.S.C. § 300h(d).

[6] U.S. Environmental Protection Agency, Regulation of Hydraulic Fracturing by the Office of Water (online at http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydroreg.cfm) (accessed Jan. 21, 2011).

[7] Phone briefing by Ann Codrington, U.S. Environmental Protection Agency, to Committee Staff (Oct. 22, 2010).

Senator Jim Jeffords, Benjamin Grumbles, the Acting Assistant Administrator for EPA at the time, wrote that the MOA "accomplished the intended goal of removing diesel from hydraulic fracturing fluids in a matter of months."[8] At a hearing on hydraulic fracturing in the Committee on Oversight and Government Reform in 2007, Rep. Darrell Issa asserted, "this practice does not include the use of diesel fuel."[9] In January 2010, Energy In Depth, a group representing most of America's oil and gas producers, wrote that "diesel fuel is simply not used in fracturing operations."[10]

Our Investigation

On February 18, 2010, the Committee commenced an investigation into the practice of hydraulic fracturing and its potential impact on water quality across the United States. This investigation was intended to build on work begun by Ranking Member Henry A. Waxman in 2007 as Chairman of the Committee on Oversight and Government Reform.

The Committee initially sent letters to eight oil and gas service companies engaged in hydraulic fracturing in the United States regarding the type and volume of chemicals they used in hydraulic fracturing fluids between 2005 and 2009. In May, the Committee sent letters to six additional oil and gas service companies to assess a broader range of industry practices.[11]

The 14 oil and gas service companies voluntarily provided the Committee with data on the volume of diesel fuel and other hydraulic fracturing fluids they used during the five year period.[12] For each hydraulic fracturing fluid, the companies provided the Committee a Material

[8] Letter from Benjamin Grumbles, Acting Assistant Administrator, U.S. Environmental Protection Agency, to Senator Jim Jeffords (Dec. 7, 2004) as cited in the Congressional Record, S7278 (June 23, 2005).

[9] House Committee on Oversight and Government Reform, Opening Statement of Rep. Darrell Issa, *Oil and Gas Exemptions in Federal Environmental Protections*, 110th Cong. (Oct. 31, 2007).

[10] Energy in Depth, *When Gummy Bears Attack* (Jan. 20, 2010) (online at http://www.energyindepth.org/2010/01/when-gummy-bears-attack/) (accessed Jan. 21, 2011).

[11] The Committee sent letters to Basic Energy Services, BJ Services, Calfrac Well Services, Complete Production Services, Frac Tech Services, Halliburton, Key Energy Services, RPC, Sanjel Corporation, Schlumberger, Superior Well Services, Trican Well Service, Universal Well Services, and Weatherford.

[12] BJ Services, Halliburton, and Schlumberger already had provided Chairman Henry A. Waxman and the Oversight Committee with data for 2005 through 2007. For BJ Services, the

Safety Data Sheet (MSDS) detailing the fluid's chemical components. If the MSDS for a particular product listed a chemical component as proprietary, the company that used that product was asked to provide the proprietary information.

Using this information, our staff calculated how much diesel fuel and fracturing fluids containing diesel fuel these 14 companies used between 2005 and 2009.[13]

Use of Diesel Fuel in Hydraulic Fracturing

Between 2005 and 2009, 12 of the 14 companies used 32.2 million gallons of diesel fuel or fluids containing diesel fuel.[14] BJ Services used the most diesel fuel and fluids containing diesel, more than 11.5 million gallons, followed by Halliburton, which used 7.2 million gallons. Four other companies, RPC (4.3 million gallons), Sanjel (3.6 million gallons), Weatherford (2.1 million gallons), and Key Energy Services (1.6 million gallons), used more than one million gallons of diesel fuel and fluids containing diesel.

These 12 companies injected these diesel-containing fluids in 19 states. Diesel-containing fluids were used most frequently in Texas, which accounted for half of the total volume injected, 16 million gallons. The companies injected at least one million gallons of diesel-containing fluids in Oklahoma (3.3 million gallons), North Dakota (3.1 million gallons), Louisiana (2.9 million gallons), Wyoming (2.9 million gallons), and Colorado (1.3 million gallons).

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

Diesel fuel was a significant component of the diesel-containing fluids these companies injected. The companies used 10.2 million gallons of straight diesel fuel and 21.8 million gallons of products containing at least 30% diesel fuel.

2005-2007 data is limited to natural gas wells. For Schlumberger, the 2005-2007 data is limited to coalbed methane wells.

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

[14] Calfrac Well Services and Universal Well Services did not use any fracturing fluids containing diesel during this time period.

Lack of Regulation

Under the Safe Drinking Water Act, oil and gas service companies that inject diesel fuel or fluids containing diesel fuel as part of the hydraulic fracturing process must obtain a permit under the underground injection control program.[15] The purpose of this permitting requirement is to distinguish between underground injections that threaten drinking water supplies, which are denied permits, and those that do not, which are allowed to go forward. EPA's regulations prohibit any underground injection that "allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation ... or may otherwise adversely affect the health of persons."[16] The person seeking the injection permit has the burden of demonstrating that the injection will not endanger drinking water sources.[17]

To assess whether the companies obtained the required permits before using diesel fuel or hydraulic fracturing fluids containing diesel, our staff contacted the state agencies and regional EPA offices responsible for overseeing underground injection wells in the 19 states where the companies reported using products containing diesel fuel.[18] The staff asked these agencies if they had ever issued a permit under the UIC program for diesel fuel or hydraulic fracturing fluids containing diesel or if an oil and gas service company had ever requested such a permit. Each state and regional EPA office contacted stated that no such permit had ever been sought or granted.

In some instances, the officials we contacted expressed doubt that companies still used diesel as a hydraulic fracturing fluid or additive or were unaware of continued diesel fuel use. An engineer from the Colorado Oil and Gas Conservation Commission, for example, said that diesel is "rarely used" and said he knew of only one time diesel fuel was used in hydraulic

[15] U.S. Environmental Protection Agency, Regulation of Hydraulic Fracturing by the Office of Water (online at http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydroreg.cfm) (accessed Jan. 21, 2011).

[16] 40 CFR § 144.12(a).

[17] 42 USC 300h (b)(1).

[18] Committee staff spoke with state agencies and regional EPA offices responsible for Class II injection wells in Alabama, Alaska, Arkansas, Colorado, Florida, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Montana, New Mexico, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming. Despite repeated attempts, Committee staff was unable to speak with anyone at the North Dakota Industrial Commission or California Department of Conservation.

fracturing in Colorado.[19] The Railroad Commission of Texas, which regulates oil and gas activity in the state, responded that it only recently learned that handful of companies may have used diesel fuel without prior approval. The Commission has contacted these operators for additional information.[20]

Impact on Underground Sources of Drinking Water

A key unanswered question is whether the unregulated injection of diesel fuel or fluids containing diesel is adversely affecting drinking water supplies. In an attempt to answer this question, we asked each of the oil and gas service companies to provide data on whether it has performed hydraulic fracturing in or near underground sources of drinking water. None of the hydraulic fracturing service companies could provide this data because they do not track the proximity of the wells they fracture to underground sources of drinking water. They reported that the operators of the oil and gas wells would be more likely to maintain the requested information.

BJ Services, for example, responded that the company "does not track or maintain such data because it is the responsibility of the well operator to drill in compliance with the applicable statutes and regulations concerning subsurface aquifers."[21] Calfrac Well Services stated that "the presence of 'underground sources of drinking water' is a matter which is addressed by the well operator and governmental authorities in the well permitting and drilling process."[22] Frac Tech similarly stated that "the location of drinking water aquifers and the isolation of the well from any drinking water aquifers is handled by others in the well process."[23] Key Energy Services asserted that "because Key is not the owner nor the operator of the wells on which it provides

[19] E-mail from State of Colorado Oil and Gas Conservation Commission to Committee staff (Sept. 23, 2010).

[20] E-mail from Railroad Commission of Texas to Committee staff (Nov. 2, 2010).

[21] Letter from Mark R. Paoletta, Counsel to BJ Services, to Henry A. Waxman, Chairman, Committee on Energy and Commerce, and Edward J. Markey, Chairman, Subcommittee on Energy and Environment (Mar. 5, 2010).

[22] Letter from John Grisdale, President, Calfrac Well Services, to Henry A. Waxman, Chairman, Committee on Energy and Commerce, and Edward J. Markey, Chairman, Subcommittee on Energy and Environment (Mar. 19, 2010).

[23] E-mail from Ronald J. Tenpas, Counsel to Frac Tech, to Committee staff (Mar. 24, 2010).

services, Key does not possess information about the location of drinking water, if any, around the wells."[24]

We then asked the oil and gas companies that operate the wells the same question. Several of these companies responded that they operated wells only in formations where natural gas deposits lie deep below the water table.[25] Other companies, however, reported operating wells in shallower formations that meet the SDWA definition of drinking water.[26]

Although the oil and gas service companies did not keep records of whether they operated in or near underground sources of drinking water, they were able to report on whether their wells were drilled in coalbed methane formations. Diesel use in coalbed methane formations is of particular concern, since these formations tend to be shallower and closer to drinking water sources than conventional oil and gas production wells.[27] For this reason, we asked each company that reported using products containing diesel fuel whether they used these products in coalbed methane formations.

The three largest companies—Halliburton, BJ Services, and Schlumberger—told the Committee that they stopped using diesel fuel in coalbed methane formations located in underground sources of drinking water. Three smaller companies reported using a limited

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[24] Letter from Peter S. Spivack, Counsel to Key Energy Services, to Henry A. Waxman, Chairman, Committee on Energy and Commerce, and Edward J. Markey, Chairman, Subcommittee on Energy and Environment (May 28, 2010).

[25] *See, e.g.*, Letter from Jason B. Hutt, Counsel to Chesapeake, to Henry A. Waxman, Chairman, Committee on Energy and Commerce, and Edward J. Markey, Chairman, Subcommittee on Energy and Environment (Aug. 27, 2010); Letter from Jeff Wojahn, President, Encana, to Henry A. Waxman, Chairman, Committee on Energy and Commerce, and Edward J. Markey, Chairman, Subcommittee on Energy and Environment (Aug. 19, 2010).

[26] *See, e.g.*, Letter, Appendix, from Shirley C. Woodward, Counsel to BP, to Henry A. Waxman, Chairman, Committee on Energy and Commerce, and Edward J. Markey, Chairman, Subcommittee on Energy and Environment, (Aug. 12, 2010) (stating that BP operates wells in underground sources of drinking water); Letter from William F. Whitsitt, Executive Vice President, Public Affairs, Devon, to Henry A. Waxman, Chairman, Committee on Energy and Commerce, and Edward J. Markey, Chairman, Subcommittee on Energy and Environment (Aug. 5, 2010) (stating that Devon operates wells at depths of 1,000 to 2,000 feet and that "fresh water zones are present at this depth of field").

[27] U.S. Environmental Protection Agency, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* (June 2004) (EPA 816-R-04-003) at ES-7.

volume of products containing diesel in coalbed methane wells but did not provide information on the proximity of these wells to drinking water sources.

Halliburton reported that it used diesel-containing products in a small number of coalbed methane wells between 2005 and 2007, but the company explained that the fracturing occurred either below any drinking water source or in aquifers that do not meet the definition of an underground source of drinking water. The company says it has not used products containing diesel fuels in coalbed methane wells since 2007.[28] Schlumberger reported that the company has policies in place to ensure that company employees do not use fluids containing diesel in coalbed methane formations.[29]

In 2008, BJ Services informed the Committee on Oversight and Government Reform that it had used 1,700 gallons of diesel-based polymer slurries in Arkansas and Oklahoma between 2005 and 2007 "in violation of the MOA."[30] BJ Services now maintains that these injections did not violate the MOA, stating that the "inadvertent use" of diesel-based polymer slurries in Arkansas and Oklahoma occurred "hundreds or thousands of feet" beneath any freshwater-bearing zone.[31] BJ Services confirmed that it "has not used diesel fuel in coalbed methane formations in USDWs since the 2003 MOA was put in place."[32]

Three other companies reported using some products containing diesel fuel in coalbed methane formations in small amounts: RPC (28,600 gallons), Sanjel (4,600 gallons), and Weatherford (2,300 gallons). We did not receive any information from these companies on the proximity of the coalbed methane wells to underground sources of drinking water.

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[28] Letter from Robert J. Moran, Halliburton, to Henry A. Waxman, Chairman, Committee on Energy and Commerce, and Edward J. Markey, Chairman, Subcommittee on Energy and Environment (Aug. 26, 2010); e-mail from Thomas C. Jackson to Committee staff (Sept. 10, 2010).

[29] Letter from Steven R. Ross and John F. Sopko, Counsel to Schlumberger, to Henry A. Waxman, Chairman, Committee on Energy and Commerce, and Edward J. Markey, Chairman, Subcommittee on Energy and Environment (Sept. 15, 2010).

[30] Letter from L. Andrew Zausner, Counsel to BJ Services, to Henry A. Waxman, Chairman, Committee on Oversight and Government Reform (Jan. 24, 2008).

[31] Letter from Jason B. Hutt, Counsel to BJ Services, to Committee staff (Oct. 15, 2010).

[32] *Id.*

Conclusion

The information we have reviewed shows that the oil and gas industry has injected millions of gallons of diesel fuel and hydraulic fracturing fluids containing diesel fuel since 2005. These activities appear to be a violation of the Safe Drinking Water Act because the companies did not obtain permits authorizing the injection of diesel fuel.

We are unable to draw definitive conclusions about the potential impact of these injections on public health or the environment. The oil and gas service companies we contacted were able to provide only limited information about the proximity of their hydraulic fracturing operations to underground sources of drinking water. Moreover, because the companies did not apply for the permits required under the Safe Drinking Water Act, the regulatory agencies that would have reviewed the permit applications knew little about the diesel injections or what their potential impact might be.

We urge you to examine the use of hydraulic fracturing fluids containing diesel fuel as part of your investigation into the industry's practices. This appears to be an area of significant noncompliance with the requirements of the Safe Drinking Water Act.

Sincerely,

Henry A. Waxman
Ranking Member
Committee on Energy and Commerce

Edward J. Markey
Ranking Member
Committee on Natural Resources

Diana DeGette
Ranking Member
Subcommittee on Oversight and Investigations

Attachment

cc: The Honorable Fred Upton
Chairman

The Honorable Joe Barton
Chairman Emeritus

The Honorable Cliff Stearns
Chairman
Subcommittee on Oversight and Investigations

Attachment

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

Company	Volume (gallons)
Basic Energy Services	204,013
BJ Services	11,555,538
Complete	4,625
Frac Tech	159,371
Halliburton	7,207,216
Key Energy Services	1,641,213
RPC	4,314,110
Sanjel	3,641,270
Schlumberger	443,689
Superior	833,431
Trican	92,537
Weatherford	2,105,062
Total	**32,202,075**

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

State	Volume (gallons)	State	Volume (gallons)
AK	39,375	MS	221,044
AL	2,464	MT	662,946
AR	414,492	ND	3,138,950
CA	26,466	NM	605,480
CO	1,331,543	OK	3,337,325
FL	377	PA	589
KS	50,304	TX	16,031,927
KY	212	UT	404,572
LA	2,971,255	WY	2,954,747
MI	8,007	**Total**	**32,202,075**

Environmental Contaminants Program Report Number: R6/726C/13

U.S. FISH & WILDLIFE SERVICE

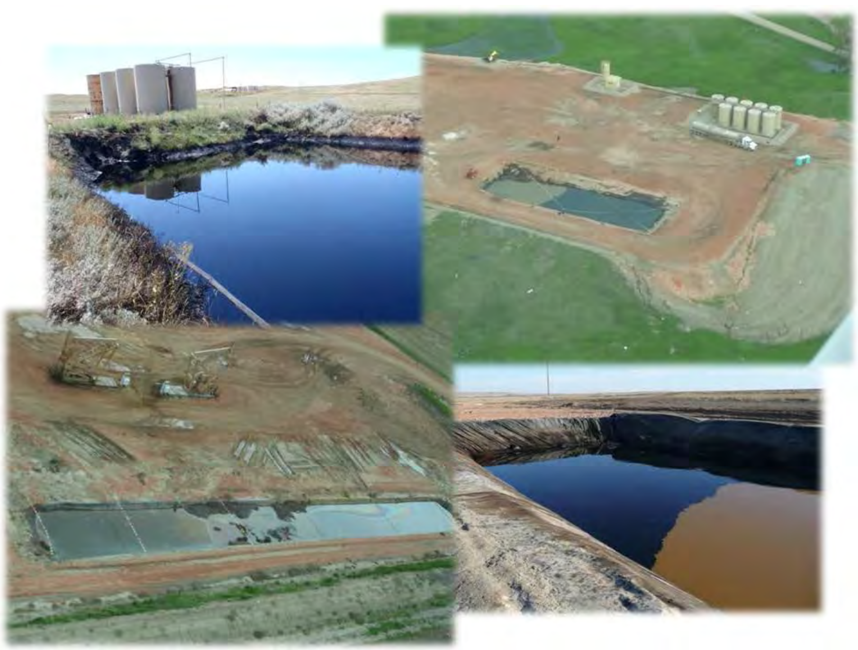
REGION 6

ENVIRONMENTAL CONTAMINANTS PROGRAM

Migratory Bird Mortality in Oil and Gas Facilities in Colorado, Kansas, Montana, Nebraska, North Dakota, South Dakota, Utah, and Wyoming

Report by
Pedro 'Pete' Ramirez, Jr.
Environmental Contaminants Specialist
U.S. Fish & Wildlife Service
Cheyenne, Wyoming

February 25, 2013



ABSTRACT

U.S. Fish and Wildlife Service (Service) law enforcement special agents and environmental contaminants specialists conducted inspections of oil and gas production facilities and commercial oilfield wastewater disposal facilities from 2007 through 2010 within Colorado, Kansas, Nebraska, Montana, North Dakota, South Dakota, Utah, and Wyoming to document risks and hazards to migratory birds. Service personnel recovered 1,405 bird carcasses from 205 oil and gas facilities during the three-year investigation (*i.e.* on average, 2.3 bird carcasses per facility per year). Approximately half of the bird carcasses (719) were recovered from dehydrator tanks at natural gas production facilities in Wyoming. We attributed the large number of carcass recovery from dehydrator tanks to the ease of detection and recovery of carcasses from these tanks compared to the larger reserve pits and production skim pits similarly inspected. Dehydrator tanks typically ranged from 4 to 6 feet in diameter and 3 to 5 feet in height. Investigators recovered 24 percent (333) of the bird carcasses from reserve pits between 2007 and 2010. An increase in drilling activity in Colorado, North Dakota, Utah, and Wyoming and associated increase in the number of reserve pits may account for the large amount of bird mortality in reserve pits. Reserve pits are not typically covered with netting to exclude birds and other wildlife. Ground-feeding songbirds and aquatic birds were the most common bird carcasses recovered from reserve pits, 76 percent and 69 percent, respectively. Ground-feeding songbirds and aquatic birds were the most frequent victims in oil and gas facilities, excluding dehydration tanks, comprising 48 and 47 percent, respectively, of all bird carcasses recovered from oil and gas facilities. Investigators also documented bird mortality in flare pits, emergency spill catchment pits, and open-topped tanks or small containers containing exposed oil or hydrocarbons. Ongoing wildlife mortality incidents necessitate implementation of best management practices by oil operators to prevent bird mortality and the continued inspections of these facilities by state and federal regulatory agencies to ensure compliance with applicable environmental and wildlife protection laws. Multiple inspections should be conducted throughout the year, especially between the spring and fall, to document most bird mortality in oil and gas facilities. Inspections should not be limited to production skim pits, reserve pits, and open-topped tanks but should include all hazards such as leaking valves, pipes, and wellheads. Detailed field notes by oil and gas facility inspectors should include the specific location and probable cause of the mortality incident (i.e. reserve pit, production skim pit, dehydration tank, open-topped tank, etc.). This data will serve to identify hazards encountered by migratory birds at oil and gas facilities and provide specific solutions and best management practices (BMPs) to minimize those hazards.

Acknowledgements: *Field inspections of oil and gas facilities were conducted by Ron Armstrong, John Brooks, Roy Brown, Dan Coil, Mike Damico, Dom Dominici, Tim Eicher, Kevin Ellis, Roger Gephart, Rich Grosz, Jim Hampton, Kenny Kessler, Pedro Ramirez, Brian Richards, and Mark Webb of the U.S. Fish and Wildlife Service and Randy Lamdin, U.S. Environmental Protection Agency. Manuscript reviewers included: Chris Cline, Craig Giggleman, Joel Lusk, Roy Brown and Richard Grosz of the U.S. Fish and Wildlife Service. This study was funded by the Service's Environmental Contaminants Program (Project # 6F53).*

Table of Contents

List of Figures

List of Tables

INTRODUCTION

Exposure to oil and other pollution hazards at oil and gas production facilities and oilfield wastewater disposal facilities poses a significant risk to migratory birds and other wildlife (Flickinger 1981, Grover 1983, Lee 1990, Esmoil and Anderson 1995, Ramirez 2005, 2009 and 2010, and Trail 2006). For example, waterfowl can mistake earthen pits in oil and gas facilities for natural bodies of water (Flickinger 1981, Esmoil and Anderson 1995). Exposure to oil either spilled on the ground or contained in pits, open-topped tanks or in smaller, open containers also attracts and entraps insects, which may, in turn attract and entrap birds (Grover 1983). Horvath and Zeil (1996) reported the entrapment of large numbers of insects in oil pools and suggested that the insects may be "attracted by the strong polarization of light reflected from these pools" of oil. Passerine songbirds attempting to feed on the insects stuck in the oil become coated with oil and are unable to fly depending on the severity of the oiling on their feathers. What ensues is escalating rates of wildlife mortality with the oiled, entrapped songbirds attracting other songbirds with their alarm calls or attracting raptors or other predators seeking prey, which, in turn can be subsequently contaminated with oiled. These oiled birds can also be scavenged by raccoons, coyotes or other wildlife that may also become oiled or ingest the oil with their prey. Oil ingested by avian and mammalian wildlife can cause impaired reproduction or make an animal more vulnerable to disease, starvation, and predation by causing a variety of systemic effects such as anemia, immune suppression, and red blood cell damage, (Albers 2003). In 1997, the U.S. Fish and Wildlife Service (Service) estimated that 2 million migratory birds were lost each year to oil pits throughout the United States. Since that time, many oil operators have implemented measures to prevent migratory bird and other wildlife mortality in oilfield waste pits. Almost 10 years later, Trail (2006) updated the mortality rates associated with oilfield production skim pits and commercial and centralized oilfield wastewater disposal facilities (COWDFs) and estimated that 500,000 to 1 million birds are lost annually.

Early documentation of bird mortality in an oil pit was reported by Borell (1936) who found 131 birds (6 raptors and 125 songbirds) entrapped in five pits containing tar and oil used in association with road construction. King (1956) reported bird mortalities found in oilfield production skim pits in Wyoming. Subsequently several oil operators expressed a commitment to "keep all open pits free of oil, burning and covering oil spills" and draining pits or installing bird deterrents such as "tin flashers and spirolenum whirlers" (King 1956). Similar observations were made eight years later in the oilfields of the San Joaquin Valley of California (Bloch 1964) and 13 years later in the plains of northeastern Colorado (Tully and Boulter 1970). Following the Tully and Boulter report of wildlife mortalities in oil pits, the Colorado Oil and Gas Conservation Commission advised oil operators to "prevent additional wildlife losses, prevent future pollution problems and to clean up their field maintenance problems" (Tully 1973). During the 1990's, forty years after the King (1956) report, Service law enforcement agents continued to identify high rates of bird mortality in oilfield sumps and pits (EPA 2003). In 1996, the Service, working with the U.S. Environmental Protection Agency (EPA) Region 8, inspected production skim pits in oil and gas facilities in Colorado, North Dakota, Montana, South Dakota, Utah, and Wyoming. Aerial surveys were also conducted from 1997 through 1999 on approximately 5,600 pits in the six state area (EPA 2003) of which 516 sites were identified as warranting follow up ground inspections. Field inspections of these pits resulted in 428 enforcement actions. The combined efforts of Service and EPA personnel resulted in the documentation of 411 pits with some oil on the surface (80 percent of sites), 181 pits with 100 percent oil coverage (35 percent of sites), and bird mortalities documented at 40 sites (8 percent of sites).

Wildlife mortality in oil and gas facilities is not limited to production skim pits. Mortality also occurs when wildlife is exposed to oil and gas waste fluids in reserve pits, flare pits, emergency spill catchment pits, open-topped dehydrator tanks, and open-topped tanks or small containers (Figure 1). Reserve pits are earthen pits excavated adjacent to drilling rigs used for the disposal of drilling muds and well cuttings. Reserve pits range in size from 85 feet (ft) by 140 ft (26 by 43 meters) to 120 by 200 ft (37 by 61 meters) (Ramirez 2009). Flare pits are excavated below vertical pipes, also known as flare stacks, used to flare or burn off gas that is not feasible to use or transport. The flare pits are designed to contain oil and other liquid hydrocarbons that are released from the flare stack. Emergency spill catchment pits are designed to catch any accidental releases or spills of oil or other hydrocarbons.

Oil production sites typically consist of a well, the well head, and pump jack as well as a heater treater used to separate produced water from crude oil using heat. Produced water is water present in the oil and gas-bearing formations that is produced along with the oil and gas. Heater treaters used to remove produced water from oil can be either horizontal or vertical with a firebox at the bottom (Raymond and Leffler 2006). Demulsified crude oil or natural gas is typically used to fuel the firebox. Exhaust gases from the firebox are vented to the atmosphere through a vertical pipe also referred to as a "vent stack."

Brine, produced water, and crude oil are typically temporarily stored in tanks. Storage tanks containing oil or other hydrocarbons are usually closed; however, tanks containing brine or produced water can be open-topped. The contents in storage tanks are loaded onto vacuum trucks (tanker trucks) and transported off-site. Brine and produced water are taken to COWDFs or underground injection control (UIC) facilities for disposal. COWDFs typically use one or more evaporation ponds (>1 acre in size) for wastewater disposal. COWDFs also may contain one or more skim pits to separate oil from the wastewater. UIC facilities dispose of wastewater through deep well injection.

Conventional natural gas well production sites contain the well, wellhead that has a series of valves termed a "Christmas tree." Natural gas from the well and wellhead is directed to a pipeline if the gas is dry. If the gas contains fluids, including water, natural gasoline, and or condensate (a light crude oil), it is piped to a treater or dehydration unit for the removal of water, condensate, and other fluids from the gas prior to collection and transport. Dehydration units may also be used to remove water from the natural gas stream and the waste water will either evaporate or collected in small open-topped tanks (dehydrator tanks). Hydrocarbon liquids are removed from the natural gas and stored in close-topped tanks on site for transportation via tanker trucks to an oil refinery for further processing. Formation water produced with the natural gas is also stored in tanks at the well pad and transported via tanker trucks to COWDFs or UIC facilities for disposal. Organic chemicals such as glycols and amines are typically used in the dehydrators to remove water from the natural gas stream.

Many of the COWDFs have been in operation for 20 years; consequently, years of evaporative concentration of the produced water has concentrated salts in the ponds at these facilities. Sodium concentrations in some of these evaporation ponds exceed the thresholds for sodium toxicity in waterfowl (Ramirez 2010).

Figure 1. Hazards to birds in oil and gas production facilities.

Sodium toxicity is suspected as a cause of eared grebe (*Podiceps nigricollis*) and waterfowl mortality in these facilities (Ramirez 2010). Accelerated natural gas development may result in the construction of additional COWDFs in the region with a concomitant increase in exposure to migratory bird populations. For example, three COWDFs have been permitted and constructed in Wyoming to dispose of produced water from the Jonah, Pinedale Anticline and Wamsutter natural gas fields within the last 3 years. Operators of oil and gas production facilities have made progress in implementing proactive measures such as netting to prevent migratory bird and other wildlife mortality in production skim pits as well as in COWDFs. However, the degree of bird mortality at production skim pits had not been updated to evaluate the current use of protective measures and bird mortality rates at oil and gas production facilities to that found from 1997 to 1999 and reported by EPA (2003). Therefore, we initiated this study to update this information.

Given the accelerated development of oil and gas in the Service's Mountain-Prairie Region, Service law enforcement agents and environmental contaminants specialists conducted inspections of oil and gas production facilities from 2007 to 2010 to document the number of oil/gas production skim pits, reserve pits, and commercial oilfield wastewater disposal facilities in non-compliance as well as those within compliance within the mountain/prairie region; to compare non-compliance data with environmental compliance data from 1997 to 1999 as reported by EPA (2003); and to develop an estimate for regional impacts on various categories of migratory birds.

METHODS

Aerial surveys of oil and gas production facilities in Colorado, Kansas, Nebraska, Montana, North Dakota, South Dakota, Utah, and Wyoming were conducted from 2007 through 2010 to identify reserve pits, and production skim pits with significant amounts of oil or other hydrocarbons that could pose a risk to migratory birds. Service law enforcement agents and environmental contaminants specialists made follow up ground inspections of sites that had been identified in the aerial surveys as posing potential risks to migratory birds. The number of oil and gas facilities inspected by Service law enforcement agents varied by state and by year with a minimum of 384 sites and a maximum of 505 sites inspected in the eight state area during the study period. Follow up inspections were typically made during the spring, summer, and early fall. Weather conditions precluded the need for surveys during the winter when most pits were frozen. Sites were generally visited only once unless circumstances dictated the necessity of follow up inspections. Data collected included physical locations of oil and gas pits mapped using Global Positioning Satellite (GPS) technology; compliance status of the oil pits; the number and type of migratory bird carcasses found in pits or elsewhere in the oil and gas facilities (e.g. flare pits, heater treaters, natural gas dehydration unit tanks, spill containment devices); and any other pertinent information such as other impacted wildlife, obvious breeches, spills, condition of the site, operator, lease number, well name or number, and legal location. During the follow up inspections, Service law enforcement agents typically walked the perimeter of reserve and production skim pits. Bird carcasses observed on the surface or edges of pits or ponds were collected by hand and placed in plastic bags. Bird carcasses on the surface of pits that could not be reached by hand were retrieved using an aluminum extension pole fitted with a hook, trowel or large spoon at one end. Disposable nitrile or latex gloves were used in handling the bird carcasses. All bird carcasses collected were labeled with evidence tags and later stored in freezers. Where necessary for enforcement actions, carcasses were submitted to the National Fish and Wildlife Service Forensic Laboratory in Ashland, Oregon, for identification purposes following evidence chain-of-custody procedures. Identification of bird carcasses to species was generally not done in bird mortality cases in which the oil operators did not contest the citations issued under the Migratory Bird Treaty Act by Service law enforcement agents (Roy Brown, US Fish and Wildlife Service, personal communications, Jan 16, 2013). In Wyoming, one oil company discovered and voluntarily reported bird mortality incidents in dehydrator tanks to the Service in 2009. Personnel from the oil company subsequently inspected 4,255 of their natural gas production sites with dehydrator tanks and forwarded bird carcasses recovered from the tanks to a Service law enforcement agent.

Wastewater samples were collected from some COWDFs in Wyoming by Service environmental contaminants specialists as part of ongoing annual multiple inspections of COWDFs in Wyoming with EPA and the Wyoming Department of Environmental Quality (WDEQ) (Ramirez 2010). The wastewater samples were collected in 1-liter chemically-clean polyethylene bottles with teflon-lined lids. The pH in the water samples collected for trace element analyses was lowered to approximately 2.0 with laboratory grade nitric acid. Water samples for the other analytes were kept chilled in an ice-filled cooler and then transferred to a refrigerator. Samples were submitted to designated laboratories under contract with the Service's Analytical Control Facility (ACF) at Shepherdstown, West Virginia, for analysis of trace elements, total alkalinity, total dissolved solids, sulfates, chlorides, bicarbonates, calcium, total cations and total anions. Trace element analysis included scans for arsenic, mercury, and selenium using atomic absorption spectroscopy. Inductively Coupled Plasma Emission Spectroscopy was used to scan for a variety of elements including boron, barium, chromium, copper, lead, selenium, vanadium, and zinc. The ACF provided quality assurance and quality control.

RESULTS

During this three-year inspection period, 1,755 bird carcasses were recovered from 205 oil and gas facilities in Colorado, Kansas, Nebraska, Montana, North Dakota, South Dakota, Utah, and Wyoming (Table 1). In addition to documenting bird mortality in production skim pits and reserve pits, Service law enforcement agents and environmental contaminants specialists documented migratory bird mortality in heater treaters, in dehydrator tanks, and in trays or tanks placed underneath well chemical tanks to contain spills (SPCC trays).

In 2009, the discovery of bird carcasses in dehydrator tanks in southwestern Wyoming resulted in inspections by oil company personnel of an additional 4,255 sites, 123 of which were subsequently closed by the operator. A total of 517 bird carcasses were retrieved from dehydrator tanks in Wyoming in 2009. Most, if not all, the bird carcasses found in dehydrator tanks were songbirds (Order Passeriformes). Subsequently, oil operators retrofitted the openings of dehydrator tanks with netting or wire mesh to exclude birds. Half of the bird carcasses (719) recovered during this investigation were found in dehydrator tanks in Wyoming between 2009 and 2010 (Figure 2).

Reserve pits accounted for 24 percent (333) of the bird carcasses recovered between 2007 and 2010. From 3 to 5 percent of the bird carcasses were recovered from production skim pits, COWDFs, and trays or tanks placed underneath well chemical tanks to contain spills (SPCC trays) (Figure 2). Detailed information on the site or cause of bird mortality was not specified by Service law enforcement agents in 11 percent of the oil and gas facilities with documented bird mortality.

Table 1. Numbers of sites with bird mortality and bird carcasses recovered.

State		Year				
		2007	2008	2009	2010	Total
CO	# Sites	10	1	ND*	ND	11
	# Birds	(16)	(1)			(17)
KS	# Sites	1	ND	ND	4	5
	# Birds	(2)			(5)	(7)
MT	# Sites	16	ND	1	ND	17
	# Birds	(59)		(2)		(61)
ND	# Sites	14	14	7	5	40
	# Birds	(25)	(22)	(8)	(6)	(61)
NE	# Sites	3	1	ND	ND	4
	# Birds	(4)	(1)			(5)
UT	# Sites	ND	ND	4	ND	4
	# Birds			(47)		(47)
WY	# Sites	10	11	108	8	137
	# Birds	(43)	(135)	(1014)	(52)	(1244)
Total	# Sites	47	25	116	17	205
	# Birds	(149)	(159)	(1071)	(63)	(1442)

*ND = No Data reported

Service law enforcement agents documented bird mortality in SPCC trays primarily in North Dakota and Wyoming: in 2007 (1 vesper sparrow (*Pooecetes gramineus*)), 2009 (6 birds in one SPCC tray), and 2010 (31 birds in several SPCC trays). Bird mortality in SPCC trays was not common as typically the spill containment trays or tanks are empty and do not contain oil or chemicals. Between 2007 and 2008, Service law enforcement agents inspected heater treaters in 60 sites in Kansas and recovered 6 bird carcasses from three heater/treaters.

Of the 1,755 bird carcasses recovered between 2007 and 2010, approximately 74 percent (1,043) were not taxonomically identified to order, family, or species. Most of the unidentified bird carcasses were recovered from dehydrator tanks (51% of total carcasses recovered). Songbirds (Order Passeriformes) were the primary bird mortality victims in dehydrator tanks. Assuming that all of the bird carcasses retrieved from dehydrator tanks were passerine songbirds, passerine birds (Order Passeriformes) comprised 87 percent of all bird carcasses recovered. Waterfowl (Order Anseriformes) made up 12 percent of all bird carcasses recovered (Figure 3). Waterfowl (Order Anseriformes) and passerine songbirds (Order Passeriformes) made up the majority of bird carcasses, 46 and 49 percent, respectively, recovered from pits (reserve, production skim, and flare pits), open-topped tanks, SPCC trays, and spilled oil in oil and gas facilities.

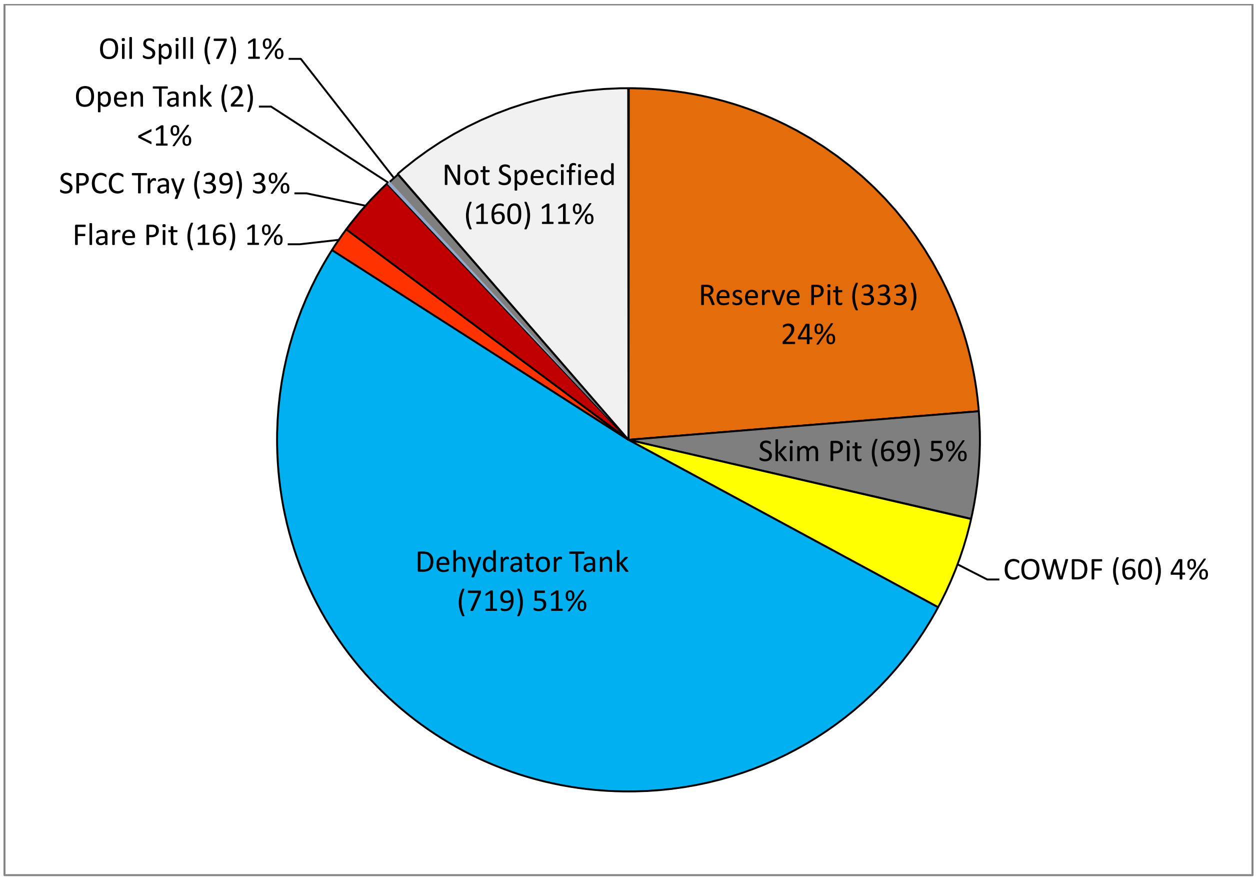


Figure 2. Number of bird carcasses recovered from oil and gas facilities, 2007 to 2010 (number of bird carcasses shown in parenthesis).

Bird carcasses recovered from oil and gas facilities were grouped into the following ecological categories as defined by Trail (2006):

Waterbirds = Podicipediformes + Anseriformes
Wading Birds = Charadriiformes + Gruiformes
Birds of Prey = Falconiformes + Strigiformes
Ground Feeders = Columbiformes + Corvidae + Mimidae + Emberizidae + Icteridae (except *Icterus*) + Fringillidae
Aerial Feeders = Tyrannidae + Hirundinidae

Ground feeders and waterbirds accounted for 48 and 47 percent of all bird carcasses recovered from oil and gas facilities, excluding dehydration tanks (Figure 5). Reserve pits accounted for 76 percent of the mortality of ground feeders and 69 percent of waterbirds (Figures 6 and 7). Water quality results are shown in Tables 3 and 4. Water samples from four COWDFs had high total dissolved solids (TDS) and are classified as hypersaline, salinity higher than (>35,000

TDS). Although salinity classifications for water salinity vary in the literature, most geoscientific literature uses the following terminology: freshwater <3,000 ppm TDS); saline 3 – 35,000 ppm; and hypersaline > 35,000 ppm (Last and Ginn 2005). High concentrations of boron, barium, selenium, and strontium were found in water samples collected from several COWDFs in Wyoming.

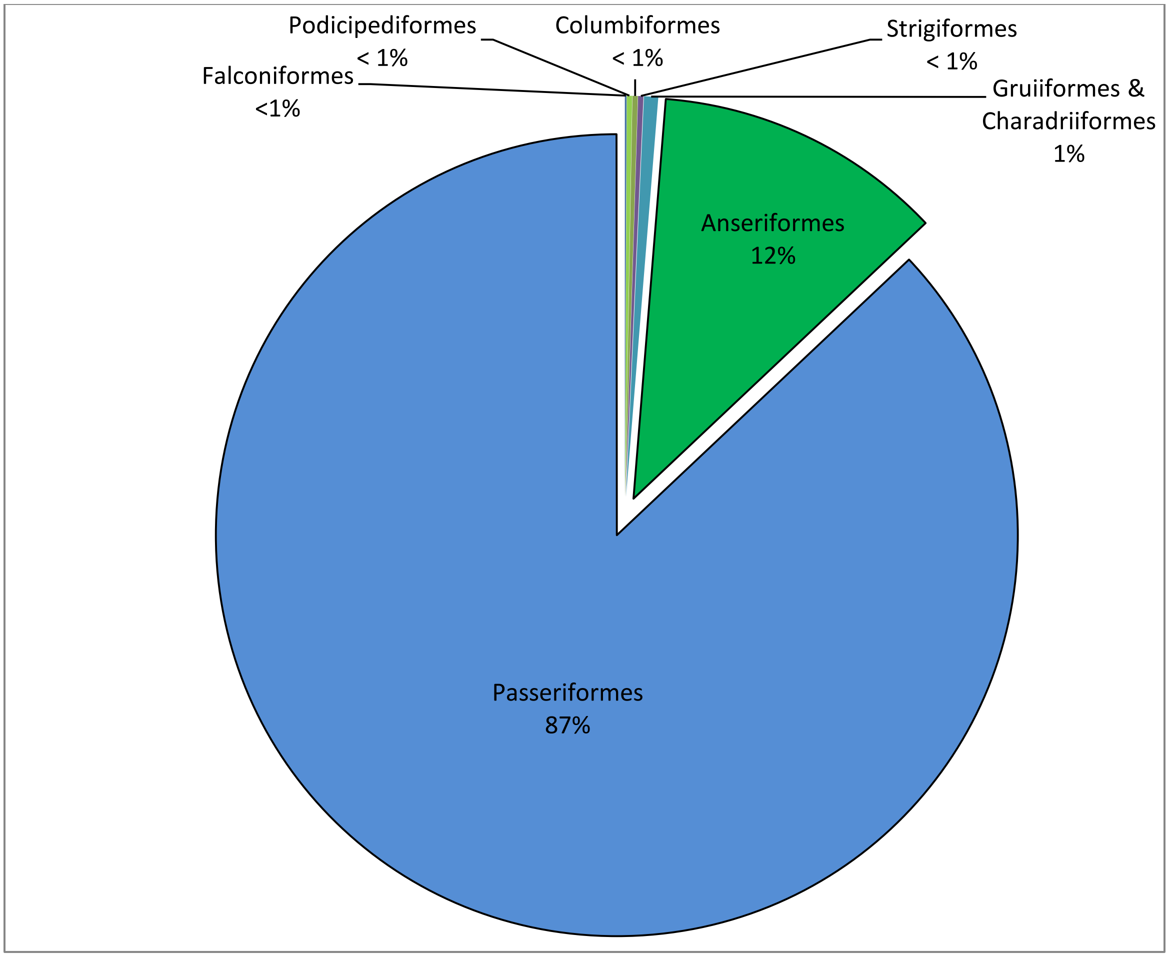


Figure 3. Bird carcasses recovered from oil and gas facilities, including dehydration tanks, summarized by avian order.

Table 2. Bird carcasses recovered from oil and gas sites in Colorado, Kansas, Montana, North Dakota, Nebraska, South Dakota, Utah, and Wyoming between 2007 and 2010.

Order Family Species	**Reserve Pit**	**Skim Pit**	**COWDF**	**Dehy Tank**	**Flare Pit**	**SPCC Tray**	**Open Tank**	**Oil Spill**	**Not Specified**	**Totals**
Waterbirds										
Podicipediformes / Podicipedidae										
Unidentified grebe	1		2							3
Anseriformes / Anatidae										
Blue-winged teal (*Anas discors*)	6		3							9
Green-winged teal (*Anas crecca*)	1								1	2
Unspecified teal (*A. discors* or *A. crecca*)	11	1								12
Gadwall (*Anas strepera*)	4									4
Common goldeneye (*Bucephala clangula*)	1									1
Mallard (*Anas platyrhynchos*)	5	1							4	10
Northern shoveler (*Anas clypeata*)	7									7
Hooded merganser (*Lophodytes cucullatus*)	1									1
Ruddy duck (*Oxyura jamaicensis*)			1							1
Unidentified duck (Anatidae)	79	3	35							117
Wading Birds										
Gruiformes / Rallidae										
American coot (*Fulica americana*)			2							2
Charadriiformes										
Charadriidae										
Killdeer (*Charadrius vociferus*)	1									1
Scolopacidae										
Red-necked phalarope (*Phalaropus lobatus*)	1									1
Common snipe (*Gallinago gallinago*)	1									1
Unspecified shorebird (*Scolopacidae*)	2									2
Laridae										
Unspecified gull (*Larus* species)	1									1
Falconiformes / Falconidae										
American kestrel (*Falco sparverius*)					1					1
Strigiformes / Strigidae										
Great-horned owl (*Bubo virginianus*)	1	1								2
Unspecified owl (Strigidae)	1									1

Order Family Species	**Reserve Pit**	**Skim Pit**	**COWDF**	**Dehy Tank**	**Flare Pit**	**SPCC Tray**	**Open Tank**	**Oil Spill**	**Not Specified**	**Totals**
Ground Feeders										
Columbiformes / Columbidae										
Mourning dove (*Zenaida macroura*)	1								2	3
Passeriformes										
Corvidae										
Raven (*Corvus corax*)	1									1
Mimidae										
Gray catbird (*Dumetella carolinensis*)					1					1
Emberizidae										
Vesper sparrow (*Pooecetes gramineus*)	1				1	1				3
Lark sparrow (*Chondestes grammacus*)	1								1	2
Lark bunting (*Calamospiza melanocorys*)		1								1
Song sparrow (*Melospiza melodia*)	1									1
Unspecified sparrow (Emberizidae)		1							1	2
Icteridae										
Red-winged blackbird (*Agelaius phoeniceus*)								1		1
Unspecified meadowlark (*Sturnella* species)									2	2
Unspecified blackbird (*Agelaius* species)					2					2
Brewer's blackbird (*Euphagus cyanocephalus*)					2					2
Common grackle (*Quiscalus quiscula*)					2					2
Brown-headed cowbird (*Molothrus ater*)					1					1
Fringillidae										
Gray-crowned rosy finch (*Leucosticte arctoa*)	116									116
Unspecified passerine (Passeriformes)	11	19			2				2	34
Aerial Feeders										
Tyrannidae										
Eastern kingbird (*Tyrannus tyrannus*)					1					1
Western kingbird (*Tyrannus verticalis*)	1									1
Unspecified kingbird (*Tyrannus species*)								2	1	3
Unspecified flycatcher (Tyrannidae)					1					1
Hirundinidae										
Barn swallow (*Hirundo rustica*)								1		1
Unidentified birds	76	42	15	719	2	38	2	3	146	1,043
Totals	333	69	58	719	16	39	2	7	160	1,403

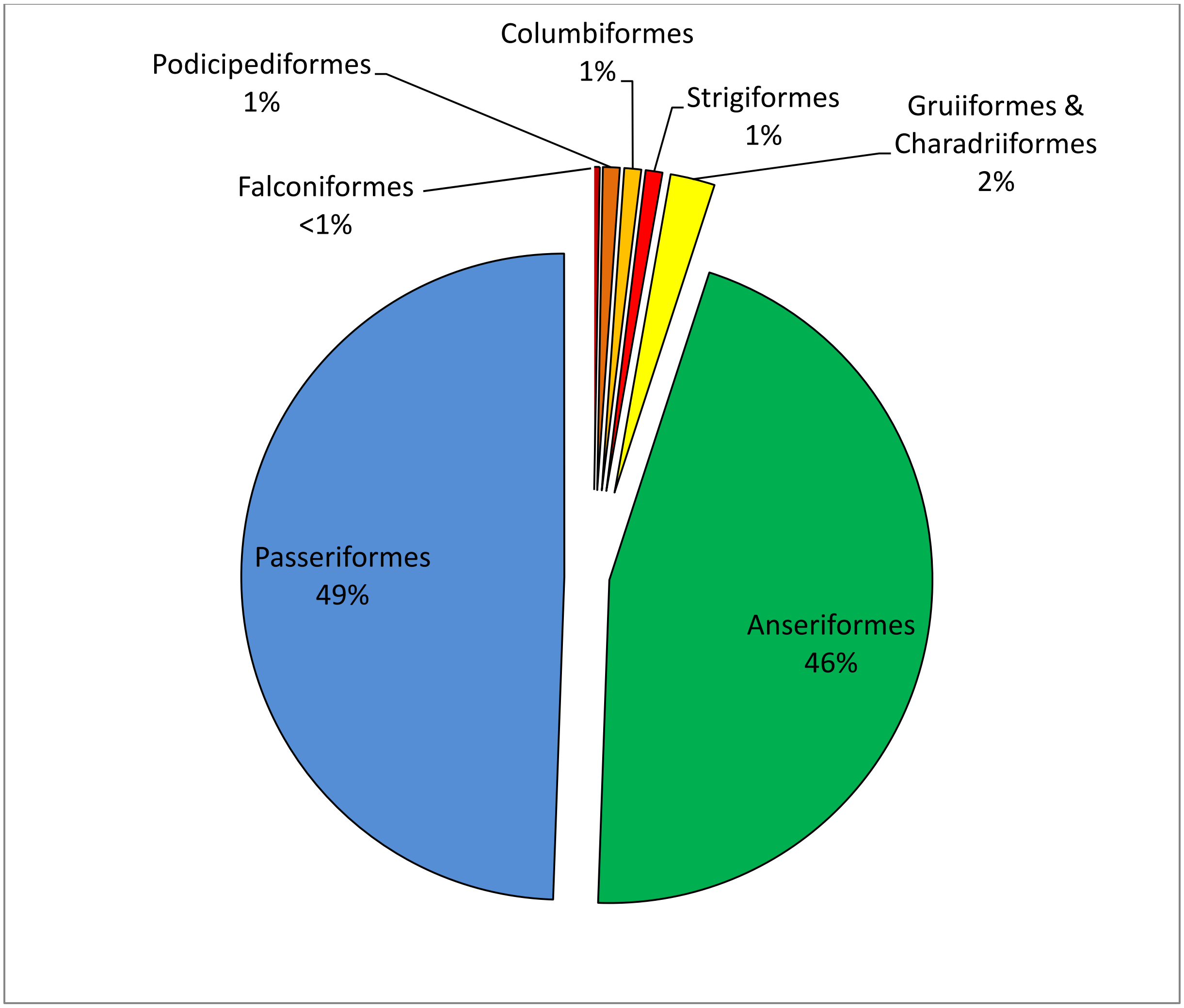


Figure 4. Bird carcasses recovered from oil and gas facilities, excluding dehydration tanks, summarized by avian order.

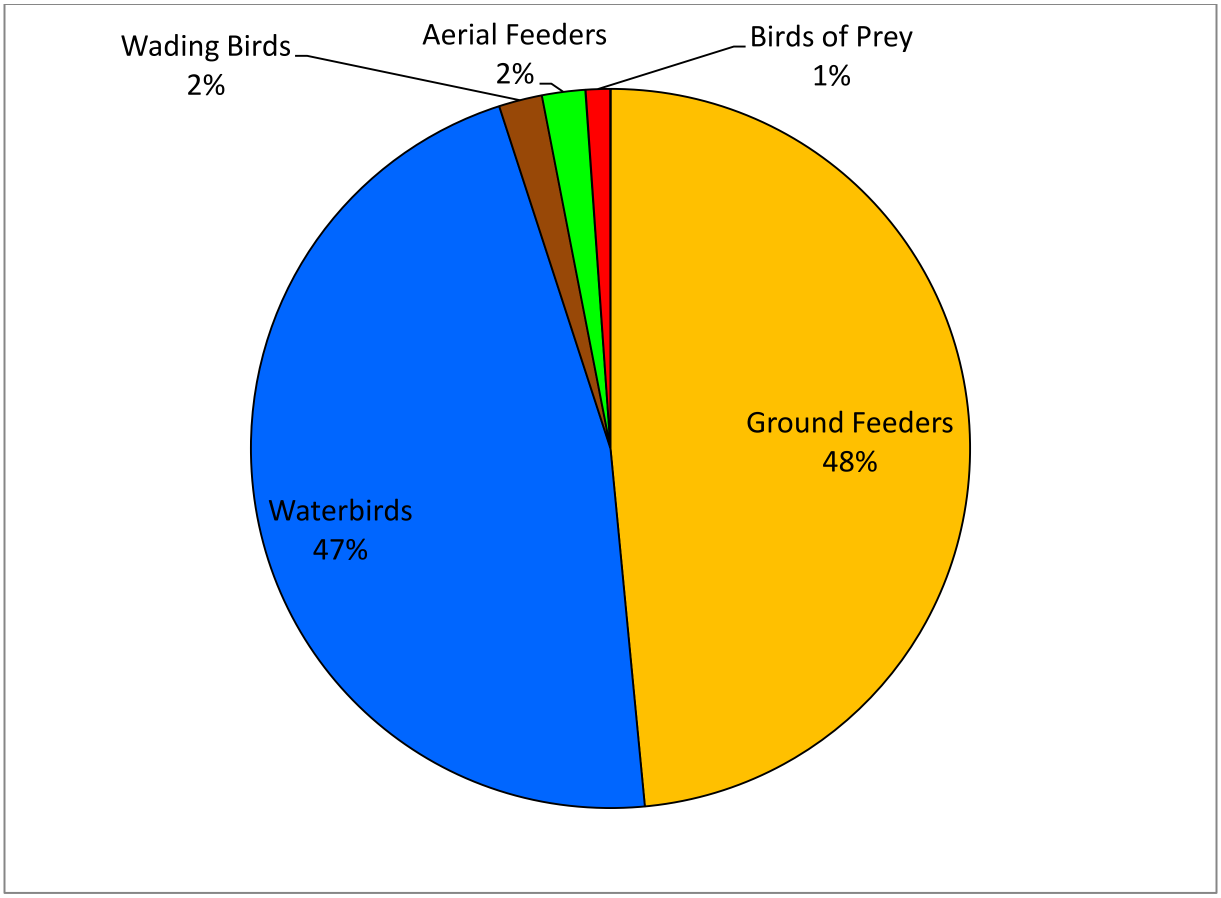


Figure 5. Bird mortality in oil and gas facilities by ecological category, excluding dehydration tanks.

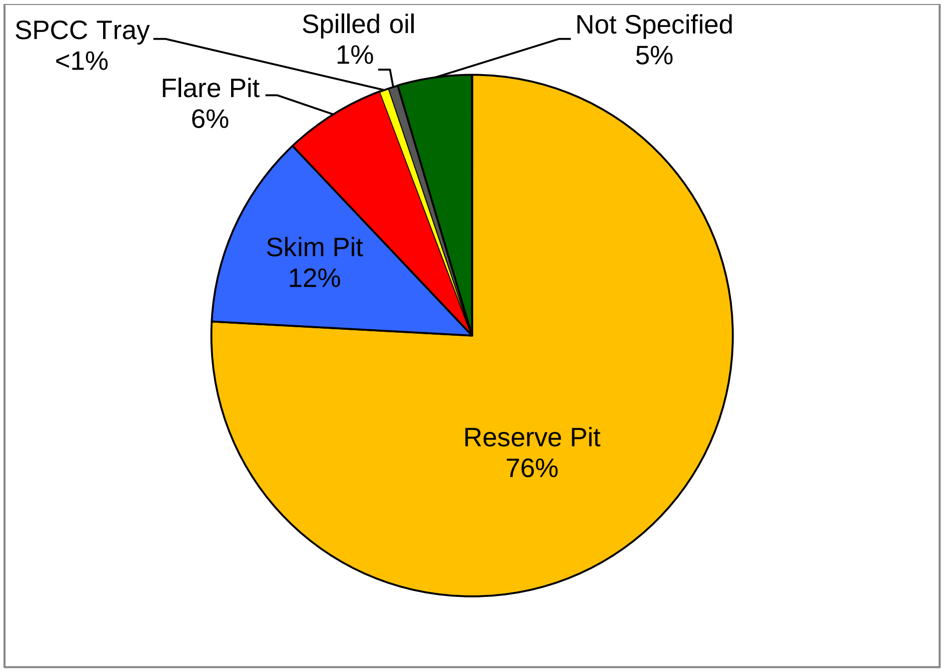


Figure 6. Mortality of Ground Feeding birds by oil and gas site type, excluding dehydration tanks.

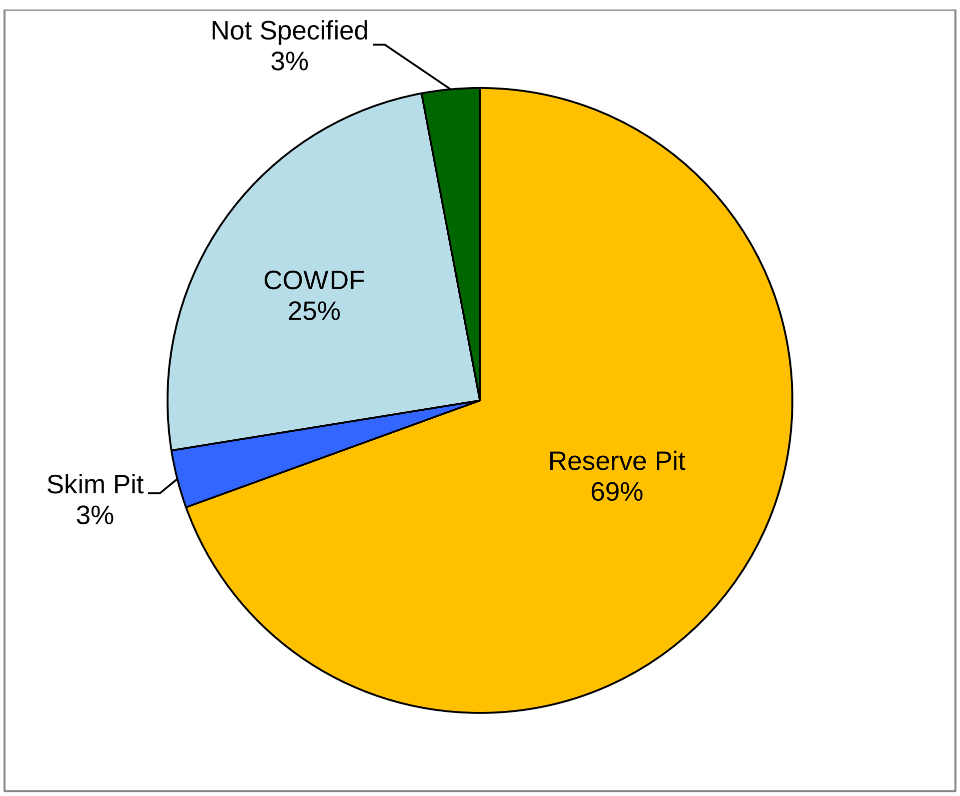


Figure 7. Mortality of Waterbirds by oil and gas site type.

Table 3. Trace element concentrations (in ug/L) in wastewater from oilfield wastewater disposal facilities in Wyoming.

COWDF #	CAM 1	CON 1	CON 2	CON 2	JOH 1	SWE 1	SWE 1	SWE 2	SWE 3	WAS 1	UIN 1
Sample ID	JWSMB1	JWS CANNON01	JWSW1	JWS WERNER01	HPR01	SWH COWDF1	SWH COWDF01	BPW COWDF01	RGSC COWDF01	ODS COWDF01	DB COWDF1
Date Collected	13-Apr-09	26-May-11	14-Apr-09	26-May-11	13-May-09	8-Jun-09	6-May-11	6-May-11	5-May-11	16-May-11	8-Jun-09
Al	< 2,500	<1000	< 2,500	<1000	< 2,500	< 2,500	<1000	<1000	<1000	<1000	< 2,500
As	168	36.9	0.168	107	< 0.0250	0.0404	75.4	95.4	80.9	162	0.0301
B	50,600	25,500	50.6	35,400	5.76	28.7	53,700	87,400	33,900	56,300	30.9
Ba	6,470	18,600	6.47	33,000	0.857	30.1	31,100	<10	<10	<10	< 25
Be	< 25	<10	< 25	<10	< 25	< 25	<10	29,100	674,000	133,000	
Cd	< 25	<5	< 25	<5	< 25	< 25	5.6	<5	<5	<5	< 25
Cr	<50	<20	<50	<20	<50	<50	29	22	43	67	<50
Cu	0.497	138	0.497	249	< 0.0500	0.143	232	486	185	89	0.067
Fe	< 2,500	9,920	< 2,500	15,400	8.56	3.58	2,210	<0.25	0.32	<0.25	<0.05
Hg	<0.05	<0.25	<0.05	<0.25	<0.05	<0.05	<0.25	362,000	1,380,000	1,490,000	575,000
Mg	179,000	45,600	179,000	292,000	17,900	67,400	176,000	71,100	67,000	111,000	23,300
Mn	63.9	420	63.9	1,370	736	2,370	56	15.4	28.3	31.6	0.0475
Mo	< 25	18,300	< 25	<10	< 25	< 25	<10	27,800,000	10,800,000	5,570,000	3,880,000
Ni	25.9	23.9	25.9	91.5	< 25	36.4	53.2	178	45.2	35.3	25.7
Pb	<50	<20	<50	<20	<50	<50	<20	<20	<20	<20	<50
Se	411	487	411	492	<250	<250	330	701	440	<100	<250
Sr	12,800	21,800	12,800	61,300	7,020	19,700	20,300	7,590	31,500	5,980	13,800
V	94	<100	94	<100	<50	<50	<100	<100	<100	<100	<50
Zn	<500	<200	<500	<200	<500	<500	<200	<200	201	<200	<500

Table 4. Ion concentrations (in mg/L) in wastewater from oilfield wastewater disposal facilities in Wyoming.

COWDF Site #	Sample Id	Date Collected	Calcium Ca	Chlorides Cl(-)	Sodium Na	Sulfates SO4(-2)	Total Dissolved Solids TDS
UIN 1	DBCOWDF2	8-Jun-09	267	6,800	3,580	86	12,000
JOH 1	HPR01	13-May-09	364	5,400	3,190	< 50.0	9,900
CON 1	JWSCANNON01	28-May-11	122	8,479	8,920	18	31,497
CAM 1	JWSMB2	13-Apr-09	54	43,000	26,900	210	73,000
CON 2	JWSW2	14-Apr-09	4,960	34,000	12,000	< 50.0	58,000
CON 2	JWSWERNER01	28-May-11	1,829	21,250	12,820	422	47,035
WAS 1	ODSCOWDF01	16-May-11	53	842	4,350	621	19,841
SWE 2	RGSCCOWDF01	5-May-11	276	2,506	10,800	102	36,842
SWE 3	SWHCOWDF2	8-Jun-09	397	17,000	10,600	< 50.0	35,000

DISCUSSION

Service law enforcement agents and Environmental Contaminants Specialists documented bird mortality in a variety of sites at oil and gas facilities: COWDF evaporation ponds and skim pits, reserve pits, production skim pits, flare pits, and open-topped tanks as well as in oil spilled in oil production facilities. These are the same type of sites where previous investigators have documented bird mortality (EPA 2003, Flickinger 1981, Grover 1983, Lee 1990, Esmoil and Anderson 1995, Ramirez 2005, Trail 2006, and Ramirez 2010). In addition to the above sites, bird mortality was also documented in dehydrator tanks and SPCC trays during this investigation. Bird mortality in dehydrator tanks was initially documented by Service law enforcement agents in Wyoming in 2009. Half of all bird carcasses (719) recovered in this multi-state investigation were recovered from dehydrator tanks in Wyoming. The large number of carcasses found in dehydrator tanks can probably be attributed to the ease of detection and recovery of carcasses from these tanks compared to the larger reserve pits and production skim pits. The dehydrator tanks typically range from 4 to 6 feet in diameter and 3 to 5 feet in height with a partially covered top (Figure 8).

Figure 8. Dehydrator tank with a partially-covered top.

The large number of bird carcasses (719) recovered from dehydrator tanks compared to pits and open-topped tanks is in large part due to the small size of the dehydrator tanks, and the containment of the carcasses. Birds entering and dying in the dehydrator tanks quickly succumb to oiling and are unable to climb or fly out. Scavengers are unable to access the carcasses and remove them from the dehydrator tanks. Birds entering the dehydrator tanks are probably attracted to these vessels by insects entrapped in the fluid. Horvath and Zeil (1996) suggest that insects are attracted to oil surfaces because light reflected off the oil "closely mimics the polarization and reflectivity characteristics of water." The scale of bird mortality in dehydrator tanks may be indicative of higher bird mortality that goes undetected in production skim pits, reserve pits, and COWDF evaporation ponds where the pit and pond surface areas are much larger and bird carcasses can go unobserved due to their removal by scavengers, or people. Birds that do manage to escape typically seek a place to hide, such as under vegetation, where they eventually die. Additionally, bird carcasses in pits or COWDF evaporation ponds can sink into the pit or pond fluids within a very short time frame (Flickinger and Bunck 1987).

Reserve pits accounted for 24 percent of the bird carcasses recovered at oil and gas facilities. Most of the bird mortality in reserve pits occurs after well completion when the drilling rig and associated equipment have been removed from the well pad. Colorado, Kansas, Nebraska, Montana, North Dakota, South Dakota, Utah, and Wyoming allow oil operators one year after well completion to close reserve pits (Ramirez 2009). If the reserve pit contains condensates, oil or other hydrocarbons or harmful well stimulation chemicals, the risk of mortality to birds landing in the pits is high. Reserve pits accounted for 24 percent (333) of the bird carcasses recovered between 2007 and 2010. An increase in drilling activity in Colorado, North Dakota, Utah, and Wyoming and the associated increase in the number of reserve pits may account for the large amount of bird mortality in reserve pits. Reserve pits are not typically covered with netting to exclude birds and other wildlife probably due to the expense and logistics of installing netting and having to remove it just prior to the closure of the pit up to a year after well completion. Reserve pits accounted for 76 percent of the mortality of ground-feeding songbirds and 69 percent of aquatic birds.

Ground-feeding songbirds and waterbirds accounted for 48 and 47 percent of all bird carcasses recovered from oil and gas facilities, excluding dehydration tanks. Ground-feeding birds are more susceptible to mortality in pits, SPCC trays, and spilled oil, especially if insects are entrapped in the oil. If ground-feeding birds walking along the edge of pits or entering the SPCC trays come into contact with oil, they may become entrapped in the fluids and die.

Of the states investigated between 2007 and 2010, bird mortality in reserve pits was observed in Colorado, North Dakota, Utah and Wyoming. Three of these states, (Colorado, North Dakota, and Wyoming had the highest amount of drilling activity (Figure 9) and, thus, were expected to have the most number of reserve pits. Colorado experienced the highest drilling activity in 2007 and 2008, while drilling was highest in North Dakota in 2010. Reserve pits comprised the biggest threat to birds at oil and gas facilities in North Dakota. In Utah, reserve pits comprised 77 percent of the sites with bird mortality in 2009. In Wyoming, reserve pits accounted for 13 to 52 percent of the sites with bird mortality during the study period. The North Dakota Oil and Gas Division amended the state oil and gas rules in April 2012 to prohibit the use of reserve pits for wells drilled below a depth of 5,000 ft (1,524 meters). North Dakota promulgated the rule change in response to spring flooding in 2011 which caused several reserve pits to overflow and discharge pit fluids onto adjacent lands and wetlands (McEnroe and Sapa 2011).

COWDFs and production skim pits accounted for four and five percent, respectively, of the bird carcasses recovered at oil and gas facilities. The low numbers may be due to proactive measures facility operators are taking to prevent bird mortality at COWDFs and production skim pits such as netting small pits and keeping large evaporation ponds free of oil. Past inspections of COWDFs in Wyoming conducted by the Service, EPA, and Wyoming Department of Environmental Quality between 1998 and 2008 documented oil in COWDF evaporation ponds in half of 154 inspections conducted over a 10-year period (Ramirez 2010). Between 1997 and 2001 the US EPA, Service and other state and federal regulatory agencies inspected a total of 36 COWDFs in Colorado, Utah, and Wyoming (EPA 2003). In Wyoming, the EPA (2003) documented problems, including oil in evaporation ponds in all (100%) of the COWDFs inspected in 1997 and 1998. The EPA (2003) also documented oil in COWDF evaporation ponds in Colorado. Most of the COWDFs initially inspected in

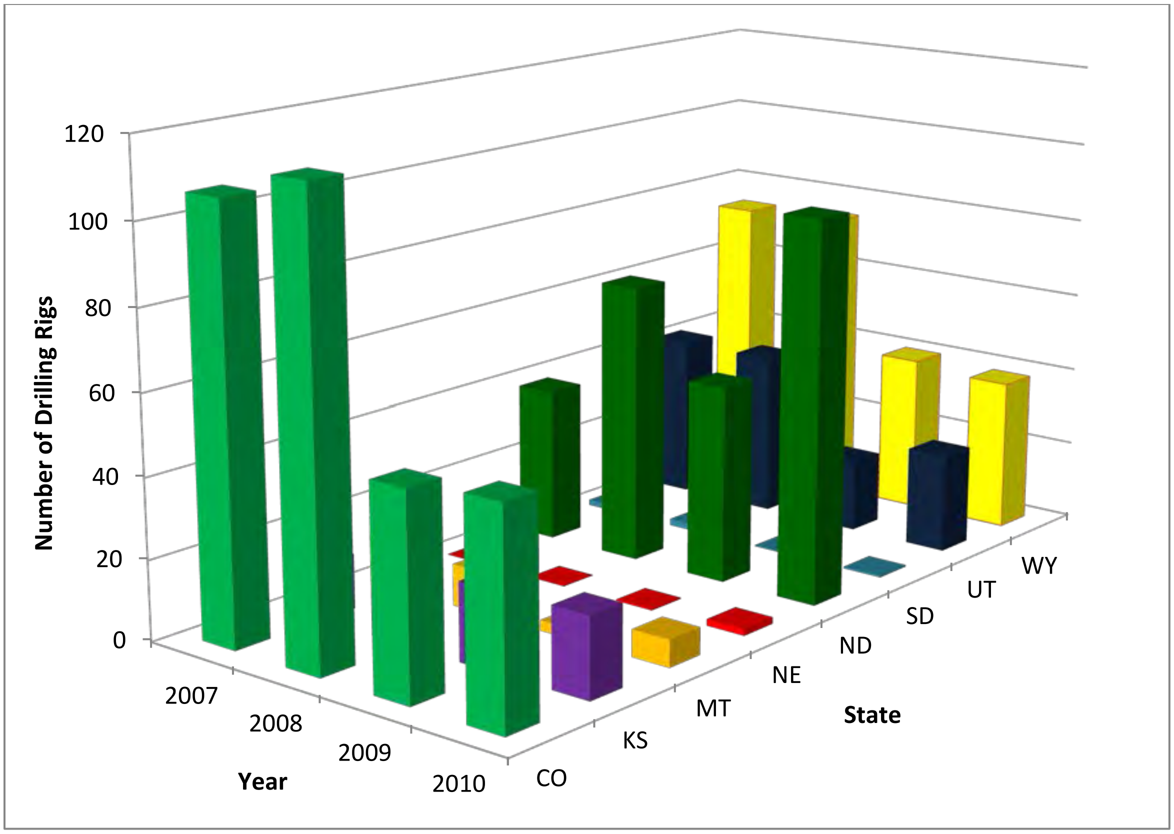


Figure 9. Number of drilling rigs in the study area, 2007- 2010 (Baker Hughes 2012).

Wyoming by the EPA and the Service in 1997 and 1998 were permitted and constructed between 1980 and 1982. Wyoming had a total of 22 COWDFs in 2001. The increase in natural gas drilling and production after 2005 led to a concurrent increase in the permitting and construction of additional COWDFs for the disposal of produced water from natural gas wells.

To accommodate the increase in wastewater disposal from the increase in natural gas drilling and production, the number of COWDFs in Wyoming increased from 22 facilities in 2001 to 26 in 2012. The majority of the new COWDFs were permitted and constructed in Carbon, Converse and Sweetwater Counties to provide disposal facilities for water produced from natural gas fields to the north and south of Wamsutter in Carbon and Sweetwater Counties and oilfields between Douglas and Bill, Wyoming. Oil operators in Wyoming generally have three options for disposal of produced water: surface discharge, deep injection well disposal or disposal in a COWDF. Surface discharge of produced water is an accepted option if the water meets State water quality standards. Formation water produced from conventional natural gas wells is typically 10 times more toxic than produced water from oil wells and cannot be discharged into surface waters (Jacobs et. al. 1992). Oil operators in Wyoming typically opt to dispose of poor quality produced water in COWDFs as deep well injection is more expensive.

Hypersaline conditions result in COWDF ponds from the continual concentration of dissolved solids (salts) due to evaporation. Two of the four COWDFs with hypersaline water have been operational for over 25 years and two for 10 to 15 years. Hypersaline conditions also decrease the evaporation rate of water (Hammer 1986). Over time, the remaining COWDFs are likely to become hypersaline. One of the risks to aquatic birds that land on hypersaline COWDF evaporation ponds is the crystallization of salts from the super-saturated water onto the birds' feathers. Salts crystallizing on feathers disrupt feather morphology and allow water to penetrate through the feathers and onto the skin; thus causing hypothermia and mortality (Sladky et. al. 2004). Bird mortality due to salt crystallization is known to occur in hypersaline industrial wastewater ponds (Meteyer et. al. 1997, Sladky et. al. 2004, Jehl et. al. 2012). Additionally, evaporation concentrates trace elements such as boron, selenium and strontium in the wastewater; however, we expect that there would be low risk of avian exposure to these elements through ingestion because we did not observe aquatic invertebrates or submerged aquatic vegetation at these sites during our inspections and perhaps because salinity concentrations observed at COWDF evaporation ponds are not favorable to aquatic life.

Production skim pits accounted for five percent of the bird carcasses recovered at oil and gas facilities, a decrease from nine percent in the late 1990's. EPA (2003) documented bird mortality in 9 percent of oil and gas sites inspected between 1997 and 1999 in Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming. Approximately 51 percent of the pits surveyed by the EPA (2003) in the 1990's had oil on the surface. In general, the threat of production skim pits to wildlife has been reduced in the past decade due to proactive efforts made by the oil industry, including closing production skim pits, removing oil from pits, and or enclosing production skim pits with netting to exclude wildlife. Bird mortality problems currently stem from poorly maintained netting (holes in the netting, and or nets sagging into the pit fluids), and upsets in the oil-water separation resulting in the discharge of oil into uncovered secondary or tertiary production skim pits.

Passerine songbirds (order Passeriformes) comprised most of the bird mortality (87 percent) followed by waterfowl (order Anseriformes) (12 percent). In comparison, Trail (2006) determined that passerine songbirds and waterfowl comprised 62 and 10 percent of all bird remains recovered from oil pits by the Service from 1992 to 2005. Trail (2006) attributed the low number of waterfowl to the reduction in the size of oil pits. Conversely, Grover (1983) reported a mortality pattern comprised of 37 percent songbirds and 33 percent ducks. Ground feeders and waterbirds comprised 48 and 47 percent, respectively, of the carcasses recovered in this study, dehydration tanks excluded. Trail (2006) found that ground feeders and water birds accounted for 63 and 12 percent, respectively, of avian mortality in oil pits. Reserve pits potentially present a greater hazard to waterbirds as these pits are typically not netted to exclude wildlife as are production skim pits. Additionally, reserve pits are generally two to four times larger than production skim pits (Ramirez 2005 and 2009) and may be more attractive to waterbirds than production skim pits. Esmoil and Anderson (1995) found increased mortality with increased pit size and Lokemoen (1973) reported pond size as a significant factor affecting duck use.

Past reports on bird mortality in oil pits showed large numbers of waterfowl mortality in large pits and produced water impoundments located in drainages (Bloch 1964, King 1956, Lee 1990). In the 1960's and 1970's oil operators disposed of produced water and waste oil into natural basins or by creating impoundments in natural drainages (Bloch 1964, Grover 1983, Lee 1990). Bloch (1964) reported 1,000 duck carcasses in a series of three oil pits created by constructing berms in a natural drainage. The three pits ranged in size from 200 by 300 ft (61 to 91 meters) up to 600 x 900 ft (183 to 274 meters). Lee (1990) described an "oil-covered alkali basin" in Texas that killed hundreds of ducks and grebes in 1976. The use of large earthen pits up to six acres (2.4 hectares) in size to store oil and oilfield waste was a common industry practice in the early 1900's (Barrett 2001). The discharge of produced water and waste oil into impoundments in natural drainages was probably a common practice in Wyoming during the early 1900's (Hancock 1921) (Figure 10). This practice has largely been eliminated (Lee 1990); however, in Wyoming, produced water meeting water quality standards and legally discharged into streams can be impounded to benefit livestock and wildlife. The produced water typically flows through a heater treater and production skim pits to remove the oil. Malfunction of the heater treater or the production skim pit can result in oil discharges into streams and downstream impoundments posing a risk to birds and other wildlife. Although the disposal of waste oil into natural basins or large impoundments is no longer an accepted industry practice, large evaporation ponds in COWDFs pose a risk to migrating birds especially if these ponds contain oil or eventually become hypersaline. The risk increases during times of drought when the availability of wetland habitat is limited.

The absence of observed bird mortality may lead oil operators and COWDF operators into complacency; however, bird mortalities in oil and gas facilities appear to be episodic. There may be long periods without incident, but then a large number of birds may be killed during short periods, such as migration. Grover (1983) found that in southeastern New Mexico, wildlife losses in oil pits during the summer consisted of inexperienced, recently fledged or weaned wildlife. During the fall, waterfowl and shorebirds were the primary victims of oil pits. Esmoil found a disproportionate number of loggerhead shrikes (*Lanis ludovicianus*) killed during a two-week period that coincided with fledging (Ramirez 2010).

MANAGEMENT RECOMMENDATIONS

Although the oil industry has taken proactive measures to minimize risks to birds and other wildlife at oil and gas production facilities and COWDFs, oil and COWDF operators should implement the following best management practices (BMPs) to prevent wildlife mortality at oil and gas exploration and production facilities:

- Use closed containment systems to store oil, condensate, or other hydrocarbons at oil and gas exploration and production facilities;
- Eliminate the use of pits to store drilling fluids, produced water, or other wastes;
- If pits or ponds must be used, install effective wildlife exclusionary devices to prevent wildlife access to pits and ponds;
- Buckets, trays, or open-topped vessels used to contain drips or leaks should be covered with wire mesh or netting to prevent entry by bird and other small animals;

- If evaporation ponds are used for water disposal, implement engineering controls to prevent the discharge of wastewater containing oil and surfactants into the evaporation pond; and
- Where possible, use deep well injection of oilfield wastewater to eliminate the need for evaporation ponds and the risk to migratory birds and other wildlife from exposed oil, surfactants and hypersaline conditions.

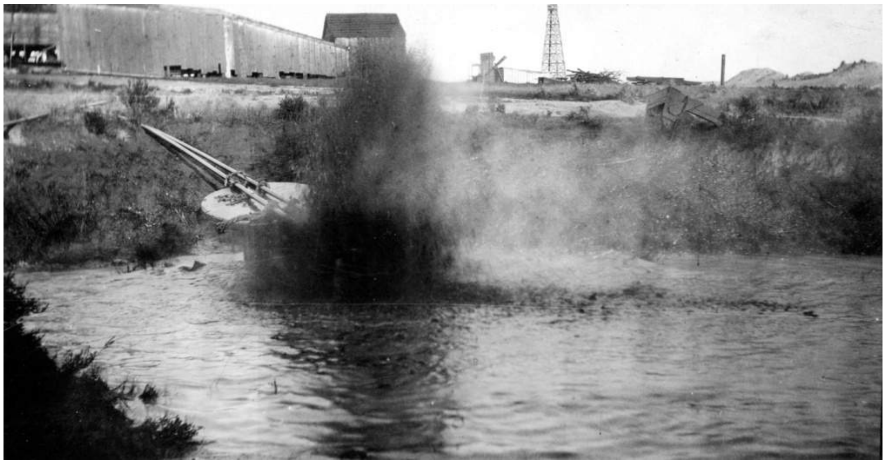


Figure 10. Discharge of oil into a dammed up gulch, Lance Creek field, Niobrara County, Wyoming, 1918 (USGS Historical Photos) (Hancock 1921).

Continued wildlife mortality incidents at oil and gas production facilities and COWDFs necessitate continued inspections of these facilities by regulatory agencies to ensure compliance with applicable environmental and wildlife protection laws. Single inspections reveal only a small fraction of the annual avian mortality in an oil pit or sink and remain undetected within a very short time frame, as few as 4 days in warmer months (Flickinger and Bunck 1987). Carcasses present in or near the edges of pits can be removed by scavengers such as coyotes, raccoons, and raptors or by people. Flickinger and Bunck

(1987) recommended that pits be inspected at least once a week to document all passerine mortality in summer, with inspections at least every three weeks in winter.

Trail (2006) proposed a total of 24 inspections from March through October to document most bird mortality in oil pits. The proposed inspections should consist of two inspections per month in March, April, September, and October; and four inspections per month in May, June, July, and August.

Inspections of oil and gas facilities should not be limited to production skim pits, reserve pits, and open-topped tanks. Puddled oil from leaking valves, pipes, and wellheads will also entrap small mammals, small reptiles such as lizards, and songbirds. Open-topped drip buckets placed under valves to catch oil drips can also entrap small wildlife. Service biologists have documented birds entrapped in small puddles of oil spilled on the ground (Figure 11).

Figure 11. Horned lark entrapped in puddle of oil at an oil production facility in Wyoming.

Detailed field notes should include the specific location and probable cause of the mortality incident (i.e. reserve pit, production skim pit, dehydration tank, open-topped tank, etc.). This data would serve to document specific problem areas or hazards to birds at oil and gas facilities and assist in developing solutions or best management practices (BMPs) to minimize or eliminate those hazards.

Although the cause of most bird mortality incidents at oil and gas exploration and production facilities and COWDFs involves exposure to oil or other hydrocarbons, bird carcasses with no obvious signs of external oiling should be submitted for necropsy to determine if mortality was caused by salt crystallization or exposure to other substances such as surfactants or other chemicals.

Outreach efforts should continue to encourage industry to implement BMPs to eliminate or minimize risks to migratory birds and other wildlife at oil and gas production facilities and COWDFs. Since 75 percent of all bird mortalities were documented in dehydration tanks and reserve pits, outreach efforts should focus on informing the oil industry about these two hazards. Manufacturers of dehydration tanks should design these containers with smaller openings covered with a small meshed screen to prevent entry by birds.

Outreach efforts should encourage drilling contractors and oil operators to use closed loop drilling systems and eliminate the use of reserve pits. Closed loop drilling systems eliminate the risk to birds and also reduce the amount of drilling waste, recycle drilling fluids, and reduce drilling costs (Ramirez 2009). Eliminating the use of reserve pits will also eliminate the risk of soil, groundwater, and surface water contamination (Ramirez 2009).

State and federal agencies should increase the monitoring of COWDFs for surface and groundwater contamination. Air emissions of volatile organic compounds (VOCs) from COWDF evaporation ponds should also be monitored. Most COWDFs use sprayers or evaporators to enhance the evaporation of wastewater (Ramirez 2010). The sprayers can exacerbate the emissions of VOCs from the evaporation ponds as well as cause the aerial drift of hypersaline wastewater outside of the facility boundary thus adversely impacting soils and vegetation. Regulatory agencies should also monitor COWDF evaporation ponds for hypersaline conditions that could cause bird mortality. Surfactants from flowback water disposed of into COWDFs can reduce water surface tension and pose a hazard to birds landing on the evaporation ponds (Ramirez 2010).

Although biologists and wildlife law enforcement agents have conducted numerous investigations of bird mortality in oil pits, research is needed in the following areas to better manage oil and gas exploration and production facilities and COWDFs to prevent bird and other wildlife mortality:

- the persistence of surfactants in hydraulic fracturing flowback water and risks to birds if the flowback water is disposed in COWDFs and reserve pits;
- the impacts of aerial drift from COWDF evaporation-enhancing sprayers to resident wildlife and their habitats;
- the effects of volatile organic compound emissions from COWDFs on resident birds and other wildlife; and
- the efficacy of decoy wetlands used to lure aquatic birds away from COWDF evaporation ponds.

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APPENDIX
PART 5

APPENDIX INDEX

DOC. #	DOCUMENT DESCRIPTION	PAGE #
1	Sec'y Energy Advisory Bd., U.S. Dep't Energy, Shale Gas Production Subcommittee 90-Day Report (2011), available at http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf.	1–42
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Evaluating a groundwater supply contamination incident attributed to Marcellus Shale gas development

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High-volume hydraulic fracturing (HVHF) has revolutionized the oil and gas industry worldwide but has been accompanied by highly controversial incidents of reported water contamination. For example, groundwater contamination by stray natural gas and spillage of brine and other gas drilling-related fluids is known to occur. However, contamination of shallow potable aquifers by HVHF at depth has never been fully documented. We investigated a case where Marcellus Shale gas wells in Pennsylvania caused inundation of natural gas and foam in initially potable groundwater used by several households. With comprehensive 2D gas chromatography coupled to time-of-flight mass spectrometry (GCxGC-TOFMS), an unresolved complex mixture of organic compounds was identified in the aquifer. Similar signatures were also observed in flowback from Marcellus Shale gas wells. A compound identified in flowback, 2-n-Butoxyethanol, was also positively identified in one of the foaming drinking water wells at nanogram-per-liter concentrations. The most likely explanation of the incident is that stray natural gas and drilling or HF compounds were driven ∼1–3 km along shallow to intermediate depth fractures to the aquifer used as a potable water source. Part of the problem may have been wastewaters from a pit leak reported at the nearest gas well pad—the only nearby pad where wells were hydraulically fractured before the contamination incident. If samples of drilling, pit, and HVHF fluids had been available, GCxGC-TOFMS might have fingerprinted the contamination source. Such evaluations would contribute significantly to better management practices as the shale gas industry expands worldwide.

high-volume hydraulic fracturing | shale gas | natural gas | water quality | Marcellus Shale

Horizontal drilling and high-volume hydraulic fracturing (HVHF) are used in combination to extract natural gas, condensate, and oil from shale reservoirs in the United States at rates affecting the world economy (1–4). In the shale gas-rich Marcellus Formation, such slick water HVHF began in 2004, leading to >8,000 Marcellus wells drilled in Pennsylvania (PA) alone as of October 2014. Nearly 70% of these have been hydraulically fractured using large volumes of water and sand with relatively small volumes of gels, acids, biocide, and other compounds (5, 6). The fast rate of such shale development in the northeastern United States has led to several cases of water resource impacts, including surface discharges of contaminants as well as subsurface gas migration (6–12). Although media reports of incidents are common, published reports are few (10).

The most useful evidence for incidents links contaminants directly to the source with a high degree of certainty. To evaluate impacts, a "multiple lines of evidence" approach (13–16) is generally necessary, including (*i*) time series analyses of natural gas and organic and inorganic compound concentrations, (*ii*) comparisons of natural gas isotopic compositions between gas well annular gas and groundwater, (*iii*) assessments of gas well construction, (*iv*), chronology of events, (*v*) hydrogeologic characterization, and (*vi*) geospatial relationships.

Here we provide data for a contamination incident from PA where the regulator (PA Department of Environmental Protection, PADEP) concluded that stray natural gas derived from nearby Marcellus Shale gas wells contaminated the aquifer used by at least three households in southeastern Bradford County, PA (Fig. 1). In addition to gas, the well waters were also observed to foam (Fig. 1*C*), but no cause was determined. To investigate this and other contaminants present, we demonstrate an investigative approach to identify unique organic unresolved complex mixtures (UCMs) and a target compound linked to shale gas-related contamination (2-n-Butoxyethanol, 2-BE).

History

Between 2009 and 2010, five gas well pads, known as Welles 1 through 5, were constructed about 1–2.25 km north of a small valley along the north branch tributary of Sugar Run where several private homes used groundwater for drinking (Fig. 1 *A* and *B* and Table S1). On each well pad, two wells with horizontal sections at depth were drilled and surface casing was emplaced to about 300 meters below ground surface (m-bgs) on the vertical section. The vertical casing consists of steel pipe surrounded by cement. At intermediate depths, no casing was installed. Production casing was used through the zone of gas production in the Marcellus Shale at depths between 2,100 m-bgs and 2,300 m-bgs (horizontal section).

By the end of September 2009 after both gas wells on the Welles 1 well pad were drilled, no construction problems associated with gas migration (6) were noted; however, a drilling fluid

Significance

New techniques of high-volume hydraulic fracturing (HVHF) are now used to unlock oil and gas from rocks with very low permeability. Some members of the public protest against HVHF due to fears that associated compounds could migrate into aquifers. We report a case where natural gas and other contaminants migrated laterally through kilometers of rock at shallow to intermediate depths, impacting an aquifer used as a potable water source. The incident was attributed to Marcellus Shale gas development. The organic contaminants—likely derived from drilling or HVHF fluids—were detected using instrumentation not available in most commercial laboratories. More such incidents must be analyzed and data released publicly so that similar problems can be avoided through use of better management practices.

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Conflict of interest statement: G.T.L. and Appalachia Consulting provided litigation support and environmental consulting services to the impacted households.

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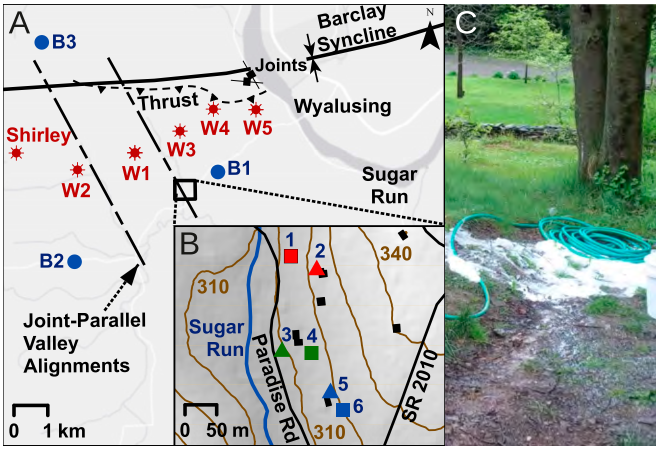

Fig. 1. (*A*) Study area showing the communities of Wyalusing and Sugar Run located on Susquehanna river (dark grey), gas wells (Shirley, Welles 1–5 well pads labeled as W1 through W5), domestic water wells not impacted by gas drilling activities (B1–B3), and notable geologic features (thrust fault surface expression, regional joint orientation, axis of syncline). (*B*) Expanded view of tributary of Sugar Run creek (blue line) showing domestic water Wells 1–6 impacted by gas drilling activities. Wells 2, 3, and 5 (triangles) are original impacted wells. Wells 1, 4, and 6 (squares) are replacement wells provided by gas company that also showed contamination. Brown lines are elevation contours (m-msl). Black squares are structures and lines are roads. (*C*) Foam emitted during purging of domestic water Well 2 in Spring, 2012.

leak from a pit was documented by the PADEP on 7 August 2009 (Table S1). HVHF was completed for Welles 1-3H and Welles 1-5H in February 2010. Gas well naming convention includes the propery owner (e.g., "Welles"), followed by the pad number (e.g., "1") and then the individual well designation (e.g., "3H" and "5H").

Gas wells on Welles 2–5 pads were drilled between September 2009 and May 2010. In May 2010, annular pressures measured in Welles 3-2H (~64 atm), Welles 3-5H (~48 atm), Welles 4-2H (~33 atm), and Welles 4-5H (~34 atm) exceeded the maximum allowable pressure of 24 atm (17). In July 2010, natural gas and sediment were reported in well water by at least three households along the north branch of Sugar Run (Fig. 1 and Table S1). White foam was also observed in the water from impacted wells (Fig. 1*C*). Further, vapor intrusion of natural gas was reported in one basement, requiring household evacuation as a safety precaution.

On 11 May 2011, the PADEP cited the gas company for violations of the PA Oil and Gas Act and Clean Streams Law for allowing natural gas to enter aquifers (Table S1). Although they did not admit culpability, the gas company complied with the PADEP consent order and agreement (COA). The company remediated gas wells present at the Welles 3–5 pads with cement squeezes and plugs (*SI Text* and Table S1) to reduce gas well annular pressures.

The impacted water wells (Fig. 1) were sampled by environmental consultants and the PADEP and analyzed by commercial laboratories between July 2010 and May 2012 (Fig. 2 and Table S2). The gas company installed replacement groundwater wells (e.g., Wells 1, 4, and 6 illustrated in Fig. 1*B*); however, these wells also exhibited impacts, and treatment systems were installed for each household in late summer of 2010.

A civil lawsuit initiated by the homeowners was settled in June 2012, and the gas company acquired the properties as part of a monetary settlement. No nondisclosure agreements were signed except for a subset of proprietary files. The Welles gas wells were identified by consultants working on the behalf of the homeowners as the most probable source of stray gas due to (*i*) nondetectable concentrations of dissolved methane in a predrill analysis of Well 2 (Figs. 1*B* and 2), (*ii*) groundwater quality time series data, (*iii*) comparison of isotopic signatures of natural gas from gas well annular spaces and in the potable wells, (*iv*) timing of the issues after gas drilling (Fig. 2 and Table S1), (*v*) excessive gas well annular pressures, and (*vi*) documentation of hydrogeologic conditions conducive to gas migration.

PADEP correspondence with the gas company in August 2010 requested documentation on the gas company's implementation of a 3-string casing design to include intermediate casing that would provide greater shallow aquifer protection. Following the case settlement and compliance with the PADEP's COA, the PADEP allowed the company to hydraulically fracture the gas wells on Welles 2–5 pads between November 2012 and September 2013 (www.FracFocus.org).

Here, we report new analyses on additional samples from the household wells before ownership passed to the gas company (e.g., data plotted for November 2012 in Fig. 2 and Tables S3–S6). Also, to investigate the cause of foam (Fig. 1*C*) and impacts previously unidentified, we used an analytical technique, comprehensive 2D gas chromatography coupled to time-of-flight mass spectrometry (GCxGC-TOFMS), that has not been previously used in similar cases. Although many attributes of the technique provide advantages for environmental forensics, few laboratories have GCxGC-TOFMS capabilities (14). We explored broad nontargeted organic compound classes at detection levels of nanograms per liter (e.g., detection limits lower than those achieved in most commercial laboratories). The method is amenable for forensic use in that it explores for broad classes of organic compounds and signatures rather than focusing on a specific list of target analytes that may or may not be present when impacts occur. No samples of HVHF fluid or flowback/production waters were available to us from the Welles series wells, but we investigated flowback and production waters from other similar unconventional gas wells in PA.

Methods

Samples were collected and analyzed from (*i*) ~30 Marcellus Shale flowback/production waters sampled throughout PA and provided to us by commercial entities, (*ii*) one of the original household wells, (*iii*) two of the wells that were drilled as replacements for the homeowners that were still contaminated, (*iv*) one natural brine spring (Salt Springs) located about 50 km

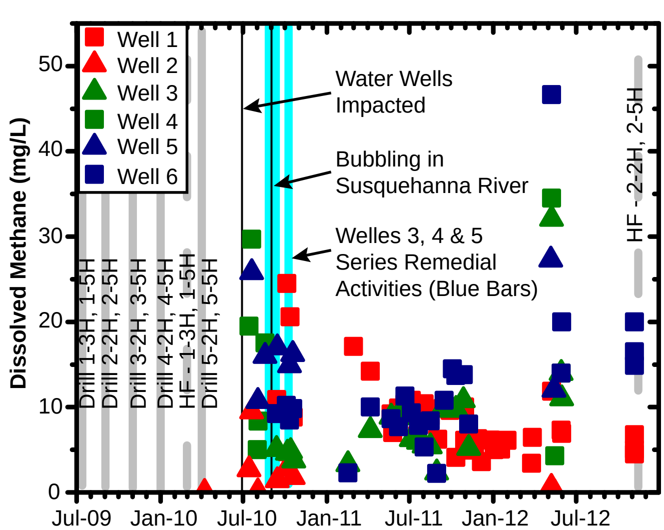

Fig. 2. Time series plot of dissolved methane concentrations with notable events, such as gas drilling, high-volume hydraulic fracturing (dashed grey lines labeled HF), gas well remedial activities, and onset of impacts to water Wells 1–6.

away in Susquehanna County, and (*v*) several potable water wells near the pollution incident that represent natural background. These background wells include a well from one of the relocated households, three non-impacted households located within 5 km of the impacted homes, and a private house near Salt Springs. We also obtained and analyzed one common drilling additive (Airfoam HD). Sampling methodologies are described in *SI Text*.

Subsets of these samples were analyzed via gas chromatographic separation, specifically using GCxGC-TOFMS, isotope ratio mass spectrometry, and inductively coupled plasma atomic emission spectrometry (ICP-AES) (see *SI Text* and Table S3). GCxGC-TOFMS has previously been successful in identifying hydrocarbons in crude oil forensics (13). Here, TOFMS was used to detect analytes as they eluted from the second column. Concentrations were quantified, when possible, by running samples with known compounds injected in tandem with the sample. Additionally, surrogate standards were added to all samples before extraction to account for sample extraction efficiency.

Available natural gas analyses completed during investigations before settlement (Table S2 and Figs. S1 and S2) and completed on a subset of the samples we collected in November 2012 (Table S5) are reported in *SI Text*.

Aquifer testing was also conducted using household Well 4 as a pumping well and the other original and replacement wells as monitoring wells to investigate shallow aquifer characteristics (Fig. S3).

Results

Dissolved Organic Analysis. Every flowback/produced water sample we analyzed had a similar UCM of hydrocarbons when evaluated with GCxGC-TOFMS (Fig. 3). All groundwater samples from impacted sites (Wells 1, 3, and 6; see Fig. 1) that were analyzed with GCxGC-TOFMS showed UCMs similar to those detected in the flowback/production waters (e.g., Fig. 4*A* and Figs. S4–S6). Well 1 was analyzed both before and after purging (at which time the water no longer foamed). Peak intensities for the UCM were generally greater after purging (compare Fig. 4*A* and Fig. S6).

Classes of analytes in GCxGC-TOFMS, such as aliphatic hydrocarbons or organic acids, align along a diagonal of the 2D cross-plot chromatograms. For the specific conditions used here, aliphatic hydrocarbons cluster near the origin, while compounds with increasing heteratomic substitution or unsaturation lie further along the *y* axis. With the exception of the surrogate compounds (Table S7), only general classifications were determined from mass spectra. The detected molecules elute showing molecular weights <1,000 atomic mass units, and mass-to-charge ratios (*m/z*) of 50–550. Each flowback/production water sample had a similar but distinct pattern of saturated versus branched chain alkanes (compare Fig. 3 *A* and *C*).

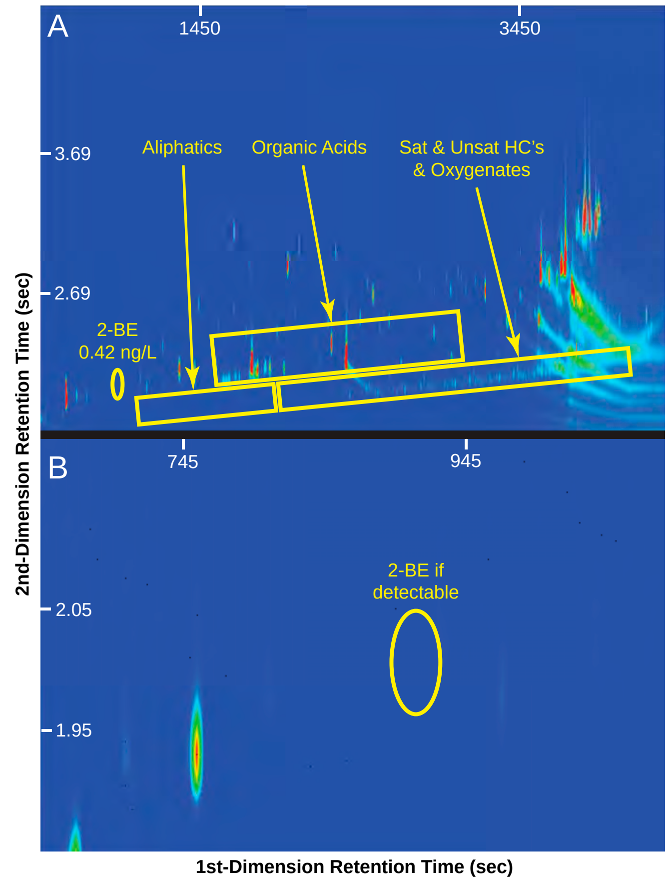

Fig. 4. GCxGC-TOFMS chromatograms for (*A*) Well 1 (PLG-12-67A) before purging and (*B*) background Well B1 (PLG-13-7A) that was not impacted by gas drilling activities. The hydrocarbon UCM observed in Well 1 is similar to that observed in flowback samples (e.g., Fig. 3). The 2-BE was positively identified in Well 1 (impacted by gas drilling activities), but not as part of background water quality. *B* is magnified to illustrate the absence of 2-BE.

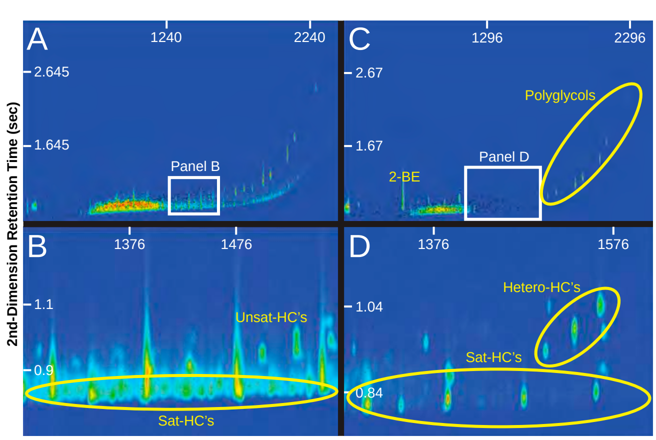

Fig. 3. GCxGC-TOFMS chromatograms of flowback water. (*A*) Example from a gas well in Connelsville, PA. (*B*) Magnified portion of *A* as indicated by white rectangle. (*C*) Example from a gas well in Kittanning, PA. (*D*) Magnified portion of *C* as indicated by white rectangle. General compound classes are illustrated in panels. Unresolved complex mixture (UCM) concentrations are relative to each panel, but increase in concentration from cool (e.g., blue) to bright (e.g., red) color.

A few of the ~30 flowback/production water samples were positively identified as containing 2-BE (Chemical Abstracts Service (CAS) number 111-76-2) and glycols—compounds commonly used during drilling and HVHF (Fig. 3*C*). For example, 2-BE was the only compound identified using GCxGC-TOFMS in the drilling additive and surfactant Airfoam HD (Fig. 5). The groundwater well analyzed before and after purging (Well 1) also contained detectable 2-BE. In contrast to the UCM, which increased in peak intensity with purging, concentrations of 2-BE decreased after purging: Sample PLG-12-67A before purge (Fig. 4*A*) contained ~0.42 ng/L 2-BE versus sample PLG-12-68A (after purging, Fig. S6) contained ~0.086 ng/L 2-BE (concentrations on as-received basis). No 2-BE was detected in the other two groundwater wells, although they contained the UCM [no 2-BE was detected in Well 3 (Fig. S4) or Well 6 (Fig. S5)].

To confirm the presence of 2-BE, sample extracts were reanalyzed using GCxGC with a high-resolution TOFMS (GCxGC-HR-TOFMS) at Leco Corporation. For example, the presence of 2-BE was confirmed in the accurate mass spectra for prepurge sample PLG-12-67A from Well 1 (e.g., one of the replacement wells) by comparison with the 2-BE standard (Fig. S7). Only 2-BE matched the molecular ion determined by the GCxGC-HR-TOFMS within 5 ppm. None of the field blanks or preparatory blanks contained

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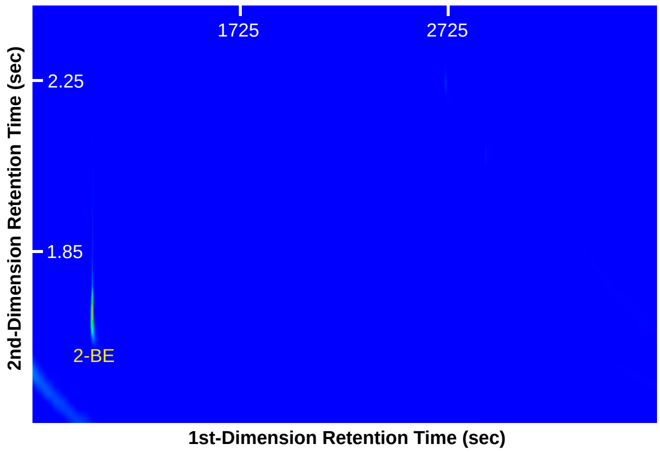

Fig. 5. GCxGC-TOFMS chromatogram for Airfoam illustrating 2-BE as the sole detectable component.

2-BE above detection (~0.01 ng/L). Likewise, neither UCM nor 2-BE were detected from groundwater (e.g., Fig. 4*B* and Fig. S8) sampled from three household wells (e.g., B1, B2, and B3 illustrated in Fig. 1) located outside of the impacted area and used to evaluate background conditions.

Inorganic Analysis. Conservative inorganic constituents (e.g., Cl and Br) can be used to determine if flowback or production waters have contaminated groundwater because these wastewaters can contain total dissolved solids in concentrations greater than 300,000 mg/L (6, 18). Further, if upward migration of HVHF fluids occurred after mixing with formation waters, dissolved Cl/Br mass ratios are more likely to be useful as effective fingerprints than the HVHF fluid components themselves, due to their more conservative behavior in groundwater (6, 10). Crossplots of Cl/Br (mass ratio) versus Cl concentration (Fig. 6) can help elucidate the source of Cl. For example, the natural water quality data for Salt Spring in Susquehanna County, PA, documents that Appalachian Basin brine (ABB) up-wells naturally into groundwater and surface water in Susquehanna County in that location as well as others (18). Although diluted, this spring water has a similar composition to flowback/production waters throughout PA and a few other brine springs and deep formation waters in the state (18–26) (Fig. 6 and Table S6). Conversely, Fig. 6 illustrates that the Cl concentrations and Cl:Br ratios of the impacted household waters from Bradford County are more likely gaining dissolved salts from sources with higher Cl:Br mass ratios than ABB.

Dissolved Gas and Isotopic Analyses. The dissolved methane concentrations measured in the impacted wells reached as high as 46.6 mg/L between 2010 and 2012 (Fig. 2 and Table S2). Such a high value is similar to methane concentrations we measured in three samples from Salt Springs State Park, where ABB is emitting naturally (Susquehanna County, 35.2 ± 1.53 mg/L, Table S5). In contrast, the predrill concentration in Well 2 was reported as <0.02 mg/L (e.g., plotting at the origin in Fig. 2). Likewise, the 1,701 drinking water wells collected by gas companies before drilling in adjacent Susquehanna County between 2008 and 2011 and analyzed in commercial laboratories (27) varied from a high (90th percentile) of 1.8 mg/L for valleys to a low of 0.017 mg/L for uplands. A steady decrease in dissolved methane was observed for at least one impacted household well (Well 1) with ample time series data, subsequent to the remediation of the Welles 3, 4, and 5 series gas wells (Fig. 2). An anomalous concentration spike was observed for all sampled wells in May 2012; however, differences in well purging and sampling protocols from that event complicate comparison with those that preceded it.

A plot of δD versus $\delta^{13}C$ data for methane is illustrated in Fig. S1 for the (*i*) impacted household wells, (*ii*) annular space of Welles 2, 3, 4, and 5 gas wells, and (*iii*) predrill private household wells from the region (16). Notably, methane isotopic characteristics are consistent between gas sampled from the annular spaces of Welles 2, 3, 4, and 5 gas wells and groundwater sampled from the impacted homeowner wells. In contrast, methane characterized from predrill water wells in the region (16) illustrate generally different isotopic characteristics (Fig. S1). In addition, Fig. S2 illustrates that $\delta^{13}C$ for methane and ethane are also consistent among gas samples from Welles 3, 4, and 5 wells' annuli and the impacted groundwater wells.

Hydrogeologic Considerations. The impacted homeowner wells lie along the north branch of Sugar Run valley between the axes of two east–west aligned structural folds (Fig. 1 and Fig. S9). The concave Barclay fold (syncline), is located 1–3 km to the north of Welles 1–5 pads; the convex Wilmot fold (anticline) lies to the south at a distance of 5–7 km (Fig. S9). Under the impacted valley (between the folds), bedrock strata dip ~5–10 degrees downward to the northwest toward the Welles series gas wells.

In September 2010, significant gas bubbling commenced in the Susquehanna River near the community of Sugar Run southeast of the impacted homeowner wells (Fig. 1 and Fig. S9). When projected back to the Welles gas wells, bedding planes that outcrop near the river (and that presumably facilitate methane migration) intersect the boreholes at ~400–600 m-bgs (Fig. S9). In comparison, the gas wells were cased to ~300 m-bgs (Fig. S10).

Well-developed vertical to near-vertical fractures (joints) are observed in outcrop to trend NNW–SSE in the study area. A second, lesser-developed set is aligned E–W. Many stream valleys, such as the impacted north branch of Sugar Run, lie parallel to the NNW–SSE joints, consistent with joint-controlled valley development (Fig. 1). In addition to jointing, Fig. 1 and Fig. S9 also illustrate the surficial trace of a thrust fault identified from seismic reflection data. The fault plane dips ~16 degrees downward to the south: This dip intersects the Welles 1–5 series gas wells at depths between ~180 m-bgs and 580 m-bgs (Figs. S9 and S10). Thus, the thrust fault structural plane likely intersects some uncased portions of boreholes at the Welles 1, 2, and 3 pads. Of

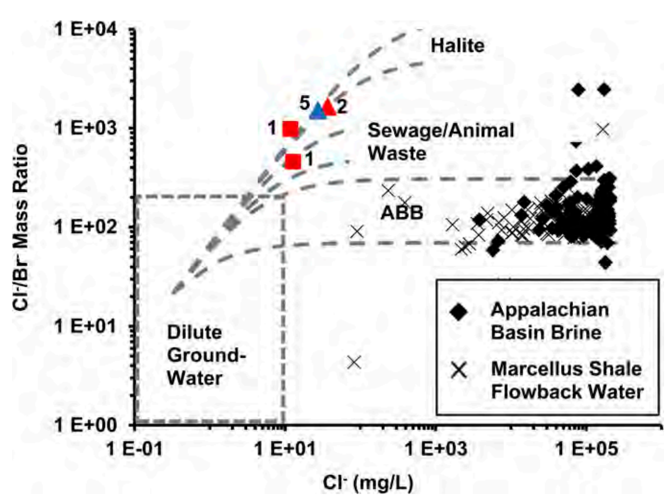

Fig. 6. Crossplot of Cl/Br mass ratio vs. Cl concentrations for samples collected from Wells 1, 2, and 5 (labeled) with bounding upper and lower conservative mixing curves for various endmembers (e.g., Appalachian Basin brine, sewage and animal waste, and halite sources). Appalachian Basin brine samples (20–22, 24) and Marcellus Shale flowback samples (23, 25, 26) are also plotted for comparison.

these three series, the Welles 1 and 2 wells did not reveal excessive, sustained annular gas pressures; however, elevated annular pressures of ∼64 atm and ∼48 atm were detected for Welles 3-2H and 3-5H, respectively. In response to the PADEP's COA with the gas company, cement was squeezed into boreholes for the Welles 3, 4, and 5 series (Table S1 and Fig. S10), with subsequent decreases in gas well annular pressure.

To evaluate the local bedrock aquifer used by the three impacted households, aquifer testing was conducted for 7 h in November 2012, using Well 4 as a pumping well (25.8 L/min). Static groundwater elevations near the three impacted households ranged from 303.5 m above mean sea level (m-msl) to 308.9 m-msl, with flow converging toward the north branch of Sugar Run (Fig. S3). The aquifer test results indicated preferential drawdown parallel to the valley alignment, suggesting aquifer anisotropy and/or heterogeneity. Additional aquifer characterization is provided in *SI Text*.

Discussion

Even though drinking water consistently foamed in three households in Bradford County (e.g., Fig. 1*C*), commercial laboratories reported no compounds other than natural gas present at concentrations above regulatory recommended action levels, and no constituents were detected above regulatory drinking water standards. However, commercial laboratory analyses did sporadically detect ethylene and propylene glycol and surfactants near microgram-per-liter detection limits (*SI Text*). When we analyzed a subset of the household waters with GCxGC-TOFMS in 2012, we detected very low concentrations of 2-BE. This compound is of special interest because the US Environmental Protection Agency (USEPA) has suggested that 2-BE could be an indicator of contamination from HVHF activities (29). Additional information on 2-BE is provided in *SI Text*. GCxGC-TOFMS also documented a UCM of organic contaminants in all three water wells analyzed. Background groundwater outside of the affected area had no such contamination (Fig. 4*B* and Fig. S8). It is not possible to prove unambiguously that the UCM and 2-BE were derived from shale gas-related activities. However, the timing (Fig. 2 and Table S1) and the presence of UCMs and 2-BE in flowback/production waters in PA (Fig. 3) are consistent with shale gas activity as the most probable source.

We also conclude that the foam identified from the homeowner wells was likely derived from either the UCM hydrocarbons (28) or 2-BE (a known surfactant). Methane degassing is exacerbated during the onset of household well pumping due to rapid water level drawdown and drop in hydrostatic pressure. The resulting effervescence and groundwater agitation then aids as a foaming facilitator. Given that 2-BE was only found in Well 1, despite foaming observed in all water wells, it might be reasonable to conclude that the UCM aided by gas effervescence was the most probable cause. Further, foaming and concentrations of 2-BE decreased with increasing well purging, unlike the UCM. On the other hand, 2-BE is a known surfactant, making it a more probable cause of foaming at low concentrations. Detection of 2-BE is difficult at these low concentrations in the presence of other organic compounds. Therefore, the compound may have been present in the foaming drinking waters even though we could not detect it in all wells.

There are no reports of 2-BE as a natural constituent in waters from shale (30). However, the common drilling additive Airfoam HD contains 2-BE as the only detectable organic component from our analyses (Fig. 5). Although we have no evidence that Airfoam HD was used in the Welles series gas wells in drilling fluids, this substance has been commonly used in northern and central PA. Indeed, it was cited by the PADEP as the cause of foam from a spring discharging to the canyon wall above Pine Creek in Lycoming County (PA) that began 15 March 2010. Further, a more recent PADEP contamination determination letter, dated 14 May 2014, identified at least one private water well in Springville Township, Susquehanna County, PA, that was impacted by drilling fluids using Airfoam HD as a surfactant. Here, 2-BE in addition to volatile organic compounds and ethyl glycol were detected at microgram-per-liter concentrations in that household well and were deemed responsible for the foaming groundwater in the household well. This contamination was attributed to drilling fluid additives and not HVHF by the PADEP.

Notably, the Welles 1 gas well pad was the location of a drilling fluid pit leak in August 2009 (Table S1). Further, well construction issues required remedial efforts in the Welles 3–5 series gas wells. Therefore, drilling fluids used in their installation could reasonably account for the observed foam impacts to household Wells 1–6 (Fig. 1*C*). Since 2-BE and the UCM were identified together, drilling fluids might be the source of both.

Alternately, since the UCMs are similar in the well waters and flowback/production waters and 2-BE was only observed with the UCM, another scenario is that the UCM and 2-BE are derived from HVHF fluids. In fact, HVHF was initiated in February 2010 at the Welles 1 pad—5 mo before the turbidity and natural gas problems in the homeowner wells (Table S1 and Fig. 2). This well pad was also one of the two closest pads to the aquifer contamination incident. Notably, gas wells situated on the Welles 2–5 pads were hydraulically fractured in 2012 using fluids containing 2-BE (www.fracfocus.org; see Table S8). Although no data were reported online (www.fracfocus.org) regarding the compounds used during HVHF of Welles 1 pad wells, it is reasonable that the same nonemulsifier agent (which contained 2-BE) was likely used. Therefore, we conclude that it is possible that HVHF fluids used at the Welles 1 pad contaminated the drinking water aquifer.

If HVHF fluids did contaminate the water wells, it would be surprising if such contamination were due to fluids returning upward from deep strata, given that (*i*) this has never been reported (6), (*ii*) the time required to travel 2 km up from the Marcellus along natural fractures is likely to be thousands to millions of years (31), and (*iii*) Fig. 6 shows that the Cl:Br ratios in the drinking waters indicate the absence of salts that would be diagnostic of fluids from the Marcellus Shale (e.g., flowback/production waters). The most likely way for HVHF fluids to contaminate the shallow aquifers would therefore be through surface spillage of HVHF fluids before injection or by shallow subsurface leakage during injection.

It is possible that the provenance of the UCM and 2-BE was different from that of the stray gas. Indeed, the most reasonable explanation for the natural gas impacts to water wells is that gas migrated from Welles 3-2H or possibly from multiple gas wells drilled on the Welles 3–5 pads due to excessive annular pressures and lack of competent annular cement that allowed gas to move vertically upward along the wellbore and into shallow uncased portions of bedrock fractures, including an identified fault zone (Table S1, Fig. 1, and Figs. S9 and S10). Induced fracture propagation below the surface casing of Welles 3-2H is also possible given the recorded gas well annular pressures (see *SI Text*). In addition to potentially opening fracture pathways, excessive annular pressures and natural gas buoyancy likely drove gas up-dip along bedding-plane partings to the southeast, intermittently stair-stepping upward along near-vertical joints to Sugar Run (Fig. 1 and Figs. S3, S9, and S11). Well water turbidity was likely due to the entrainment of fine-grained sediment as a result of off-gassing and groundwater effervescence (32). The lower hydrostatic pressure of the shallow aquifer beneath the impacted valley, exacerbated by household pumping, likely drew in the contaminating fluids (Figs. S3 and S11).

Conclusions

We used comprehensive GCxGC-TOFMS to document that organic compounds derived from one or more shale gas wells in

ENVIRONMENTAL SCIENCES

PA were the likely cause of foaming and a complex suite of UCMs in three homeowner wells. In one well, 2-BE was positively identified and is a common constituent of both HVHF and drilling fluids. These impacts were likely caused by drilling or HVHF fluids used in the gas wells. Two of the closest shale gas wells were hydraulically fractured by the time of the impact, and the well pad was cited by the PADEP for a pit leak. Despite noticeable white foaming of groundwater, reported concentrations for dissolved organics were below applicable regulatory standards when investigated by both environmental consultants and the PADEP. Only natural gas was previously reported as a confirmed contaminant. If contaminants entered groundwater during HVHF or drilling, then they persisted 2.5 y in the subsurface, i.e., until the November 2012 sampling.

Importantly, the techniques we needed to identify the impacts, GCxGC-TOFMS and GCxGC-HR-TOFMS, are not readily available in most commercial laboratories. Investigating gas drilling impacts with these analytical methods may be more effective than using target compound lists that may or may not include appropriate analytes and appropriate laboratory detection limits.

Although much of the concern shown by the public focuses on the possibility that some of the 1,000 compounds (29, 33) used in HVHF could migrate upward from the target shale, such upward leakage has never been documented. This is probably because HVHF fluids remain trapped in deep rock strata. However, the public cannot ascertain the cause of most shale gas-related problems (10) because the full datasets are often not released publicly and explained.

The data released here do not implicate upward flowing fluids along fractures from the target shale as the source of contaminants but rather implicate fluids flowing vertically along gas well boreholes and through intersecting shallow to intermediate flow paths via bedrock fractures. Flow along such pathways is likely when fluids are driven by high annular gas pressure or possibly by high pressures during HVHF injection. Such shallow- to intermediate-depth contaminant flow paths are not limited to HVHF but rather have been previously observed with conventional oil and gas wells. As shale gas development expands worldwide, problems such as those that occurred in northeastern PA will only be avoided by using conservative well construction practices, such as intermediate casing strings, proper cementation, and mitigating overpressured gas well annuli.

ACKNOWLEDGMENTS. The homeowners whose wells were affected are acknowledged for their willingness to allow our data collection and data release to the general public. David Oakley and Don Fisher are acknowledged for assistance with Fig. S9. Leco Corporation is acknowledged for funding for the Pegasus GCxGC-TOFMS and data collection on the GCxGC-HR-TOFMS. Some reference materials and chromatographic consumables were donated by Restek Corporation. Funding for P.G. was derived from National Science Foundation (NSF) Grant OCE-11-40159 (to S.L.B.) and the Penn State Earth and Environmental Systems Institute. T.S. acknowledges funding from NSF ANT 1043500 for mass spectrometric instrument support.

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Supporting Information

Llewellyn et al. 10.1073/pnas.1420279112

SI Text

SI History

Given the early groundwater problems reported, venting of the annular spaces in the gas wells commenced in July 2010. Casings were perforated and cement was injected into the annular space (cement squeezing) from August to September 2010 to bolster the gas wells' integrity and reduce annular pressures in the Welles 3, 4, and 5 series gas wells (Table S1 and Fig. S10). The remedial cement squeezes were coincident with reports of natural gas bubbling in the Susquehanna River near the town of Sugar Run, ~3.5 km southeast of the Welles series gas wells (Fig. 1 and Fig. S9). The Welles series wells were the closest associated gas drilling activity at that time.

With commercial laboratory analyses, more than 250 target compounds were analyzed on at least one occasion (inorganics, volatile organics, semivolatile organics, glycols, radiologicals, and surfactants, among others). Despite visible foaming during initial purging, no analyte concentrations exceeded PADEP primary drinking water maximum contaminant levels or medium-specific concentrations as regulated under PA Act 2. Almost no targeted volatile or semivolatile organic compounds were detected, except for carbon disulfide in household Wells 2 (0.45 μg/L) and 5 (0.96 μg/L). This compound is not uncommonly found in such analyses and is not uniquely linked to gas drilling. Although not reported by the commercial laboratory, our evaluation of the laboratory reports (Method 8270C for Well 1 for semivolatile organics) revealed various nontargeted compounds with ~10–36 carbon atoms (estimated total concentration of ~25–50 μg/L) that were present in at least one groundwater sample collected. Surfactants (methylene blue active substances) were also detected at the detection limit (0.12 mg/L) by a commercial laboratory in one sample from Well 1 on 26 March 2012. Ethylene glycol was detected in Wells 1 and 5 on 26 March 2012 and 14 May 2012 at concentrations of 5,100 and 3,200 μg/L, respectively. Propylene glycol was also detected in Well 5 on 14 May 2012 at a concentration of 960 μg/L. All of these analytes and corresponding low concentrations were detected sporadically with intermittent "nondetections" when analyzed for. The civil case focused on the most obvious contamination–natural gas impacts.

SI Methods

Sampling. The new analyses reported here were measured on samples collected from outside spigots using pumps and infrastructure already in place and from a sample from Salt Springs. Before sampling, water was purged for the amount of time indicated in Table S4 with field water quality parameters noted (e.g., pH, conductivity, temperature). All samples were preserved on ice for transport, and were subsequently refrigerated.

Samples for dissolved gases were collected using two types of vessels: 125-mL glass serum bottles and 1-L sample bottles designed by Isotech, Inc. for natural gas isotopic analysis. In all cases, water was allowed to enter the bottles gently using vinyl tubing attached to an outside spigot (to minimize agitation and off-gasing). Isotech bottles (which contain biocide in a specially designed cap) were filled following Isotech protocol for collecting dissolved gas samples (www.isotechlabs.com/customersupport/samplingprocedures/DGbottle.pdf). The bottles were filled with water, inverted, and submerged in a water-filled 5-gallon bucket. The source of water was allowed to keep flowing into the sample bottle until another two volumes of water had been displaced.

For the serum bottles, a slight headspace was left so the bottles could be capped with a 20-mm butyl rubber stopper. Then 1.25 mL of benzylkonium chloride (or, for some test bottles, sodium azide) were added, using a syringe, to kill microbiota. As the biocide was added, a second syringe was inserted into the septa cap and used to evacuate headspace. The water emitting at Salt Springs in Salt Springs Park (Susquehanna County, PA) was sampled by submerging three 125-mL glass serum bottles into the spring water, allowing the bottles to fill, and then capping them with a 20-mm blue butyl rubber stopper under water. Two syringes were then used to add 1.25 mL of sodium azide and to evacuate the remaining headspace.

Samples of almost 30 flowback or production waters were shared with us from natural gas wells drilled in the PA Marcellus before treatment at a brine wastewater remediation plant. Additionally, a sample of drilling foam (M-I SWACO Platinum AirFoam) was obtained.

GCxGC Analysis. An extended organic analysis was completed on the flowback/production waters and samples from three of the potable wells (one original and two replacement wells, bottles labeled PLG-12-60A, PLG-12-68A, and PLG-12-64A). In addition, one of the replacement wells that was sampled after purging (PLG-12-68A) was compared with water before purging (PLG-12-67A). Three background potable water samples were also analyzed from houses outside of the impacted area, but within 5 km of the incident: bottles PLG 13-5B, PLG 13-6A, and PLG 13-7A.

Samples were prepared using separatory funnel-based liquid/liquid extraction under both acidic and basic pH by extraction in dichloromethane following a modification of USEPA Method 3510C (www.epa.gov/osw/hazard/testmethods/sw846/pdfs/3510c.pdf). Many of the flowback samples formed emulsions, especially during the first sample extraction, and were therefore separated using centrifugation. Samples were also spiked with control "surrogate" compounds to measure extraction efficiency (see Table S7).

Sample extracts from flowback and production waters were first characterized by GC-TOFMS. Spectra were very complex, resulting in large UCMs in every sample. To further identify compounds in the UCMs, analysis by GCxGC-TOFMS was used. The GCxGC-TOFMS was a Pegasus-4D system (Leco Corporation).

The sample of Airfoam HD was also analyzed with GCxGC-TOFMS. Additional preparatory blanks and a trip blank taken with the samples were also prepared and analyzed.

The potable waters were compared with the data from flowback/produced waters as well as reference standards. These standards, chosen from among the compounds used in hydraulic fracturing in PA (files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/MarcellusShale/Frac%20list%206-30-2010.pdf), were run under identical conditions at a concentration of 200 pg/uL as a single-point calibration. When these compounds were detected in the potable water samples, concentrations were estimated from the area under the peak for a given fragment and mass/charge ratio.

Dissolved Gases. Samples were analyzed for dissolved hydrocarbons including methane and ethane within 1 wk of collection. To analyze the 1-L bottles for dissolved gases, ultra-high-purity helium was introduced to create headspace (10% by volume standard temperature and pressure) (1). Headspace hydrocarbons were then analyzed using an HP 5890 Series II Gas Chromatograph with a flame ionization detector and a custom vacuum inlet system. Daily standard curves were generated using 1.83 ppm, 14.9 ppm, and 1,000 ppm methane standards from Scott Specialty Gases. Analytical precision for measurement of these standards was better than ±2%.

When headspace is created, gas in the water equilibrates between the aqueous phase and the gases in the headspace, and the concentration can be determined from

$$TC = C_{AH} + C_A,$$

where TC is the total concentration (in milligrams per liter) of the original aqueous sample, C_{AH} is the measured concentration in the gas phase (in milligrams per liter), and C_A is the concentration (in milligrams per liter) that has remained in the aqueous phase, as indicated by the Henry's Law constant at 21 °C.

To analyze $\delta^{13}C$ in methane and ethane, ~5 nmols of analyte were injected into a helium carrier stream and purified using a modified PreCon peripheral device before analysis on a MAT 252 mass spectrometer. Precision of measurements of daily standards (1.84 ppm) is ±0.3‰, with daily standards providing the means of accurately reporting data directly on the Vienna Pee Dee Belemnite scale.

A few samples were also sent to Isotech for analysis of $\delta^{13}C$ (in CH_4 and C_2H_6) and δD in CH_4. Samples analyzed at Pennsylvania State University and Isotech varied between 0‰ and 0.7‰.

Inorganic Analysis. Anions were analyzed using a Dionex ICS 2500 ion chromatograph (IC) on filtered unacidified samples using an IonPac AS18 anion exchange column (4 × 250 mm) and IonPac AG18 guard column (4 × 50 mm) at Pennsylvania State University. Major elements were analyzed on a Perkin-Elmer Optima 5300 ICP-AES on filtered, acidified samples. Analytical precision on the ICP-AES is estimated to be ±3% for all major elements and ±10% for minor elements. Detection limits for the IC data were calculated as the concentration of the lowest standard used during analysis minus the relative SD for multiple analyses of that standard.

Hydrogeology. The impacted area (Fig. 1) lies within the Glaciated Low Plateau section of the Appalachian Plateau province. Bedrock consists of gently folded sandstone, siltstone, and shale overlain by glacial drift. In the study area, sandstone of the Upper Devonian Catskill Formation dominates the uppermost stratigraphic section, with siltstone and shale of the Lock Haven Formation outcropping infrequently in low-lying areas to the north (Fig. 1). Average elevation drop from ridge to valley is ~125 m. Drift and alluvial sediments vary in thickness from a thin veneer on hill slopes to 60 m in major valleys. Fig. S11 illustrates approximate bedrock elevations in meters above mean sea level. Groundwater discharges into the valley along the north branch of Sugar Run where the affected houses are located (Fig. 1 and Fig. S3*A*).

Two principal aquifers are present. Shallow unconfined outwash acts as an aquifer in the major valleys, while confined bedrock units act as aquifers in the uplands. Groundwater flows from hilltops to valley discharge zones. Groundwater is largely of the $Ca-HCO_3^-$ type; however, Na−Cl type groundwater, which occurs in some major valleys, has been attributed to upward seepage of ABB (2–4). For example, Cl−Br ratios are consistent with transport of ABB upward into shallow aquifers along permeable faults and topographic lineaments (3). Thermogenic natural gas is also common in shallow groundwater throughout the region (5–7).

In response to the groundwater quality problems, the gas company installed a replacement potable well for each household in September 2010. However, these replacement wells exhibited elevated natural gas concentrations. Water wells 1–6 are cased to ~6.5 m-bgs and are completed as open rock wells to a maximum depth of ~60 m-bgs. We completed a pumping test in November 2012 to evaluate aquifer characteristics. Well 4 (a replacement well) was pumped for 7 h at a constant pumping rate of 25.8 L/min while evaluating the hydraulic responses of the original and replacement potable wells (Fig. S3). Water level monitoring revealed a maximum drawdown of 15.2 m in the pumping well, and the drawdown ellipse was aligned NNW−SSE along the dominant set of fractures (joints) and the valley orientation (Fig. 1 and Figs. S3 and S11), indicating aquifer anisotropy and/or heterogeneity.

Asymmetric drawdown observed could be due to the dominant vertical joints oriented NNW−SSE as observed in local bedrock outcrops. Alternately, asymmetric drawdown could be due to openings between bedding planes that terminate in the valley wall (e.g., stress relief fracturing). Consistent with bedrock heterogeneity, the steep hydraulic gradient observed east of the pumping well (e.g., into the bedrock valley wall) suggests lower permeability in the more upland areas away from the incised valley. Shallow valley aquifer parameters were estimated: storativity (S) ~1.6×10^{-5}, maximum transmissivity tensor (Tss) ~5.9 m^2/d, and minimum transmissivity tensor (Tnn) ~2.6 m^2/d with a NNW−SSE major axis orientation. The geometric mean of principal transmissivities was estimated at 3.9 m^2/d; given a saturated well thickness of 23 m for Well 4, the hydraulic conductivity (K) is estimated at 2×10^{-6} m/s.

Welles 3-2H pressures and fracturing potential. Based upon the observed annular pressures recorded at gas well Welles 3-2H (~64 atm), it is possible that fracturing was induced near the well's surface casing shoe (base of surface casing), providing an additional migration pathway for contaminants. Although fracture gradients vary regionally, 0.16 atm/m is used as a guideline to avoid potential fracture propagation in PA injection wells (8). For gas well Welles 3-2H, the approximate threshold for fracture propagation would be an approximate pressure of 51 atm at the surface casing shoe—surface casing extends 320 m-bgs. Given the maximum recorded annular pressure of 64 atm in connection with Welles 3-2H, it is indeed possible that fracture propagation was induced, providing a pathway for contaminant migration. Notably, 196 bbl of cement (~31,100 L) was reportedly squeezed at a relatively shallow depth interval (~500–600 m-bgs) at Welles 3-2H as part of its remediation (Fig. S10).

Uses and sources of 2-BE. In addition to being used in gas drilling and HVHF fluids, 2-BE is used in industry as a solvent for paints and surface coatings and as an ingredient for paint thinners, herbicides, degreasers, dyes, soaps, and cosmetics. It is a fully miscible, clear liquid with an ether-like odor at thresholds of 0.10–0.40 ppm in air. Domestic US production of 2-BE has steadily increased—reported amounts include 59 million kilograms, 123 million kilograms, 136 million kilograms, and 185 million kilograms for years 1975, 1984, 1986, and 1995, respectively, by producers such as Dow Chemical, Eastman Chemical Co., Occidental Petroleum Corp., and Shell Chemical Co., among others. Besides areas undergoing gas drilling development, areas most prone to water resource discharges of 2-BE include those near manufacturing or processing facilities that use 2-BE, municipal landfills, hazardous waste sites, and areas treated with herbicides that contain 2-BE. Although not expected to be significant, release of 2-BE could also result from consumer product use, such as outdoor use of liquid cleaners and paints (9).

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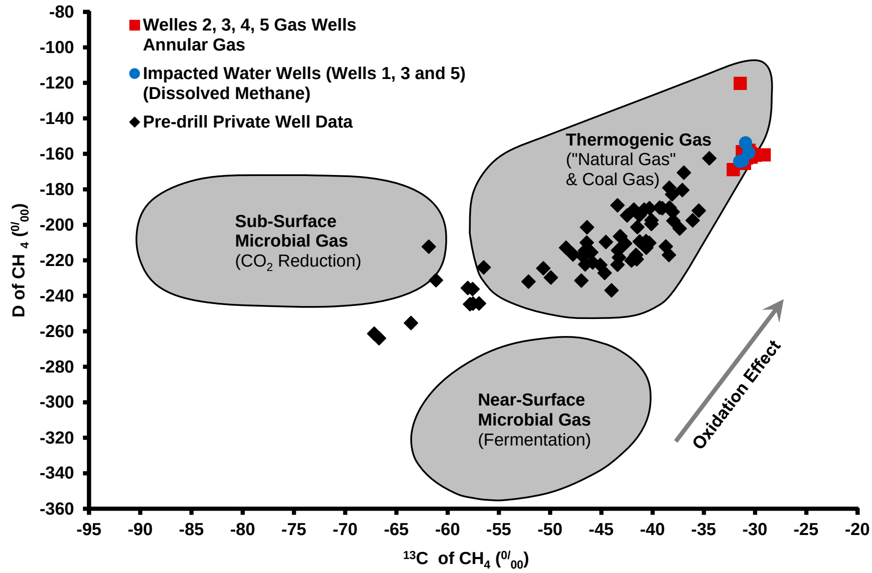


Fig. S1. Crossplot of δD of CH_4 vs. $\delta^{13}C$ of CH_4 (per mil) illustrating isotopic similarity between natural gas sampled from the annuli of gas wells (Welles 2, 3, 4, and 5 series) and impacted water wells (Wells 1, 3, and 5). Isotopic data were not available for other impacted water wells. Predrill private well data were collected throughout Bradford, Sullivan, Susquehanna, and Tioga counties in NE Pennsylvania (7). Regions for different types of microbial and thermogenic gas are illustrated (10).

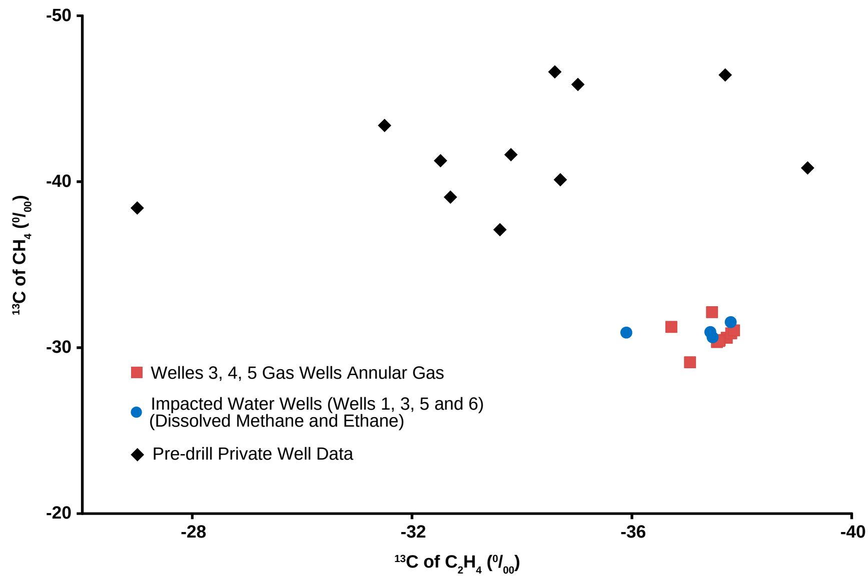


Fig. S2. Crossplot of $\delta^{13}C$ of CH_4 vs. $\delta^{13}C$ of C_2H_6 (per mil) illustrating isotopic similarity between natural gas sampled from annuli of gas wells (Welles 3, 4, and 5 series) and impacted water wells (Wells 1, 3, 5, and 6). Isotopic data were not available for other impacted water wells. Predrill private well data collected throughout Bradford, Sullivan, Susquehanna, and Tioga counties in NE Pennsylvania (7).

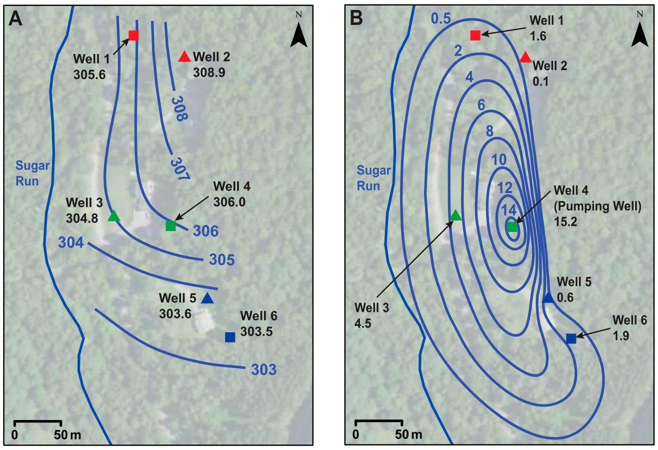


Fig. S3. (*A*) Groundwater elevation contours (meters above mean sea level) under ambient conditions illustrate groundwater convergence toward the valley center (Sugar Run tributary). (*B*) Drawdown (meters) induced by constant rate (25.8 L/min) 7-h aquifer test of Well 4. Using analysis methods outlined previously (11, 12), the maximum (T_{ss}) and minimum (T_{nn}) transmissivity components were estimated at 5.9 m^2/d and 2.6 m^2/d, respectively. The storage coefficient was estimated at 1.6×10^{-5}.

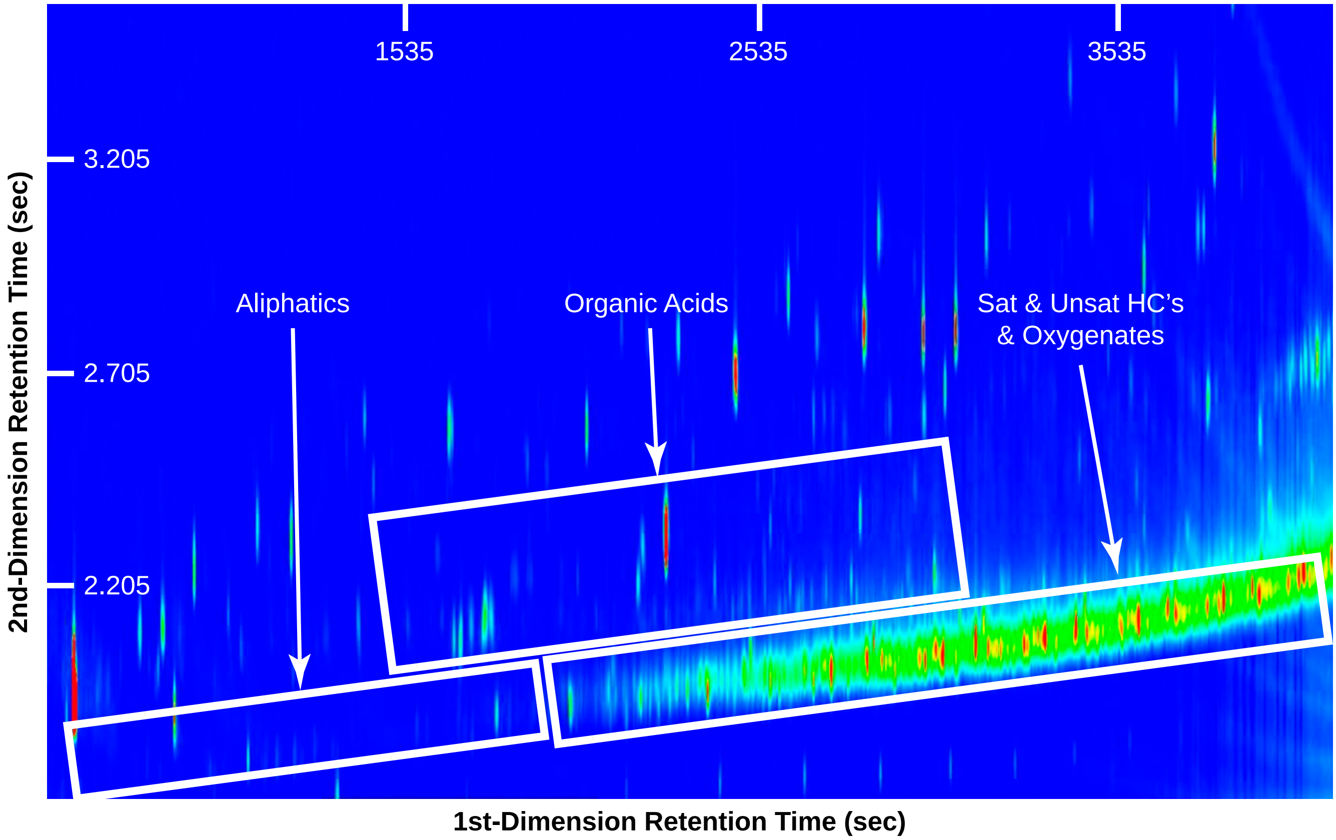


Fig. S4. GCxGC-TOFMS chromatogram illustrating UCM from Well 3 (PLG-12-60A), one of the original impacted household water wells. Compound classes are illustrated. Color variations indicate relative compound concentrations, with blue being the lowest and red being the highest.

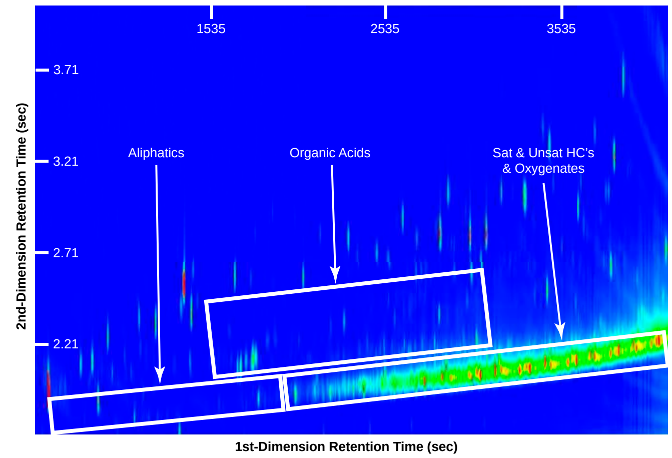


Fig. S5. GCxGC-TOFMS chromatogram illustrating UCM from Well 6 (PLG-12-64A), which was installed as a replacement for Well 5 by the gas company in August/September 2010 and exhibits impacts. Compound classes are illustrated. Color variations indicate relative compound concentrations, with blue being the lowest and red being the highest.

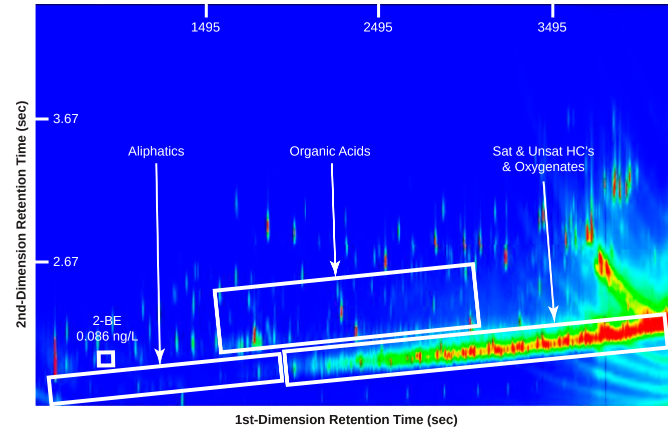


Fig. S6. GCxGC-TOFMS chromatogram illustrating UCM from Well 1 (PLG-12-68A) after purging, which was installed as a replacement for Well 2 by the gas company in August/September 2010 and exhibits impacts. The presence of 2-BE is still identified but at a lower concentration than prepurge Well 1 sample (compare Fig. 4*A*).

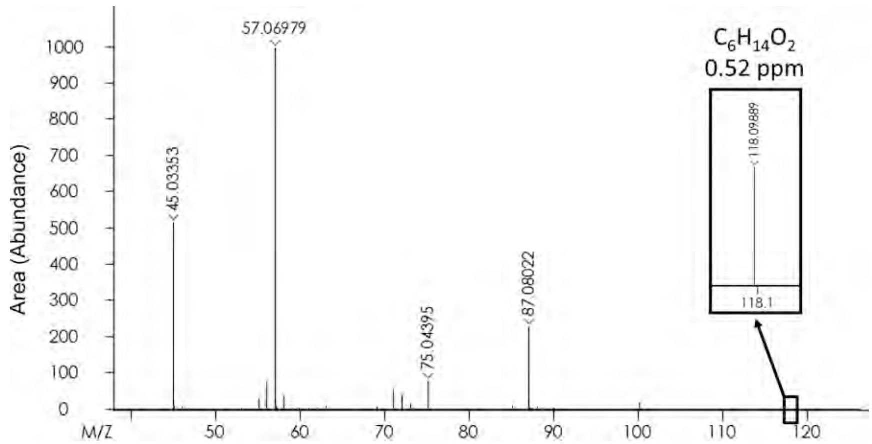


Fig. S7. The accurate high resolution mass spectrometer mass spectrum indicating presence of 2-BE in Well 1 (PLG-12-67A) before purging.

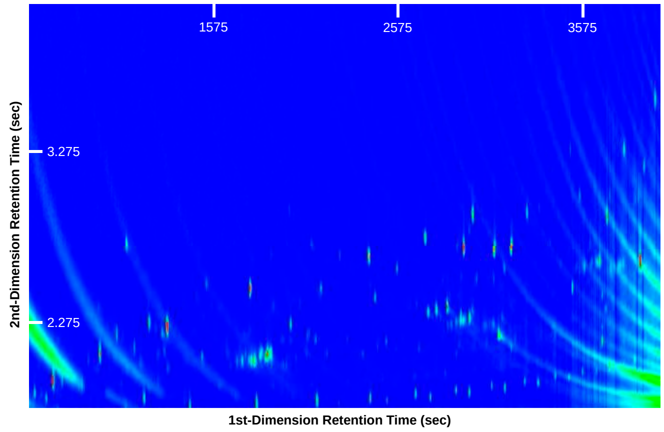


Fig. S8. GCxGC-TOFMS chromatogram illustrating absent UCM from background well B1 (bottle PLG-13-7A) that was not impacted by gas drilling activities. Other background wells (B2 and B3) produced similar GCxGC-TOFMS chromatograms, indicating the same.

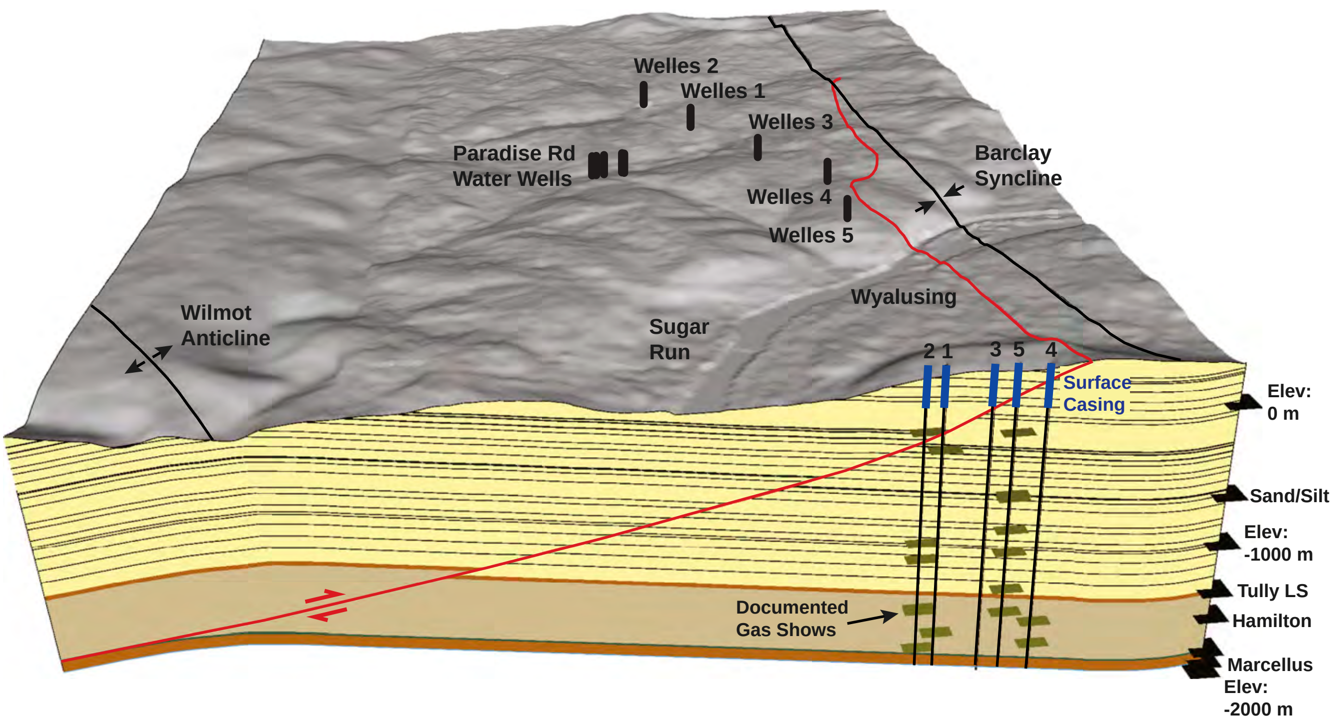


Fig. S9. Block diagram illustrating a shallow angle thrust fault (red line), Barclay and Wilmot structural fold surficial traces (surficial black lines), and bedding planes (subsurface black lines). Stratigraphic units and markers are illustrated on the right side. Viewpoint is toward the west. A light detection and ranging (LIDAR) digital elevation model (DEM) was used to construct the land surface. Water well positions (Wells 1 through 6) are illustrated. Generalized gas well depictions (Welles 1–5 series) are illustrated and projected to the front of the block for comparison with the thrust fault, bedding planes, and documented gas shows overlying the Marcellus Shale (see Fig. S10). In September 2010, gas was observed bubbling from the Susquehanna River in numerous locations between the communities of Sugar Run and Wyalusing. Gas bubbling ceased following gas well remedial activities conducted at the Welles 3, 4, and 5 well pads.

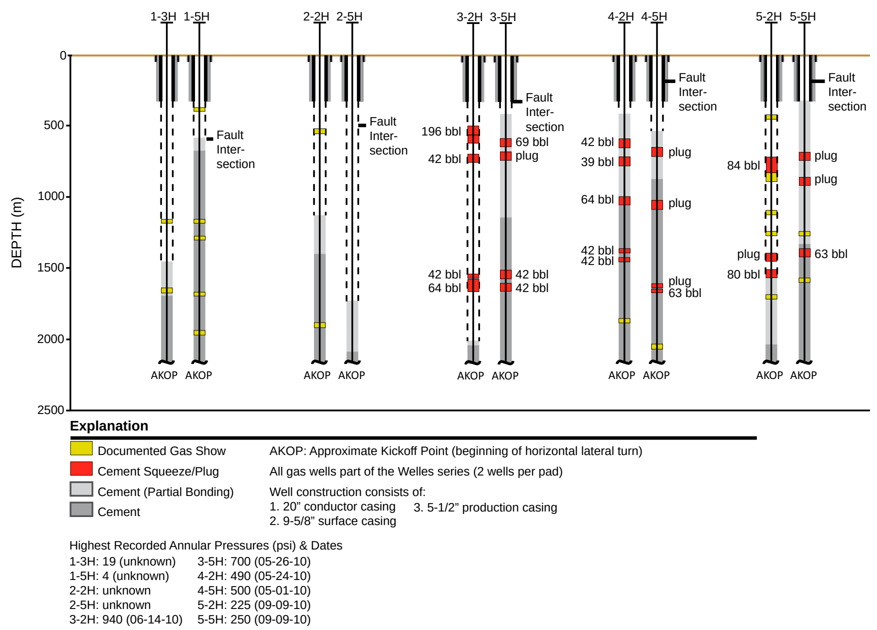


Fig. S10. Schematic illustrating construction of Welles 1–5 series gas wells. Depth intervals of gas shows are illustrated in yellow, as documented in gas well logs. Intervals illustrated in red indicate remedial activities, including cement squeezes and plugs with known quantities of cement used. Originally emplaced cement is illustrated in dark gray, and "partially bonded" cement is illustrated in light gray. Highest recorded gas well annular pressures (pounds per square inch) are provided with record date.

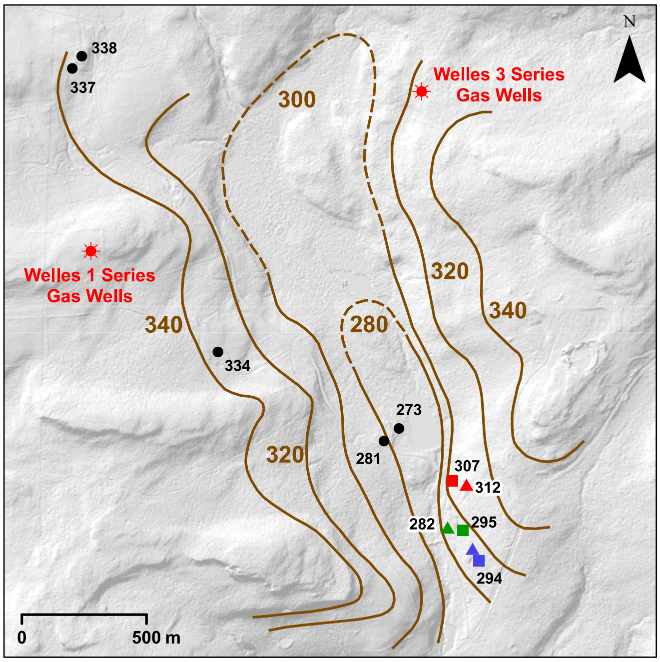


Fig. S11. LIDAR hillshade digital elevation map illustrating land surface with bedrock elevation contours in meters above mean sea level (brown lines). Dashed lines indicate uncertainty. Welles 1 and 3 series gas wells are illustrated as red asterisks. Control points and corresponding bedrock elevations are illustrated for Wells 1 and 2 (red), Wells 3 and 4 (green), Wells 5 and 6 (blue), and additional domestic well records obtained from the Pennsylvania Topographic and Geologic Survey's PaGWIS database (black circles). Squares and triangles represent replacement and original household wells, respectively. Like colors represent each household.

Table S1. Generalized timeline of events

Date, m/d/y	Event
04/23/2009	Welles 1 Pad constructed
05/15/2009	Welles 2 Pad constructed
06/15/2009	2 wells set on Welles 1 pad using 45 feet of conductor casing
06/28/2009	First spud of Welles 1-3H and 1-5H
08/07/2009	Leak out of a pit at Welles 1-3H, 1-5H
08/23/2009	Welles 3 Pad constructed
09/02/2009	Welles 1-3H, 1-5H cited by PADEP for discharge of contaminated fluids (from drilling or well) to ground
09/23/2009	Rig release from Welles pad 1
09/28/2009	First spud of Welles 2-2H and 2-5H
10/23/2009	Completion of Welles 2-2H
10/30/2009	First spud of Welles 3-2H and 3-5H
11/04/2009	Welles 4 Pad constructed
12/17/2009	Welles 5 Pad constructed
01/08/2010	First spud of Welles 4-2H and 4-5H
02/01/2010	Fracture stimulation (i.e., hydraulic fracturing), 20 stages, at Welles 1-3H and 1-5H
03/21/2010	Spud of Welles 5-2H and 5-5H
04/2/2010	1-3H initial annular gas pressure, 0 psi; 5-5H initial annular pressure, 0 psi; homeowner first notifies company of silt in a spring
04/14/2010	Drilling commences on Welles 5-2H
05/2/21010	Drilling finishes on Welles 5-2H
Early 05/2010	Homeowner notices sediment in water from well 3 (Fig. 1)
05/08/2010	Drilling completed for Welles 3-2H
05/12/2010	Rig release from Welles 3 pad
05/24/2010	Initial annular pressure on 3-2H, 950 psi, and for 3-5H, 700 psi
06/13/2010	Water pump has sediment in it at well 3
07/12/2010	Gas company notified of turbid water well 2 (Fig. 1); gas company observes sediment on filters in homeowner wells; registered water driller requested to investigate
07/12/2010	Homeowner at well 2 contacts gas company about turbidity; also turbidity issue at well 3
07/13/2010	Homeowner of well 2 notifies PA Department of Environmental Protection (DEP); company delivers water to both residences; homeowner tells gas company that their water from well 5 (Fig. 1) can be ignited, but gas company visits and ignition is not achieved; gas company delivers water for homeowners with wells 2 and 3
07/14/2010	DEP finds methane in well 3 but none in well 2
07/15/2010	DEP worker measures 3 vol.% methane in well 3 and none in well 2
07/17/2010	Water well driller retained by gas company notifies gas company that the water wells are bubbling at wells 3 and 2; gas company visits and observes the same
07/17/2010	Bubbling reported in well waters; well evacuated to allow recharge; lower explosive limit reported at 3% in well 3 and 68% in 2
07/19/2010	Letter sent to gas company by owner of well 3; gas company visits and sees no problems
07/20/2010	Welles 5-2H and 5-5Htreated by gas company
07/21/2010	Inspection of well 5 reveals no issues although some effervescence was observed, but no turbidity; gas company notifies DEP of the complaints and waits for DEP to indicate path forward
07/22/2010	Gas company is informed that a natural spring has dried up; gas company visits well 5 where the homeowner has been advised by a physician to not drink, cook, or bathe in the water
07/24/2010	Diagnostic tests run on Welles 3-5H and 3-2H to find problems (includes cement logging)
07/25/2010	Backhoe used to dig out cellar of Welles 3-2H to correct eccentric wellhead; unable to dig past big rock
07/26/2010	Four residents experiencing gas in water at faucets
07/30/2010	Another resident notifies gas company of turbidity in water
07/31/2010	Environmental teams for gas company collect samples of groundwater from residences in a screening sweep within 1-mile radius of Welles 1 and 3 pads
08/02/2010	Gas company installs methane monitor in well 3 (Fig. 1)
08/04/2010	Methane monitor sounds off at well 3 (Fig. 1); gas company responds to secure safety of residence and notify emergency responders
08/05/2010	Gas company makes an offer to replace water wells
08/06/2010	Four residences are set up by gas company with water tanks
08/06/2010	Track hoe used at Welles 3-2H to excavate cellar and repair eccentric wellhead; perforated shallow casing and squeezed with cement
08/10/2010	Shallow squeeze job on Welles 3-2H
08/13/2010	Squeeze job at two shallow depths on Welles 3-2H
08/17/2010	Gas company initiated drilling of replacement water well for a homeowner
08/19/2010	Perforated Welles-3-5H at shallow depth and pumped in 10 bbls of Na silicate, but unable to place cement; perforated shallow casing and squeezed in cement
08/20/2010	Installed methane monitors
08/26/2010	Completed water well for a homeowner

Table S1. Cont.

Date, m/d/y	Event
08/31/2010	Replacement water well started for a homeowner
09/01/2010	Another replacement water well started for a homeowner
09/02/2010	Second replacement water well finished for a homeowner
09/03/2010	Squeeze job at two shallow depths of Welles 3-5H with Na silicate and cement
09/03/1010	Ran temperature and audio log and performed squeeze job at an intermediate depth with cement (Welles 3-2H)
09/03/2010	Bubbles reported in Susquehanna River near Sugar Run, PA
09/04/2010	Ran temperature and audio log and did a cement squeeze job at intermediate depth at Welles 4-2H
09/04/2010	Ran temperature and audio log and did a cement squeeze job at intermediate depth at Welles 5-2H
09/07/2010	Replacement water well started for a homeowner
09/08/2010	Ran temperature and audio log and completed cement squeeze job at intermediate depth in Welles 5-5H
09/08/2010	Replacement water wells for two homeowners were completed
09/10/2010	Replacement water well completed for a homeowner
09/10/2010	Gas sensor and data logger installed in a residence
05/11/2011	PADEP cited gas company for violation of PA Oil and Gas Act and Clean Streams Law for allowing natural gas to enter aquifers; company had to identify, evaluate, and rehabilitate gas wells
09/29/2011	Welles 1-3H cited by PADEP for "failure to control residual waste to prevent water pollution"
11/29/2012	Welles 2-2H cited by PADEP for spill of high conductivity water on well pad
Fall 2012	Pumping test completed (Fig. S3)
11/11/2012 to 09/15/2013	Wells on Welles 2–5 well pads were hydraulically stimulated
10/18/2013	Spill on Welles 4–2H
11/04/2013	On PA DEP website under Welles 2-2H, Consent Agreements of Civil Penalty noted, $35,862 fine
10/18/2013	Spill on Welles 4-2H noted
10/25/2013	Spill associated with flowback fluids (10–15 gallons) noted on PA DEP website for Welles 5-6H

Table S2. Methane data used in initial investigation

	Analyst	Date, m/d/y	Methane, μg/L
Well 1	Unknown	9/14/2010	10,900
	Unknown	10/6/2010	24,500
	Unknown	10/13/2010	20,600
	Unknown	10/20/2010	8,820
	Unknown	3/1/2011	17,100
	Unknown	4/7/2011	14,200
	Unknown	5/23/2011	9,210
	Property owners' consultant	5/26/2011	7,000
	Unknown	6/8/2011	9,890
	Unknown	6/22/2011	10,400
	Unknown	7/6/2011	10,800
	Unknown	7/20/2011	6,650
	Unknown	8/3/2011	10,400
	Unknown	8/17/2011	8,880
	Unknown	9/2/2011	6,230
	Unknown	9/14/2011	9,870
	Unknown	9/29/2011	9,620
	Unknown	10/12/2011	4,100
	Unknown	10/31/2011	6,090
	Unknown	10/31/2011	10,000
	Unknown	11/9/2011	4,940
	Unknown	11/22/2011	5,510
	Property owners' consultant	11/29/2011	6,300
	Unknown	12/7/2011	3,600
	Unknown	12/27/2011	6,120
	Unknown	1/4/2012	5,020
	Unknown	1/18/2012	5,060
	Unknown	2/1/2012	6,100
	Property owners' consultant	3/26/2012	3,400
	Unknown	3/28/2012	6,460
	Gas company's consultant	5/9/2012	11,850
	Property owner's consultant	5/30/2012	7,300
	Property owner's consultant	5/31/2012	6,900
Well 2	Property owner's initial laboratory baseline	4/8/2010	<20
	Unknown	7/15/2010	2,690
	Unknown	7/21/2010	9,480
	Unknown	8/3/2010	95.7
	Unknown	9/15/2010	1,410
	Unknown	10/6/2010	2,780
	Unknown	10/13/2010	4,580
	Unknown	10/20/2010	1,780
	Unknown	10/31/2010	ND
	Gas company's consultant	5/8/2012	630
	Property owners' consultant	5/15/2012	15
Well 3	Unknown	7/15/2010	19,500
	Unknown	7/21/2010	29,700
	Unknown	8/4/2010	8,360
	Unknown	8/2/2010	5,020
	Gas company's consultant	8/19/2010	17,510
	Gas company's consultant	5/9/2012	34,520
	Property owners' consultant	5/16/2012	4,300
	Property owner' consultant	5/30/2012	14,000
Well 4	Unknown	9/13/2010	5,070
	Unknown	10/7/2010	4,620
	Unknown	10/14/2010	4,810
	Unknown	10/21/2010	3,710
	Unknown	2/17/2011	3,270
	Unknown	4/7/2011	7,290
	Unknown	5/23/2011	8,860
	Unknown	6/8/2011	8,790
	Unknown	6/22/2011	10,400

Table S2. Cont.

	Analyst	Date, m/d/y	Methane, μg/L
	Unknown	7/6/2011	6,240
	Unknown	7/22/2011	5,920
	Unknown	8/3/2011	5,490
	Unknown	8/17/2011	5,390
	Unknown	8/31/2011	2,330
	Unknown	9/16/2011	10,100
	Unknown	10/3/2011	9,670
	Unknown	10/12/2011	9,760
	Unknown	10/28/2011	10,800
	Unknown	11/9/2011	5,190
	Gas company's consultant	5/9/2012	32,060
	Property owners' consultant	5/30/2012	14,000
	Property owners' consultant	5/31/2012	11,000
Well 5	Unknown	7/21/2010	25,800
	Unknown	8/3/2010	10,700
	Unknown	9/15/2010	17,000
	Unknown	10/12/2010	14,900
	Unknown	10/19/2010	16,200
	Gas company's consultant	8/19/2010	16,000
	Gas company's consultant	5/7/2012	27,280
	Property owners' consultant	5/14/2012	12,000
Well 6	Unknown	9/13/2010	9,230
	Unknown	10/5/2010	10,200
	Unknown	10/12/2010	8,480
	Unknown	10/19/2010	9,820
	Unknown	2/17/2011	2,290
	Unknown	4/7/2011	10,000
	Unknown	5/23/2011	8,630
	Unknown	6/8/2011	7,710
	Unknown	6/22/2011	11,300
	Unknown	7/6/2011	9,310
	Unknown	7/22/2011	7,850
	Unknown	8/3/2011	5,330
	Unknown	8/17/2011	8,380
	Unknown	8/31/2011	2,210
	Unknown	9/16/2011	10,800
	Unknown	10/4/2011	14,500
	Unknown	10/12/2011	13,700
	Unknown	10/28/2011	13,800
	Unknown	11/9/2011	8,020
	Gas company's consultant	5/9/2012	46,640
	Property owners' consultant	5/30/2012	14,000
	Property owners' consultant	5/31/2012	20,000

ND, not determined.

Table S3. GCxGC-TOFMS instrument parameters

	Parameter
GC instrument	
Carrier gas	helium
mode	split 10:1
Flow	1.00 mL/min
Septum purge flow	3.00 mL/min
Injection volume	1 μL
Injector temperature	250 °C
Transfer line temperature	300 °C
Oven equilibration time	0.5 min
First dimension oven*	
Initial temperature	40 °C
Hold time	0.20 min
Rate	1.60 °C/min
Final temperature	315 °C
Modulator	
Temperature offset	15 °C
Modulator period	5.00 s
Hot pulse time	0.6 s
Cool time	1.9 s
Second dimension oven†	
Initial temperature	55 °C
Hold time	0.20 min
Rate	1.60 °C/min
Final temperature	330 °C
Mass spectrometer	
Acquisition delay	320 s
Mass range	45–550 u
Acquisition rate	200 spectra/s
Detector voltage	2,000 V
Ionization energy	70 eV
Mass defect	0 mu/100 u
Ion source temperature	200 °C

*Rtx-Dioxin2, 60 m × 0.25 mm ID × 0.25 μm df.
†Rxi-17SilMS, 1.9 m × 0.15 mm ID × 0.15 μm df.

Table S4. Site descriptions for PSU analyses

Site names	Sample site	Sample site	Latitude	Longitude	GCxGC-TOFMS bottle ID	Sample date, m/d/y	Sampling protocol
		Analyzed with GCxGC: impacted houses					
Well 3 (PLG 12-60)	Fig. 1*B*	original well	41.642	−76.295	PLG-12–60 A	11/7/2012	sampled before purging
Well 6 (PLG 12-65)	Fig. 1*B*	replacement well	41.641	−76.294	PLG-12–64 A	11/7/2012	after purging ~5 min
Well 1 (PLG 12-69)	Fig. 1*B*	replacement well	41.643	−76.294	PLG 12–67 A	11/7/2012	before purging
					PLG 12–68 A	11/7/2012	after purging ~10 min
		Analyzed with GCxGC: nonimpacted houses					
Well B1 (PLG 13-7)	5 km from incident	nonimpacted household well	41.646	−76.286	PLG 13–7 A	3/16/2013	water purged
Well B2 (PLG-13-5)	5 km from incident	nonimpacted household well	41.628	−76.324	PLG 13–5B	3/16/2013	water purged
Well B3 (PLG-13-6)	5 km from incident	nonimpacted household well	41.671	−76.332	PLG 13–6A	3/16/2013	water purged
		Analyzed for inorganic solutes and/or dissolved gases					
PLG-12-33	on Route 29 near Salt Spring Park	private home, Susquehanna County	41.964	−75.819	NA	7/12/2012	water purged
PLG-12-34	Salt Spring State Park	Salt Springs, Susquehanna County	41.964	−75.819	NA	7/12/2012	see *Methods*
PLG-12-70	Wyalusing, PA	new house	41.708	−76.261	NA	11/7/2012	water purged
PLG-13-2	within 5 km of impacted valley	nonimpacted household well	41.643	−76.278	NA	3/16/2013	water purged
PLG-13-4	within 5 km of impacted valley	nonimpacted household well	41.648	−76.292	NA	3/2/2013	water purged

NA, not analyzed with GCxGC-TOFMS.

Table S5. Hydrocarbon analyses (Pennsylvania State University and Isotech)

Site ID	Bottle ID*	Sample date, m/d/y	Location of analysis	Bottle	Biocide	CH_4 mg/L	STD%	C_2H_6, mg/L	STD%	$\delta^{13}CH_4$	$\delta^{13}C_2H_6$
Well 6 on Fig. 1	1	11/7/2012	Penn State	Isotech	benzyl Cl	14.88	17.06	0.21	2.91	−31.9	—
(replacement well)	2	11/7/2012	Isotech	Isotech	benzyl Cl	20.00	—	0.36	—	−30.9	−35.6
	2	11/7/2012	PSU	Isotech	benzyl Cl	16.48	12.40	0.25	3.24	−30.8	—
Well 1 on Fig. 1	1	11/7/2012	PSU	Isotech	benzyl Cl	6.76	19.28	0.11	8.53	−33.3	—
(replacement well)	2	11/7/2012	Isotech	Isotech	benzyl Cl	4.50	—	0.15	—	−31.5	−37.8
	2	11/7/2012	PSU	Isotech	benzyl Cl	5.00	19.34	0.13	5.27	−32.8	—
PLG 12-70 (new house)	70	11/7/2012	PSU	125 mL serum	benzyl Cl	0.80	0.21	—	—	−67.9	—
	70NB	11/7/2012	PSU	125 mL serum	no biocide	0.90	0.89	—	—	−64.0	—
PLG-12-34 (Salt Springs)	PLG-12-34A	7/12/2012	PSU	125 mL serum	Na azide	35.27	5.89	0.37	0.36		—
	PLG-12-34B	7/12/2012	PSU	125 mL serum	Na azide	36.66	5.19	0.36	7.22		—
	PLG-12-34C	7/12/2012	PSU	125 mL serum	Na azide	33.61	2.9	0.3	1.18		—

*Where a 1 or 2 are indicated, two bottles were collected at the site: one sent to Isotech (2) and then back to Pennsylvania State University (PSU) for analysis, the other (1) only analyzed at PSU.

Table S6. Inorganic analyses, mg/L

Site ID	Date, m/d/y	Ba (0.005)	Ca (0.01)	Fe (0.01)	K (0.01)	Mg (0.01)	Na (0.01)	P (0.01)	Si (0.01)	Sr (0.005)	Cl	SO_4	NO_3	Br
PLG 12-60	11/7/2012	0.2	26.1	0.18	1.46	4.40	31.3	0.02	4.59	0.49	6.6	9.4	<0.7	<0.1
PLG 12-65	11/7/2012	0.2	36.7	0.20	3.85	6.30	18.6	<0.01	4.52	0.95	19	11	4.9	<0.1
PLG 12-70	11/7/2012	0.1	43.3	<0.01	1.06	11.0	17.4	<0.01	4.88	0.25	0.98	19	<0.7	<0.1
PLG-12-33	7/12/2012	0.2	25.5	0.22	1.45	8.40	50.5	0.02	5.53	0.52	5.3	18	<0.4	<0.1
PLG-12-34	7/12/2012	110	367	1.61	13.5	55.0	1,800	0.70	3.75	65.8	2,680	<1.9	<0.4	48.1
PLG-12-69*	7/12/2012	0.2	28.8	0.04	1.62	4.20	30.3	0.06	4.77	1.33	14	6.8	<0.4	<0.1
PLG-12-69†	7/12/2012	0.2	28.1	<0.01	1.68	4.10	30.1	0.20	4.69	1.31	13	7.5	<0.4	<0.1
PLG 13-2	3/2/2013	0.3	40.1	<0.01	2.03	5.22	20.4	0.01	5.35	2.06	5.7	14	0.3	0.01
PLG 13-4	3/2/2013	0.5	28.5	<0.01	2.72	3.02	28.2	<0.01	4.96	1.80	9.9	7.4	<0.4	0.02
PLG 13-5	3/2/2013	0.2	63.6	<0.01	1.13	9.26	12.1	<0.01	4.59	0.20	28	20	2.7	<0.01
PLG 13-7	3/16/2013	0.3	54.5	<0.01	1.41	7.53	9.1	<0.01	5.15	0.85	34	15	0.3	<0.01
PLG-13-6	3/2/2013	0.2	46.6	<0.01	1.20	6.48	8.2	0.06	4.87	0.41	8.3	16	1.3	<0.01

Detection limits are given in parentheses next to element, if applicable.
*Prepurge.
†Postpurge.

Table S7. List of surrogate compounds used in analyses

Compound name	CAS no.	Concentration in final extract, pg/uL
2-Fluorobiphenyl	321-60-8	200
Nitrobenzene-d5	4165-60-0	200
p-Terphenyl-d14	1718-51-0	200
2-Chlorophenol-d4	93951-73-6	200
2-Fluorophenol	367-12-4	200
Phenol-d6	13127-88-3	200
2,4,6-Tribromophenol	118-79-6	200
PCB 18	37680-65-2	200
PCB 28	7012-37-5	200
PCB 52	35693-99-3	200
Triphenylmethane	519-73-3	40
Triphenylphosphate	115-86-6	80
Tris-(1,3-dichloroisopropyl)phosphate	13674-87-8	200

Table S8. Reported hydrofracturing compounds used in Welles 2-5H

Compound	Maximum concentration in hydraulic fracturing fluid, % by mass
Hydrochloric acid	0.03543
Trisodium nitrilotriacetate	0.00056
Sodium sulfate	0.00003
Sodium hydroxide	0.00001
Methanol (methy alcohol)	0.00021
Ethoxylated alcohols (C14–15)	0.00011
Modified thiourea polymer	0.00011
Propargyl alcohol (2-propynol)	0.00004
Alkenes	0.00002
2-butoxyethanol (ethylene glycol monobutyl ether)	0.00006
Methanol (methyl alcohol)	0.00006
Diethanolamine	0.00001
Petroleum distillate hydrotreated light	0.01532
Ammonium acetate	0.00263
Sodium polyacrylate	0.00881
Glutararaldehyde	0.00719
Didecyl dimethyl ammonium chloride	0.00213
Quaternary ammonium compound	0.00147
Ethanol	0.00107
Petroleum distillate lydrotreated Light	0.00025
Quaternary ammonium chloride (ammonium chloride)	0.00011
Alcohol ethoxylated C12–C16	0.00004
Ethoxylated alcohols	0.00004
Alchohol ethoxylate	0.00004
Alcohols, C12–C14—secondary, ethoxylated	Not available
Ethoxylated oleylamine	Not available
Polyacrylamide (acrylamide, ammonium acrylate copolymer)	Not available
Polyethylene glycol monnleate	Not available
Sobitan monooleate	Not available
Sorbitol tetraoleate	Not available

From FracFocus.org.

FORM 5A
Rev 06/12

State of Colorado
Oil and Gas Conservation Commission

1120 Lincoln Street, Suite 801, Denver, Colorado 80203 Phone: (303) 894-2100 Fax: (303) 894-2109

DE	ET	OE	ES

Document Number: 400453700

Date Received: 08/01/2013

COMPLETED INTERVAL REPORT

The completed interval Report, Form 5A, shall be submitted within thirty (30) days of completing a formation (successful or not), when a formation is temporarily abandoned or permanently abandoned, for a recompletion, reperforation or restimulation, or when a formation is commingled. Fill out a section for each formation. Attach as many pages as required to fully describe the work. List in order of completion.

1. OGCC Operator Number: 100185
2. Name of Operator: ENCANA OIL & GAS (USA) INC
3. Address: 370 17TH ST STE 1700
City: DENVER State: CO Zip: 80202-

4. Contact Name: Cristi Cota-Smith
Phone: (720) 876-3083
Fax: (720) 876-4083

5. API Number 05-045-20640-00
6. County: GARFIELD
7. Well Name: SG
Well Number: 8508D-21 N22496
8. Location: QtrQtr: SESW Section: 22 Township: 4S Range: 96W Meridian: 6
9. Field Name: WILDCAT Field Code: 99999

Completed Interval

FORMATION: WILLIAMS FORK Status: PRODUCING Treatment Type: FRACTURE STIMULATION

Treatment Date: 03/11/2013 End Date: 03/25/2013 Date of First Production this formation: 06/20/2013

Perforations Top: 8060 Bottom: 11838 No. Holes: 330 Hole size: 0.42

Provide a brief summary of the formation treatment: Open Hole: ☐

Stage 1 - Stage 11 treated with a total of 190,980 bbls of Slickwater (BWS).

This formation is commingled with another formation: ☐ Yes ☒ No

Total fluid used in treatment (bbl): 190980
Total gas used in treatment (mcf): 0
Type of gas used in treatment:
Total acid used in treatment (bbl): 0
Recycled water used in treatment (bbl): 190980
Fresh water used in treatment (bbl): 0
Total proppant used (lbs): 0

Max pressure during treatment (psi): 7082
Fluid density at initial fracture (lbs/gal): 8.40
Min frac gradient (psi/ft): 0.65
Number of staged intervals: 11
Flowback volume recovered (bbl):
Disposition method for flowback: RECYCLE
Rule 805 green completion techniques were utilized: ☒
Reason why green completion not utilized:

Fracture stimulations must be reported on FracFocus.org

Test Information:

Date: 07/01/2013 Hours: 24 Bbl oil: 0 Mcf Gas: 921 Bbl H2O: 160

Calculated 24 hour rate: Bbl oil: 0 Mcf Gas: 921 Bbl H2O: 160 GOR: 0

Test Method: Flowing Casing PSI: 2798 Tubing PSI: 0 Choke Size: 22/64

Gas Disposition: SOLD Gas Type: DRY Btu Gas: 1170 API Gravity Oil: 0

Tubing Size: Tubing Setting Depth: Tbg setting date: Packer Depth:

Reason for Non-Production:

Date formation Abandoned: Squeeze: ☐ Yes ☐ No If yes, number of sacks cmt

** Bridge Plug Depth: ** Sacks cement on top: ** Wireline and Cement Job Summary must be attached.

Comment:

I hereby certify all statements made in this form are, to the best of my knowledge, true, correct, and complete.

Signed: Print Name: Cristi L. Cota-Smith

Title: Permitting Analyst Date: 8/1/2013 Email: cristi.cota-smith@encana.com

Attachment Check List

Att Doc Num	Name
400453700	FORM 5A SUBMITTED
400453702	WELLBORE DIAGRAM

Total Attach: 2 Files

General Comments

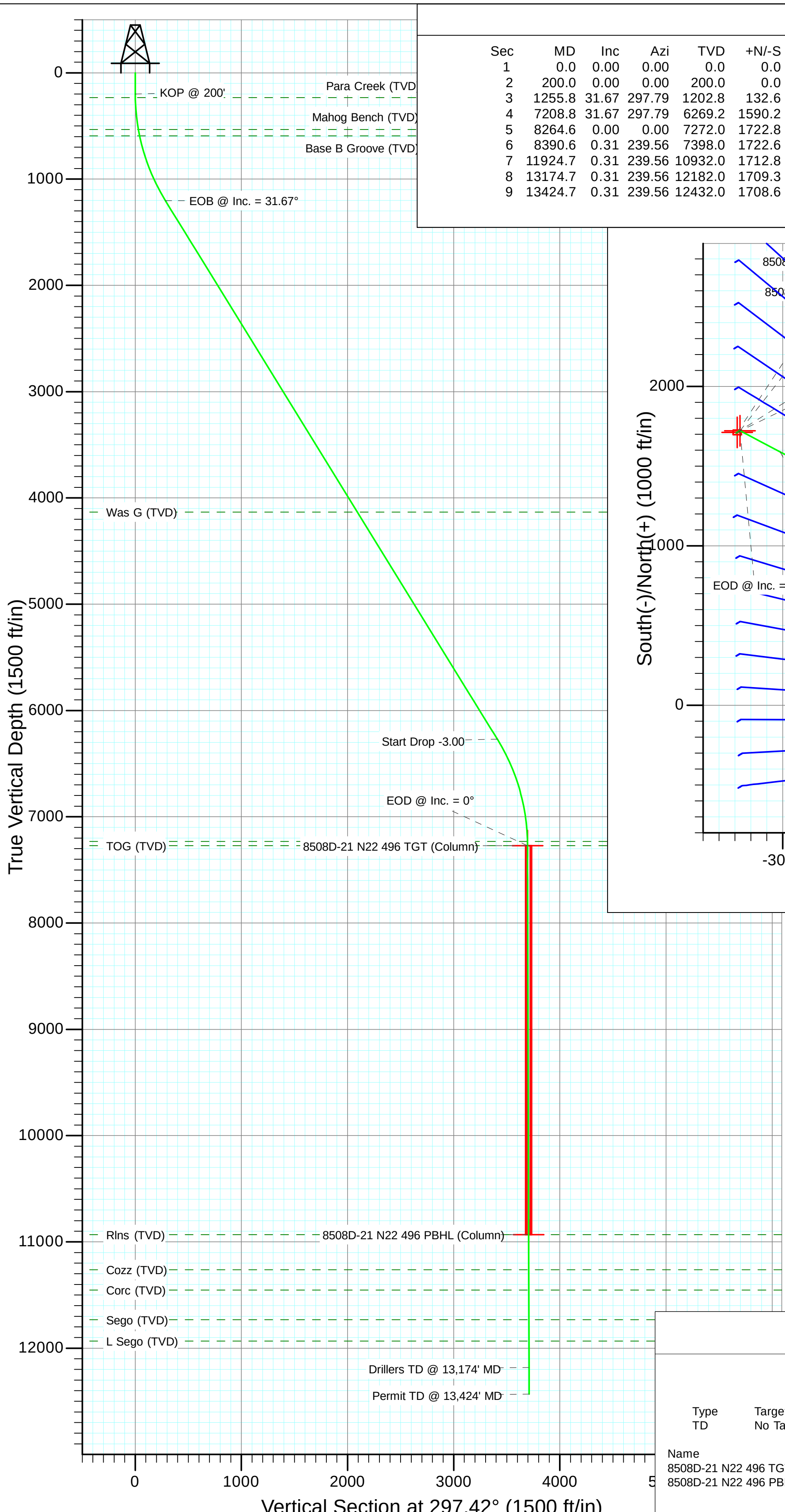
User Group	Comment	Comment Date
Permit	Passes Permitting.	12/6/2013 3:10:41 PM

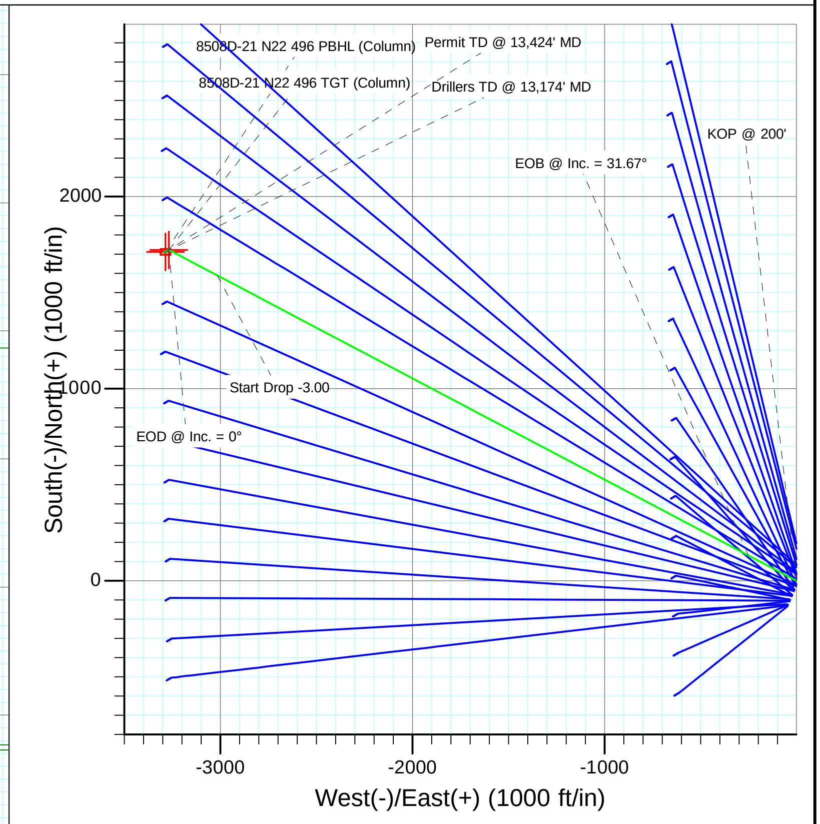
Total: 1 comment(s)

Project: Story Gulch
Site: S22-T4S-R96W (N22 496) (Column Pattern)
Well: 8508D-21 N22 496
Wellbore: DD
Design: Plan #1

SECTION DETAILS

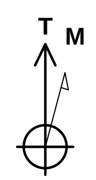
Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	Dleg	TFace	VSect	Target
1	0.0	0.00	0.00	0.0	0.0	0.0	0.00	0.00	0.0	
2	200.0	0.00	0.00	200.0	0.0	0.0	0.00	0.00	0.0	
3	1255.8	31.67	297.79	1202.8	132.6	-251.7	3.00	297.79	284.5	
4	7208.8	31.67	297.79	6269.2	1590.2	-3016.9	0.00	0.00	3410.3	
5	8264.6	0.00	0.00	7272.0	1722.8	-3268.6	3.00	180.00	3694.8	8508D-21 N22 496 TGT (Column)
6	8390.6	0.31	239.56	7398.0	1722.6	-3268.9	0.25	239.56	3694.9	
7	11924.7	0.31	239.56	10932.0	1712.8	-3285.6	0.00	0.00	3705.3	8508D-21 N22 496 PBHL (Column)
8	13174.7	0.31	239.56	12182.0	1709.3	-3291.6	0.00	0.00	3708.9	
9	13424.7	0.31	239.56	12432.0	1708.6	-3292.8	0.00	0.00	3709.7	





FORMATION TOP DETAILS

TVDPath	MDPath	Formation
232.0	232.0	Para Creek (TVD)
532.0	533.7	Mahog Bench (TVD)
592.0	594.8	Base B Groove (TVD)
4132.0	4697.6	Was G (TVD)
7232.0	8224.6	WF (TVD)
7272.0	8264.6	TOG (TVD)
10932.0	11924.7	Rlns (TVD)
11262.0	12254.7	Cozz (TVD)
11452.0	12444.7	Corc (TVD)
11732.0	12724.7	Sego (TVD)
11932.0	12924.7	L Sego (TVD)



Azimuths to True North
Magnetic North: 10.52°

Magnetic Field
Strength: 52372.2snT
Dip Angle: 65.88°
Date: 12/2/2010
Model: IGRF2010

Plan #1
8508D-21 N22 496
WELL @ 7602.0ft (Original Well Elev)

North American Datum 1983
Well 8508D-21 N22 496, True North

Type	Target	Azimuth	Origin Type	N/S	E/W	From TVD
TD	No Target (Freehand)	297.42	Slot	0.0	0.0	0.0

Name	TVD	+N/-S	+E/-W	Latitude	Longitude
8508D-21 N22 496 TGT (Column)	7272.0	1722.8	-3268.6	39° 41' 19.71 N	108° 10' 7.34 W
8508D-21 N22 496 PBHL (Column)	10932.0	1712.8	-3285.6	39° 41' 19.61 N	108° 10' 7.55 W

Cathedral Energy

Planning Report

Database:	EDM 5000.1 US Multi Users DB	**Local Co-ordinate Reference:**	Well 8508D-21 N22 496
Company:	EnCana Oil & Gas (USA) Inc	**TVD Reference:**	WELL @ 7602.0ft (Original Well Elev)
Project:	Story Gulch	**MD Reference:**	WELL @ 7602.0ft (Original Well Elev)
Site:	S22-T4S-R96W (N22 496) (Column Pattern)	**North Reference:**	True
Well:	8508D-21 N22 496	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	DD		
Design:	Plan #1		

Project	Story Gulch		
Map System:	US State Plane 1983	**System Datum:**	Mean Sea Level
Geo Datum:	North American Datum 1983		
Map Zone:	Colorado Central Zone		

Site	S22-T4S-R96W (N22 496) (Column Pattern)				
Site Position:		**Northing:**	1,685,048.56 ft	**Latitude:**	39° 41' 3.24 N
From:	Lat/Long	**Easting:**	2,252,316.79 ft	**Longitude:**	108° 9' 25.11 W
Position Uncertainty:	0.0 ft	**Slot Radius:**	13.200 in	**Grid Convergence:**	-1.68 °

Well	8508D-21 N22 496					
Well Position	**+N/-S**	0.0 ft	**Northing:**	1,684,993.70 ft	**Latitude:**	39° 41' 2.69 N
	+E/-W	0.0 ft	**Easting:**	2,252,282.84 ft	**Longitude:**	108° 9' 25.52 W
Position Uncertainty		0.0 ft	**Wellhead Elevation:**	ft	**Ground Level:**	7,569.0 ft

Wellbore DD

Magnetics	Model Name	Sample Date	Declination (°)	Dip Angle (°)	Field Strength (nT)
	IGRF2010	12/2/2010	10.52	65.88	52,372

Design Plan #1

Audit Notes:

Version:		**Phase:**	PLAN	**Tie On Depth:**	0.0

Vertical Section:	Depth From (TVD) (ft)	+N/-S (ft)	+E/-W (ft)	Direction (°)
	0.0	0.0	0.0	297.42

Plan Sections

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Turn Rate (°/100ft)	TFO (°)	Target
0.0	0.00	0.00	0.0	0.0	0.0	0.00	0.00	0.00	0.00	
200.0	0.00	0.00	200.0	0.0	0.0	0.00	0.00	0.00	0.00	
1,255.8	31.67	297.79	1,202.8	132.6	-251.7	3.00	3.00	0.00	297.79	
7,208.8	31.67	297.79	6,269.2	1,590.2	-3,016.9	0.00	0.00	0.00	0.00	
8,264.6	0.00	0.00	7,272.0	1,722.8	-3,268.6	3.00	-3.00	0.00	180.00	8508D-21 N22 496 T(
8,390.6	0.31	239.56	7,398.0	1,722.6	-3,268.9	0.25	0.25	-95.61	239.56	
11,924.7	0.31	239.56	10,932.0	1,712.8	-3,285.6	0.00	0.00	0.00	0.00	8508D-21 N22 496 PI
13,174.7	0.31	239.56	12,182.0	1,709.3	-3,291.6	0.00	0.00	0.00	0.00	
13,424.7	0.31	239.56	12,432.0	1,708.6	-3,292.8	0.00	0.00	0.00	0.00	

Cathedral Energy
Planning Report

Database:	EDM 5000.1 US Multi Users DB	**Local Co-ordinate Reference:**	Well 8508D-21 N22 496
Company:	EnCana Oil & Gas (USA) Inc	**TVD Reference:**	WELL @ 7602.0ft (Original Well Elev)
Project:	Story Gulch	**MD Reference:**	WELL @ 7602.0ft (Original Well Elev)
Site:	S22-T4S-R96W (N22 496) (Column Pattern)	**North Reference:**	True
Well:	8508D-21 N22 496	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	DD		
Design:	Plan #1		

Planned Survey

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Vertical Section (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Comments / Formations
0.0	0.00	0.00	0.0	0.0	0.0	0.0	0.00	0.00	
100.0	0.00	0.00	100.0	0.0	0.0	0.0	0.00	0.00	
200.0	0.00	0.00	200.0	0.0	0.0	0.0	0.00	0.00	KOP @ 200'
232.0	0.96	297.79	232.0	0.1	-0.2	0.3	3.00	3.00	Para Creek (TVD)
300.0	3.00	297.79	300.0	1.2	-2.3	2.6	3.00	3.00	
400.0	6.00	297.79	399.6	4.9	-9.3	10.5	3.00	3.00	
500.0	9.00	297.79	498.8	11.0	-20.8	23.5	3.00	3.00	
533.7	10.01	297.79	532.0	13.6	-25.7	29.1	3.00	3.00	Mahog Bench (TVD)
594.8	11.84	297.79	592.0	19.0	-36.0	40.7	3.00	3.00	Base B Groove (TVD)
600.0	12.00	297.79	597.1	19.5	-36.9	41.7	3.00	3.00	
700.0	15.00	297.79	694.3	30.3	-57.6	65.1	3.00	3.00	
800.0	18.00	297.79	790.2	43.6	-82.7	93.5	3.00	3.00	
900.0	21.00	297.79	884.4	59.1	-112.2	126.8	3.00	3.00	
1,000.0	24.00	297.79	976.8	77.0	-146.1	165.1	3.00	3.00	
1,100.0	27.00	297.79	1,067.1	97.1	-184.1	208.2	3.00	3.00	
1,200.0	30.00	297.79	1,154.9	119.3	-226.4	255.9	3.00	3.00	
1,255.8	31.67	297.79	1,202.8	132.6	-251.7	284.5	3.00	3.00	EOB @ Inc. = 31.67°
1,300.0	31.67	297.79	1,240.5	143.5	-272.2	307.7	0.00	0.00	
1,400.0	31.67	297.79	1,325.6	167.9	-318.6	360.2	0.00	0.00	
1,500.0	31.67	297.79	1,410.7	192.4	-365.1	412.7	0.00	0.00	
1,600.0	31.67	297.79	1,495.8	216.9	-411.5	465.2	0.00	0.00	
1,700.0	31.67	297.79	1,580.9	241.4	-458.0	517.7	0.00	0.00	
1,800.0	31.67	297.79	1,666.0	265.9	-504.4	570.2	0.00	0.00	
1,900.0	31.67	297.79	1,751.1	290.4	-550.9	622.7	0.00	0.00	
2,000.0	31.67	297.79	1,836.2	314.8	-597.4	675.2	0.00	0.00	
2,100.0	31.67	297.79	1,921.3	339.3	-643.8	727.7	0.00	0.00	
2,200.0	31.67	297.79	2,006.4	363.8	-690.3	780.2	0.00	0.00	
2,300.0	31.67	297.79	2,091.5	388.3	-736.7	832.8	0.00	0.00	
2,400.0	31.67	297.79	2,176.6	412.8	-783.2	885.3	0.00	0.00	
2,500.0	31.67	297.79	2,261.7	437.3	-829.6	937.8	0.00	0.00	
2,600.0	31.67	297.79	2,346.8	461.8	-876.1	990.3	0.00	0.00	
2,700.0	31.67	297.79	2,431.9	486.2	-922.5	1,042.8	0.00	0.00	
2,800.0	31.67	297.79	2,517.0	510.7	-969.0	1,095.3	0.00	0.00	
2,900.0	31.67	297.79	2,602.1	535.2	-1,015.4	1,147.8	0.00	0.00	
3,000.0	31.67	297.79	2,687.2	559.7	-1,061.9	1,200.3	0.00	0.00	
3,100.0	31.67	297.79	2,772.3	584.2	-1,108.3	1,252.8	0.00	0.00	
3,200.0	31.67	297.79	2,857.4	608.7	-1,154.8	1,305.3	0.00	0.00	
3,300.0	31.67	297.79	2,942.5	633.1	-1,201.2	1,357.8	0.00	0.00	
3,400.0	31.67	297.79	3,027.7	657.6	-1,247.7	1,410.3	0.00	0.00	
3,500.0	31.67	297.79	3,112.8	682.1	-1,294.1	1,462.9	0.00	0.00	
3,600.0	31.67	297.79	3,197.9	706.6	-1,340.6	1,515.4	0.00	0.00	
3,700.0	31.67	297.79	3,283.0	731.1	-1,387.0	1,567.9	0.00	0.00	
3,800.0	31.67	297.79	3,368.1	755.6	-1,433.5	1,620.4	0.00	0.00	
3,900.0	31.67	297.79	3,453.2	780.0	-1,479.9	1,672.9	0.00	0.00	
4,000.0	31.67	297.79	3,538.3	804.5	-1,526.4	1,725.4	0.00	0.00	
4,100.0	31.67	297.79	3,623.4	829.0	-1,572.8	1,777.9	0.00	0.00	
4,200.0	31.67	297.79	3,708.5	853.5	-1,619.3	1,830.4	0.00	0.00	
4,300.0	31.67	297.79	3,793.6	878.0	-1,665.7	1,882.9	0.00	0.00	
4,400.0	31.67	297.79	3,878.7	902.5	-1,712.2	1,935.4	0.00	0.00	
4,500.0	31.67	297.79	3,963.8	926.9	-1,758.6	1,987.9	0.00	0.00	
4,600.0	31.67	297.79	4,048.9	951.4	-1,805.1	2,040.4	0.00	0.00	
4,697.6	31.67	297.79	4,132.0	975.3	-1,850.4	2,091.7	0.00	0.00	Was G (TVD)

Cathedral Energy

Planning Report

Database:	EDM 5000.1 US Multi Users DB	**Local Co-ordinate Reference:**	Well 8508D-21 N22 496
Company:	EnCana Oil & Gas (USA) Inc	**TVD Reference:**	WELL @ 7602.0ft (Original Well Elev)
Project:	Story Gulch	**MD Reference:**	WELL @ 7602.0ft (Original Well Elev)
Site:	S22-T4S-R96W (N22 496) (Column Pattern)	**North Reference:**	True
Well:	8508D-21 N22 496	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	DD		
Design:	Plan #1		

Planned Survey

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Vertical Section (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Comments / Formations
4,700.0	31.67	297.79	4,134.0	975.9	-1,851.5	2,092.9	0.00	0.00	
4,800.0	31.67	297.79	4,219.1	1,000.4	-1,898.0	2,145.5	0.00	0.00	
4,900.0	31.67	297.79	4,304.2	1,024.9	-1,944.4	2,198.0	0.00	0.00	
5,000.0	31.67	297.79	4,389.3	1,049.4	-1,990.9	2,250.5	0.00	0.00	
5,100.0	31.67	297.79	4,474.4	1,073.8	-2,037.3	2,303.0	0.00	0.00	
5,200.0	31.67	297.79	4,559.5	1,098.3	-2,083.8	2,355.5	0.00	0.00	
5,300.0	31.67	297.79	4,644.6	1,122.8	-2,130.3	2,408.0	0.00	0.00	
5,400.0	31.67	297.79	4,729.7	1,147.3	-2,176.7	2,460.5	0.00	0.00	
5,500.0	31.67	297.79	4,814.9	1,171.8	-2,223.2	2,513.0	0.00	0.00	
5,600.0	31.67	297.79	4,900.0	1,196.3	-2,269.6	2,565.5	0.00	0.00	
5,700.0	31.67	297.79	4,985.1	1,220.7	-2,316.1	2,618.0	0.00	0.00	
5,800.0	31.67	297.79	5,070.2	1,245.2	-2,362.5	2,670.5	0.00	0.00	
5,900.0	31.67	297.79	5,155.3	1,269.7	-2,409.0	2,723.0	0.00	0.00	
6,000.0	31.67	297.79	5,240.4	1,294.2	-2,455.4	2,775.5	0.00	0.00	
6,100.0	31.67	297.79	5,325.5	1,318.7	-2,501.9	2,828.1	0.00	0.00	
6,200.0	31.67	297.79	5,410.6	1,343.2	-2,548.3	2,880.6	0.00	0.00	
6,300.0	31.67	297.79	5,495.7	1,367.6	-2,594.8	2,933.1	0.00	0.00	
6,400.0	31.67	297.79	5,580.8	1,392.1	-2,641.2	2,985.6	0.00	0.00	
6,500.0	31.67	297.79	5,665.9	1,416.6	-2,687.7	3,038.1	0.00	0.00	
6,600.0	31.67	297.79	5,751.0	1,441.1	-2,734.1	3,090.6	0.00	0.00	
6,700.0	31.67	297.79	5,836.1	1,465.6	-2,780.6	3,143.1	0.00	0.00	
6,800.0	31.67	297.79	5,921.2	1,490.1	-2,827.0	3,195.6	0.00	0.00	
6,900.0	31.67	297.79	6,006.3	1,514.5	-2,873.5	3,248.1	0.00	0.00	
7,000.0	31.67	297.79	6,091.4	1,539.0	-2,919.9	3,300.6	0.00	0.00	
7,100.0	31.67	297.79	6,176.5	1,563.5	-2,966.4	3,353.1	0.00	0.00	
7,200.0	31.67	297.79	6,261.6	1,588.0	-3,012.8	3,405.6	0.00	0.00	
7,208.8	31.67	297.79	6,269.2	1,590.2	-3,016.9	3,410.3	0.00	0.00	Start Drop -3.00
7,300.0	28.94	297.79	6,347.8	1,611.6	-3,057.6	3,456.3	3.00	-3.00	
7,400.0	25.94	297.79	6,436.6	1,633.1	-3,098.4	3,502.4	3.00	-3.00	
7,500.0	22.94	297.79	6,527.6	1,652.4	-3,135.0	3,543.7	3.00	-3.00	
7,600.0	19.94	297.79	6,620.7	1,669.4	-3,167.3	3,580.3	3.00	-3.00	
7,700.0	16.94	297.79	6,715.5	1,684.2	-3,195.3	3,611.9	3.00	-3.00	
7,800.0	13.94	297.79	6,811.9	1,696.6	-3,218.8	3,638.5	3.00	-3.00	
7,900.0	10.94	297.79	6,909.6	1,706.6	-3,237.9	3,660.1	3.00	-3.00	
8,000.0	7.94	297.79	7,008.2	1,714.3	-3,252.4	3,676.5	3.00	-3.00	
8,100.0	4.94	297.79	7,107.6	1,719.5	-3,262.3	3,687.7	3.00	-3.00	
8,200.0	1.94	297.79	7,207.4	1,722.3	-3,267.6	3,693.7	3.00	-3.00	
8,224.6	1.20	297.79	7,232.0	1,722.6	-3,268.2	3,694.3	3.00	-3.00	WF (TVD)
8,264.6	0.00	0.00	7,272.0	1,722.8	-3,268.6	3,694.8	3.00	-3.00	EOD @ Inc. = 0° - TOG (TVD) - 8508D-21 N22
8,300.0	0.09	239.56	7,307.4	1,722.8	-3,268.6	3,694.8	0.25	0.25	
8,390.6	0.31	239.56	7,398.0	1,722.6	-3,268.9	3,694.9	0.25	0.25	
8,400.0	0.31	239.56	7,407.4	1,722.6	-3,268.9	3,695.0	0.00	0.00	
8,500.0	0.31	239.56	7,507.4	1,722.3	-3,269.4	3,695.3	0.00	0.00	
8,600.0	0.31	239.56	7,607.3	1,722.0	-3,269.9	3,695.6	0.00	0.00	
8,700.0	0.31	239.56	7,707.3	1,721.8	-3,270.4	3,695.8	0.00	0.00	
8,800.0	0.31	239.56	7,807.3	1,721.5	-3,270.8	3,696.1	0.00	0.00	
8,900.0	0.31	239.56	7,907.3	1,721.2	-3,271.3	3,696.4	0.00	0.00	
9,000.0	0.31	239.56	8,007.3	1,720.9	-3,271.8	3,696.7	0.00	0.00	
9,100.0	0.31	239.56	8,107.3	1,720.7	-3,272.3	3,697.0	0.00	0.00	
9,200.0	0.31	239.56	8,207.3	1,720.4	-3,272.7	3,697.3	0.00	0.00	
9,300.0	0.31	239.56	8,307.3	1,720.1	-3,273.2	3,697.6	0.00	0.00	
9,400.0	0.31	239.56	8,407.3	1,719.8	-3,273.7	3,697.9	0.00	0.00	

Cathedral Energy
Planning Report

Database:	EDM 5000.1 US Multi Users DB	**Local Co-ordinate Reference:**	Well 8508D-21 N22 496
Company:	EnCana Oil & Gas (USA) Inc	**TVD Reference:**	WELL @ 7602.0ft (Original Well Elev)
Project:	Story Gulch	**MD Reference:**	WELL @ 7602.0ft (Original Well Elev)
Site:	S22-T4S-R96W (N22 496) (Column Pattern)	**North Reference:**	True
Well:	8508D-21 N22 496	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	DD		
Design:	Plan #1		

Planned Survey

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Vertical Section (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Comments / Formations
9,500.0	0.31	239.56	8,507.3	1,719.5	-3,274.2	3,698.2	0.00	0.00	
9,600.0	0.31	239.56	8,607.3	1,719.3	-3,274.6	3,698.5	0.00	0.00	
9,700.0	0.31	239.56	8,707.3	1,719.0	-3,275.1	3,698.8	0.00	0.00	
9,800.0	0.31	239.56	8,807.3	1,718.7	-3,275.6	3,699.1	0.00	0.00	
9,900.0	0.31	239.56	8,907.3	1,718.4	-3,276.1	3,699.4	0.00	0.00	
10,000.0	0.31	239.56	9,007.3	1,718.1	-3,276.5	3,699.6	0.00	0.00	
10,100.0	0.31	239.56	9,107.3	1,717.9	-3,277.0	3,699.9	0.00	0.00	
10,200.0	0.31	239.56	9,207.3	1,717.6	-3,277.5	3,700.2	0.00	0.00	
10,300.0	0.31	239.56	9,307.3	1,717.3	-3,277.9	3,700.5	0.00	0.00	
10,400.0	0.31	239.56	9,407.3	1,717.0	-3,278.4	3,700.8	0.00	0.00	
10,500.0	0.31	239.56	9,507.3	1,716.8	-3,278.9	3,701.1	0.00	0.00	
10,600.0	0.31	239.56	9,607.3	1,716.5	-3,279.4	3,701.4	0.00	0.00	
10,700.0	0.31	239.56	9,707.3	1,716.2	-3,279.8	3,701.7	0.00	0.00	
10,800.0	0.31	239.56	9,807.3	1,715.9	-3,280.3	3,702.0	0.00	0.00	
10,900.0	0.31	239.56	9,907.3	1,715.6	-3,280.8	3,702.3	0.00	0.00	
11,000.0	0.31	239.56	10,007.3	1,715.4	-3,281.3	3,702.6	0.00	0.00	
11,100.0	0.31	239.56	10,107.3	1,715.1	-3,281.7	3,702.9	0.00	0.00	
11,200.0	0.31	239.56	10,207.3	1,714.8	-3,282.2	3,703.2	0.00	0.00	
11,300.0	0.31	239.56	10,307.3	1,714.5	-3,282.7	3,703.4	0.00	0.00	
11,400.0	0.31	239.56	10,407.3	1,714.2	-3,283.2	3,703.7	0.00	0.00	
11,500.0	0.31	239.56	10,507.3	1,714.0	-3,283.6	3,704.0	0.00	0.00	
11,600.0	0.31	239.56	10,607.3	1,713.7	-3,284.1	3,704.3	0.00	0.00	
11,700.0	0.31	239.56	10,707.3	1,713.4	-3,284.6	3,704.6	0.00	0.00	
11,800.0	0.31	239.56	10,807.3	1,713.1	-3,285.1	3,704.9	0.00	0.00	
11,900.0	0.31	239.56	10,907.3	1,712.9	-3,285.5	3,705.2	0.00	0.00	
11,924.7	0.31	239.56	10,932.0	1,712.8	-3,285.6	3,705.3	0.00	0.00	Rlns (TVD) - 8508D-21 N22 496 PBHL (Columr
12,000.0	0.31	239.56	11,007.3	1,712.6	-3,286.0	3,705.5	0.00	0.00	
12,100.0	0.31	239.56	11,107.3	1,712.3	-3,286.5	3,705.8	0.00	0.00	
12,200.0	0.31	239.56	11,207.3	1,712.0	-3,287.0	3,706.1	0.00	0.00	
12,254.7	0.31	239.56	11,262.0	1,711.9	-3,287.2	3,706.2	0.00	0.00	Cozz (TVD)
12,300.0	0.31	239.56	11,307.3	1,711.7	-3,287.4	3,706.4	0.00	0.00	
12,400.0	0.31	239.56	11,407.3	1,711.5	-3,287.9	3,706.7	0.00	0.00	
12,444.7	0.31	239.56	11,452.0	1,711.3	-3,288.1	3,706.8	0.00	0.00	Corc (TVD)
12,500.0	0.31	239.56	11,507.3	1,711.2	-3,288.4	3,707.0	0.00	0.00	
12,600.0	0.31	239.56	11,607.3	1,710.9	-3,288.8	3,707.2	0.00	0.00	
12,700.0	0.31	239.56	11,707.3	1,710.6	-3,289.3	3,707.5	0.00	0.00	
12,724.7	0.31	239.56	11,732.0	1,710.6	-3,289.4	3,707.6	0.00	0.00	Sego (TVD)
12,800.0	0.31	239.56	11,807.3	1,710.3	-3,289.8	3,707.8	0.00	0.00	
12,900.0	0.31	239.56	11,907.3	1,710.1	-3,290.3	3,708.1	0.00	0.00	
12,924.7	0.31	239.56	11,932.0	1,710.0	-3,290.4	3,708.2	0.00	0.00	L Sego (TVD)
13,000.0	0.31	239.56	12,007.3	1,709.8	-3,290.7	3,708.4	0.00	0.00	
13,100.0	0.31	239.56	12,107.3	1,709.5	-3,291.2	3,708.7	0.00	0.00	
13,174.7	0.31	239.56	12,182.0	1,709.3	-3,291.6	3,708.9	0.00	0.00	Drillers TD @ 13,174' MD
13,200.0	0.31	239.56	12,207.3	1,709.2	-3,291.7	3,709.0	0.00	0.00	
13,300.0	0.31	239.56	12,307.3	1,709.0	-3,292.2	3,709.3	0.00	0.00	
13,400.0	0.31	239.56	12,407.3	1,708.7	-3,292.6	3,709.6	0.00	0.00	
13,424.7	0.31	239.56	12,432.0	1,708.6	-3,292.8	3,709.7	0.00	0.00	Permit TD @ 13,424' MD

Cathedral Energy

Planning Report

Database:	EDM 5000.1 US Multi Users DB	**Local Co-ordinate Reference:**	Well 8508D-21 N22 496
Company:	EnCana Oil & Gas (USA) Inc	**TVD Reference:**	WELL @ 7602.0ft (Original Well Elev)
Project:	Story Gulch	**MD Reference:**	WELL @ 7602.0ft (Original Well Elev)
Site:	S22-T4S-R96W (N22 496) (Column Pattern)	**North Reference:**	True
Well:	8508D-21 N22 496	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	DD		
Design:	Plan #1		

Targets

Target Name - hit/miss target - Shape	Dip Angle (°)	Dip Dir. (°)	TVD (ft)	+N/-S (ft)	+E/-W (ft)	Northing (ft)	Easting (ft)	Latitude	Longitude
8508D-21 N22 496 TGT - plan hits target center - Point	0.00	0.00	7,272.0	1,722.8	-3,268.6	1,686,811.36	2,249,066.02	39° 41' 19.71 N	108° 10' 7.34 W
8508D-21 N22 496 PBH - plan hits target center - Rectangle (sides W30.0 H50.0 D0.0)	0.00	0.00	10,932.0	1,712.8	-3,285.6	1,686,801.84	2,249,048.69	39° 41' 19.61 N	108° 10' 7.55 W

Formations

Measured Depth (ft)	Vertical Depth (ft)	Name	Lithology	Dip (°)	Dip Direction (°)
232.0	232.0	Para Creek (TVD)			
533.7	532.0	Mahog Bench (TVD)			
594.8	592.0	Base B Groove (TVD)			
4,697.6	4,132.0	Was G (TVD)			
8,224.6	7,232.0	WF (TVD)			
8,264.6	7,272.0	TOG (TVD)			
11,924.7	10,932.0	Rlns (TVD)			
12,254.7	11,262.0	Cozz (TVD)			
12,444.7	11,452.0	Corc (TVD)			
12,724.7	11,732.0	Sego (TVD)			
12,924.7	11,932.0	L Sego (TVD)			

Plan Annotations

Measured Depth (ft)	Vertical Depth (ft)	Local Coordinates +N/-S (ft)	+E/-W (ft)	Comment
200.0	200.0	0.0	0.0	KOP @ 200'
1,255.8	1,202.8	132.6	-251.7	EOB @ Inc. = 31.67°
7,208.8	6,269.2	1,590.2	-3,016.9	Start Drop -3.00
8,264.6	7,272.0	1,722.8	-3,268.6	EOD @ Inc. = 0°
13,174.7	12,182.0	1,722.6	-3,268.9	Drillers TD @ 13,174' MD
13,424.7	12,432.0	1,712.8	-3,285.6	Permit TD @ 13,424' MD

IMPORTANT: SOME DATA FIELDS HAVE BEEN MODIFIED.

FORM 5A
Rev 02/08

State of Colorado
Oil and Gas Conservation Commission

1120 Lincoln Street, Suite 801, Denver, Colorado 80205 Phone: (303) 894-2100 Fax: (303) 894-2109

DE	ET	OE	ES

Document Number: 400107704

COMPLETED INTERVAL REPORT

The completed interval Report, Form 5A, shall be submitted within thirty (30) days of completing a formation (successful or not), when a formation is temporarily abandoned or permanently abandoned, for a recompletion, reperforation or restimulation, or when a formation is commingled. Fill out a section for each formation. Attach as many pages as required to fully describe the work. List in order of completion.

1. OGCC Operator Number: 10091
2. Name of Operator: BERRY PETROLEUM COMPANY
3. Address: 1999 BROADWAY STE 3700
City: DENVER State: CO Zip: 80202
4. Contact Name: Kallasandra Moran
Phone: (303) 999-4225
Fax: (303) 999-4325

5. API Number 05-045-13096-00
6. County: GARFIELD
7. Well Name: LONG RIDGE Well Number: 01B M15 595
8. Location: QtrQtr: SWSW Section: 15 Township: 5S Range: 95W Meridian: 6
9. Field Name: PARACHUTE Field Code: 67350

Completed Interval

FORMATION: WILLIAMS FORK Status: PRODUCING

Treatment Date: 11/03/2010 Date of First Production this formation: 11/09/2010

Perforations Top: 11549 Bottom: 11948 No. Holes: 50 Hole size: 0.35

Provide a brief summary of the formation treatment: Open Hole: ☐

Perf'd & frac'd inital 2 of 7 stages:
11,549' - 11,718' - 30 holes total @ 2 spf. Frac'd with 204,307 lbs 30/50 white sand and 6,652 bbl slick water. Led with 1000 gal 7.5% acid.
11,809' - 11,948' - 20 holes total at 2 spf. Frac'd with 141,309 lbs 30/50 white sand and 4,731 bbl slick water. Led with 500 gal 7.5% acid.

This formation is commingled with another formation: ☐ Yes ☒ No

Test Information:

Date: 11/10/2010 Hours: 6 Bbls oil: 0 Mcf Gas: 35 Bbls H2O: 60

Calculated 24 hour rate: Bbls oil: 0 Mcf Gas: 140 Bbls H2O: 240 GOR: 0

Test Method: Flowing Casing PSI: 680 Tubing PSI: Choke Size: 18/64

Gas Disposition: SOLD Gas Type: DRY BTU Gas: 1128 API Gravity Oil: 0

Tubing Size: Tubing Setting Depth: Tbg setting date: Packer Depth:

Reason for Non-Production:

Date formation Abandoned: Squeeze: ☐ Yes ☐ No If yes, number of sacks cmt

Bridge Plug Depth: Sacks cement on top:

Comment:

Form 10 - First date of production mailed to the COGCC 11/10/2010.
Completed 2 stages of initial 7 stage frac. Remaining stages to be completed 1/1/2011.

IMPORTANT: SOME DATA FIELDS HAVE BEEN MODIFIED.

I hereby certify all statements made in this form are, to the best of my knowledge, true, correct, and complete.

Signed: ______________________ Print Name: Kallasandra M. Moran

Title: Permit Agent Date: 11/10/2010 Email: kmoran@bry-consultant.com

Attachment Check List

Att Doc Num	Name
400107704	FORM 5A SUBMITTED
400107705	OPERATIONS SUMMARY
400107706	WELLBORE DIAGRAM

Total Attach: 3 Files

General Comments

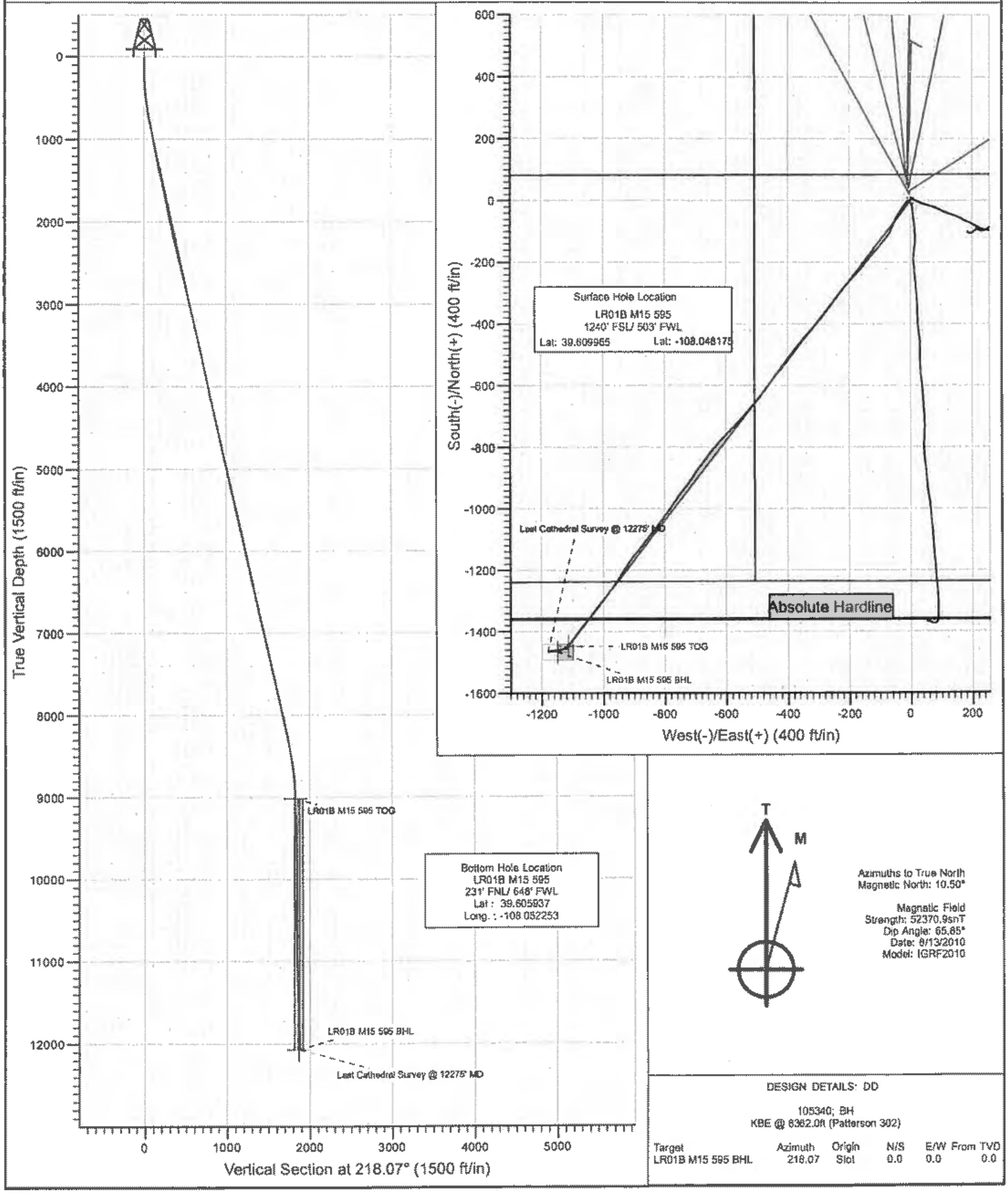
User Group	Comment	Comment Date

Total: 0 comment(s)

Berry Petroleum Company

Project: Garfield County
Site: M15 595
Well: LR01B M15 595
Wellbore: DD
Design: Final Survey

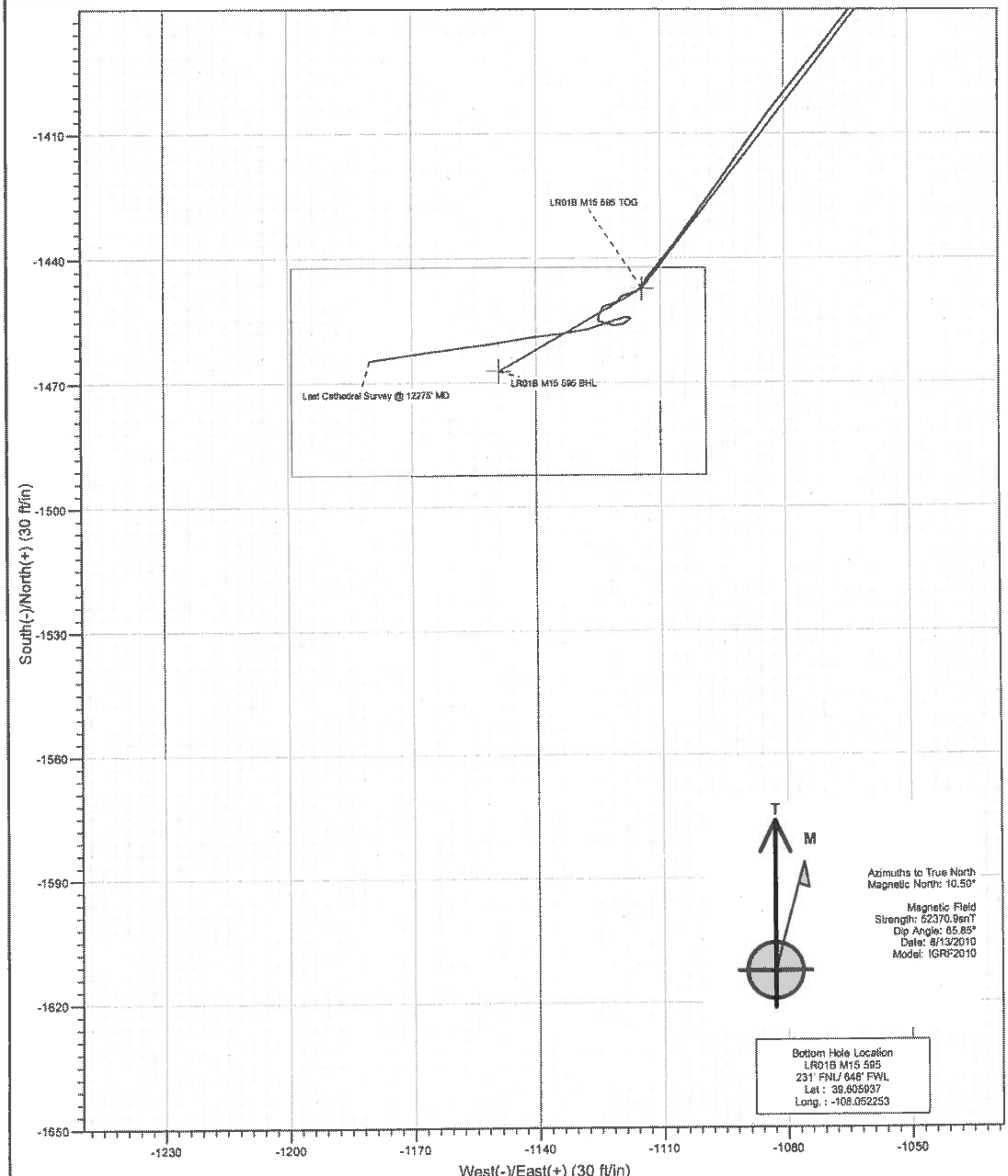
CATHEDRAL



Berry Petroleum Company

Project: Garfield County
Site: M15 595
Well: LR01B M15 595
Wellbore: DD
Design: DD

CATHEDRAL



Cathedral Energy Services

Survey Report

Company:	Berry Petroleum Company (NAD 83)	**Local Co-ordinate Reference:**	Well LR01B M15 595
Project:	Garfield County	**TVD Reference:**	KBE @ 8362.0ft (Patterson 302)
Site:	M15 595	**MD Reference:**	KBE @ 8362.0ft (Patterson 302)
Well:	LR01B M15 595	**North Reference:**	True
Wellbore:	DD	**Survey Calculation Method:**	Minimum Curvature
Design:	DD	**Database:**	EDM 5000.1 US Multi Users DB

Project Garfield County

Map System:	US State Plane 1983	**System Datum:**	Mean Sea Level
Geo Datum:	North American Datum 1983		
Map Zone:	Colorado Central Zone		

Site M15 595

Site Position:		**Northing:**	1,657,208.58 ft	**Latitude:**	39.610181
From:	Lat/Long	**Easting:**	2,282,155.00 ft	**Longitude:**	-108.048225
Position Uncertainty:	0.0 ft	**Slot Radius:**	13.200 in	**Grid Convergence:**	-1.61 °

Well LR01B M15 595

Well Position	**+N/-S**	0.0 ft	**Northing:**	1,657,129.53 ft	**Latitude:**	39.609965
	+E/-W	0.0 ft	**Easting:**	2,282,168.88 ft	**Longitude:**	-108.048175
Position Uncertainty		0.0 ft	**Wellhead Elevation:**	ft	**Ground Level:**	8,347.0 ft

Wellbore DD

Magnetics	**Model Name**	**Sample Date**	**Declination (°)**	**Dip Angle (°)**	**Field Strength (nT)**
	IGRF2010	8/13/2010	10.50	65.65	52,371

Design DD

Audit Notes:

Version: 1.0 **Phase:** ACTUAL **Tie On Depth:** 0.0

Vertical Section:	**Depth From (TVD) (ft)**	**+N/-S (ft)**	**+E/-W (ft)**	**Direction (°)**
	0.0	0.0	0.0	218.07

Survey Program **Date** 8/31/2010

From (ft)	**To (ft)**	**Survey (Wellbore)**	**Tool Name**	**Description**
154.0	12,275.0	Survey #1 (DD)	MWD	Geolink MWD

Survey

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Vertical Section (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Formations / Comments
0.0	0.00	0.00	0.0	0.0	0.0	0.0	0.00	0.00	
154.0	1.00	333.70	154.0	1.2	-0.6	-0.6	0.65	0.65	
227.0	1.50	270.80	227.0	1.8	-1.8	-0.3	1.88	0.68	
319.0	3.80	241.10	318.9	0.3	-5.7	3.3	2.83	2.50	
410.0	6.20	224.00	409.5	-4.7	-11.8	10.9	3.08	2.64	
501.0	7.00	219.70	499.9	-12.5	-18.7	21.4	1.03	0.88	
591.0	8.30	214.30	589.1	-22.0	-25.9	33.3	1.65	1.44	
681.0	9.40	210.80	678.1	-33.7	-33.3	47.1	1.36	1.22	
773.0	9.20	217.80	768.8	-46.0	-41.7	61.9	1.25	-0.22	
865.0	12.70	203.90	859.2	-61.1	-50.3	79.1	4.74	3.80	
961.0	11.30	199.60	953.1	-79.6	-57.7	98.2	1.73	-1.46	
1,056.0	10.30	203.40	1,046.4	-96.1	-64.2	115.3	1.29	-1.05	
1,151.0	9.50	216.20	1,140.0	-110.3	-72.2	131.3	2.48	-0.84	

Cathedral Energy Services

Survey Report

Company:	Berry Petroleum Company (NAD 83)	**Local Co-ordinate Reference:**	Well LR01B M15 595
Project:	Garfield County	**TVD Reference:**	KBE @ 8362.0ft (Patterson 302)
Site:	M15 595	**MD Reference:**	KBE @ 8362.0ft (Patterson 302)
Well:	LR01B M15 595	**North Reference:**	True
Wellbore:	DD	**Survey Calculation Method:**	Minimum Curvature
Design:	DD	**Database:**	EDM 5000.1 US Multi Users DB

Survey

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Vertical Section (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Formations / Comments
1,245.0	10.80	219.00	1,232.5	-123.4	-82.3	147.9	1.46	1.38	
1,340.0	12.00	217.70	1,325.6	-138.1	-94.0	166.7	1.29	1.26	
1,435.0	13.10	221.20	1,418.4	-154.0	-107.1	187.3	1.41	1.16	
1,469.0	13.70	221.50	1,451.4	-159.9	-112.3	195.1	1.76	1.76	
1,531.0	13.20	221.90	1,511.7	-170.7	-121.9	209.5	0.82	-0.81	
1,593.0	12.30	220.70	1,572.2	-181.0	-130.9	223.2	1.51	-1.45	
1,657.0	12.00	218.40	1,634.8	-191.3	-139.5	236.7	0.89	-0.47	
1,720.0	11.50	218.00	1,696.5	-201.4	-147.4	249.5	0.80	-0.79	
1,783.0	11.20	217.00	1,758.2	-211.3	-155.0	261.9	0.57	-0.48	
1,847.0	11.00	220.80	1,821.0	-220.8	-162.7	274.2	1.18	-0.31	
1,910.0	11.40	222.50	1,882.8	-230.0	-170.8	286.4	0.82	0.63	
1,974.0	12.00	222.70	1,945.5	-239.5	-179.8	299.4	0.94	0.94	
2,037.0	12.00	223.10	2,007.1	-249.1	-188.6	312.4	0.13	0.00	
2,100.0	12.00	223.50	2,068.7	-258.7	-197.5	325.4	0.13	0.00	
2,163.0	12.70	221.00	2,130.3	-268.8	-206.6	338.9	1.40	1.11	
2,226.0	13.20	217.00	2,191.7	-279.8	-215.5	353.0	1.63	0.79	
2,290.0	13.20	216.00	2,254.0	-291.4	-224.2	367.6	0.36	0.00	
2,353.0	13.30	216.30	2,315.3	-303.0	-232.7	382.0	0.19	0.16	
2,415.0	14.10	218.30	2,375.6	-314.9	-241.4	396.7	1.29	1.29	
2,478.0	13.70	218.30	2,436.7	-327.1	-250.3	411.8	0.63	-0.63	
2,541.0	13.00	216.10	2,498.0	-338.8	-258.9	426.4	1.11	-1.11	
2,604.0	13.60	217.10	2,559.3	-350.4	-267.6	440.9	1.02	0.95	
2,668.0	14.00	218.40	2,621.5	-362.5	-278.9	456.1	0.79	0.62	
2,731.0	14.10	217.90	2,682.6	-374.5	-286.4	471.4	0.25	0.16	
2,794.0	14.60	217.70	2,743.8	-386.9	-295.9	487.0	0.80	0.79	
2,857.0	14.10	218.90	2,804.7	-399.1	-305.8	502.8	0.92	-0.79	
2,920.0	14.80	221.40	2,865.7	-411.0	-315.7	518.2	1.26	0.79	
2,982.0	14.50	222.10	2,925.7	-422.7	-326.0	533.8	0.33	-0.18	
3,155.0	12.10	217.60	3,094.1	-453.1	-351.6	573.5	1.51	-1.39	
3,249.0	13.20	219.90	3,185.8	-469.1	-364.5	594.1	1.29	1.17	
3,344.0	13.70	221.80	3,278.2	-485.9	-379.0	616.2	0.70	0.53	
3,438.0	13.80	215.50	3,369.5	-503.3	-392.9	638.5	1.60	0.11	
3,533.0	14.30	218.10	3,461.8	-521.7	-406.7	661.5	0.85	0.53	
3,628.0	12.80	213.80	3,554.0	-539.7	-419.8	683.8	1.90	-1.58	
3,723.0	12.00	214.60	3,646.8	-556.6	-431.3	704.1	0.87	-0.84	
3,818.0	11.00	213.00	3,739.9	-572.3	-441.9	723.0	1.12	-1.05	
3,913.0	12.30	217.10	3,832.9	-588.0	-452.9	742.2	1.62	1.37	
4,008.0	11.70	214.80	3,925.8	-603.9	-464.5	761.9	0.81	-0.63	
4,103.0	12.10	218.70	4,018.8	-619.8	-476.0	781.5	0.59	0.42	
4,198.0	13.80	219.00	4,111.4	-636.6	-489.1	802.8	1.87	1.79	
4,293.0	13.10	220.20	4,203.8	-653.8	-503.1	824.8	0.79	-0.74	
4,388.0	12.80	222.70	4,296.4	-669.6	-517.2	846.1	0.67	-0.32	
4,482.0	12.30	220.00	4,388.1	-684.9	-530.7	866.5	0.82	-0.53	
4,576.0	13.10	220.30	4,479.8	-700.7	-544.1	887.1	0.85	0.85	
4,671.0	12.50	223.50	4,572.4	-716.4	-558.1	908.1	0.98	-0.63	
4,766.0	13.80	223.50	4,665.0	-732.1	-573.0	929.6	1.37	1.37	
4,861.0	13.00	225.30	4,757.4	-747.8	-588.4	951.5	0.95	-0.84	
4,954.0	12.70	225.00	4,848.0	-762.4	-603.0	972.0	0.33	-0.32	
5,049.0	13.40	220.10	4,940.6	-778.2	-617.5	993.4	1.38	0.74	
5,143.0	12.50	221.70	5,032.2	-794.1	-631.3	1,014.4	1.03	-0.96	
5,239.0	12.90	219.60	5,125.8	-810.1	-645.0	1,035.5	0.64	0.42	
5,333.0	12.90	215.70	5,217.5	-826.7	-657.8	1,056.5	0.93	0.00	
5,428.0	12.50	214.30	5,310.1	-843.8	-669.8	1,077.4	0.53	-0.42	

Cathedral Energy Services

Survey Report

Company:	Berry Petroleum Company (NAD 83)	**Local Co-ordinate Reference:**	Well LR01B M15 595
Project:	Garfield County	**TVD Reference:**	KBE @ 8382.0ft (Patterson 302)
Site:	M15 595	**MD Reference:**	KBE @ 8362.0ft (Patterson 302)
Well:	LR01B M15 595	**North Reference:**	True
Wellbore:	DD	**Survey Calculation Method:**	Minimum Curvature
Design:	DD	**Database:**	EDM 5000.1 US Multi Users DB

Survey

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Vertical Section (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Formations / Comments
5,522.0	12.80	220.00	5,401.9	-860.2	-682.2	1,097.9	1.37	0.32	
5,617.0	13.20	214.30	5,494.4	-877.2	-695.1	1,119.3	1.41	0.42	
5,712.0	12.00	211.50	5,587.2	-894.6	-706.4	1,139.9	1.42	-1.26	
5,806.0	13.10	217.70	5,678.9	-911.4	-718.0	1,160.2	1.85	1.17	
5,900.0	11.60	219.10	5,770.7	-927.2	-730.5	1,180.4	1.63	-1.60	
5,994.0	12.70	217.70	5,862.6	-942.7	-742.8	1,200.1	1.21	1.17	
6,089.0	13.60	213.40	5,955.1	-960.3	-755.3	1,221.7	1.40	0.95	
6,164.0	12.90	213.40	6,047.8	-978.4	-767.3	1,243.4	0.74	-0.74	
6,278.0	12.10	215.00	6,139.4	-995.3	-778.7	1,263.7	0.93	-0.85	
6,373.0	13.30	214.40	6,232.0	-1,012.4	-790.6	1,284.6	1.27	1.26	
6,467.0	12.70	216.70	6,323.6	-1,029.8	-802.9	1,305.7	0.84	-0.64	
6,562.0	11.70	216.50	6,416.5	-1,045.8	-814.9	1,325.7	1.05	-1.05	
6,658.0	11.70	217.70	6,510.5	-1,061.3	-826.6	1,345.2	0.25	0.00	
6,753.0	12.00	220.10	6,603.5	-1,076.5	-838.9	1,364.7	0.61	0.32	
6,849.0	12.40	215.20	6,697.3	-1,092.5	-851.2	1,385.0	1.18	0.42	
6,943.0	13.70	216.60	6,788.9	-1,108.5	-864.0	1,406.2	1.61	1.38	
7,038.0	12.80	217.40	6,881.4	-1,126.8	-877.4	1,428.0	0.99	-0.95	
7,133.0	12.70	219.90	6,974.0	-1,143.0	-890.5	1,448.9	0.59	-0.11	
7,228.0	12.50	220.80	7,066.7	-1,158.8	-903.9	1,469.8	0.30	-0.21	
7,324.0	12.70	213.60	7,160.4	-1,175.4	-916.5	1,490.5	1.65	0.21	
7,419.0	11.40	211.90	7,253.3	-1,192.1	-927.3	1,510.3	1.42	-1.37	
7,514.0	13.00	213.60	7,346.2	-1,209.0	-938.2	1,530.3	1.73	1.68	
7,609.0	12.70	211.90	7,438.8	-1,226.7	-949.6	1,551.3	0.51	-0.32	
7,704.0	12.00	211.30	7,531.6	-1,244.0	-960.2	1,571.5	0.75	-0.74	
7,799.0	12.50	214.70	7,624.4	-1,260.9	-971.2	1,591.6	0.82	0.53	
7,894.0	13.60	219.60	7,717.0	-1,278.0	-984.2	1,613.0	1.64	1.16	
7,989.0	13.10	218.20	7,809.4	-1,295.1	-998.0	1,634.9	0.63	-0.53	
8,084.0	12.40	218.80	7,902.1	-1,311.5	-1,011.0	1,655.9	0.75	-0.74	
8,179.0	12.60	218.30	7,994.8	-1,327.6	-1,023.8	1,676.4	0.24	0.21	
8,273.0	12.20	217.00	8,086.6	-1,343.5	-1,036.2	1,696.6	0.52	-0.43	
8,369.0	12.00	217.50	8,180.5	-1,359.6	-1,048.3	1,716.8	0.24	-0.21	
8,464.0	11.10	217.70	8,273.6	-1,374.8	-1,059.9	1,735.8	0.95	-0.95	
8,559.0	9.30	218.50	8,367.1	-1,387.9	-1,070.3	1,752.6	1.90	-1.89	
8,653.0	9.10	219.00	8,459.9	-1,399.6	-1,079.7	1,767.6	0.23	-0.21	
8,748.0	7.90	215.00	8,553.8	-1,410.8	-1,088.2	1,781.7	1.41	-1.26	
8,843.0	7.30	215.60	8,648.0	-1,421.0	-1,095.5	1,794.2	0.64	-0.63	
8,938.0	5.70	218.00	8,742.4	-1,429.8	-1,101.7	1,804.9	1.68	-1.68	
9,032.0	4.50	216.00	8,836.0	-1,436.5	-1,106.7	1,813.3	1.28	-1.28	
9,127.0	3.60	221.80	8,930.7	-1,441.8	-1,110.8	1,820.0	1.04	-0.95	
9,221.0	2.40	209.50	9,024.6	-1,445.7	-1,113.8	1,824.9	1.44	-1.28	
9,318.0	1.30	243.30	9,121.8	-1,447.9	-1,115.7	1,827.9	1.55	-1.13	
9,411.0	1.86	259.90	9,214.5	-1,448.7	-1,118.1	1,829.9	0.72	0.54	
9,505.0	0.60	192.60	9,308.5	-1,449.8	-1,119.7	1,831.6	1.77	-1.06	
9,599.0	1.40	247.20	9,402.5	-1,450.8	-1,120.9	1,833.2	1.21	0.64	
9,693.0	1.30	256.60	9,498.5	-1,451.3	-1,123.0	1,835.0	0.30	-0.11	
9,788.0	1.00	183.20	9,591.5	-1,452.3	-1,124.1	1,836.5	1.50	-0.32	
9,882.0	1.30	220.60	9,685.4	-1,454.0	-1,124.9	1,838.3	0.84	0.32	
9,976.0	0.90	104.90	9,779.4	-1,455.0	-1,124.9	1,839.0	1.99	-0.43	
10,072.0	1.50	112.90	9,875.4	-1,455.7	-1,123.0	1,838.4	0.65	0.62	
10,166.0	0.90	82.40	9,969.4	-1,456.0	-1,121.1	1,837.8	0.91	-0.64	
10,261.0	0.70	77.20	10,064.4	-1,455.8	-1,119.8	1,836.6	0.22	-0.21	
10,356.0	0.40	92.30	10,159.4	-1,455.7	-1,118.9	1,835.9	0.35	-0.32	
10,451.0	0.70	41.30	10,254.4	-1,455.3	-1,118.2	1,835.2	0.57	0.32	

Cathedral Energy Services
Survey Report

Company:	Berry Petroleum Company (NAD 83)	**Local Co-ordinate Reference:**	Well LR01B M15 595
Project:	Garfield County	**TVD Reference:**	KBE @ 8362.0ft (Patterson 302)
Site:	M15 595	**MD Reference:**	KBE @ 8382.0ft (Patterson 302)
Well:	LR01B M15 595	**North Reference:**	True
Wellbore:	DD	**Survey Calculation Method:**	Minimum Curvature
Design:	DD	**Database:**	EDM 5000.1 US Multi Users DB

Survey

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Vertical Section (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Formations / Comments
10,546.0	0.40	80.30	10,349.4	-1,454.8	-1,117.5	1,834.3	0.49	-0.32	
10,641.0	0.30	9.80	10,444.4	-1,454.5	-1,117.1	1,833.9	0.43	-0.11	
10,736.0	0.30	270.10	10,539.4	-1,454.2	-1,117.3	1,833.8	0.48	0.00	
10,830.0	0.40	289.60	10,633.4	-1,454.1	-1,117.9	1,834.1	0.16	0.11	
10,926.0	0.80	251.80	10,729.4	-1,454.2	-1,118.8	1,834.7	0.57	0.42	
11,021.0	1.50	256.80	10,824.3	-1,454.7	-1,120.7	1,836.3	0.74	0.74	
11,118.0	1.70	246.30	10,921.3	-1,455.6	-1,123.2	1,838.5	0.36	0.21	
11,401.0	2.50	263.60	11,204.1	-1,458.0	-1,133.2	1,846.5	0.36	0.28	
11,591.0	2.90	262.30	11,393.9	-1,459.1	-1,142.1	1,852.9	0.21	0.21	
11,686.0	2.70	258.50	11,488.8	-1,459.8	-1,146.6	1,856.3	0.29	-0.21	
11,781.0	2.80	263.50	11,583.7	-1,460.5	-1,151.1	1,859.6	0.27	0.11	
11,971.0	3.60	262.20	11,773.4	-1,461.9	-1,161.7	1,867.2	0.42	0.42	
12,066.0	3.70	261.70	11,868.2	-1,462.7	-1,167.7	1,871.5	0.11	0.11	
12,160.0	3.40	261.60	11,962.0	-1,463.8	-1,173.4	1,875.8	0.32	-0.32	
12,275.0	3.40	261.60	12,076.8	-1,464.6	-1,180.2	1,880.7	0.00	0.00	Last Cathedral Survey @ 12275' MD

Targets

Target Name - hit/miss target - Shape	Dip Angle (°)	Dip Dir. (°)	TVD (ft)	+N/-S (ft)	+E/-W (ft)	Northing (ft)	Easting (ft)	Latitude	Longitude
LR01B M15 595 BHL	0.00	0.00	12,070.0	-1,467.2	-1,149.0	1,655,695.15	2,280,977.16	39.605937	-108.052253
- survey misses target center by 30.8ft at 12266.4ft MD (12068.2 TVD, -1464.5 N, -1179.7 E)									
- Rectangle (sides W50.0 H100.0 D0.0)									
LR01B M15 595 TOG	0.00	0.00	9,020.0	-1,447.2	-1,114.4	1,655,714.15	2,281,012.34	39.605992	-108.052130
- survey misses target center by 1.8ft at 9216.5ft MD (9020.1 TVD, -1445.5 N, -1113.7 E)									
- Point									

Survey Annotations

Measured Depth (ft)	Vertical Depth (ft)	Local Coordinates +N/-S (ft)	Local Coordinates +E/-W (ft)	Comment
12,275.0	12,076.8	-1,464.6	-1,180.2	Last Cathedral Survey @ 12275' MD

Checked By: ______________ Approved By: ______________ Date: ______________

Berry Petroleum Company
LR 01B M15 595
API # 05-045-13096-0000
SWSW Sec 15 Twn 5S Rng 95W
Garfield County, Colorado

Prepared Kallasandra Moran
Updated 1/21/2011

Rig Patterson 302

8370 KB
8347 GL
23 KB-GL

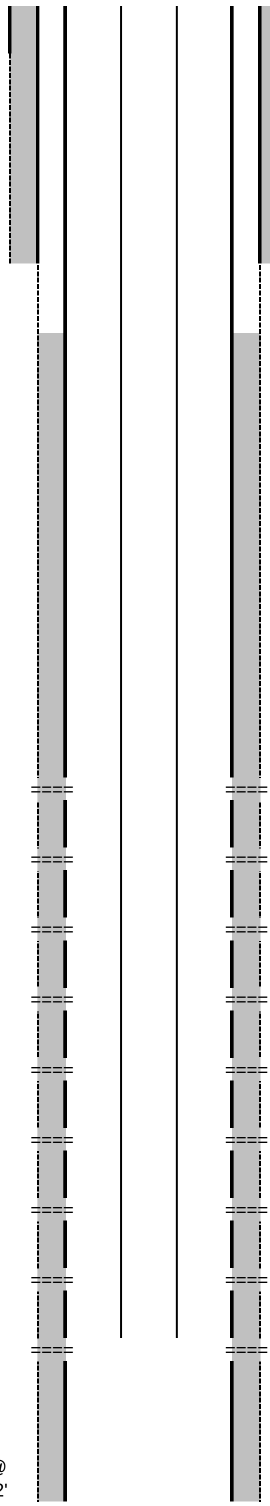
278 BHT

TOC @ 3440'

TOCC @ 4406'

7/11/2010 Set Cond
8/19/2010 Spud
8/24/2010 Set Surf
9/1/2010 Set Prod
10/6/2010 Logged
10/30/2010 PTST 7000 # @ PBTD
10/30/2010 Perf Stg 1
11/2/2010 Frac Stg 1
11/3/2010 Perf & Frac Stg 2
11/29/2010 Perf Stg 3
12/1/2010 Frac Stg 3
12/4/2010 Perf & Frac Stg 4
12/6/2010 Perf & Frac Stg 5 & 6
12/7/2010 Perf & Frac Stg 7
12/8/2010 Perf & Frac Stg 8
12/9/2010 Perf & Frac Stg 9
1/11/2011 DO CFPs
1/13/2011 Land Tubing

Marker Jts @
6094-6115 & 9719-42'



Wellhead 2" ball valve on top of cap
Csg Repair @ surface reset csg w/ slips @ 157 Mlb tension
20" Conductor @ 123' (94 #, H-40)
Cmtd 310 sx Type III lead @ 7.37 ppg & 1.48 yld

16" hole @ 3085'
70 jts 9-5/8" 36# J-55 surf csg @ 3058' w/ 1.9" parasite string, inj port @ 2972'
Cmtd 562 sx Type III lead @ 11.5 ppg & 2.88 yld and 1000 sx lead @ 11.5 ppg & 2.81 yld and 200 sx Type III @14.2 ppg & 1.46 yld

Equipment in Hole	Qty	Length	Depth
KB		23.00	23.00
Tbg Hanger		0.85	23.85
2-3/8" 4.7# L-80 TBg	124	4002.81	4026.66
2-3/8" TBG PUP N80		2.05	4028.71
2-3/8" 4.7# N-80 TBg	244	7664.19	11692.90
2-3/8" PSN		1.10	11694.00
2-3/8" 4.7# N-80 TBg	1	31.50	11725.50
Pump off bit sub		0.65	11726.15

Stage 9: Perf'd 9344 - 9628', total 30 holes @ 2 spf
Frac'd 154000 lb 30/50 white sand, 5370 bbl slickwater, led w/ 500 g 7.5% acid

Stage 8: Perf'd 9738 - 10016, total 30 holes @ 2 spf
Frac'd 144000 lb 30/50 white sand, 4967 bbl slickwater, led w/ 500 g 7.5% acid

Stage 7: Perf'd 10181 - 10430, total 38 holes @ 2 spf
Frac'd 282500 lb 30/50 white sand, 9134 bbl slickwater, led w/ 500 g 7.5% acid

Stage 6: Perf'd 10500' - 10657', total 30 holes @ 2 spf
Frazc'd 176932 lb 30/50 white sand, 5994 bbl slickwater, led w/ 500 g 7.5% acid

Stage 5: Perf'd 10721 - 10885, total 18 holes @ 2 spf
Frac'd 104300 lb 30/50 white sand, 3803 bbl slickwater, led w/ 500 g 7.5% acid

Stage 4: Perf'd 10926 - 11157', total 30 holes @ 2 spf
Frac'd 178760 lb 30/50 white sand, 6240 bbl slickwater, led w/ 500 g 7.5% acid

Stage 3: Perf'd 11200' - 11388', total 26 holes @ 2 spf
Frac'd 18900 lb 30/50 white sand, 6362 bbl slickwater, led w/ 1000 g 7.5% acid

Stage 2: Perf'd 11549 - 11718', total 30 holes @ 2 spf
Frac'd 204307 lb 30/50 white sand, 6652 bbl slickwater, led w/ 1000 g 7.5% acid

Stage 1: Perf'd 11809 - 11948', total 20 holes @ 2 spf
Frac'd 141309 lb 30/50 white sand, 4731 bbl slickwater, led w/ 500 g 7.5% acid

8-3/4" hole @ 8993' and 7-7/8" hole @ 12280'
298 jts 4-1/2" 11.6# P-110 Csg @ 12250', FC @ 12207'
Cmtd 979 sx 35:65 Poz Type III @ ?? ppg & ?? yld

PBTD @ 12076' WL Tag on 10/6/10

Discussing Hydrocarbon-related Detections in Groundwater

Associated with the Pinedale Anticline Project Area Groundwater Monitoring Program conducted by the Sublette County Conservation District

From 2004 through 2012

A publication by the

Sublette County Conservation District

October, 2013

Introduction

In recent years numerous press articles and websites reported contaminated groundwater associated with the natural gas development near Pinedale, Wyoming. In light of these reports, the Sublette County Conservation District (SCCD) felt it important to provide a factual foundation to the ongoing discussion. The SCCD has conducted a large groundwater monitoring program associated with Pinedale Anticline oil/gas exploration since 2001. The Pinedale Anticline Project Area (PAPA) is just one of several gas fields within the county (see Groundwater Sampling Area Map on following page). Results from SCCD's sampling efforts are usually the basis for the many reports which generates concern among citizens. Unfortunately, details are sometimes left out and those that are included may not be accurately depicted.

Since hydrocarbons are typically the main point of discussion, they will be the main topic within this brochure. First and foremost, it's important to discuss associated terminology as it is sometimes misused and misunderstood.

- **A detection limit** is "the lowest concentration that an analytical instrument can measure." When the instrumentation signals hydrocarbon presence, we refer to this as a **detection**.
- EPA defines **water quality standards** as "state-adopted and EPA-approved ambient standards for water bodies. The standards prescribe the use of the water body and establish the water quality criteria that must be met to protect designated uses."
- EPA also defines **contamination** as the "introduction into water, air, and soil of microorganisms, chemicals, toxic substances, wastes, or wastewater in a concentration that makes the medium unfit for its next intended use."

SCCD's groundwater program results may report a hydrocarbon-related detection, but that does not always trigger regulatory action. Further, a detection, or even exceeding a standard in a water well can not automatically be interpreted to mean the source aquifer is contaminated.

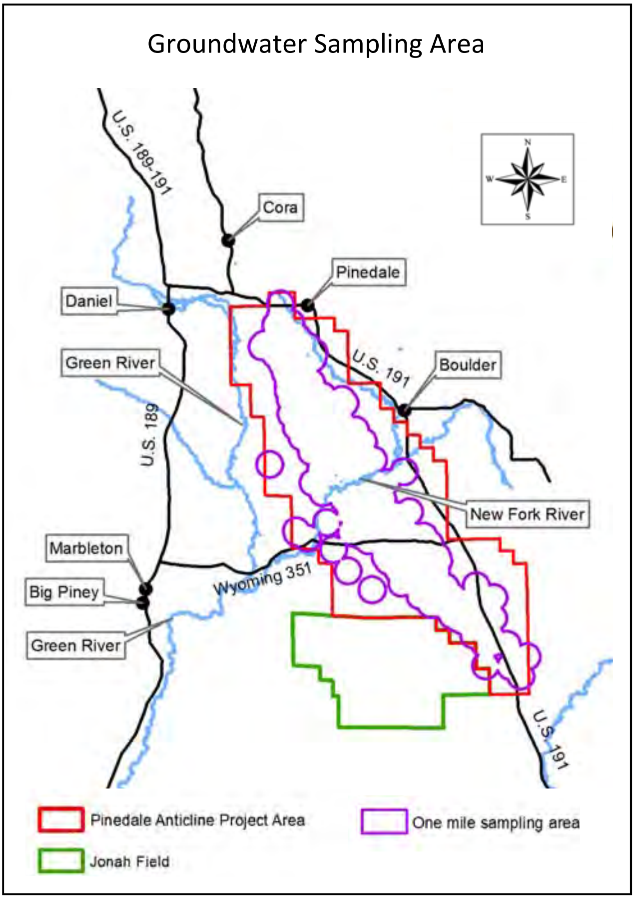
This brochure has been compiled to assist the public to better understand the complexity of this topic. Discussion points included information about how the SCCD became involved, the types of wells sampled and how samples are collected. Also included is discussion of what hydrocarbons are, the complexity of testing for their presence in wells sampled and the hydrocarbon-related results from SCCD sampling efforts.

370

As of December 31, 2012, the SCCD has collected 2,342 samples from 312 water wells within one mile of an existing or proposed gas well within the PAPA. Results from those samples show hydrocarbon detections in 48 water wells, 12 of which had detections that exceeded applicable groundwater clean-up levels. In the 2012 season, sampling found 8 water wells with detections, 3 of which had levels that exceed applicable groundwater clean-up levels.

Program background

In July 2000, The Bureau of Land Management (BLM) Record of Decision (ROD) for the Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project, Sublette County Wyoming, states, "*…the operators will conduct a survey and a complete water analysis (ex. static water level, alkalinity, salinity, benzene, oil, etc.) of all water wells within a one mile radius of existing and proposed development, and annually monitor and maintain a complete record of water analysis of all new water supply wells drilled in the project area to evaluate the quality of source options in the event some mitigation is required.*"

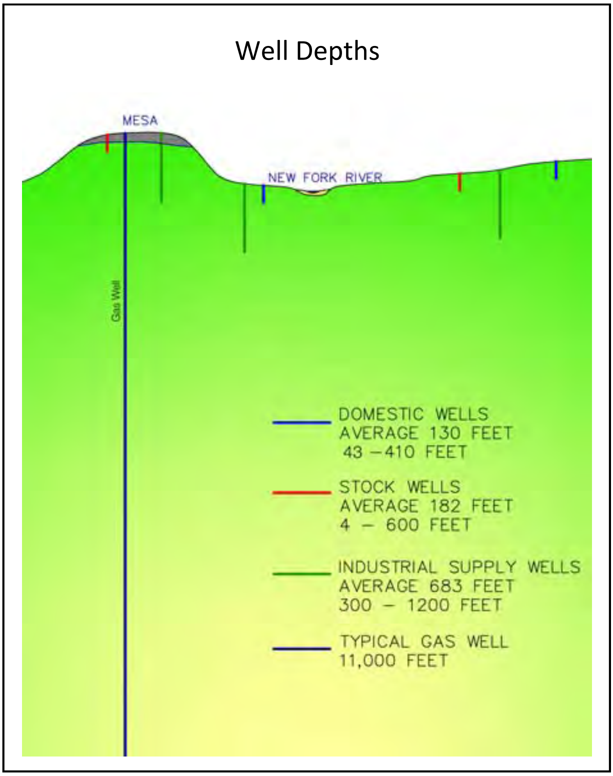


The SCCD was selected to fulfill the above requirements for the operators working within the PAPA. The operators pay for the cost of the program. The groundwater monitoring program began development in 2001 and sampling began in 2004.

Water well owners whose well is located on private lands or Wyoming State lands may participate in the program, but are not required to do so. It is, however, mandatory for water wells located on BLM administered lands within the PAPA to be included in the program.

Types of water wells sampled

Water wells sampled annually through the program include water production wells permitted through the Wyoming State Engineer's Office for designated uses of domestic, domestic/stock, stock and miscellaneous-use. Water wells used for industrial purposes within the PAPA are permitted as miscellaneous-use. Some privately owned water wells are also permitted as miscellaneous-use.



Water wells sampled by SCCD vary in depth, usually depending on the intended use. Domestic wells range from 43 to 410 feet deep with an average depth of 130 feet; stock wells range from 4 to 600 feet deep with an average depth of 182 feet; and miscellaneous use wells range from 300 to 1,200 feet deep with an average depth of 683 feet. For perspective, gas wells within the PAPA are typically over 10,000 feet deep.

What is measured in each well, each year

A number of general water quality parameters are measured in addition to the hydrocarbon component of the testing. SCCD uses field meters to measure several parameters during each well visit before collecting laboratory samples. If a well is accessible and the pump has not recently been running, water level is also measured.

372

Measured in the field: conductivity, total dissolved solids, temperature, pH and water level (if accessible and not recently pumped).
Measured by the laboratory: alkalinity, calcium, chloride, fluoride, magnesium, phosphorus, potassium, sodium, sulfate, conductivity, total dissolved solids, anion, cations, anion /cation balance, GRO (gasoline range organics) and DRO (diesel range organics).

Currently GRO and DRO are hydrocarbon indicator tests performed every time a sample is collected. If either test indicates hydrocarbon presence (any level of detection), then confirmation samples are collected. Additional analysis is ordered for specific hydrocarbons such at benzene, toluene and xylenes through a test commonly referred to as BTEX.

A chain-of-custody photo showing sample bottles filled from one well.

The current cost to have samples analyzed by a certified laboratory is $260 unless BTEX is included, then the cost is $525.

Samples are collected according to procedures described within a BLM-approved Sampling and Analysis Plan (SAP). Within the document, guidelines include sampling equipment and methods used, a listing of parameters, and quality control procedures.

To supplement the SAP, the SCCD has developed a Monitoring and Sampling Protocol Manual which guides program personnel through further quality control details. This document is updated annually by SCCD.

The BLM also has an in-depth hydrogeological study underway which will likely modify the current monitoring program. More information on this can be found on the BLM's website: http://www.blm.gov/wy/st/en/field_offices/Pinedale/anticline/resources/water.html

How samples are collected

Samples are collected a number of different ways depending on the type of well and whether or not a pump is in place. Pumps that are installed in industrial-use wells differ from those installed in domestic and stock wells as they are designed for a much higher water yield and therefore the rate and volume of water that is pumped is much greater.

373

Industrial water well samples are typically collected from a small collection valve that is tapped into a larger pipe through which water is being directed. If a well is not fitted with a collection valve, samples are generally collected directly from the end of a large hose. If a pump is not installed, two polyethylene bailers are used to collect samples from within the well. These bailers are designed with check valves at both the top and bottom, which allow water to pass through the bailers as they are lowered through the water column to the proposed sample depth. When pulled upward, the check valves are designed to close, preventing any water from entering or leaving the bailers as they pass back up through the water column. Sample depths are typically located at the center of the main water bearing zone for each particular well. This can be as far as 400 feet below water level.

Domestic well samples are typically collected from an outside faucet. SCCD sampling staff confirms with well owners that the sample collection location is prior to any filtration or treatment device that may be installed.

For samples collected with a pump, water is pumped until field parameters stabilize (recorded every 3 minutes) and/or until three casing volumes have been withdrawn. This can take 15 to 30 minutes before laboratory samples can be collected.

Left to right: sampling with a collection valve in place; when no valve is in place; and with bailers when no pump is in place.

Changes in hydrocarbon analysis

Comparing hydrocarbon-related detections from early years to later years is a difficult task due to changes in analysis methods and sampling intensity. The following is a listing of changes in testing for the presence of hydrocarbons during the SCCD groundwater sampling program's history. The changes hamper attempts to determine any trend in hydrocarbon presence.

The decisions to change methods usually originated with members of the Water Resource Task Group, a sub-committee of the Pinedale Anticline Working Group. The group was comprised of operator, government and general public representatives. Recommendations from the group were presented to the BLM for approval before changes to the sampling and analysis plan were implemented.

2004: Non-Polar method used to determine if hydrocarbons were present. The test was included in the analysis of all samples collected.

2005 - 2007: Non-Polar was used on ten percent of the samples collected. In 2006, testing indicated that there were hydrocarbons present in five of the industrial water wells tested with Non-Polar. Confirmation samples were collected from these wells with the additional analysis of BTEX, method 8021 (BTEX 8021).

This prompted the Wyoming Department of Environmental Quality (WDEQ) to request additional sampling of all industrial water wells within the PAPA and nearby Jonah Field. Third-party contractors where hired by the operators to complete the required sampling which reported the presence of hydrocarbons in additional water wells. Sampling protocol for the sampling may not have been consistent with SCCD protocol and therefore could have shown different results.

2008 - 2009: GRO and DRO replaced Non-Polar as indicator tests for hydrocarbon presence. GRO and DRO were included in the analysis for all the samples collected. When results showed a GRO and / or DRO detection, confirmation samples were collected and BTEX 8021 was added. If a well had previous hydrocarbon detections, BTEX 8021 was routinely included in the annual analysis.

375

2010 - 2013: GRO and DRO continue to be included in the annual analysis of all samples collected. When BTEX 8021 is added to the analysis, an additional method, 8260 is also used. The decision for this addition was made by the operators when it was suspected that method 8021 wasn't providing an accurate depiction of the particular hydrocarbon related profile in some of the water wells. BTEX method 8260 provides analysis of the same compounds such as benzene and toluene, and adds analysis for over 70 other hydrocarbon related compounds.

What are hydrocarbons and factors involved with testing for them

Hydrocarbons are organic compounds (such as benzene and toluene) that can be found naturally, typically originating from decayed organic matter. These compounds are commonly associated with fossil fuels and their by-products; natural gas, methane, propane, and crude oil are all examples.

Many hydrocarbons and related compounds can also be found in products used in processes associated with the development and maintenance of water wells. Lubricants and adhesives used during these processes can be present within the water well, potentially altering the results of sampling efforts. There have been instances where new water wells or recently maintained water wells (such as a newly installed pump) have yielded hydrocarbon-related detections. When these wells were sufficiently pumped, resampling then yielded results with no hydrocarbon-related detections.

Another interesting observation made by SCCD staff involved slight hydrocarbon related detections in a stock-well water when decaying animal matter was also present within the water well casing. Remember what hydrocarbons are and what creates them?

Because sampling environments cannot be completely controlled, there is potential for contamination of samples. Environmental factors that could cause these alterations to sampling results include, but are not limited to: exhaust from vehicles and generators, oil/grease

376

near sample collection points, and airborn by-products associated with nearby drilling and/or production processes. Care is always taken to avoid these potential threats as much as possible through quality control procedures.

Many of the hydrocarbon compounds measured by SCCD's sampling are volatile organic compounds, typically referred to as VOCs. These VOCs are more difficult to test for because of environmental factors that can cause the loss of (or the volatilization of) the compounds through heat or exposure to air. These factors can be caused by water heating up through the pumping process or exposure to air through aeration during the pumping process. The rate of flow can also affect these factors.

Hydrocarbon analysis is done by a certified laboratory using very sensitive equipment that can detect levels as low as 0.5 parts per billion, depending on the particular compound being analyzed and the method being used; this is also referred to as a detection limit. To put this in perspective, this would be equivalent to detecting 1/2 a drop of a particular compound in an Olympic size swimming pool, one penny in a 180 acre field, or one second in 64 years!

Regulatory process when hydrocarbons are found

When a hydrocarbon related parameter is detected through sampling conducted by SCCD, the water well owner is notified. It is then the responsibility of that well owner to notify the WDEQ and local BLM office (if the well is located on BLM administered lands).

The WDEQ uses a set of clean-up levels to help determine when a water well should be entered into the VRP (Voluntary Remediation Program). The applicable clean-up levels for groundwater in Wyoming are a combination of promulgated levels (next page) and risk-based clean-up levels. The purpose of the VRP is to assist a volunteers (in this case a water well owner or operator) in the clean-up process of a site that has been deemed contaminated.

WDEQ'/VRPs website states, *"the VRP was established in 2000 in response to the enactment of the Voluntary Remediation of Contaminated Sites law by Wyoming legislature. The program was developed by using an open process with DEQ staff and representatives from participating regulated, consulting, and environmental communities. Specifically, DEQ established a number of workgroups to focus on specific program development activities, including: risk assessment, site characterization, pollution prevention, and remedy selection."*

	detections under clean-up levels/standards	detections over cleanup levels/standards	
GRO (mg/L)	ND to 7.3	>7.3	WDEQ Clean-up Levels
DRO (mg/L)	ND to 1.1 or 10*	>1.1 or 10*	
Benzene (ug/L)	ND to 5	>5	WDEQ Clean-up Levels and/or EPA Drinking Water Standards
Ethylbenzene (ug/L)	ND to 700	>700	
Xylene (ug/L)	ND to 10,000	>10,000	
Toluene (ug/L)	ND to 1,000	>1,000	

mg/L = parts per million, ug/L = parts per billion

*The cleanup level for DRO can be 1.1 mg/L or 10 mg/L depending on further results and other factors.

Results of hydrocarbon analysis

When assessing the total number of water wells with hydrocarbon related detections, it is important to consider all the factors discussed within this brochure. Changes in testing from year to year, as well as the sensitivity and variability involved, are critical points that should be considered.

Below is an example of BTEX 8021, DRO and GRO results for a well sampled in 2010 and how they would be reflected in the summary chart to the right.

Well Id	Sample Collection Date	Benzene (ug/L)	Ethylbenzene (ug/L)	m+p-Xylenes (ug/L)	o-Xylene (ug/L)	Toluene (ug/L)	Diesel Range Organics (mg/L)	Gasoline Range Organics (mg/L)
AMI285	6/16/2010	7.6	0	0	0	5.8	0	0.13

The set of results includes detections that put this well into three different categories in 2010's totals. The benzene detection of 7.6 ug/L, is above WDEQ's clean-up level (CUL) of 5.0 ug/L which causes this well to be included in the number of wells with BTEX at or above WDEQ CUL. The toluene detection of 5.8 ug/L is below WDEQ's CUL of 1,000 ug/L, which

378

causes this well to also be included in the number of wells with BTEX below WDEQ CUL. Due to the GRO detection of 0.13 mg/L, the third category this well is included in is the GRO below WDEQ CUL.

Summary of Year to Year Hydrocarbon Analysis and Results

		2004	2005	2006	2007	2008	2009	2010	2011	2012
Analysis used	Non Polar	●	○ 10%	○ 10%	○ 10%					
	GRO & DRO					●	●	●	●	●
Additional analysis when confirmation samples were collected	GRO			●	●					
	BTEX 8021			●	●	●	●	●	●	●
	BTEX 8260							●	●	●

Number of wells with hydrocarbon-related detections			2004	2005	2006	2007	2008	2009	2010	2011	2012
	Non Polar	Domestic	0	0	0	0					
		Stock	0	0	0	0					
		Miscellaneous	0	0	4	1					
	GRO below WDEQ CUL	Domestic			0	0	1	1	0	1	0
		Stock			0	0	0	0	1	0	0
		Miscellaneous			1	5	14	9	9	8	8
	GRO at or above WDEQ CUL	Domestic			0	0	0	1	0	0	0
		Stock			0	0	0	0	0	0	0
		Miscellaneous			1	0	1	0	0	0	0
	DRO below WDEQ CUL*	Domestic					0	2	0	0	1
		Stock					0	0	0	1	0
		Miscellaneous					8	7	0	3	6
	DRO at or above WDEQ CUL*	Domestic					0	0	0	0	0
		Stock					0	0	0	0	0
		Miscellaneous					3	0	3	0	1
	BTEX 8021 below WDEQ CUL	Domestic			0	0	0	1	0	0	0
		Stock			0	0	1	0	1	0	0
		Miscellaneous			4	8	11	14	10	7	8
	BTEX 8021 at or above WDEQ CUL	Domestic			0	0	0	1	0	0	0
		Stock			0	0	0	0	0	0	0
		Miscellaneous			1	3	3	4	5	3	3
	BTEX 8260 below WDEQ CUL	Domestic							0	0	0
		Stock							1	0	0
		Miscellaneous							9	7	7
	BTEX 8260 at or above WDEQ CUL	Domestic							0	0	0
		Stock							0	0	0
		Miscellaneous							2	1	1

*A DRO CUL of 10 mg/l is used for the above chart since the acutal CUL can not be determined from SCCD data.

		2004	2005	2006	2007	2008	2009	2010	2011	2012	Totals 2004-2012
Total wells with hydrocarbon related detections below WDEQ CUL	Domestic	0	0	0	0	1	2	0	1	1	5
	Stock	0	0	0	0	1	0	1	1	0	3
	Miscellaneous	0	0	5	8	20	19	13	9	15	40
Total wells with hydrocarbon related detections at or above WDEQ CUL	Domestic	0	0	0	0	0	1	0	0	0	1
	Stock	0	0	0	0	0	0	0	0	0	0
	Miscellaneous	0	0	1	3	4	4	7	3	4	11

From 2004 through 2012, 48 wells exhibited hydrocarbon detections, 12 of which had levels that were at or above WDEQ CULs.

SCCD's annual groundwater reports are available online through the BLM's website (see address on back page). Included in the reports are field and laboratory results along with notes pertaining to each water well visit and sample collection.

At the time this publication is being written, the 2013 sampling season is being finalized and data from the year's sampling efforts will be subject to quality control procedures and an annual report will be produced and delivered to the BLM in February of 2014.

Literature cited

- The Record of Decision for the Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project, Sublette County, Wyoming, Bureau of Land Management, Pinedale Field Office, July 2000
- Water Quality Rules and Regulations, Chapter 8, Wyoming Department of Environmental Quality, 2003
- Voluntary Remediation Program, Fact Sheet #12, Soil Cleanup Level Look-Up Table, Appendix A: Cleanup Levels for Total Petroleum Hydrocarbons in Soil and Groundwater, Wyoming Department of Environmental Quality, 2008
- Pinedale Anticline Ground Water Data Summary, Sublette County Conservation District, February, 2013
- Sublette County Conservation District's Ground Water Monitoring Manual and Protocol, April, 2013
- Water Quality Monitoring Sampling and Analysis Plan for the PAPA, March 2008

Website links of interest

The latest Pinedale Anticline Groundwater reports can be found on BML's website
http://www.blm.gov/wy/st/en/field_offices/Pinedale/pawg/DataResults.html

Northern Plains & Mountains Regional Water Program – includes information related to proper water well maintenance to resources related to oil and gas development
http://region8water.colostate.edu/resources.shtml

An informative site created for domestic water well owners, by the National Ground Water Association http://wellowner.org/

Wyoming Department of Environmental Quality, "Know Your Well"
http://deq.state.wy.us/wqd/kywmain.htm

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