Damascus Citizens for Sustainability

I am asking the DRBC to note the material from DCS's September, 2013 presentation to the DRBC at this link: https://www.dropbox.com/sh/85sf163ufql57iy/AABklVH2yH3kVoHl9xDsBGdza?dl=0

It includes ten 5 minute statements and references to back up these statements and some additional documentation - all are unfortunately still relevant and important.

Water damage, human and environmental health damage are occurring from drilling elsewhere - especially, or maybe because of the exemptions from liability the industry holds (see attached in part two of this comment - 'Loopholes' Sheet). As the DRBC, itself stated,
"The Commission proposes to prohibit high volume hydraulic fracturing within the basin to effectuate the comprehensive plan for the immediate and long term development and use of the water resources of the basin, and to conserve, preserve and protect the quality and quantity of the basin's water resources for uses in accordance with the comprehensive plan."

I want to stress that NO gas or oil drilling should be allowed in the Delaware Basin in order to fulfill that protective plan. The proposed prohibition of high volume hydraulic fracturing is good and should be adopted, but additionally all - even low volume and/or vertical wells should also be prohibited.

No wastes should be imported into the Basin since there is too much possibility for accidents, illegal dumping, human error...and serious contamination will result as it has everywhere movement of these wastes is allowed. ALSO no Delaware River Basin clean water should be exported for fracking elsewhere.

There are two parts to this comment. This is part 1 of 2
The attachments are most of the 5 minute presentations, references for the first eight presenters and additional information containing leaked EPA Dimock powerpoint, two biodiversity papers by Kiviat, the New Solutions Journal issue on fracking impacts and Vidic's journal article on frack waste and the damage it can do.

The earthquake, insurance - Mortgage, and health details are in the other attachment.

Isotech - Stable Isotope Analysis

Determining the origin of methane and its effect on the aquifer.

Agenda

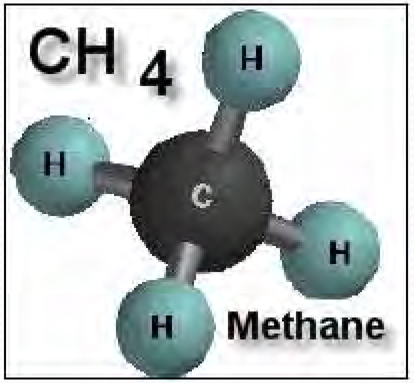
- Geologic history
- Methane characteristics
- The ratio of carbon isotopes in methane.
- The unique ratio of hydrocarbons in the Marcellus Formation
- Identifying the age of the methane.
- The effects methane and drilling have on the aquifer and trend over time.
- Conclusions.

Environment of Deposition
Middle Devonian
(385 MA)

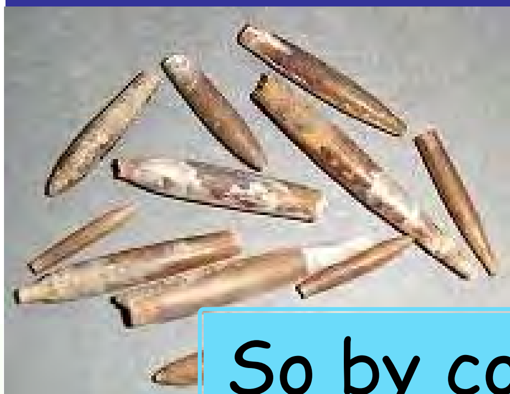

Osborn S G et al. PNAS 2011;108:8172-8176

Methane is the principal hydrocarbon detected in all stray natural gas migration incidents

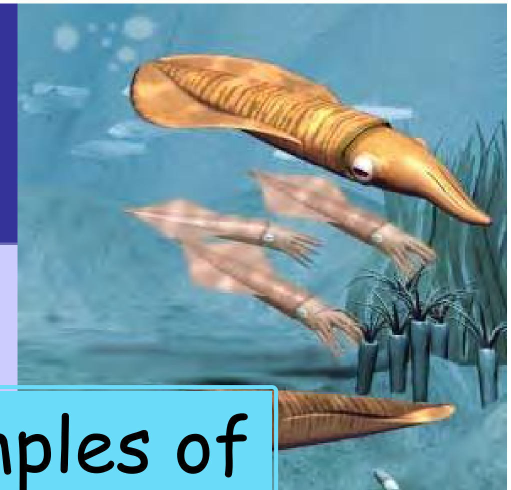
- Exposure limit (gas phase): TLV-TWA: 1,000 ppm (ACGIH, 10/2009)
- Methane (CH_4) is the simplest paraffin hydrocarbon gas
- Methane is generated by microbial & thermogenic processes
- Flammable, colorless, odorless.
- Specific gravity: 0.555 (NTP) air = 1
- Explosive range: 5-15% in ambient air
- Solubility in water: 26-32 mg/l (1 atm.)
- Non toxic, no ingestion hazard
- Simple asphyxiant, explosion hazard



Methane can migrate as free gas or dissolved in the groundwater



Delta notation



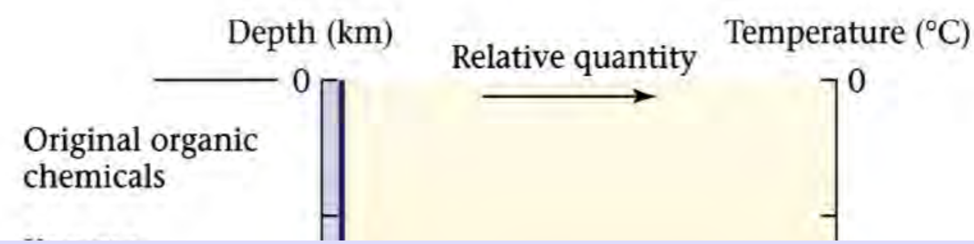
So by collecting numerous gas samples of known origin a database has been developed and fingerprinting of gas samples may performed.

$R_{reference}$= VPDB (Vienna Pee Dee Belemnite)

$$\delta^{13}\mathrm{C} = \delta\left({}^{13}\mathrm{C}\right) = \delta\left({}^{13}\mathrm{C}/{}^{12}\mathrm{C}\right) = \frac{n_{\mathrm{X}}\left({}^{13}\mathrm{C}\right)/n_{\mathrm{X}}\left({}^{12}\mathrm{C}\right) - n_{\mathrm{ref}}\left({}^{13}\mathrm{C}\right)/n_{\mathrm{ref}}\left({}^{12}\mathrm{C}\right)}{n_{\mathrm{ref}}\left({}^{13}\mathrm{C}\right)/n_{\mathrm{ref}}\left({}^{12}\mathrm{C}\right)}$$

Shale Gas

- Increasing formation temperature leads to diagnostic



The normal sequence of carbon isotopic compositions is:

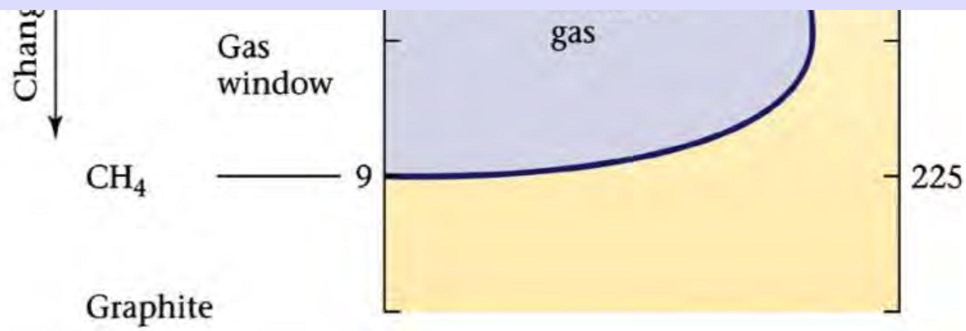
$\delta^{13}C$ methane (C_1) < $\delta^{13}C$ ethane (C_2) < $\delta^{13}C$ propane (C_3) and < $\delta^{13}C$ butane (C_4)

$$\boldsymbol{\delta^{13}C_1 < \delta^{13}C_2 < \delta^{13}C_3 \text{ and } < \delta^{13}C_4}$$

In the Marcellus they are fully reversed - $\delta^{13}C_1 > \delta^{13}C_2 > \delta^{13}C_3$

Also hydrogen isotopic compositions (δ^2H) of C_1 and C_2 are also reversed.

- Uniquely identifiable when paired with additional proxies (e.g. noble gases)



Isotope Geochemistry

- Molecular: Methane/Ethane
- Isotopic: Carbon and Hydrogen isotopes ($\delta^{13}C$-CH_4, $\delta^{2}H$-CH_4, $\delta^{13}C$-C_2H_6)
- Noble Gases

Easily Distinguishes:

☑ Biogenic vs. Thermogenic
(e.g. Schoell, 1983; Coleman et al, 1991; Baldassare and Laughrey, 1998)

☑ Distinguishing different thermogenic gases
(e.g. Schoell et al, 1983; Jenden et al, 1993; Revesz et al, 2010; Tilley et al, 2010)

? What's best for distinguishing thermally mature gases?

ISOTECH
ISOTECH LABORATORIES INC

ANALYSIS REPORT

Lab #:	235488	Job #:	17407
Sample Name/Number:	HW02z		
Company:	TechLaw, Inc.		
Date Sampled:	1/25/2012		
Container:	Dissolved Gas Bottle		
Field/Site Name:	A3TA		
Location:			
Formation/Depth:			
Sampling Point:			
Date Received:	2/03/2012	Date Reported:	2/20/2012

Component	Chemical mol. %	$\delta^{13}C$ ‰	δD ‰	$\delta^{18}O$ ‰
Carbon Monoxide	nd			
Hydrogen Sulfide	na			
Helium	0.0112			
Hydrogen	nd			
Argon	0.628			
Oxygen	0.80			
Nitrogen	40.72			
Carbon Dioxide	0.094			
Methane	57.06	-29.30	-160.6	
Ethane	0.687			
Ethylene	nd			
Propane	nd			
Propylene	0.0001			
Iso-butane	nd			
N-butane	nd			
Iso-pentane	nd			
N-pentane	nd			
Hexanes +	nd			
Water			-64.6	-9.66

Total BTU/cu.ft. dry @ 60deg F & 14.7psia, calculated: 590

Specific gravity, calculated: 0.736

^{13}C fractionation

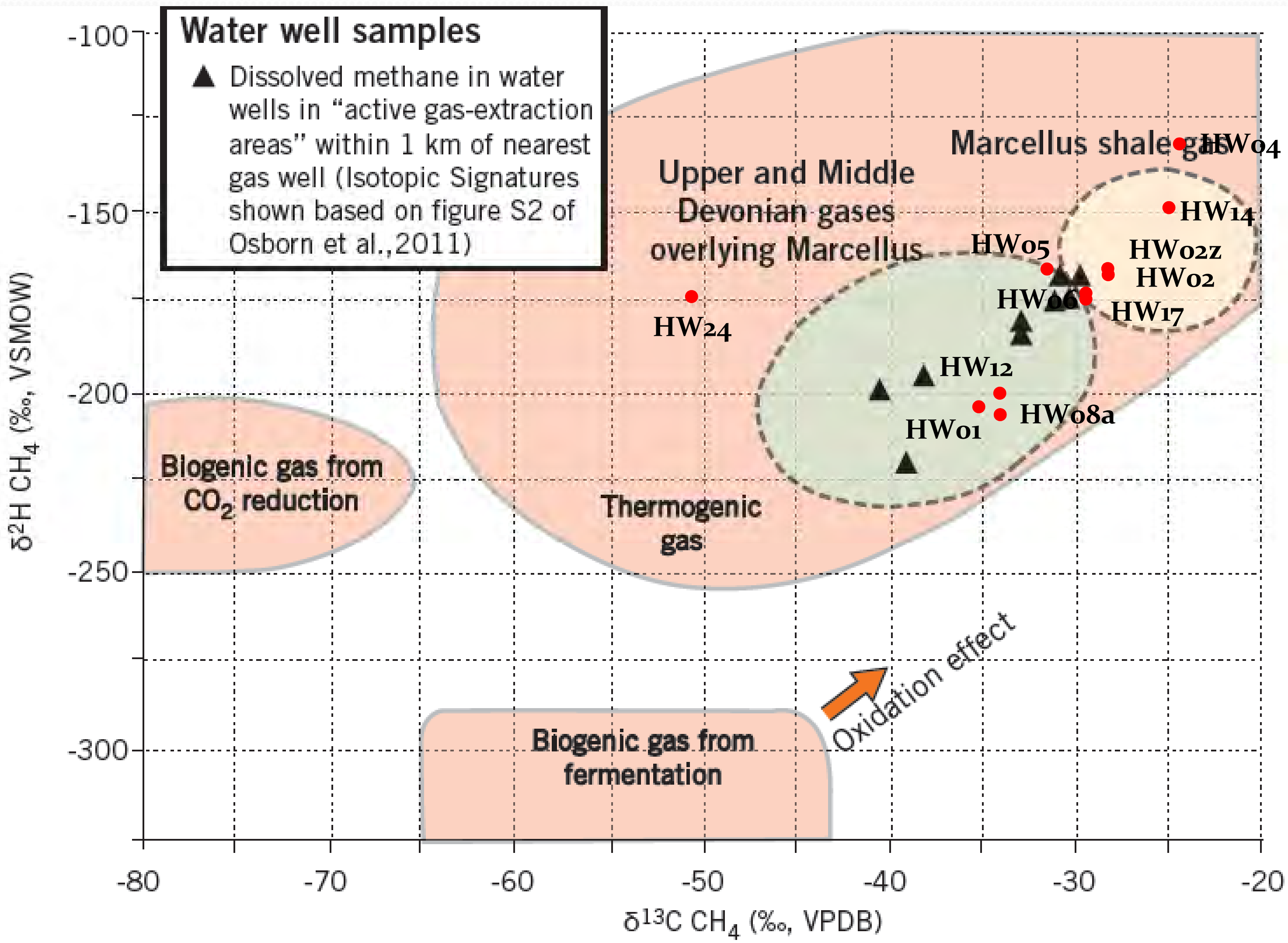
^{2}H fractionation

% argon

% nitrogen

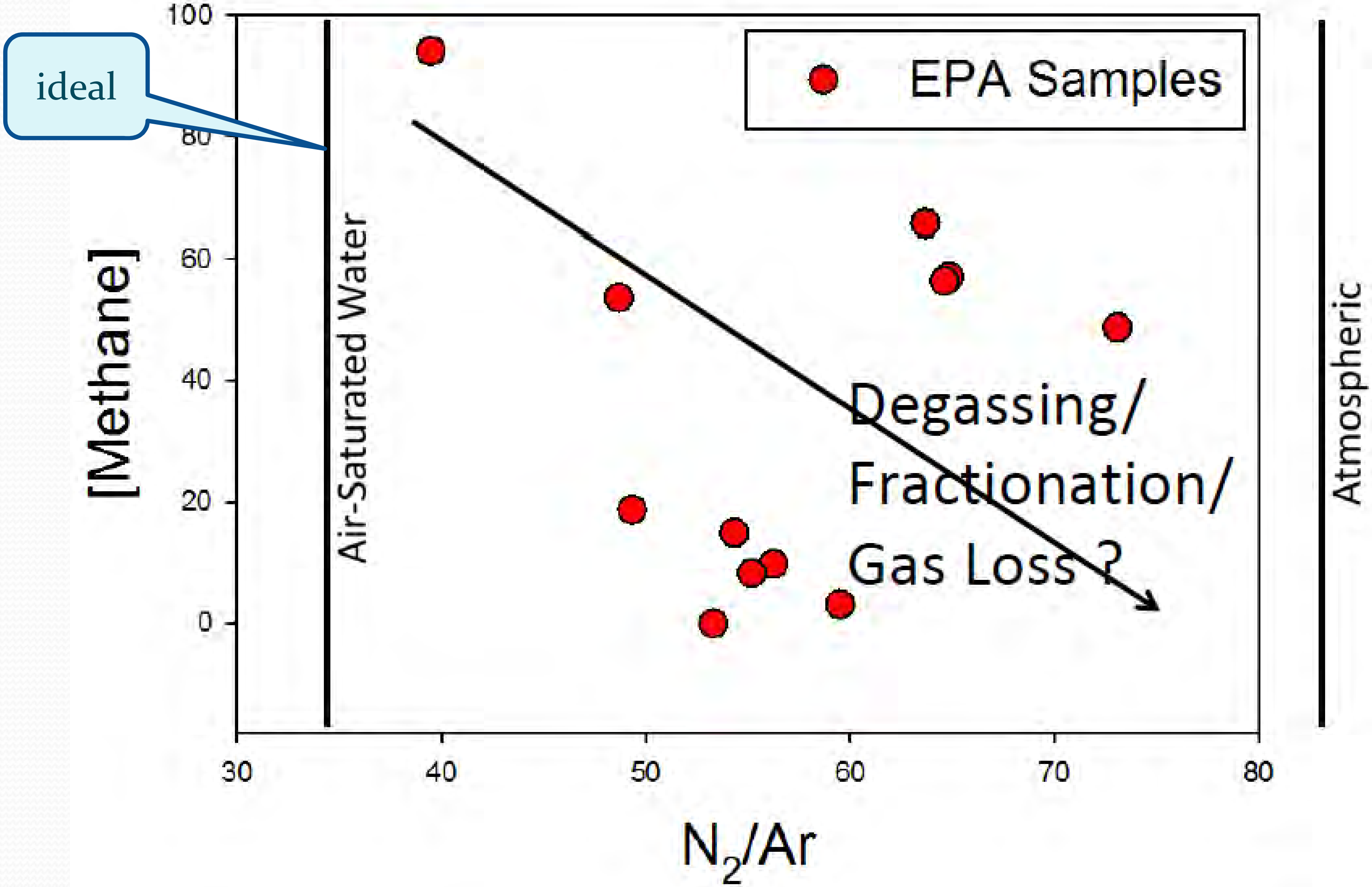
-29

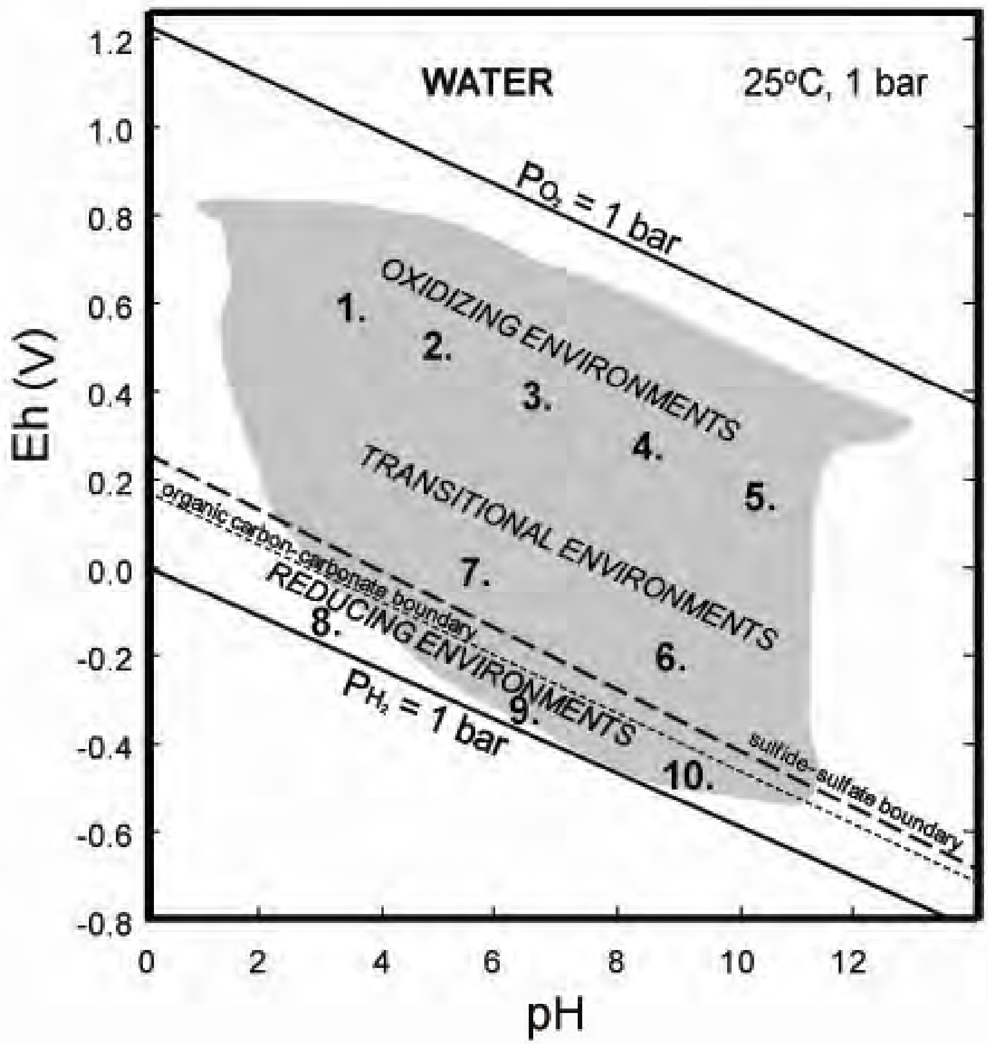
-160



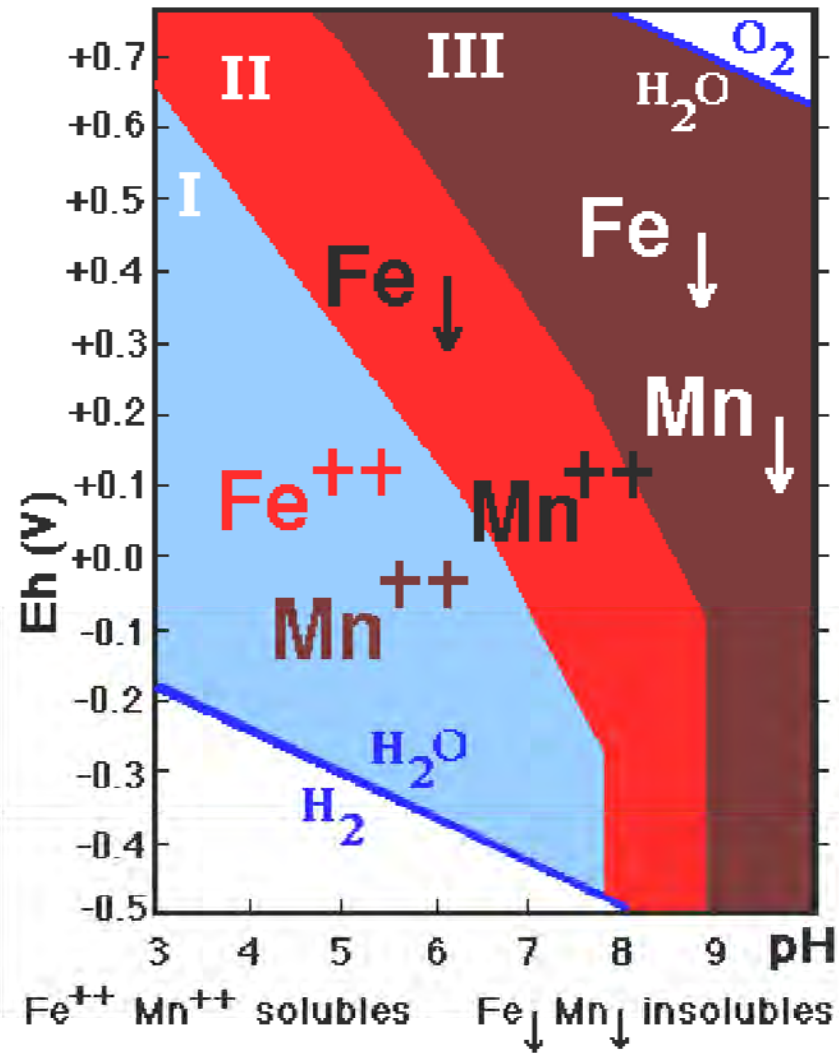
Water well samples
Dissolved methane in water wells in "active gas-extraction areas" within 1 km of nearest gas well (Isotopic Signatures shown based on figure S2 of Osborn et al.,2011)
Marcellus shale gas
Upper and Middle Devonian gases overlying Marcellus
Biogenic gas from CO_2 reduction
Thermogenic gas
Biogenic gas from fermentation
Oxidation effect
HW04
HW14
HW02z
HW02
HW05
HW06
HW17
HW24
HW12
HW08a
HW01
-100
-150
-200
-250
-300
-80
-70
-60
-50
-40
-30
-20
δ^2H CH_4 (‰, VSMOW)
$\delta^{13}C$ CH_4 (‰, VPDB)

Sample Quality - degassing?





WATER
25°C, 1 bar
P_{O_2} = 1 bar
OXIDIZING ENVIRONMENTS
TRANSITIONAL ENVIRONMENTS
REDUCING ENVIRONMENTS
organic carbon-carbonate boundary
sulfide-sulfate boundary
P_{H_2} = 1 bar
1.
2.
3.
4.
5.
6.
7.
8.
9.
10.
Eh (V)
pH

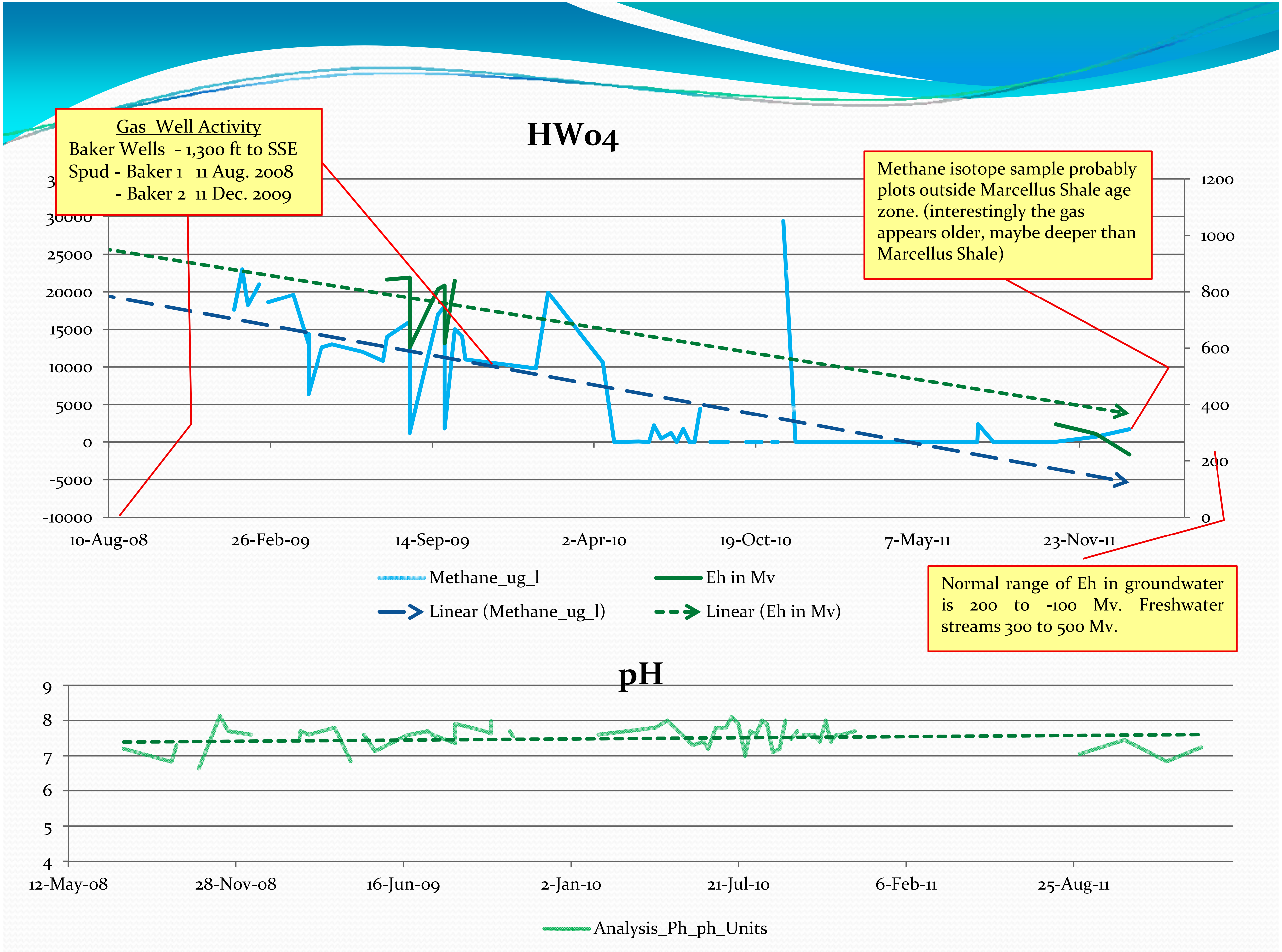


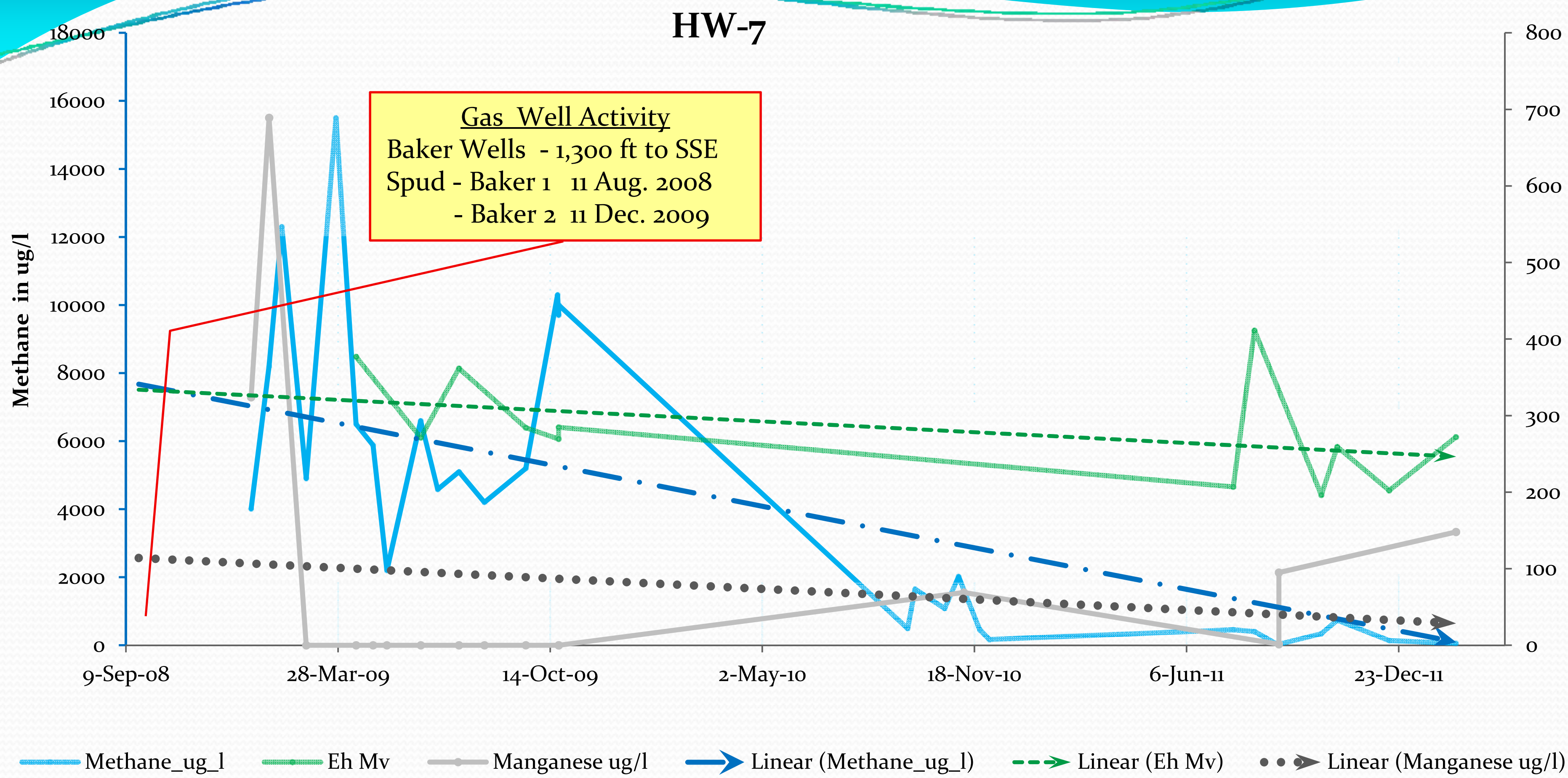
I
II
III
O_2
H_2O
Fe↓
Fe↓
Mn↓
Fe^{++}
Mn^{++}
Mn^{++}
H_2O
H_2
Eh (V)
pH
Fe^{++} Mn^{++} solubles
Fe↓ Mn↓ insolubles

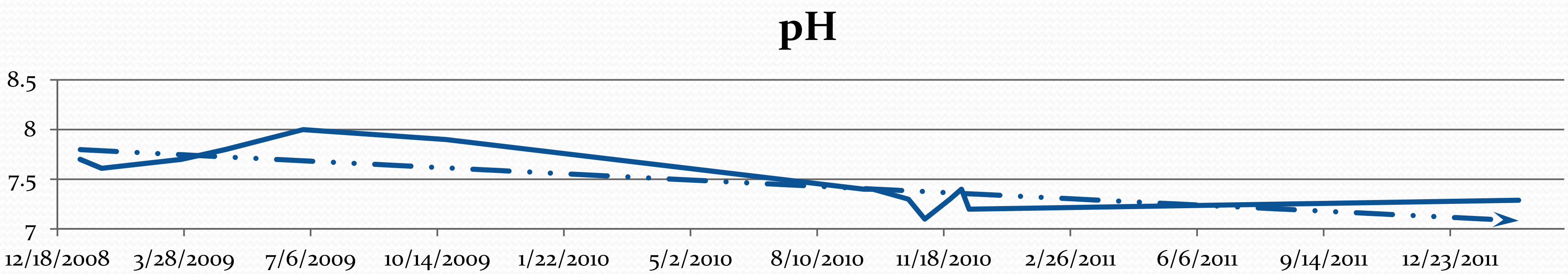
Three Patterns of Contamination

1. **Short term** (< 1 year) disruption to the aquifer caused by drilling.
2. **Long term** (> 3-4 year) disruption or contamination of the aquifer caused by drilling/fracking, releases or other situations.
3. **Natural Background Conditions** with high levels of metals and anions.

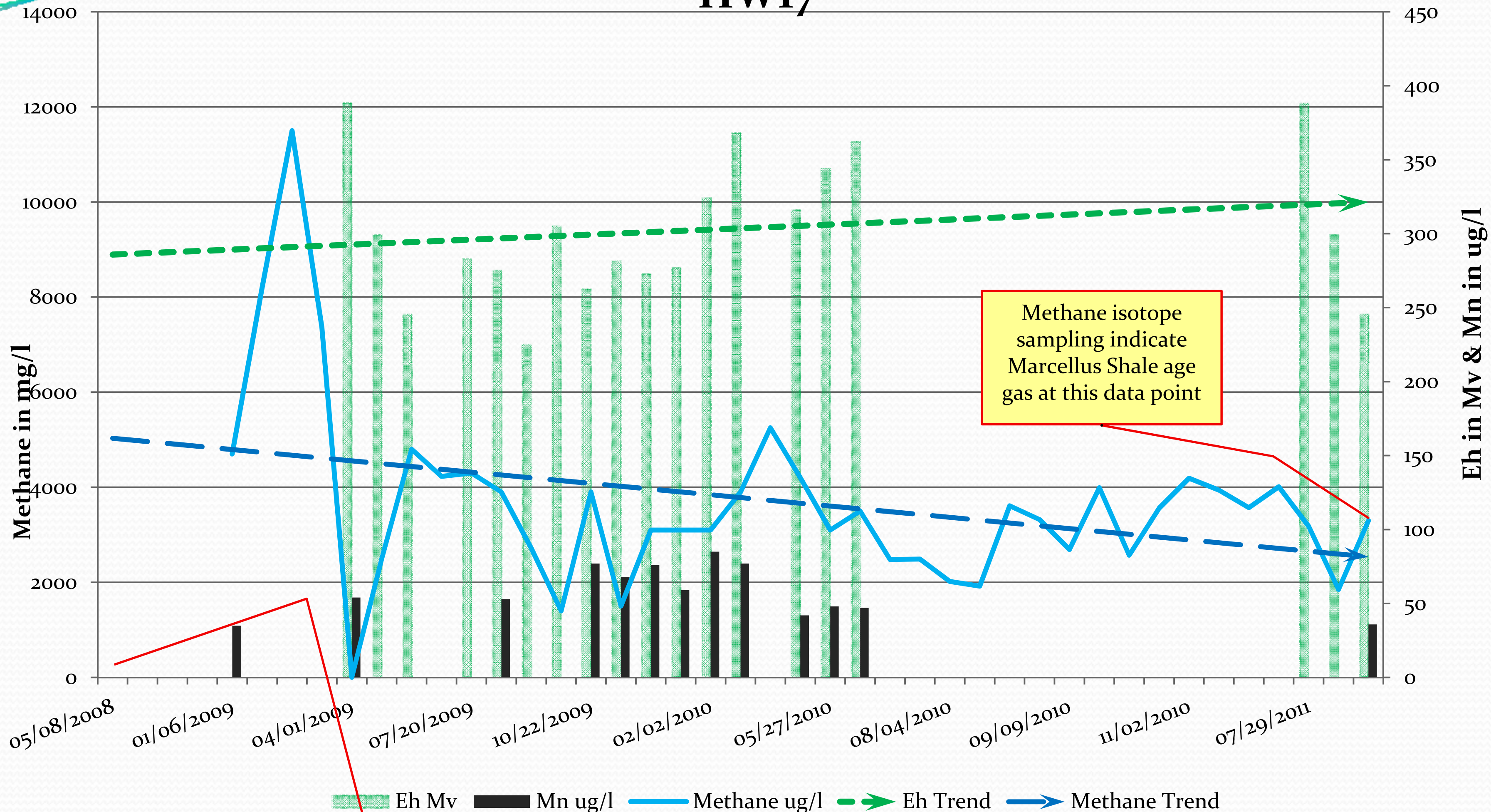
Type 1: Short Term Disruption


HW04
Gas Well Activity
Baker Wells - 1,300 ft to SSE
Spud - Baker 1 11 Aug. 2008
- Baker 2 11 Dec. 2009
Methane isotope sample probably plots outside Marcellus Shale age zone. (interestingly the gas appears older, maybe deeper than Marcellus Shale)
30000
25000
20000
15000
10000
5000
0
-5000
-10000
1200
1000
800
600
400
200
0
10-Aug-08
26-Feb-09
14-Sep-09
2-Apr-10
19-Oct-10
7-May-11
23-Nov-11
Methane_ug_l
Eh in Mv
Linear (Methane_ug_l)
Linear (Eh in Mv)
Normal range of Eh in groundwater is 200 to -100 Mv. Freshwater streams 300 to 500 Mv.
pH
9
8
7
6
5
4
12-May-08
28-Nov-08
16-Jun-09
2-Jan-10
21-Jul-10
6-Feb-11
25-Aug-11
Analysis_Ph_ph_Units


HW-7
Methane in ug/l
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
800
700
600
500
400
300
200
100
0
Gas Well Activity
Baker Wells - 1,300 ft to SSE
Spud - Baker 1 11 Aug. 2008
- Baker 2 11 Dec. 2009
9-Sep-08
28-Mar-09
14-Oct-09
2-May-10
18-Nov-10
6-Jun-11
23-Dec-11
Methane_ug_l
Eh Mv
Manganese ug/l
Linear (Methane_ug_l)
Linear (Eh Mv)
Linear (Manganese ug/l)


pH
8.5
8
7.5
7
12/18/2008
3/28/2009
7/6/2009
10/14/2009
1/22/2010
5/2/2010
8/10/2010
11/18/2010
2/26/2011
6/6/2011
9/14/2011
12/23/2011

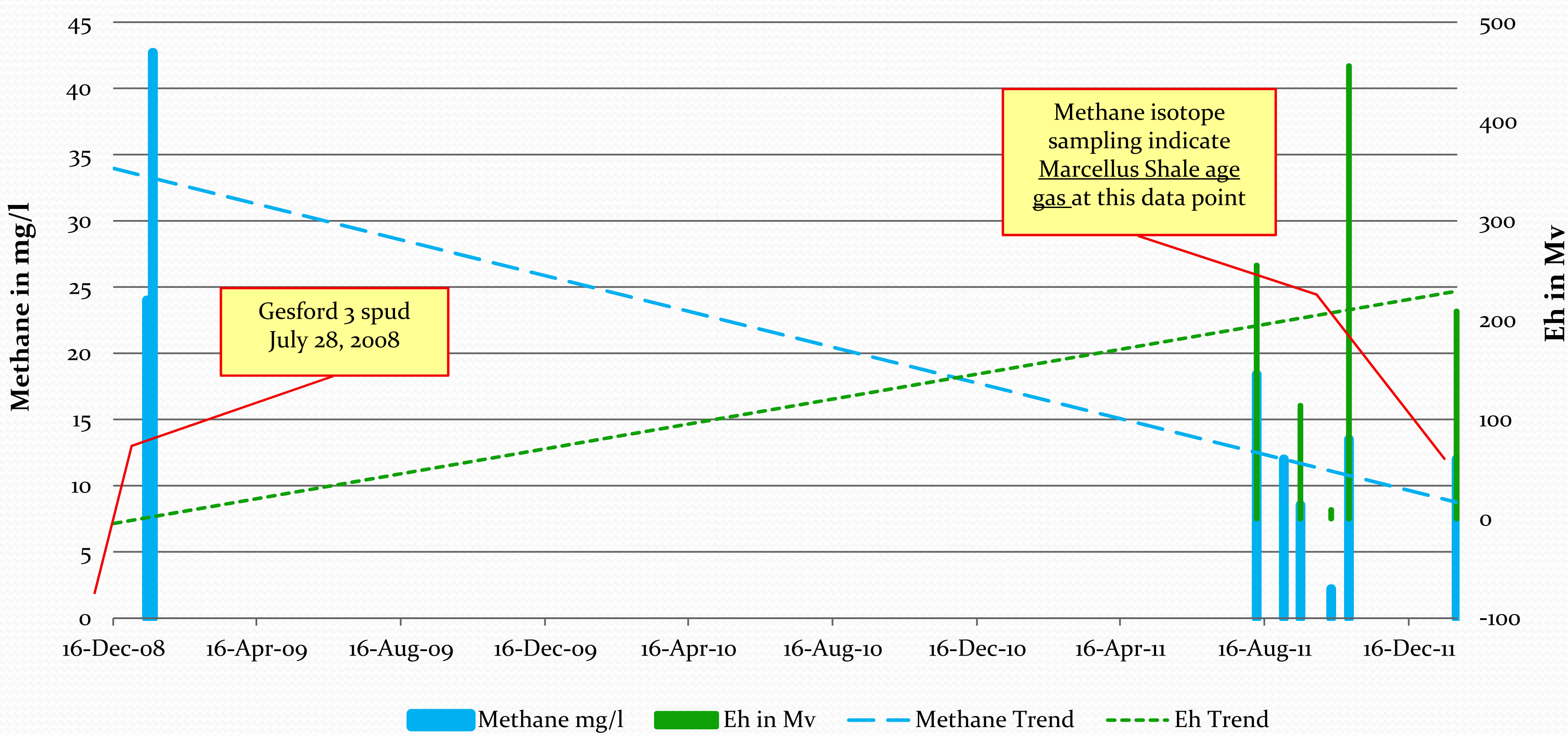
HW17



Gas Well	Date Spud	Distance to HW17
Lewis	5/28/2008	670 ft.
Ely 4H & 6H	3/27/2008	1,360 ft.
Costello 1	7/16/2008	1,350 ft.

Note incomplete data set

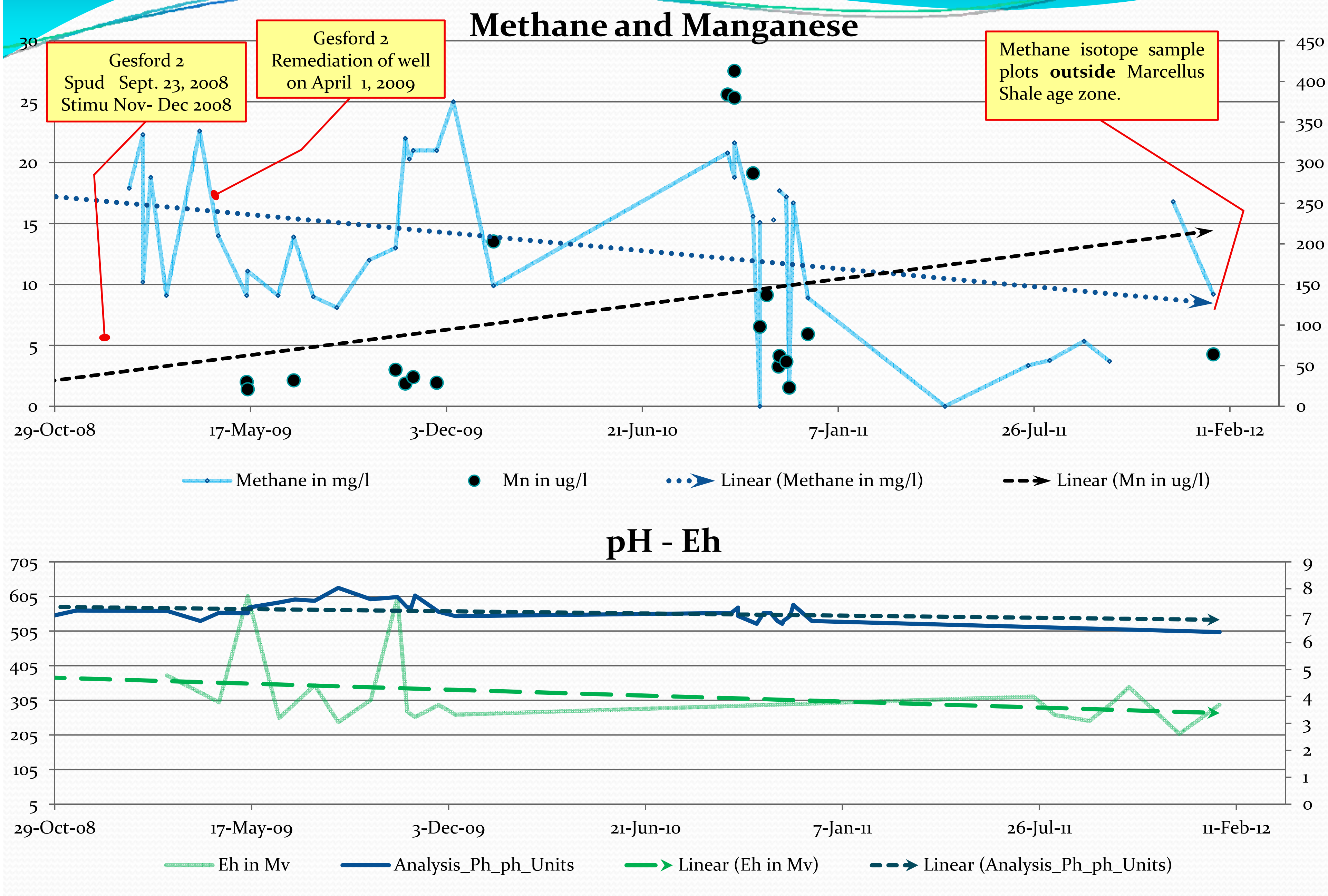
HW1 - Hubert



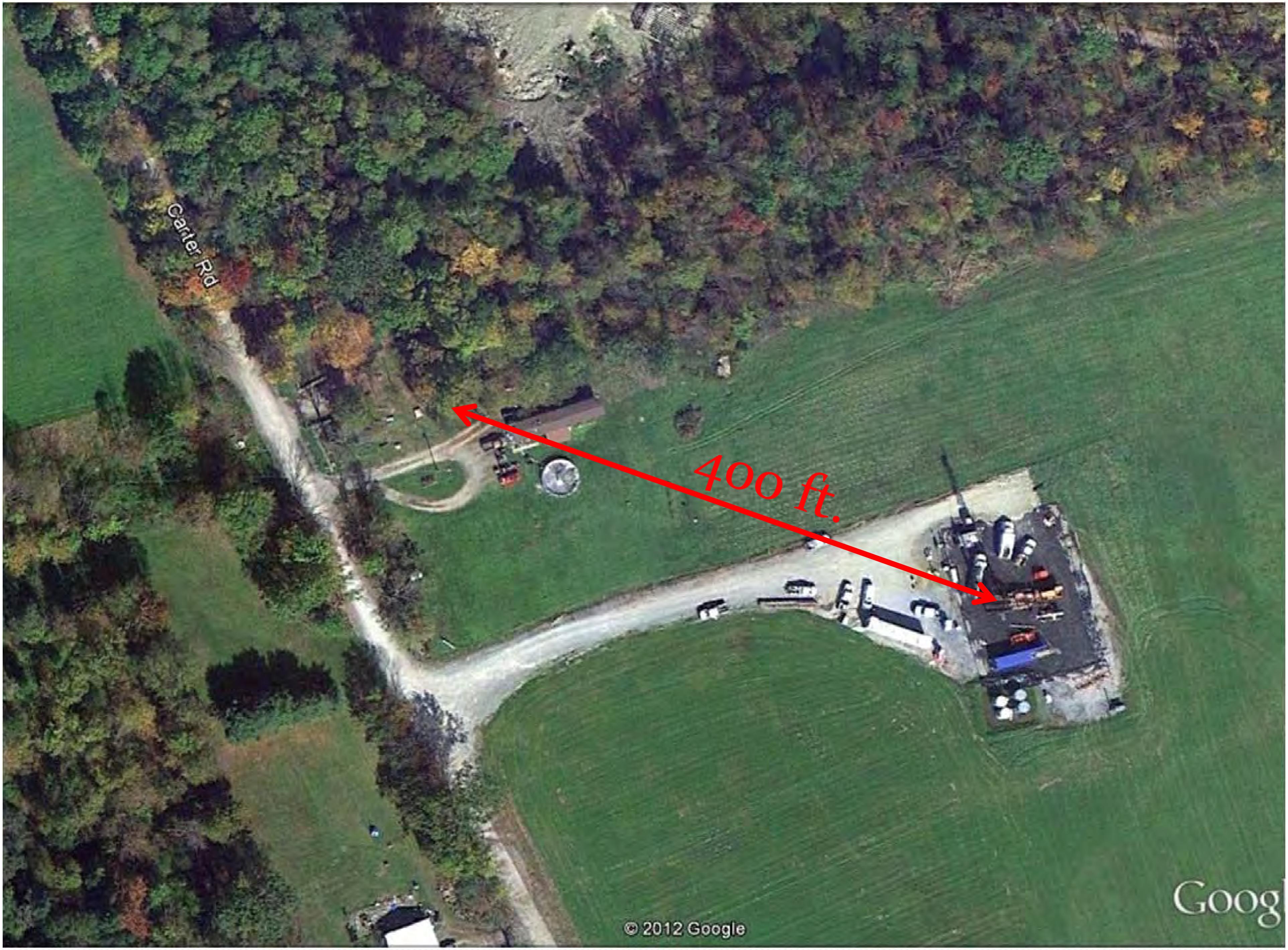
HW1 lacked data for nearly all constituents, particularly for the years 2009-2010

Type 2: Long Term Disruption

HW8



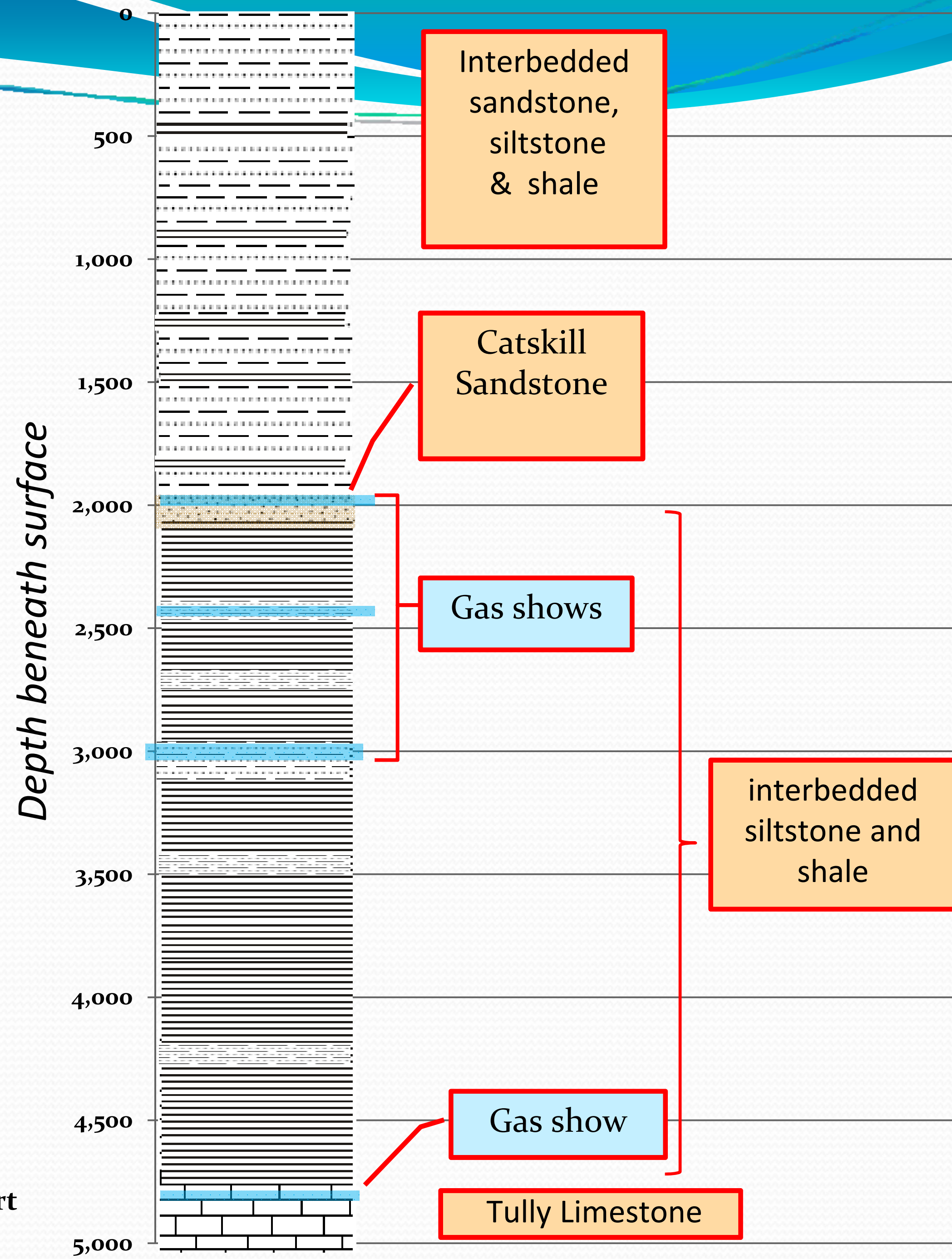
Methane and Manganese
Gesford 2
Spud Sept. 23, 2008
Stimu Nov- Dec 2008
Gesford 2
Remediation of well
on April 1, 2009
Methane isotope sample plots outside Marcellus Shale age zone.
0
5
10
15
20
25
30
0
50
100
150
200
250
300
350
400
450
29-Oct-08
17-May-09
3-Dec-09
21-Jun-10
7-Jan-11
26-Jul-11
11-Feb-12
Methane in mg/l
Mn in ug/l
Linear (Methane in mg/l)
Linear (Mn in ug/l)
pH - Eh
5
105
205
305
405
505
605
705
0
1
2
3
4
5
6
7
8
9
29-Oct-08
17-May-09
3-Dec-09
21-Jun-10
7-Jan-11
26-Jul-11
11-Feb-12
Eh in Mv
Analysis_Ph_ph_Units
Linear (Eh in Mv)
Linear (Analysis_Ph_ph_Units)



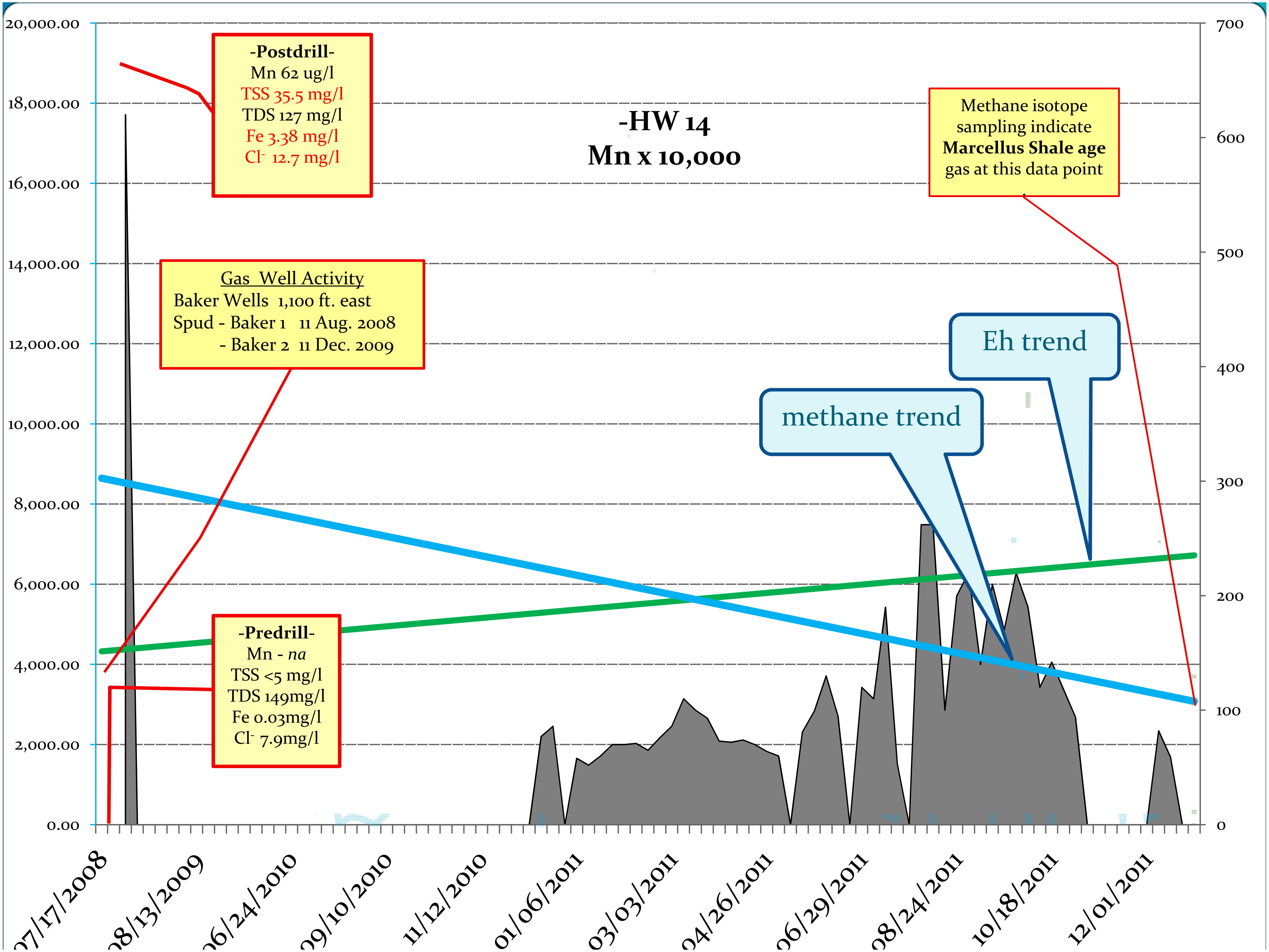
Carter Rd
400 ft.
© 2012 Google

Gas is Gas

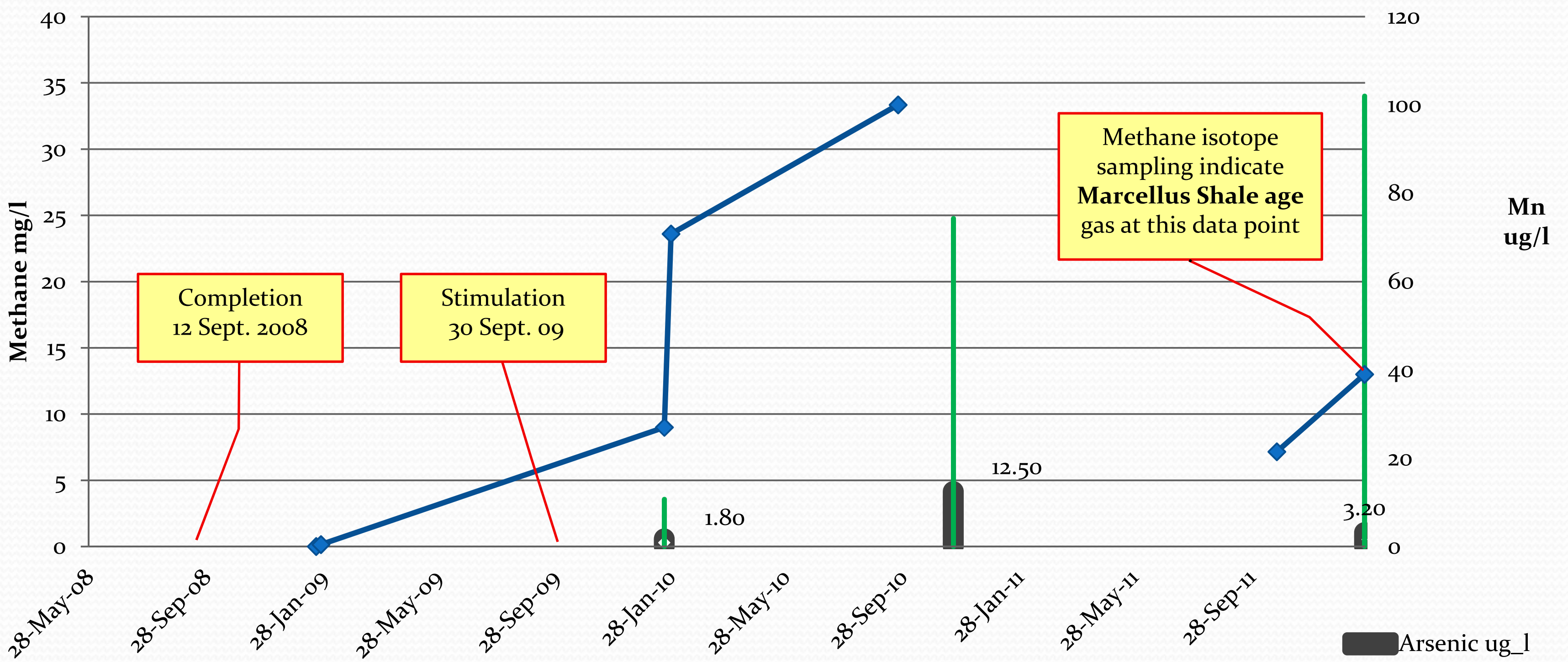
- Thermogenic gas is present throughout the upper Devonian formations. Drilling creates pathways, either temporary or permanent, that allows gas to migrate to the shallow aquifer near surface.
- Shallower (non Marcellus) gas may also include higher amounts of H2S which can have a greater impact on groundwater.
- In some cases, these gases disrupts groundwater quality



From Gesford 2 Well Record and Completion Report


-HW 14
Mn x 10,000
-Postdrill-
Mn 62 ug/l
TSS 35.5 mg/l
TDS 127 mg/l
Fe 3.38 mg/l
Cl- 12.7 mg/l
Methane isotope sampling indicate **Marcellus Shale age** gas at this data point
Gas Well Activity
Baker Wells 1,100 ft. east
Spud - Baker 1 11 Aug. 2008
- Baker 2 11 Dec. 2009
Eh trend
methane trend
-Predrill-
Mn - *na*
TSS <5 mg/l
TDS 149mg/l
Fe 0.03mg/l
Cl- 7.9mg/l
20,000.00
18,000.00
16,000.00
14,000.00
12,000.00
10,000.00
8,000.00
6,000.00
4,000.00
2,000.00
0.00
700
600
500
400
300
200
100
0
07/17/2008
08/13/2009
06/24/2010
09/10/2010
11/12/2010
01/06/2011
03/03/2011
04/26/2011
06/29/2011
08/24/2011
10/18/2011
12/01/2011

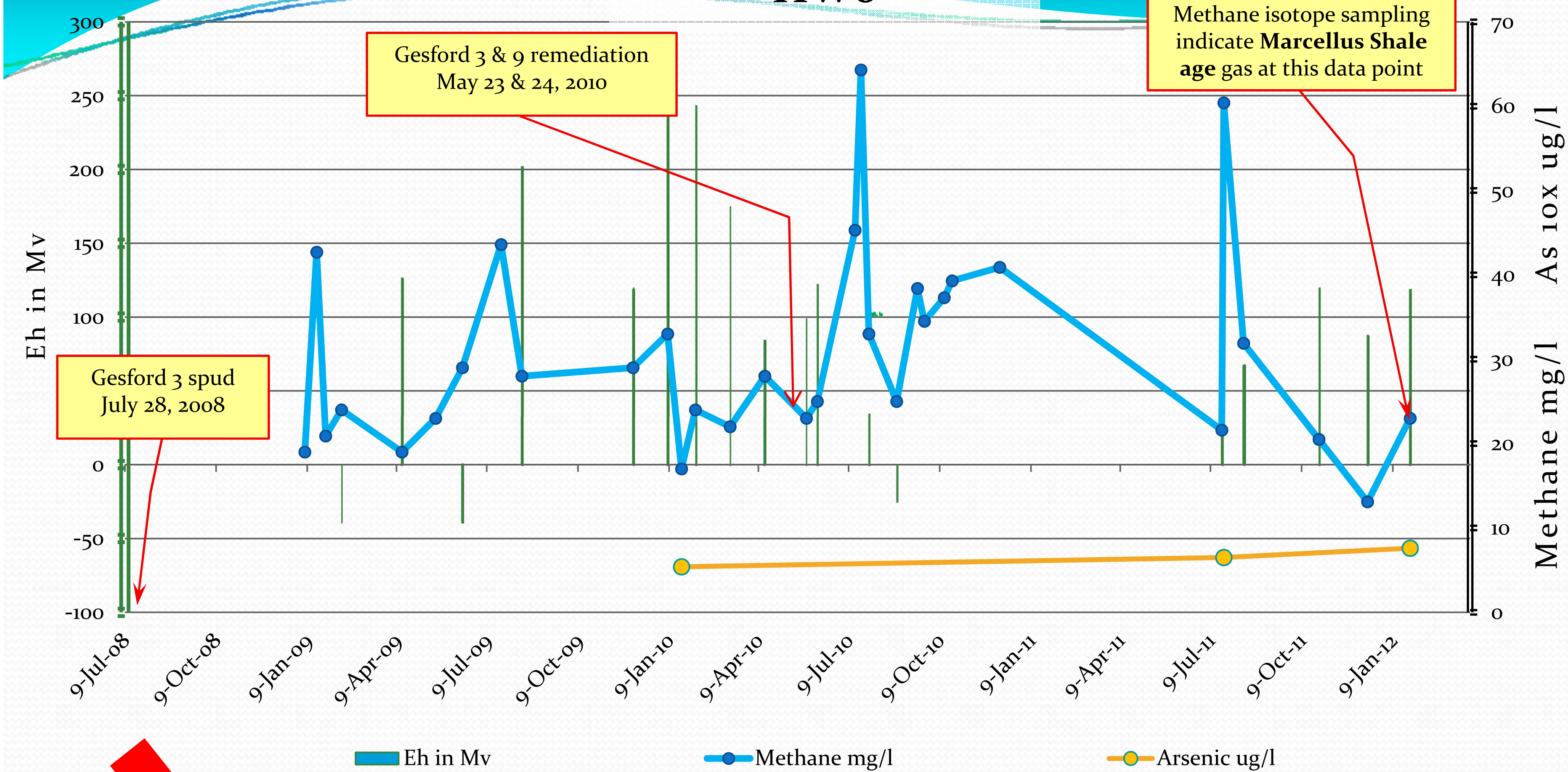
HW-2

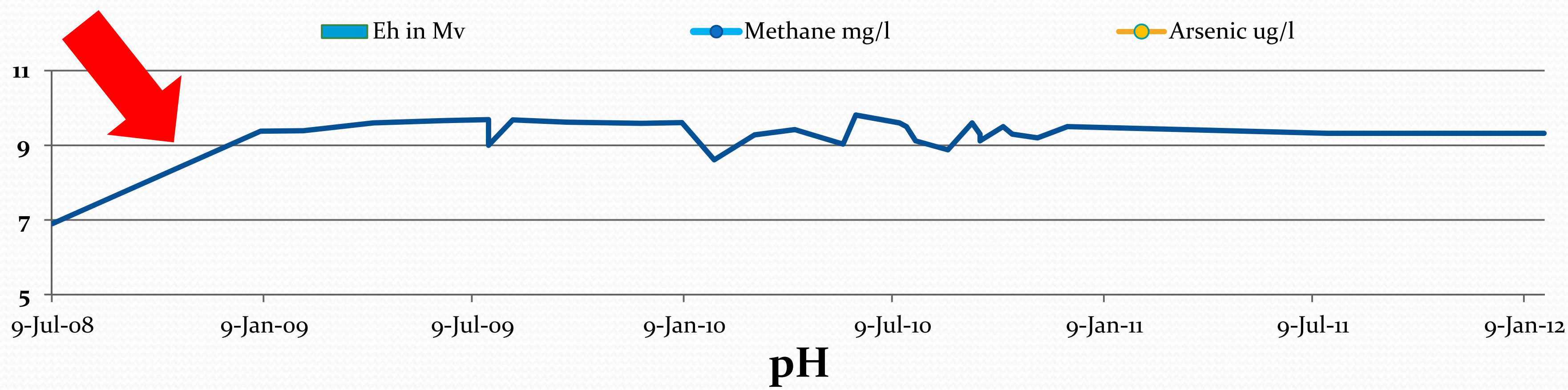


Costello	**1V**	**2V**
Spud Date:	7/26/08	8/19/08
Comp Date	9/12/08	11/11/08
Stim Date	9/30 /09	1/10/09

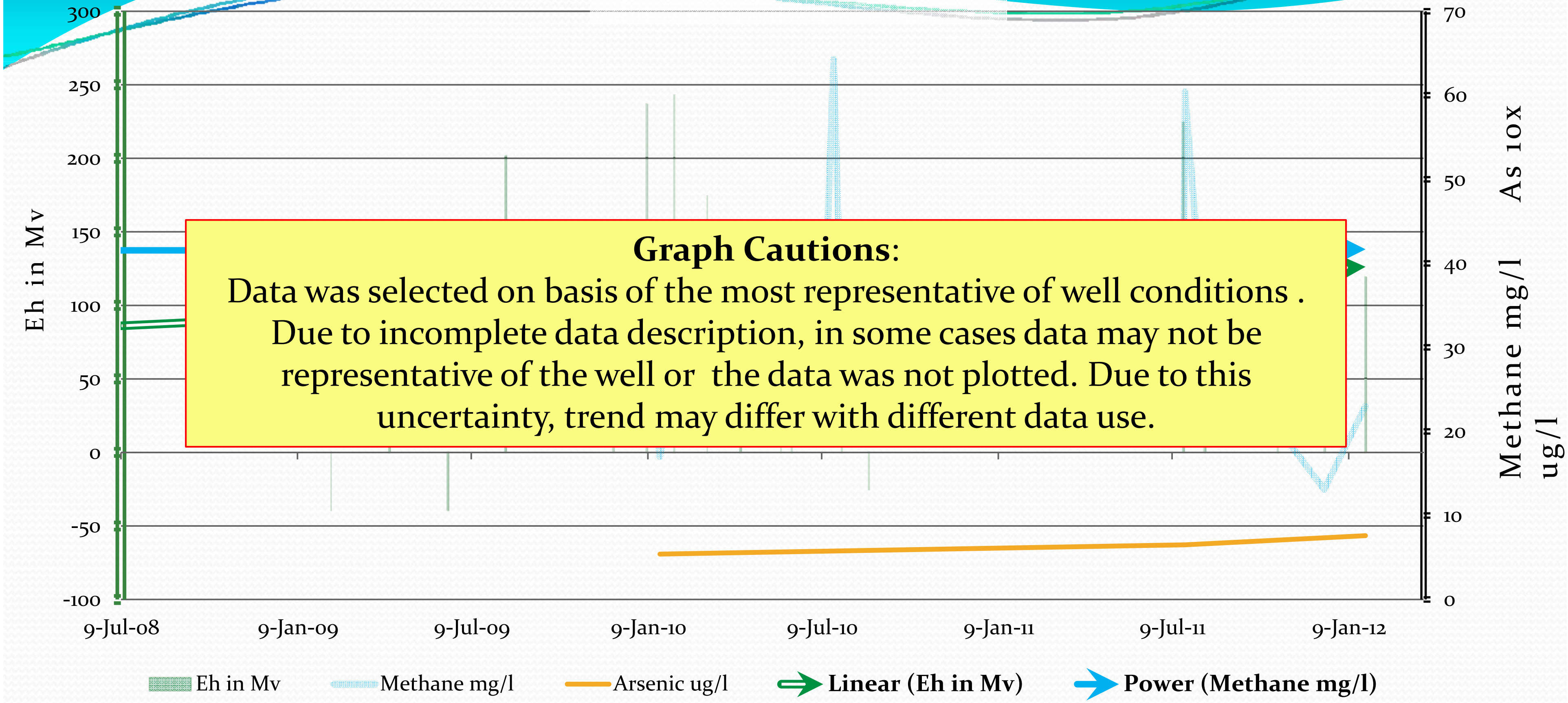
Note incomplete data set

HW6

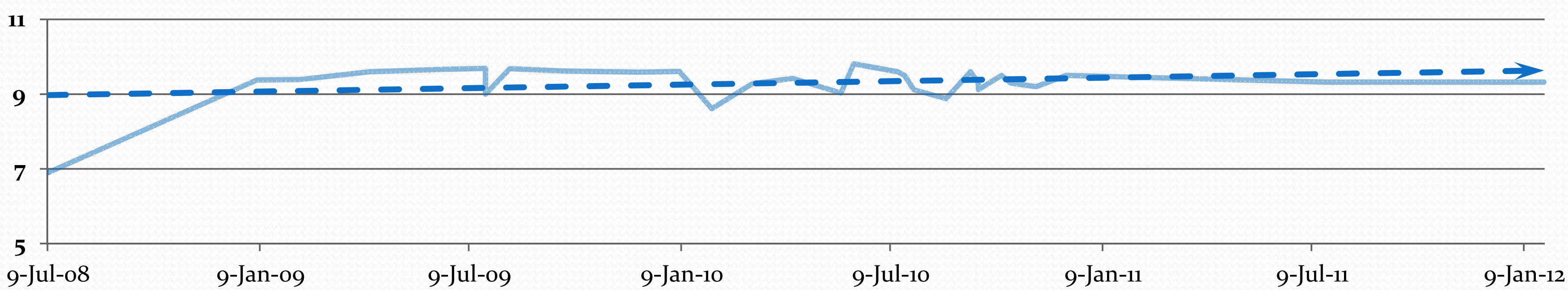

Gesford 3 & 9 remediation
May 23 & 24, 2010
Methane isotope sampling indicate **Marcellus Shale age** gas at this data point
Gesford 3 spud
July 28, 2008
Eh in Mv
As 10x ug/l
Methane mg/l
300
250
200
150
100
0
-50
-100
70
60
50
40
30
20
10
0
9-Jul-08
9-Oct-08
9-Jan-09
9-Apr-09
9-Jul-09
9-Oct-09
9-Jan-10
9-Apr-10
9-Jul-10
9-Oct-10
9-Jan-11
9-Apr-11
9-Jul-11
9-Oct-11
9-Jan-12
Eh in Mv
Methane mg/l
Arsenic ug/l


11
9
7
5
9-Jul-08
9-Jan-09
9-Jul-09
9-Jan-10
9-Jul-10
9-Jan-11
9-Jul-11
9-Jan-12
pH

HW6

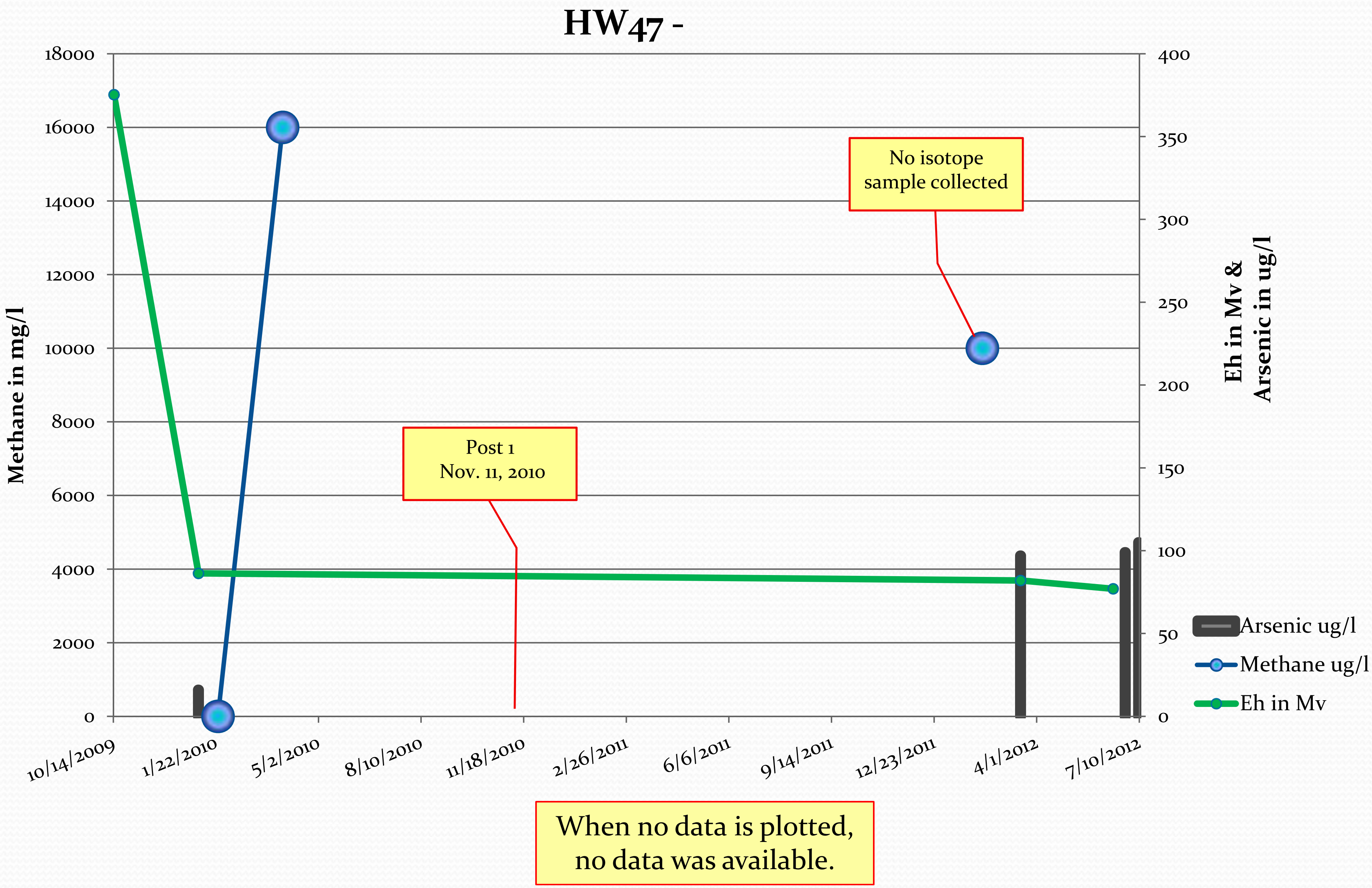


Graph Cautions:
Data was selected on basis of the most representative of well conditions . Due to incomplete data description, in some cases data may not be representative of the well or the data was not plotted. Due to this uncertainty, trend may differ with different data use.



pH

Type 3: Naturally Occurring Contamination


HW47 -
Methane in mg/l
Eh in Mv & Arsenic in ug/l
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
400
350
300
250
200
150
100
50
0
10/14/2009
1/22/2010
5/2/2010
8/10/2010
11/18/2010
2/26/2011
6/6/2011
9/14/2011
12/23/2011
4/1/2012
7/10/2012
No isotope sample collected
Post 1 Nov. 11, 2010
Arsenic ug/l
Methane ug/l
Eh in Mv
When no data is plotted, no data was available.

Conclusions

- Methane is released during the drilling and perhaps during the fracking process and other gas well work.
- Methane is at significantly higher concentrations in the aquifers after gas drilling and perhaps as a result of fracking and other gas well work.
- The methane migrating into the aquifer is both from the shallower (younger age) formations and older Marcellus Shale (and perhaps even older formations).
- Methane and other gases released during drilling (including air from the drilling) apparently cause significant damage to the water quality.
- In some cases the aquifers recover (under a year) but, in others cases the damage is long term (greater than 3 years).

Conclusions

- Methane is released during the drilling and perhaps during the fracking process and other gas well work.
- Methane is at significantly higher concentrations in the aquifers after gas drilling and perhaps as a result of fracking and other gas well work.
- The methane migrating into the aquifer is both from the shallower (younger age) formations and older Marcellus Shale (and perhaps even older formations).
- Methane and other gases released during drilling (including air from the drilling) apparently cause significant damage to the water quality.
- In some cases the aquifers recover (under a year) but, in others cases the damage is long term (greater than 3 years).

Socioeconomic Value of the Delaware River Basin in Delaware, New Jersey, New York, and Pennsylvania

The Delaware River Basin, an economic engine for over 400 years

October 11, 2011

Prepared by:

Gerald J. Kauffman
University of Delaware
Newark, Del.
302-831-4929
jerryk@udel.edu

Table of Contents

List of Figures

List of Tables

List of Appendices

Executive Summary

What do the Guggenheim Museum, New York Yankees, Boeing, Sunoco, Campbell's Soup, DuPont, Wawa, Starbucks, Iron Hill Brewery, Philadelphia Phillies, Camelback Ski Area, Pt. Pleasant Canoe Livery, Salem Nuclear Power Plant, and United States Navy all have in common? They all depend on the waters of the Delaware River Basin to sustain their businesses.

The Delaware River Basin is an economic engine that supplies drinking water to the 1st (New York City) and 7th (Philadelphia) largest metropolitan economies in the United States and supports the largest freshwater port in the world. The Delaware Basin's water supplies, natural resources, and ecosystems in Delaware, New Jersey, New York, Pennsylvania and a small sliver of Maryland:

- Contribute $25 billion in annual economic activity from recreation, water quality, water supply, hunting/fishing, ecotourism, forest, agriculture, open space, potential Marcellus Shale natural gas, and port benefits.

- Provide ecosystem goods and services (natural capital) of $21 billion per year in 2010 dollars with net present value (NPV) of $683 billion discounted over 100 years.

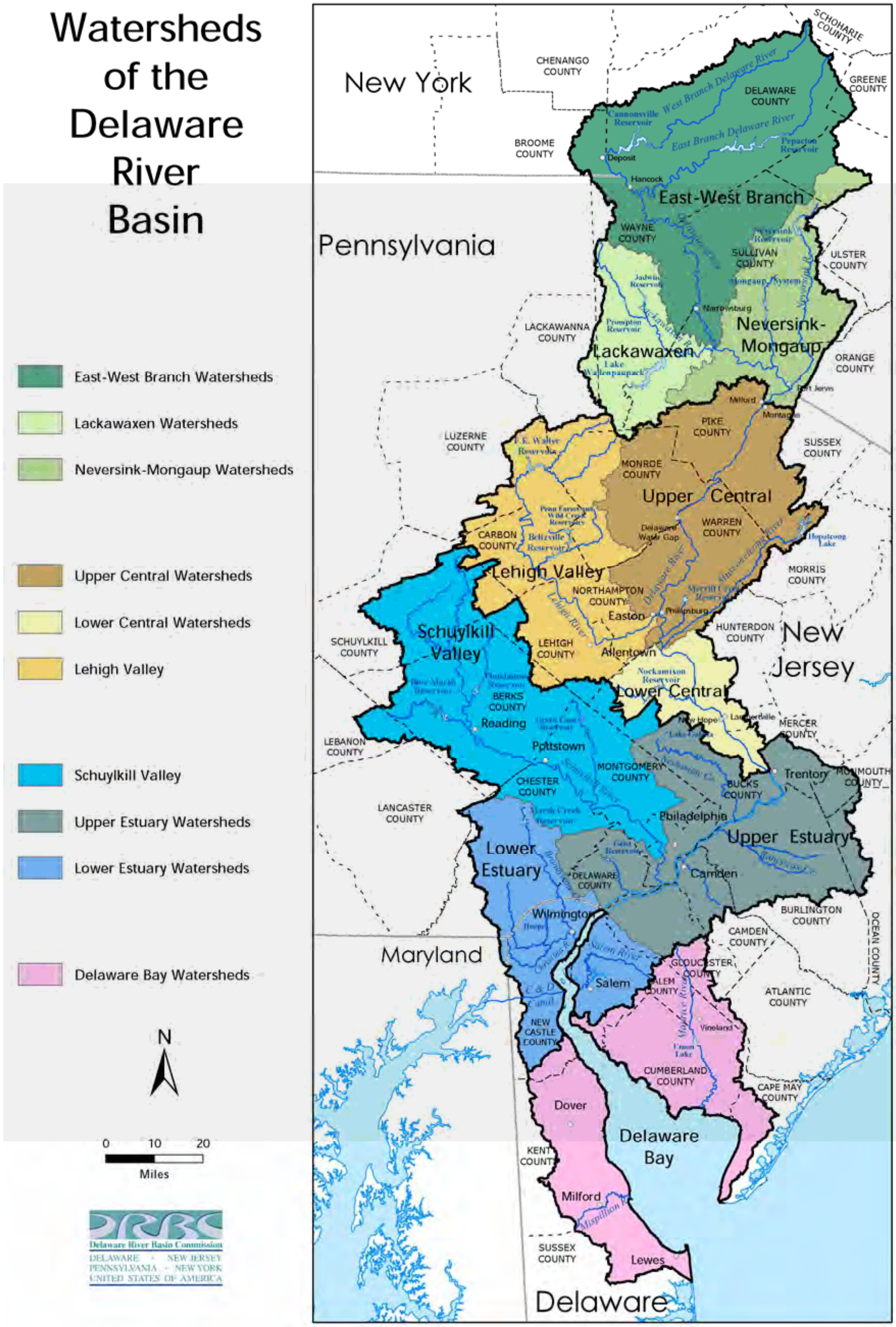
- Are directly/indirectly responsible for 600,000 jobs with $10 billion in annual wages.

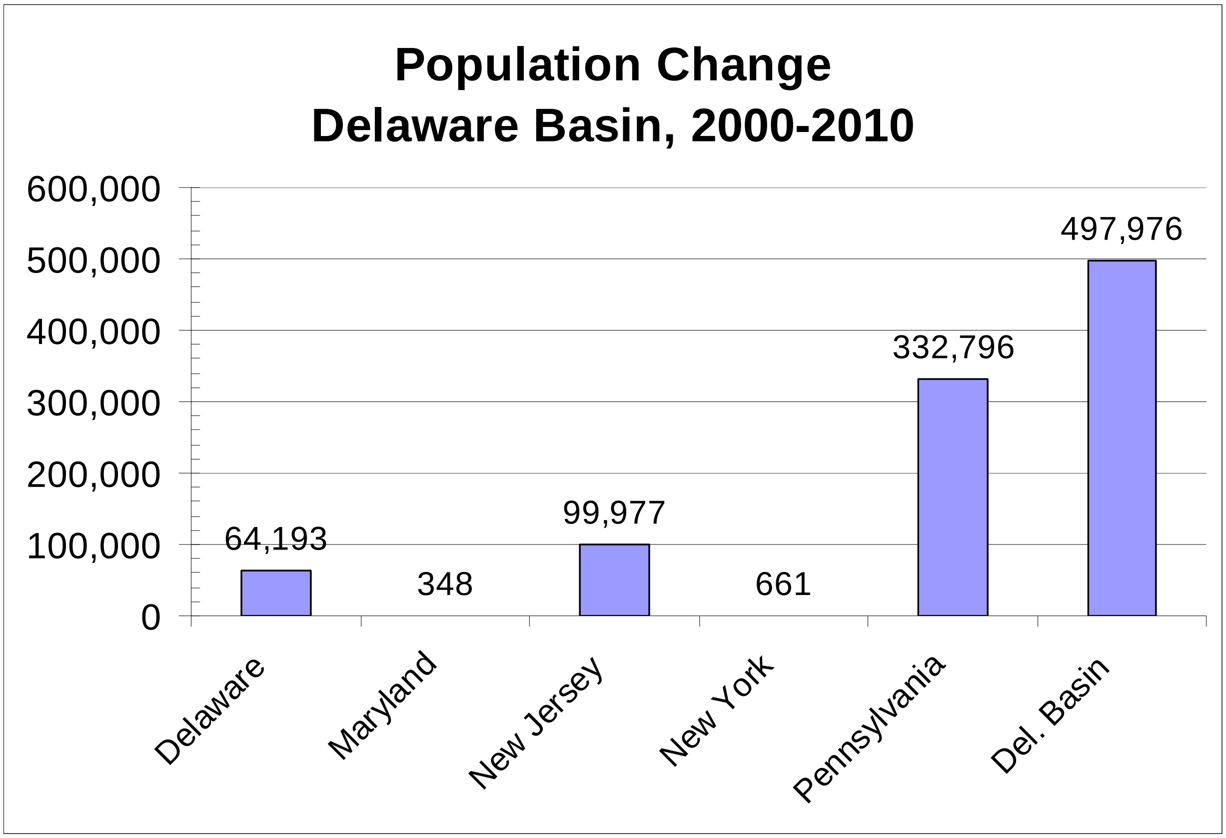
The Basin

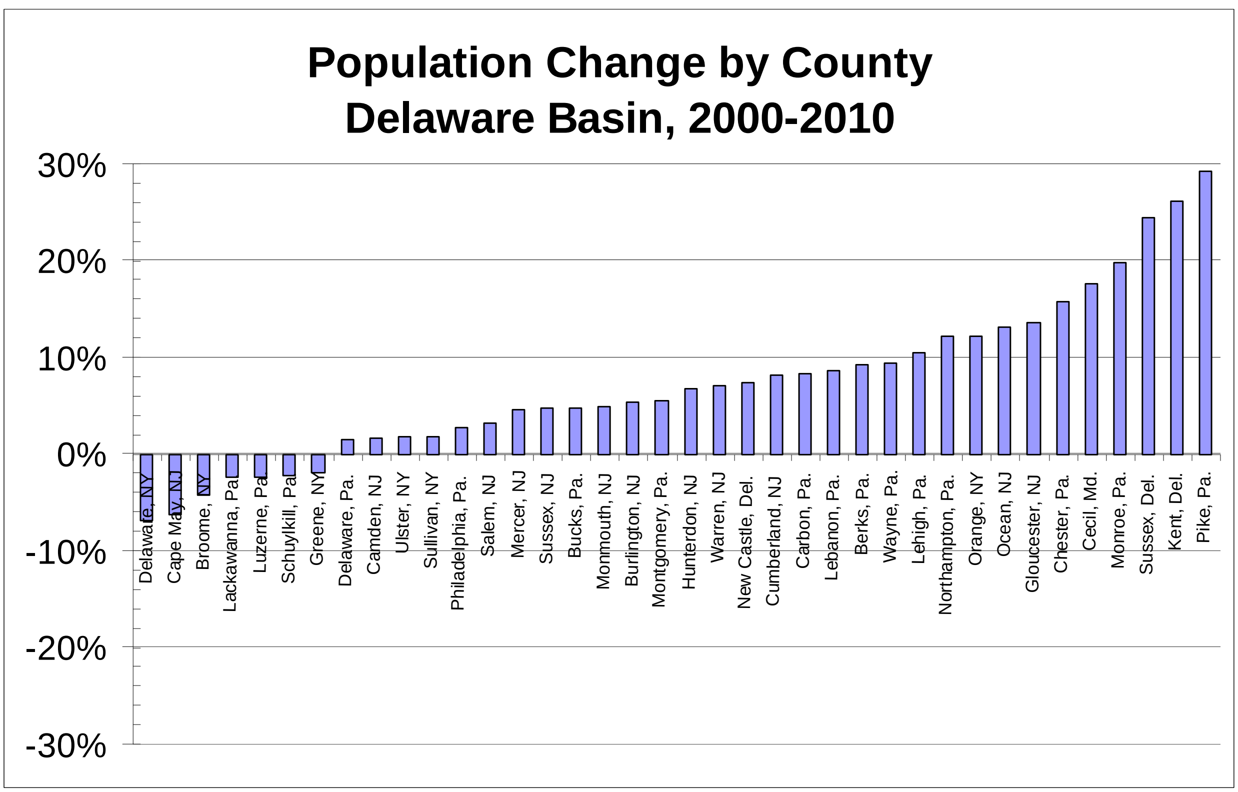
The Delaware River Basin occupies almost 13,000 sq mi (not including the river and bay) in Delaware, Maryland, New Jersey, New York, and Pennsylvania. In 2010, over 8.2 million residents lived in the basin including 654,000 people in Delaware, 2,300 in Maryland, 1,964,000 in New Jersey, 131,000 in New York, and 5,469,000 in Pennsylvania. Nearly 3,500,000 people work in the basin with 316,000 jobs in Delaware, 823,000 jobs in New Jersey, 70,000 jobs in New York, and 2,271,000 jobs in Pennsylvania. An additional 8 million people in New York City and northern New Jersey receive drinking water from the Delaware River via interbasin transfers. The Delaware Basin occupies just 0.4% of the continental U.S. yet supplies drinking water to 5% of the U.S. population.

The Delaware Basin population exceeds 8.2 million which if counted together would be the 12th most populous state after New Jersey but ahead of Virginia. The Delaware Basin occupies:
- Delaware (50% of the State's area and 74% of the First State's population)
- New Jersey (40% of the State's area and 22% of the Garden State's population)
- New York (5% of the State's area and 0.7% of the Empire State's population)
- Pennsylvania (14% of the State's area and 43% of the Keystone State's population.

Between 2000 and 2010, the population in the Delaware Basin increased by 6.1% or 472,066 people. Over the last decade, the population increased by 30% in Pike County, Pa.; by over 20% in Kent and Sussex counties, Del. and Monroe County, Pa.; and by over 10% in Gloucester and Ocean counties, NJ, Orange County, NY, and Chester, Lehigh, and Northampton counties, Pa. For the first time in two generations, Philadelphia gained population. Several counties in the basin lost population since 2000: Cape May, NJ; Broome, Delaware, and Greene counties, NY; and Lackawanna, Luzerne, and Schuylkill counties, Pa.


Watersheds of the Delaware River Basin
East-West Branch Watersheds
Lackawaxen Watersheds
Neversink-Mongaup Watersheds
Upper Central Watersheds
Lower Central Watersheds
Lehigh Valley
Schuylkill Valley
Upper Estuary Watersheds
Lower Estuary Watersheds
Delaware Bay Watersheds
N
0 10 20
Miles
Delaware River Basin Commission
DELAWARE • NEW JERSEY
PENNSYLVANIA • NEW YORK
UNITED STATES OF AMERICA
New York
Pennsylvania
New Jersey
Maryland
Delaware
East-West Branch
Lackawaxen
Neversink-Mongaup
Upper Central
Lehigh Valley
Lower Central
Schuylkill Valley
Upper Estuary
Lower Estuary
Delaware Bay
CHENANGO COUNTY
DELAWARE COUNTY
SCHOHARIE COUNTY
GREENE COUNTY
BROOME COUNTY
WAYNE COUNTY
SULLIVAN COUNTY
ULSTER COUNTY
LACKAWANNA COUNTY
ORANGE COUNTY
LUZERNE COUNTY
PIKE COUNTY
SUSSEX COUNTY
MONROE COUNTY
WARREN COUNTY
CARBON COUNTY
MORRIS COUNTY
NORTHAMPTON COUNTY
SCHUYLKILL COUNTY
LEHIGH COUNTY
HUNTERDON COUNTY
BERKS COUNTY
MERCER COUNTY
LEBANON COUNTY
MONTGOMERY COUNTY
BUCKS COUNTY
MONMOUTH COUNTY
CHESTER COUNTY
LANCASTER COUNTY
DELAWARE COUNTY
BURLINGTON COUNTY
CAMDEN COUNTY
OCEAN COUNTY
GLOUCESTER COUNTY
SALEM COUNTY
ATLANTIC COUNTY
NEW CASTLE COUNTY
CUMBERLAND COUNTY
CAPE MAY COUNTY
KENT COUNTY
SUSSEX COUNTY
Deposit
Hancock
Narrowsburg
Port Jervis
Milford
Montague
Delaware Water Gap
Phillipsburg
Easton
Allentown
Reading
Pottstown
New Hope
Lambertville
Trenton
Philadelphia
Camden
Wilmington
Salem
Vineland
Dover
Milford
Lewes


Population Change
Delaware Basin, 2000-2010
600,000
500,000
400,000
300,000
200,000
100,000
0
64,193
348
99,977
661
332,796
497,976
Delaware
Maryland
New Jersey
New York
Pennsylvania
Del. Basin


Population Change by County
Delaware Basin, 2000-2010
30%
20%
10%
0%
-10%
-20%
-30%
Delaware, NY
Cape May, NJ
Broome, NY
Lackawanna, Pa
Luzerne, Pa
Schuylkill, Pa
Greene, NY
Delaware, Pa.
Camden, NJ
Ulster, NY
Sullivan, NY
Philadelphia, Pa.
Salem, NJ
Mercer, NJ
Sussex, NJ
Bucks, Pa.
Monmouth, NJ
Burlington, NJ
Montgomery, Pa.
Hunterdon, NJ
Warren, NJ
New Castle, Del.
Cumberland, NJ
Carbon, Pa.
Lebanon, Pa.
Berks, Pa.
Wayne, Pa.
Lehigh, Pa.
Northampton, Pa.
Orange, NY
Ocean, NJ
Gloucester, NJ
Chester, Pa.
Cecil, Md.
Monroe, Pa.
Sussex, Del.
Kent, Del.
Pike, Pa.

Annual Economic Activity

The Delaware Basin contributes over $25 billion in annual market/non-market value to the regional economy from the following activities:

• Recreation	$1.22 billion
• Fish and Wildlife	$1.55 billion
• Public Parks	$1.83 billion
• Water Quality	$2.46 billion
• Navigation/Ports	$2.62 billion
• Marcellus Shale Natural Gas (potential)	$3.30 billion
• Agriculture	$3.37 billion
• Water Supply	$3.82 billion
• Forests	$5.13 billion

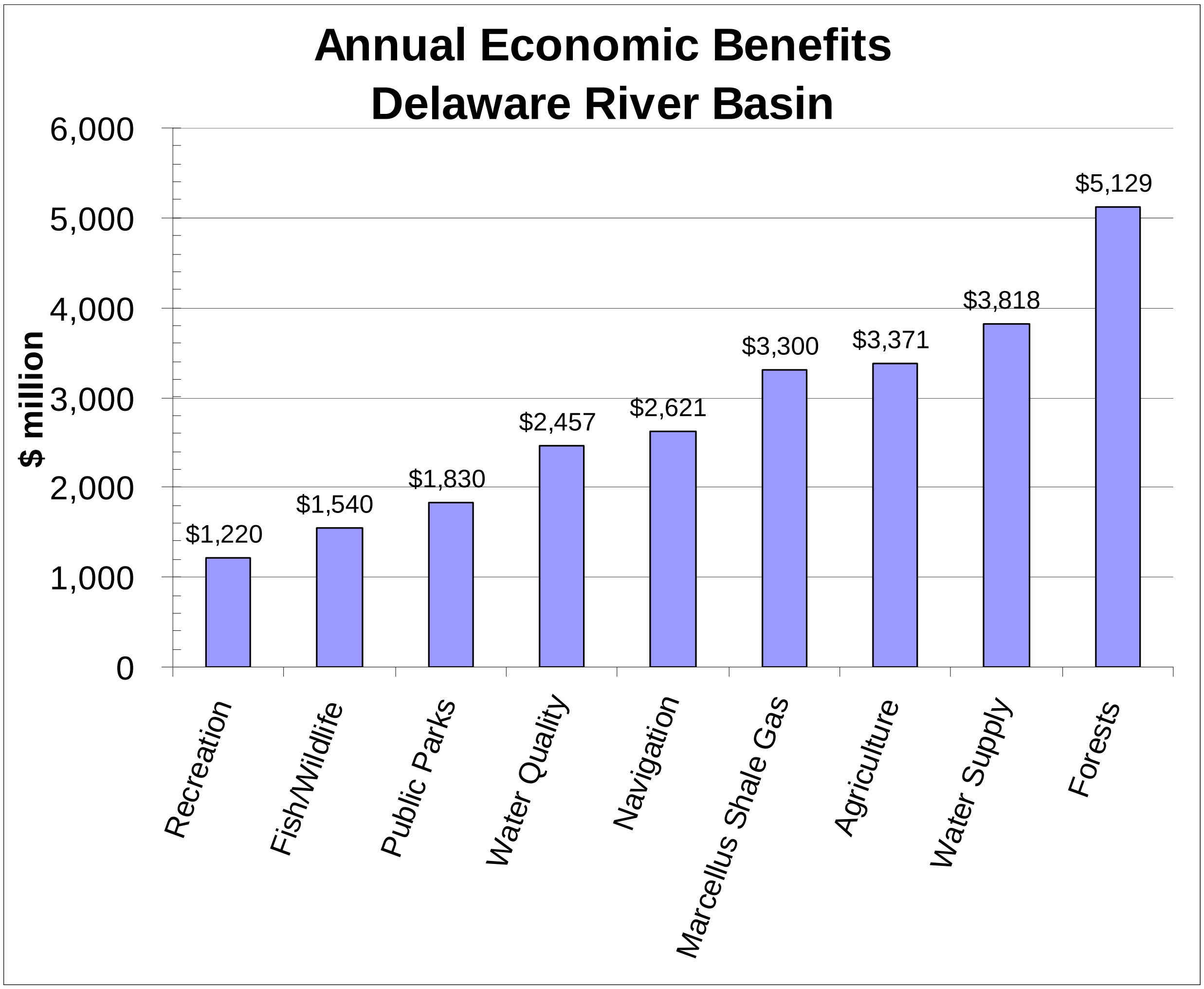


Table E1. Annual economic value supported by the Delaware River Basin.

Market Value	2010 ($ million)	Sources
Recreation (Boating, Fishing, Swimming)		
Skiing (1.9 million ski-days @ $45/day)	325	Penna Ski Areas Association (2010
Paddling-based Recreation (620,860 paddlers)	362	Outdoor Industry Association (2006)
Del. Water Gap River Recreation (267,000 visits)	41	U.S. Forest Service, Nat'l Park Service (1990)
Canoe/Kayak/Rafting (225,000 visits)	9	Canoe and Kayak Liveries (2010)
Powerboating (232,000 boat registrations)	395	National Marine Manufacturers Assoc. (2010)
Water Quality		
Water Treatment by Forests ($96/mgd)	63	Trust for Public Land, AWWA (2004)
Wastewater Treatment ($4.00/1000 gal)	1,722	DRBC and USEPA
Increased Property Value (+8%, 2000 ft of river)	13	EPA (1973), Brookings Institute (2010)
Water Supply		
Drinking Water Supply ($4.78/1000 gal)	3,145	UDWRA and DRBC (2010)
Reservoir Storage ($0.394/1000 gal)	145	UDWRA and DRBC (2010)
Irrigation Water Supply ($300/ac-ft)	32	Resources for Future (1996), USDA (2007)
Thermoelectric Power Water Supply ($44/ac-ft)	297	EIA (2002), NETL (2009)
Industrial Water Supply ($200/ac-ft)	179	Resources for Future (1996), DRBC (2010)
Hydropower Water Supply ($32/ac-ft)	20	Resources for Future (1996), DRBC (2010)
Fish/Wildlife		
Commercial Fish Landings ($0.60/lb)	34	NMFS, Nat'l. Ocean Econ. Program (2007)
Fishing (11-18 trips/angler, $53/trip)	576	U. S. Fish and Wildlife Service (2001)
Hunting (16 trips/hunter, $50/trip)	340	U. S. Fish and Wildlife Service (2001)
Wildlife/Bird-watching (8-13 trips/yr, $27/trip)	561	U. S. Fish and Wildlife Service (2001)
Shad Fishing (63,000 trips, $102/trip)	6	Pennsylvania Fish & Boat Comm. (2011)
Wild Trout Fishing	29	Sportfishing Assn./Trout Unlimited (1998)
Agriculture		
Crop, poultry, livestock value ($1,180/ac)	3,371	USDA Census of Agriculture 2007 (2009)
Public Parks		
Del. Water Gap Natl. Rec. Area (4.9 million visits)	100	U.S. National Park Service (2002)
Marcellus Shale		
Natural Gas (potential)	3,300	USGS (2011), EIA (2011)
Maritime Transportation		
Navigation ($15/ac-ft)	220	Resources for the Future (1996)
Port Activity	2,400	Economy League of Greater Phila. (2008)
Delaware Basin Market Value	**≈ $17.7 billion**	
Non-Market Value		
Recreation (Boating, Fishing, Swimming)		
Clean Water Act Restoration		
Viewing/Aesthetics ($0.58/person)	5	University of Delaware (2003)
Boating ($0.76/person)	6	University of Delaware (2003)
Fishing ($2.95/person)	24	University of Delaware (2003)
Swimming ($6.88/person)	57	University of Delaware (2003)
Water Quality		
WTP for Clean Water ($38/nonuser-$121/user)	659	University of Maryland (1989)
Forests		
Carbon Storage ($827/ac)	3,592	U.S. Forest Service, Del. Center Hort. (2008)
Carbon Sequestration ($29/ac)	126	U.S. Forest Service, Del. Center Hort. (2008)
Air Pollution Removal ($266/ac)	1,155	U.S. Forest Service, Del. Center Hort. (2008)
Building Energy Savings ($56/ac)	243	U.S. Forest Service, Del. Center Hort. (2008)
Avoided Carbon Emissions ($3/ac)	13	U.S. Forest Service, Del. Center Hort. (2008)
Public Parks		
Health Benefits ($9,734/ac)	1,283	Trust for Public Land (2009)
Community Cohesion ($2,383/ac)	314	Trust for Public Land (2009)
Stormwater Benefit ($921/ac)	121	Trust for Public Land (2009)
Air Pollution ($88/ac)	12	Trust for Public Land (2009)
Delaware Basin Non-Market Value	**≈ $7.6 billion**	

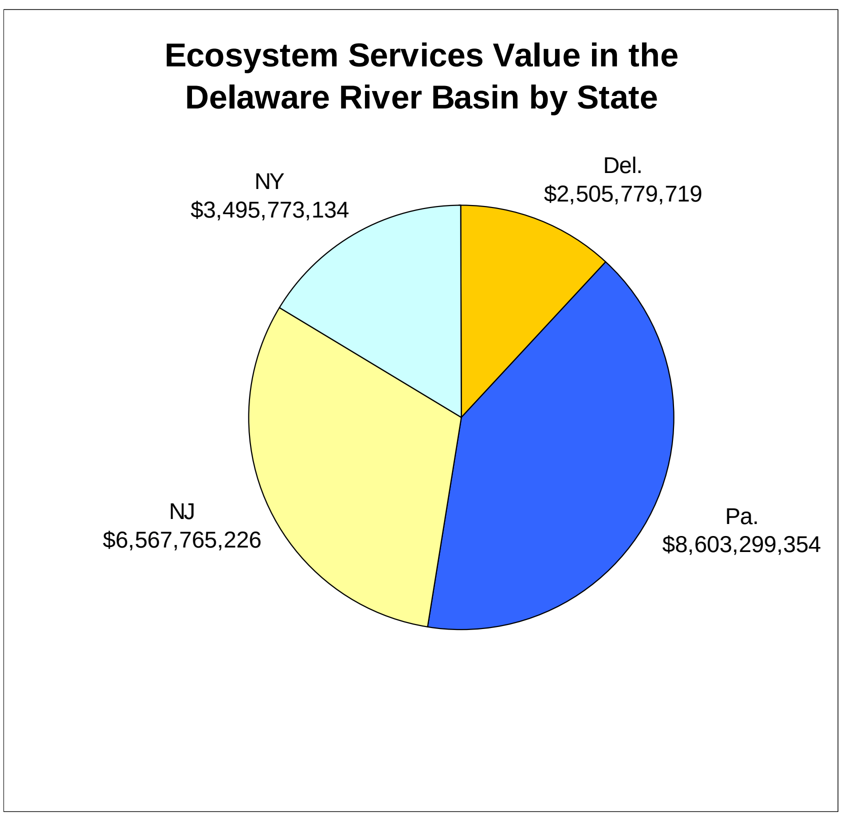
Ecosystem Services

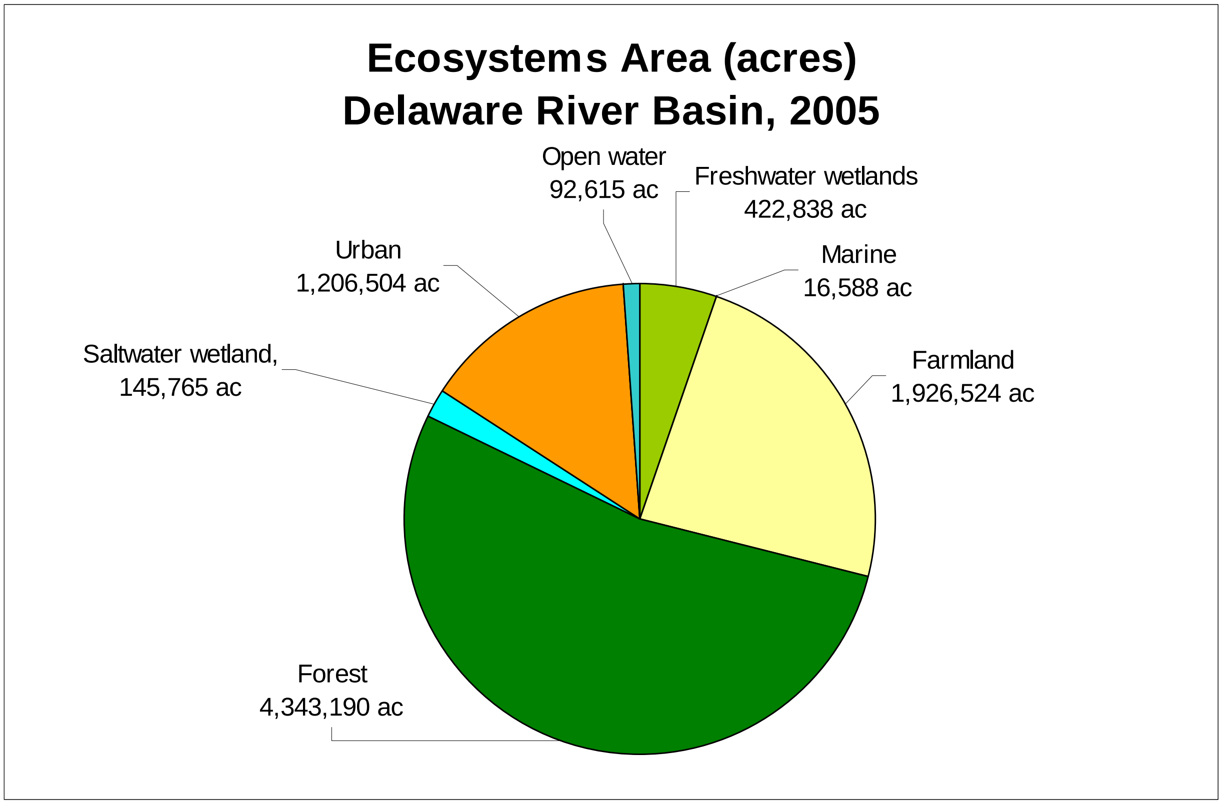
The value of natural goods and services from ecosystems in the Delaware Basin is $21 billion ($2010) with net present value (NPV) of $683 billion using a discount of 3% over 100 years. The contributions of ecosystem services by state include:

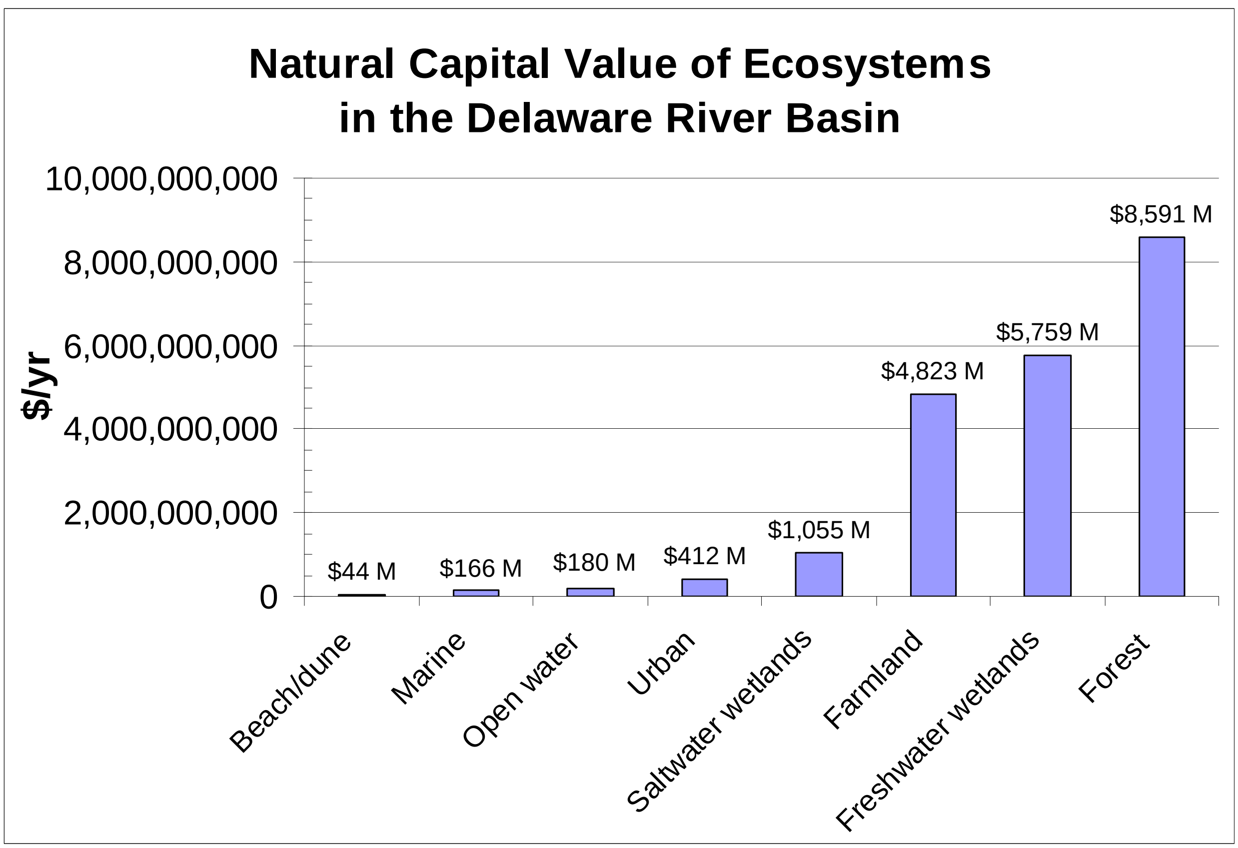
- Delaware ($2.5 billion, NPV $81.4 billion)
- New Jersey ($6.6 billion, NPV $213.4 billion)
- New York ($3.5 billion, NPV $113.6 billion)
- Pennsylvania ($8.6 billion, NPV $279.6 billion)

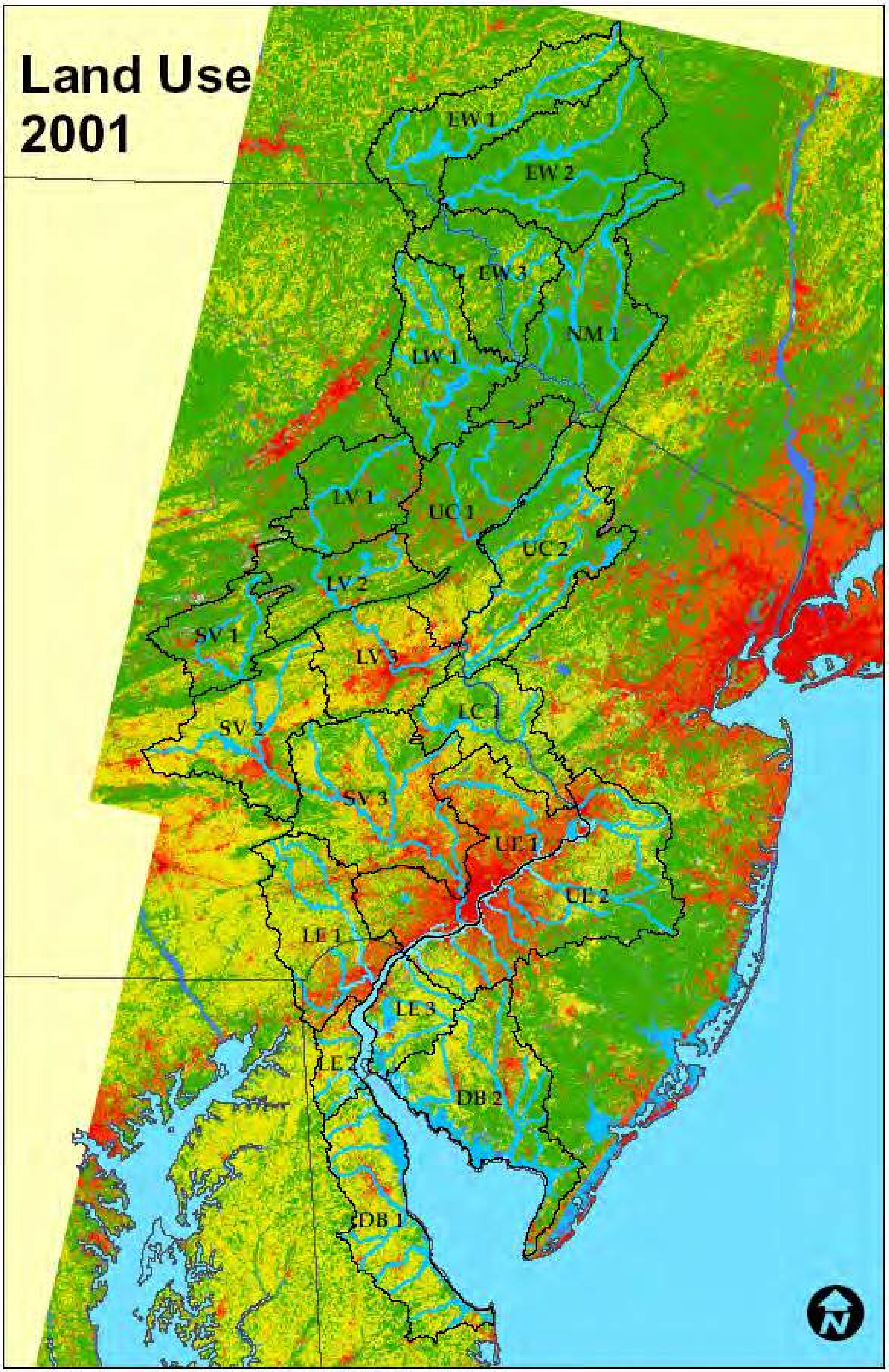
Table E2. Ecosystem goods and services provided by the Delaware River Basin

Ecosystem	Area (ac)	$/ac/yr 2010	$/yr 2010	NPV $
Freshwater wetlands	422,838	13,621	5,759,329,048	187,178,194,067
Marine	16,588	10,006	165,982,947	5,394,445,767
Farmland	1,926,524	2,503	4,823,030,404	156,748,488,136
Forest land	4,343,190	1,978	8,591,367,360	279,219,439,184
Saltwater wetland	145,765	7,235	1,054,617,851	34,275,080,170
Urban	1,206,504	342	412,157,579	13,395,121,322
Beach/dune	900	48,644	43,758,633	1,422,155,566
Open water	92,615	1,946	180,210,703	5,856,847,857
Total	**8,154,924**		**$21,030,454,525**	**$683,489,772,069**




Ecosystems Area (acres)
Delaware River Basin, 2005
Open water
92,615 ac
Freshwater wetlands
422,838 ac
Urban
1,206,504 ac
Marine
16,588 ac
Saltwater wetland,
145,765 ac
Farmland
1,926,524 ac
Forest
4,343,190 ac


Natural Capital Value of Ecosystems
in the Delaware River Basin
$/yr
10,000,000,000
8,000,000,000
6,000,000,000
4,000,000,000
2,000,000,000
0
$44 M
$166 M
$180 M
$412 M
$1,055 M
$4,823 M
$5,759 M
$8,591 M
Beach/dune
Marine
Open water
Urban
Saltwater wetlands
Farmland
Freshwater wetlands
Forest


Land Use
2001
EW 1
EW 2
EW 3
NM 1
LW 1
LV 1
UC 1
UC 2
LV 2
SV 1
LV 3
LC 1
SV 2
SV 3
UE 1
UE 2
LE 1
LE 3
LE 2
DB 2
DB 1

Jobs and Wages

The Delaware River Basin is a jobs engine that supports 600,000 direct/indirect jobs with $10 billion in annual wages in the coastal, farm, ecotourism, water/wastewater, ports, and recreation industries.

Table E3. Jobs and wages directly and indirectly supported by the Delaware River Basin

Sector	Jobs	Wages ($ million)	Source
Direct Basin Related	240,621	4,900	U.S. Bureau of Labor Statistics, 2009
Indirect Basin Related	288,745	4,000	U.S. Census Bureau, 2009
Coastal	44,658	947	National Coastal Economics Program, 2009
Farm	45,865	1,376	USDA Census of Agriculture, 2007
Fishing/Hunting/Birding	44,941	1,476	U.S. Fish and Wildlife Service, 2008
Water Supply Utilities	8,750	485	UDWRA and DRBC, 2010
Wastewater Utilities	1,298	61	UDWRA and DRBC, 2010
Watershed Organizations	201	10	UDWRA and DRBC, 2010
Ski Area Jobs	1,753	88	Penna. Ski Areas Association
Paddling-based Recreation	4,226		Outdoor Industry Association (2006
River Recreation	448	9	U. S. Forest Service/Nat'l. Park Service, 1990
Canoe/Kayak/Rafting	225		Canoe Liveries and UDWRA, 2010
Wild Trout Fishing	350	4	Maharaj, McGurrin, and Carpenter, 1998
Del. Water Gap Nat'l. Rec. Area	7,563	101	Stynes and Sun, 2002
Port Jobs	12,121	772	Economy League of Greater Phila., 2008
Delaware Basin Total	**> 600,000**	**>$10 billion**	

Within the Delaware Basin are 3,480,483 jobs earning $172.6 billion in wages including:
- Delaware (316,014 jobs earning $16.5 billion in wages)
- New Jersey (823,294 jobs, $38.1 billion in wages)
- New York (69,858 jobs earning $2.5 billion in wages)
- Pennsylvania (2,271,317 jobs earning $115.5 billion in wages)

Jobs directly associated with the Delaware River Basin (such as water/sewer construction, water utilities, fishing, recreation, tourism, and ports) employ 240,621 with $4.9 billion in wages including:
- Delaware (15,737 jobs earning $340 million in wages)
- New Jersey (62,349 jobs earning $1.3 billion in wages)
- New York (32,171 jobs earning $550 million in wages)
- Pennsylvania (130,364 jobs earning $2.8 billion in wages)

Jobs indirectly related to the waters of the Delaware Basin (based on multipliers of 2.2 for jobs and 1.8 for salaries) employ 288,745 people with $4.0 billion in wages including:
- Delaware (18,884 jobs earning $270 million in wages)
- New Jersey (74,819 jobs earning $1.0 billion in wages)
- New York (38,605 jobs earning $400 million in wages)
- Pennsylvania (156,437 jobs earning $2.2 billion in wages)

According to the National Coastal Economy Report (2009), coastal employment sectors within the Delaware River Basin are responsible for 44,658 jobs earning $947 million in wages with contributions of $1.8 billion toward the GDP including:

- Delaware (12,139 jobs, $214 million in wages, $392 million toward the GDP)
- New Jersey (4,423 jobs, $140 million in wages, $235 million toward the GDP).
- Pennsylvania (28,096 jobs, $593 million in wages, $1.2 billion toward the GDP.

Over 21,800 farms provide 45,865 jobs with $1.9 billion in wages in the Delaware Basin including:

- Delaware (3,140 farm jobs earning $129 million in wages)
- New Jersey (14,305 farm jobs earning $587 million in wages)
- New York (2,410 farm jobs earning $99 million in wages)
- Pennsylvania (26,010 farm jobs earning $1.1 billion in wages)

Fishing, hunting, and bird watching/wildlife associated recreation employ 44,941 jobs with $1.5 billion in wages in the Delaware Basin including:

- Delaware (4,080 jobs earning $134 million in wages)
- New Jersey (17,477 jobs earning $574 million in wages)
- New York (4,872 jobs earning $160 million in wages)
- Pennsylvania (18,512 jobs earning $608 million in wages)
-

Public and private water utilities that withdraw drinking water from the Delaware River Basin employ 8,750 people with wages of $485 million including:

- Delaware (141 jobs earning $7.8 million in wages)
- New Jersey (823 jobs earning $46 million in wages)
- New York (5,600 jobs earning $310 million in wages)
- Pennsylvania (2,186 jobs earning $121 million in wages)

Wastewater utilities that treat and discharge wastewater to the Delaware River Basin employ 1,298 people with wages of $61 million including:

- Delaware (108 jobs earning $5 million in wages)
- New Jersey (257 jobs earning $12 million in wages)
- New York (20 jobs earning $1 million in wages)
- Pennsylvania (913 jobs earning $43 million in wages)

Over 100 nonprofit watershed and environmental organizations employ at least 200 staff who earn at least $9.5 million in wages to restore the watersheds in the Delaware River Basin.

In the Pocono Mountains of Pennsylvania, 9 ski resorts support 1,753 direct jobs in the Delaware Basin from aggregate annual revenues of $87,655,063 from 1,908,228 skier visits.

Paddling-based recreation in the Delaware Basin is responsible for 620,860 participants and 4,226 jobs according to data prorated from the Outdoor Industry Association (2006).

The U. S. Forest Service and U.S. National Park Service estimated river recreation along the Upper Delaware River and Delaware Water Gap was responsible for 448 jobs with wages of $8.8 million in $1986.

The 37 canoe/kayak liveries along the Delaware, Lehigh, and Schuylkill, and Brandywine Rivers have earnings of $9 million per year and employ 225 people to lease watercraft to 225,000 visitors.

Along the Beaverkill, East Branch, West Branch, and upper main stem of the Delaware River in New York, wild trout fishing provides for 350 jobs with $3.6 million in wages.

The Delaware Water Gap National Recreation Area recorded 4,867,272 recreation visits in 2001 that generated $106 million in sales and 7,563 direct/indirect jobs with $100 million in wages.

Delaware River ports from Wilmington to Philadelphia to Trenton are collectively the 5th largest port in the U.S. based on imports and the 20 largest U.S. port based on exports. These ports:

- Employ 4,056 workers who earn $326 million in wages.
- Provide port jobs that support an additional two jobs each in port activity and employee spending for a total of 12,121 port related jobs with $772 million in wages.
- Most of the 4,056 direct port jobs are in cargo handling and warehousing with petroleum port jobs adding up to less than 10% of employment
- Provides good jobs, the average salary of a port employee (with benefits) is over $80,000.

1. Introduction

Objectives

This report summarizes the socioeconomic value of water, natural resources and ecosystems in the Delaware River Basin in Delaware, New Jersey, New York, and Pennsylvania estimated as:

- Economic activity including market use and nonuse value of water supply, fishing, hunting, recreation, boating, ecotourism, agriculture, and navigation/port benefits in the basin.

- Natural capital or ecosystem services value of natural goods and services provided by habitat such as wetlands, forests, farms and open water.

- Jobs and wages directly and indirectly associated with the Delaware River Basin.

Two decades ago, researchers conducted a series of studies that indicated the Delaware River and Bay was worth hundreds of millions if not billions of dollars. Latham and Stapleford (1990) from the University of Delaware estimated total contributions of Delaware Estuary (the tidal river and bay) activities within the State of Delaware accounted for 10,500 jobs with $222 million in annual wages, each direct estuary job created 2.2 indirect jobs, and the multiplier of direct/indirect wages was 1.8. The Greeley-Polhemus Group (1993) estimated the Delaware Estuary supported 123,000 jobs, $4.3 billion in wages, $24 billion in sales, $25 million in sport fishing non-market value, $1 million in commercial fish landings, and wetlands replacement values up to $638 million.

This report is designed to update economic analyses for the Delaware River and Bay conducted 20 years ago and incorporate more recent valuation data from the emerging fields of ecological economics and ecosystem services.

The Value of a Watershed

Studies for the Chesapeake Bay, Great Lakes, and Florida Everglades conclude that watersheds have significant economic value and restoration can result in green jobs and favorable cost-benefit investment ratios. The University of Maryland reported in 1988 that the Chesapeake Bay was worth $678 billion and the Chesapeake Blue Ribbon Panel (2003) reported with inflation the present value of the bay would exceed $1 trillion.

The Brookings Institution (Austin et al. 2007) found restoration of the Great Lakes would cost $26 billion in present value and aggregate economic benefits would exceed $50 billion (2:1 B/C ratio). Great Lakes benefits include $6.5-11.8 billion in tourism, fishing, and recreation dollars, $12-19 billion increase in property values from contaminated sediment cleanup, $50-125 million in reduced municipal water treatment costs, and $30 billion in short time multiplier benefits. The Great Lakes Coalition (2010) concluded investment in watershed restoration creates good paying jobs and leads to economic benefits while restoring the environment (Table 1).

The Everglades Foundation estimated that the Comprehensive Everglades Restoration Plan (CERP) would result in $6 billion in benefits and 443,000 jobs over 50 years (McCormick 2010). Net present value of the Everglades's restoration benefits would be $46 billion resulting from investments of $11.5 billion or a benefit to cost ratio of 4:1.

Table 1. Jobs and salaries created by watershed restoration work (Great Lakes Coalition (2010) from U. S. Bureau of Labor Statistics)

Job	Mean Salary	Job	Mean Salary
Wetland scientist	$45,730	Fisheries Biologist	$60,670
Research scientist	$45,730	Archeologist	$57,230
Construction manager	$93,290	Operating Engineer	$44,180
Biologist	$69,430	Environmental Engr.	$80,750
Toxicologist	$70,000	Hydrogeologist	$92,710
Chemist	$72,740	Environmental Planner	$64,680
Geologist	$58,000	Plumber/Pipefitter	$9,870
Helicopter Pilot	$90,000	Carpenter	$43,640
Info. Technology	$70,930	Electrician	$50,850
Admin. Staff	$32,990	Truck Driver	$39,260
Mechanics	$37,000	Concrete Workers	$39,410
Excavator	$38,540	Dredge Operator	$38,330
Landscape Architect	$65,910	Conservation Scientist	$61,180
Civil Engineer	$81,180	Biological technician	$41,140
General Laborer	$33,190	Pile Drive Operator	$51,410

An Economic Engine

What do the Guggenheim Museum, Boeing, Sunoco, Campbell's Soup, DuPont, Wawa, Starbucks, Iron Hill Brewery, Philadelphia Philadelphia Phillies, New York Yankees, Camelback Ski Area, Pt. Pleasant Canoe Livery, Salem Nuclear Power Plant, and the United States Navy have in common? They all depend on the waters of the Delaware River Basin to sustain their businesses.

Most economists agree that water is an undervalued resource. The astronomer Copernicus and Adam Smith of the invincible hand of the economy fame both considered the "diamond-water paradox". If water is more valuable to society than a precious gem, then why is water sold for a fraction of a penny per gallon for drinking water or not even valued at all as an ecological resource in the river or bay? Just as under-compensated police officers or teachers are more valuable to society than multimillion dollar movie stars, perhaps the value of water is just as marginalized. We tend to underprice water based on its marginal value for single uses (i.e. drinking water) and not consider the full value of water for all its myriad uses. This report attempts to quantify the highest multiobjective value of water *in toto* for its wide range of habitat, recreation, ecological, and industrial benefits in the Delaware River Basin.

If water is society's most valuable chemical, then the Delaware River with a mean annual flow of 2.7 trillion gallons per year at Trenton is the Delaware Valley's (and by aqueduct Manhattan Island's) most invaluable economic asset. For 400 years, the Delaware River has been an economic engine ever since Henry Hudson discovered the bay off Cape May in August 1609 for commerce and the Dutch East India Company during his unsuccessful quest for an inner trade route to Asia.

When William Penn founded the City of Brotherly Love in 1681 seeking refuge from religious persecution in Europe, he also found a safe harbor between the Delaware and the Schuylkill in a colony rich with lumber, fertile land, beaver pelts, and in later centuries coal and oil reserves. By the 18th century frugal yet prosperous Philadelphia Quaker merchants established triangle trade route connections to Europe and the Caribbean from their home port along the Delaware. During the American Revolution, Philadelphia was the largest city in the colonies and the 3rd largest port in the British Empire after London and Liverpool. In 1790 Ben Franklin, America's first environmentalist, was so concerned about pollution in the river that he willed funds to build the first municipal water system in the United States at Philadelphia to tap the Delaware and Schuylkill for drinking water.

The economic engine kicked into high gear during the 19th century with hydropower and steam power during the Industrial Revolution. In 1802, the DuPont family searched up and down the Atlantic Seaboard and established gunpowder mills along the falls of the Brandywine River above Wilmington as one of the first industries in the Delaware Valley. Delaware River ports grew when anthracite coal was discovered in the Lehigh Valley in 1792 and steam railroads were built in the 1830s. By the Gay Nineties, every Philadelphia wharf had railroad access and the advent of steam ships made for faster transatlantic shipping. In 1895, the Corps of Engineers dredged the Delaware River to 26 feet from the natural depth of 17 feet (Economy League 2008).

By the end of the 19th century, the Delaware River supported the largest commercial American shad and sturgeon fishery along the Atlantic coast. The sturgeon was such a lucrative fish that boom town Caviar (Bayside) near Greenwich, New Jersey was founded to process the roe for worldwide export. By the 1880s, 1,400 sailing vessels harvested 22 million pounds of oysters from the Delaware Bay. In 1886, nationally famous hotels in Gloucester, N. J. served 10,000 planked shad dinners at events that resembled modern day blue crab feasts. In 1896 over 14 million pounds of shad were caught with a value of $400,000 ($10 million in 2008 dollars). In 1896, a fisheries report to the governor of Pennsylvania listed the catch of a 76-pound striped bass above Gloucester, NJ.

At the turn of the 20th century, Delaware River ports supported a premier ship building industry. By the First World War the Delaware was known as the "Clyde of America" with ship building and repair production that rivaled its Scottish cousin. By 1912, Philadelphia and environs built and manufactured 5% of all goods in the United States. Export markets included coal, iron, cotton, leather, grain, lumber and tobacco, and gunpowder from Wilmington. By 1914, the Panama Canal opened access from the East Coast to Hawaii sugar cane fields and Philadelphia refined and shipped 500,000 tons of raw sugar or 1/6 of all sugar refined in the United States.

After the Delaware River ship channel was deepened to 41 feet in 1941, the port economy boomed during World War II as the Philadelphia Navy Yard employed 40,000 workers who built 53 ships and repaired over 500 vessels. After the war, the "Arsenal of America" manufacturing and export base declined due to decreased demand for Pennsylvania coal and decline of Lehigh Valley steel industries. In 1995, the Department of the Navy closed the Philadelphia Navy Yard and decommissioned the ghost fleet due to decreased ship building needs in the "New Navy."

During the 19th Century, the Delaware Water Gap along the Blue Mountain near Stroudsburg, Pa. was a resort that grew with the railroads from Philadelphia and New York City. In 1965, Congress authorized the National Park Service to form the Delaware Water Gap National Recreation Area that now receives 5 million visits per year, the 8th most visited unit in the National Park System.

In 1931 and amended in 1954, the U. S. Supreme Court issued a decree authorizing New York City to divert 800 mgd of water from three Catskill Mountain reservoirs in the Delaware Basin to the Hudson River Basin. The Delaware River delivers over half the drinking water to New York City.

By 1986, the Salem and Hope Creek nuclear power plants were built on Artificial Island in Salem County, New Jersey that pump 3 billion gallons per day of cooling water to provide 3,500 megawatts of electricity to the tri-state region. In 2010, a billion gallons per day of drinking water and industrial process water were withdrawn from streams and aquifers in the Delaware Basin to sustain the region's jobs and domestic, commercial, and industrial economy. The river, bay, beaches, wetlands, and forests support a billion dollar tourism, recreation, and hunting/fishing/birding economy.

After the turn of the 21st Century, new horizontal drilling and hydraulic fracturing technology kicked off the Marcellus Shale natural gas drilling boom in a 50,000 square mile basin stretching from Kentucky to Pennsylvania and New York. The Marcellus Shale occupies about 36% or 4700 square miles under the upper Delaware Basin. A 2011 USGS report indicates 7 trillion cubic feet of natural gas may be recoverable under the Delaware Basin, a potential multi-billion dollar natural resource.

The Delaware River Basin supplies drinking water to the 1st (New York City) and 5th (Philadelphia) largest metropolitan economies in the United States. The following report tabulates the substantial economic value and worth of this irreplaceable asset for over 8 million residents in Delaware, New Jersey, New York, and Pennsylvania who live in the basin and an additional 8 million people in New York City and northern New Jersey who receive drinking water from the Delaware River.

Governance

For the last fifty years, Federal, state, and local governments, nonprofits, and the private sector have focused efforts on restoring the Delaware River Basin. In 1961, JFK signed the Delaware River Basin Compact that appointed the Governors of Delaware, New Jersey, New York, and Pennsylvania as Commissioners as the first ever Federal-state watershed accord. In 1968 a full four years before the Clean Water Act was passed by Congress, the DRBC issued waste load allocations to reduce pollutant discharges from over 80 wastewater treatment plants. In 1988, the Delaware Estuary was nominated by the Governors of Delaware, New Jersey, and Pennsylvania for the National Estuary Program per Section 320 of the Federal Clean Water Act. In 1996, the Delaware Estuary was designated by Congress as one of only 28 National Estuary Programs in the United States and is now the only tri-state estuary program in the nation. In 1996, the nonprofit Partnership for the Delaware Estuary was established to implement a Comprehensive Conservation and Management Plan (CCMP). In 2011, the DRBC celebrates the 50th anniversary of its founding by JFK, Congress, and the Governors of Delaware, New Jersey, New York, and Pennsylvania.

The Watershed

The Delaware River Basin (Figure 1 and Table 2) occupies 12,769 sq mi (not including the river and bay) in Delaware (8%), New Jersey (23%), New York (20%), and Pennsylvania (49%). In 2010, 8,255,013 residents lived in the basin including 643,418 people in Delaware (9%), 2,324 in Maryland, 1,951,047 in New Jersey (24%), 124,969 in New York (2%), and 5,533,254 in Pennsylvania (66%). In 2009, nearly 3,500,000 people worked in the Delaware Basin with 316,014 jobs in Delaware (9%), 1,172 jobs in Maryland, 823,294 jobs in New Jersey (24%), 69,858 jobs in New York (2%), and 2,271,317 jobs in Pennsylvania (65%).

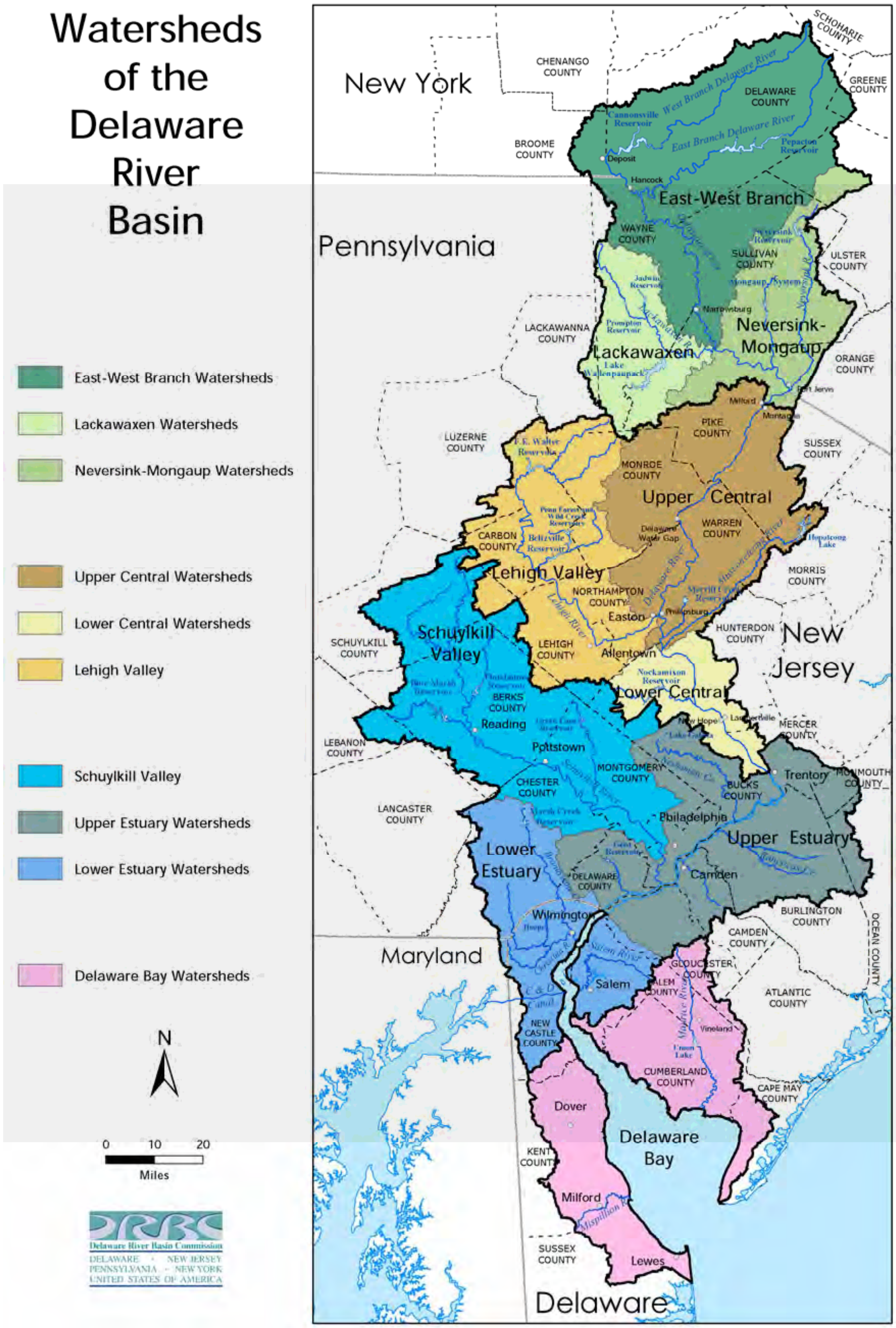


Figure 1. The Delaware River Basin. (DRBC)

Table 2. Land area, population, and employment in the Delaware River Basin

State	Area (sq mi)	Population[1] 2010	Employment[2] 2009
Delaware	965	643,418	316,014
Maryland	8	2,324	1,172
New Jersey	2,961	1,951,047	823,294
New York	2,555	124,969	69,858
Pennsylvania	6,280	5,533,254	2,271,317
Total	12,769	8,255,013	3,481,655

1. U.S. Census Bureau 2009. 2. U.S. Bureau of Labor Statistics

Table 3 summarizes the area, population, and employment by state and county in the Delaware Basin. In Delaware, the basin covers 50% of the land area yet includes 74% of the First State's population. The New Jersey portion of the basin covers 40% of the State's land area and includes 22% of the Garden State's population. New York State covers 5% of the State's land area and the basin includes 0.7% of the Empire State's population. The Pennsylvania part of the basin covers just 14% of the State's area yet includes 43% of the Keystone State's population.

The population of the Delaware Basin now exceeds 8.2 million which if considered as a single jurisdiction, it would be the 12th most populous state in the U.S. after North Carolina and New Jersey but ahead of Virginia and Massachusetts. Between 2000 and 2010, the population in the Delaware Basin increased by 6.1% or 472,066 people (Table 4 and Figure 2). Over the last decade, population increased by 30% in Pike County, Pa.; by over 20% in Kent and Sussex counties, Del. and Monroe County, Pa.; and by over 10% in Gloucester and Ocean counties, NJ, Orange County, NY, and Chester, Lehigh, and Northampton counties, Pa (Figure 3). For the first time in twp generations, Philadelphia gained population. Several counties in the basin lost population since 2000: Cape May, NJ; Broome, Delaware, and Greene counties, NY; and Lackawanna, Luzerne, and Schuylkill counties, Pa.

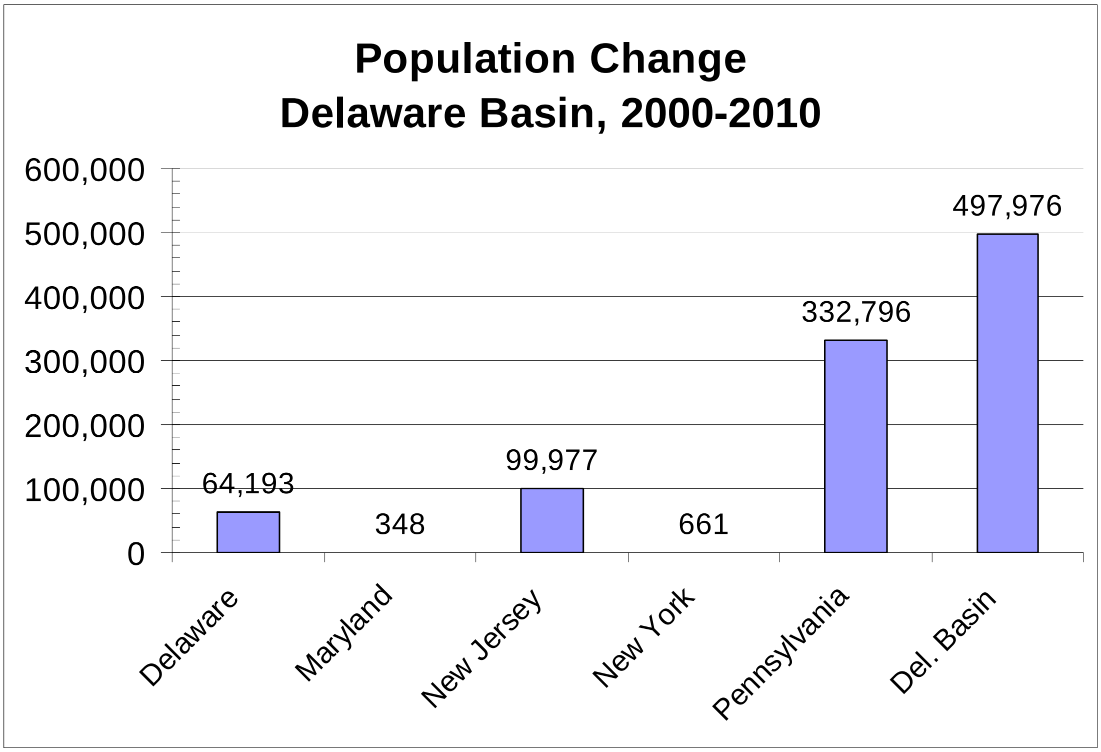
Table 3. Land area, population, and employment by county in the Delaware River Basin

State/county	Area 2005[1] (sq mi)	Population[2] 2010	Employment[3] 2009
Kent	389	108,025	50,412
New Castle	381	493,428	252,534
Sussex	195	41,965	13,068
Delaware	**965**	**643,418**	**316,014**
Cecil	**8**	2,324	**1,172**
Maryland	**8**	**2,324**	**1,172**
Burlington	495	367,157	187,758
Camden	123	432,315	169,909
Cape May	104	52,209	14,545
Cumberland	490	158,289	61,868
Gloucester	279	271,332	89,183
Hunterdon	215	65,132	23,650
Mercer	180	287,685	178,320
Monmouth	20	24,620	9,864
Ocean	30	23,616	7,495
Salem	347	66,342	21,900
Sussex	320	92,689	23,302
Warren	358	109,662	35,500
New Jersey	**2,961**	**1,951,047**	**823,294**
Broome	85	15,038	11,292
Delaware	1,295	26,111	14,240
Greene	25	1,207	572
Orange	65	19,887	10,456
Sullivan	940	47,563	25,511
Ulster	145	15,162	7,787
New York	**2,555**	**124,969**	**69,858**
Berks	777	407,843	150,665
Bucks	607	626,280	244,453
Carbon	381	63,640	16,730
Chester	616	491,070	212,996
Delaware	184	559,776	201,208
Lackawanna	25	11,335	4,830
Lebanon	20	7,221	2,750
Lehigh	347	344,571	166,932
Luzerne	50	17,491	8,074
Monroe	609	166,209	56,025
Montgomery	483	789,862	453,771
Northampton	374	299,646	96,536
Philadelphia	135	1,558,613	619,396
Pike	547	59,859	9,874
Schuylkill	420	79,358	27,077
Wayne	705	50,480	14,114
Pennsylvania	**6,280**	**5,533,254**	**2,271,317**
Delaware Basin	**12,761**	**8,255,013**	**3,481,655**

1. NOAA CSC 2005. 2. U. S. Census Bureau 2010. 3. U. S. Bureau of Labor Statistics 2009.

Table 4. Population change in the Delaware River Basin, 2000-2010 (U. S. Census)

State/ County	Population 2000	Population 2010	Change	%
Kent	85,680	108,025	22,345	26.1%
New Castle	459,829	493,428	33,599	7.3%
Sussex	33,716	41,965	8,249	24.5%
Delaware	**579,225**	**643,418**	**64,193**	**11.1%**
Cecil	1,976	2,324	348	17.6%
Maryland	**1,976**	**2,324**	**348**	**17.6%**
Burlington	348,729	367,157	18,428	5.3%
Camden	425,646	432,315	6,669	1.6%
Cape May	55,679	52,209	-3,470	-6.2%
Cumberland	146,442	158,289	11,847	8.1%
Gloucester	239,012	271,332	32,320	13.5%
Hunterdon	60,995	65,132	4,137	6.8%
Mercer	274,945	287,685	12,740	4.6%
Monmouth	23,465	24,620	1,155	4.9%
Ocean	20,887	23,616	2,729	13.1%
Salem	64,285	66,342	2,057	3.2%
Sussex	88,547	92,689	4,142	4.7%
Warren	102,438	109,662	7,224	7.1%
New Jersey	**1,851,070**	**1,951,047**	**99,977**	**5.9%**
Broome	15,713	15,038	-675	-4.3%
Delaware	28,030	26,111	-1,919	-6.8%
Greene	1,231	1,207	-24	-1.9%
Orange	17,722	19,887	2,165	12.2%
Sullivan	46,712	47,563	851	1.8%
Ulster	14,900	15,162	262	1.8%
New York	**124,308**	**124,969**	**661**	**0.5%**
Berks	373,638	407,843	34,205	9.2%
Bucks	597,632	626,280	28,648	4.8%
Carbon	58,795	63,640	4,845	8.2%
Chester	424,241	491,070	66,829	15.8%
Delaware	551,976	559,776	7,800	1.4%
Lackawanna	11,617	11,335	-282	-2.4%
Lebanon	6,648	7,221	573	8.6%
Lehigh	312,090	344,571	32,481	10.4%
Luzerne	17,916	17,491	-425	-2.4%
Monroe	138,690	166,209	27,519	19.8%
Montgomery	748,987	789,862	40,875	5.5%
Northampton	267,077	299,646	32,569	12.2%
Philadelphia	1,517,542	1,558,613	41,071	2.7%
Pike	46,303	59,859	13,556	29.3%
Schuylkill	81,159	79,358	-1,801	-2.2%
Wayne	46,147	50,480	4,333	9.4%
Pennsylvania	**5,200,458**	**5,533,254**	**332,796**	**6.2%**
Delaware Basin	**7,757,037**	**8,255,013**	**497,976**	**6.4%**



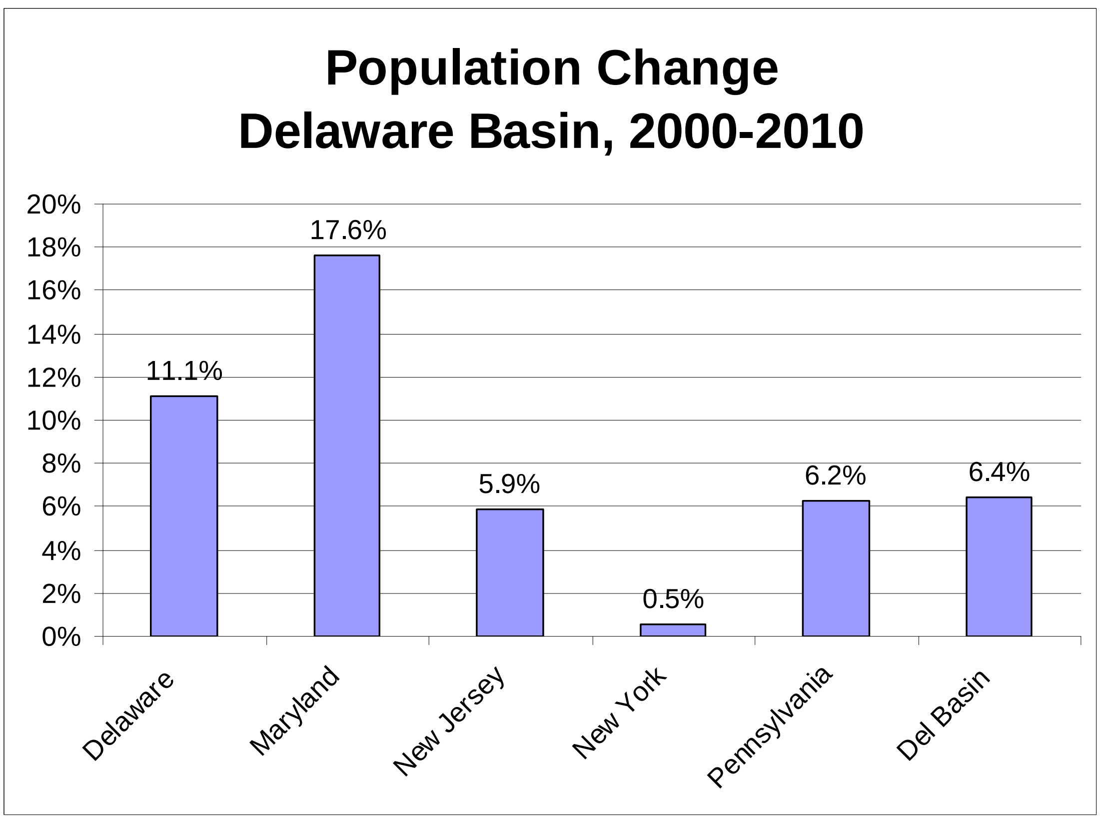
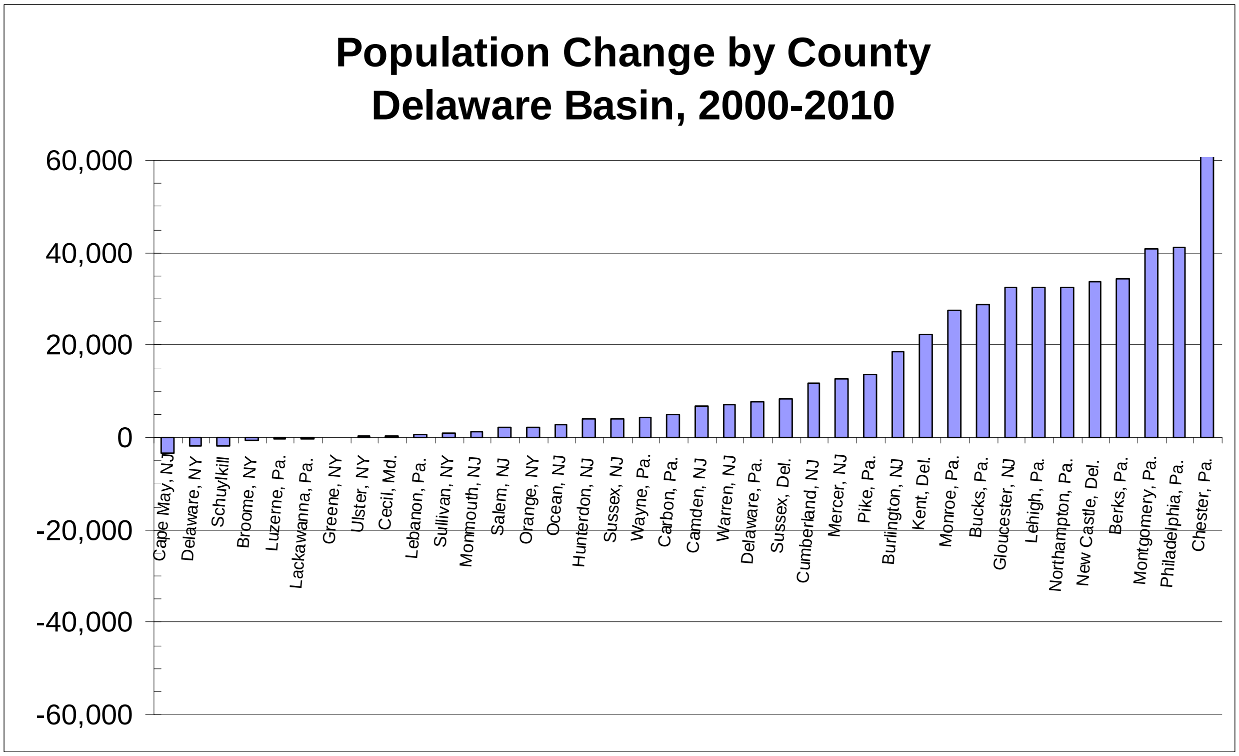


Figure 2. Population change in the Delaware River Basin, 2000-2010 (U.S. Census)



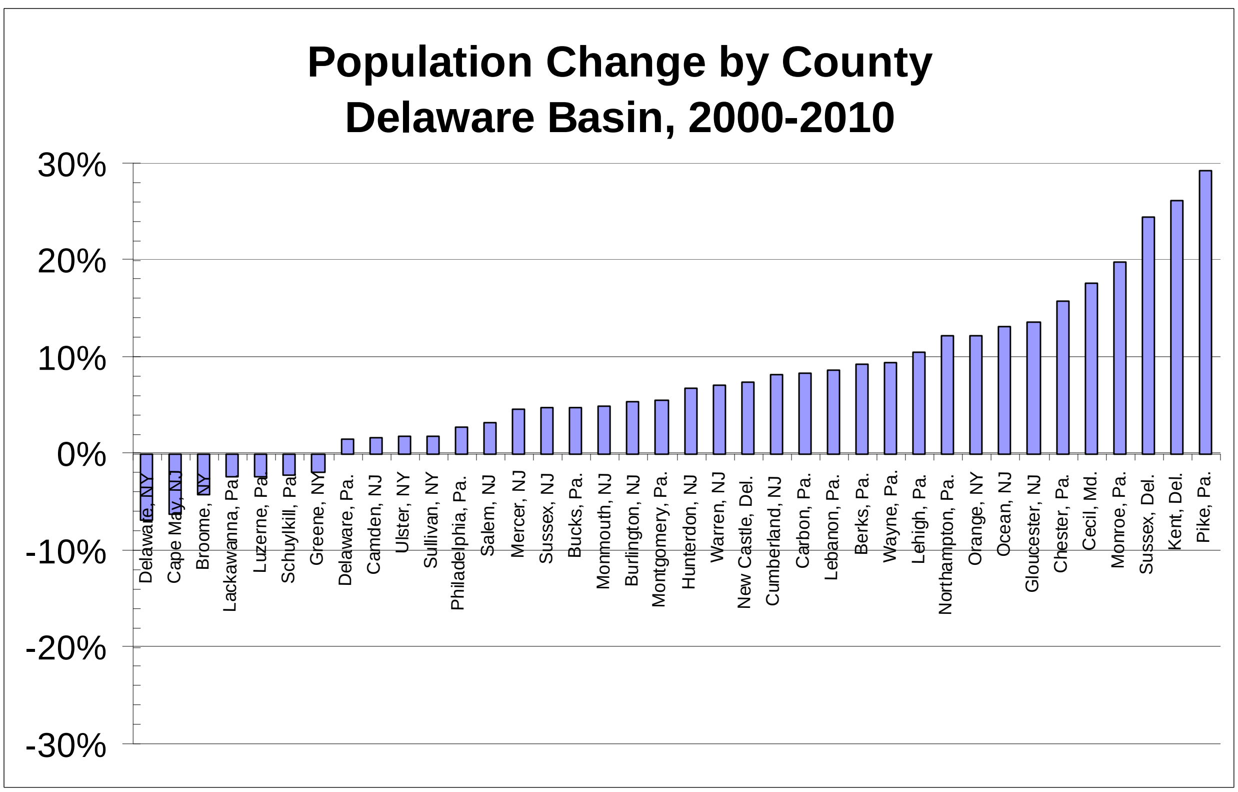


Figure 3. Population change in Delaware River Basin counties, 2000-2010 (U.S. Census)

The Delaware Basin includes 21 watersheds that flow to the river and bay (Table 5 and Figure 4).

Table 5. Watersheds in the Delaware River Basin

Watershed	Area (sq mi)	Population 2000	Pop. Density (pop./sq mi)
LE1 Brandywine/Christina	187	382,703	2,047
LE2 C&D Canal	152	54,960	362
DB1 Delaware Bay	626	141,562	226
Delaware	965	**579,225**	**600**
UC2 NJ Highlands	745	218,638	293
LC1 Del. R. above Trenton	159	55,880	351
UE2 New Jersey Coastal Plain	1,021	1,287,810	1,261
LE3 Salem River	254	54,290	214
DB2 Delaware Bay	782	234,480	300
New Jersey	**2,961**	**1,851,098**	**625**
EW1 East Branch Del. R.	666	23,040	35
EW2 West Branch Del. R.	841	19,263	23
EW3 Del. R. above Pt. Jervis	314	11,840	38
NM1 Neversink R.	734	70,164	96
New York	**2,555**	**124,307**	**49**
EW3 Del. R. above Pt. Jervis	210	7,894	38
NM1 Neversink R.	82	7,796	95
LW1 Lackawaxen R.	598	49,734	83
UC1 Pocono Mt.	779	208,478	268
LV1 Lehigh River above Lehighton	451	37,622	83
LV2 Lehigh River above Jim Thorpe	430	88,349	205
LV3 Lehigh River above Bethlehem	480	478,278	996
LC1 Del. R. above Trenton	295	103,771	352
SV1 Schuylkill above Reading	338	88,681	262
SV2 Schuylkill above Valley Forge	649	321,066	495
SV3 Schuylkill above Philadelphia	874	952,560	1,090
UE1 Penna Fall Line	693	2,579,100	3,722
LE1 Brandywine/Christina	401	277,129	691
Pennsylvania	**6,280**	**5,200,458**	**828**
Delaware Basin	**12,761**	**7,755,088**	**608**

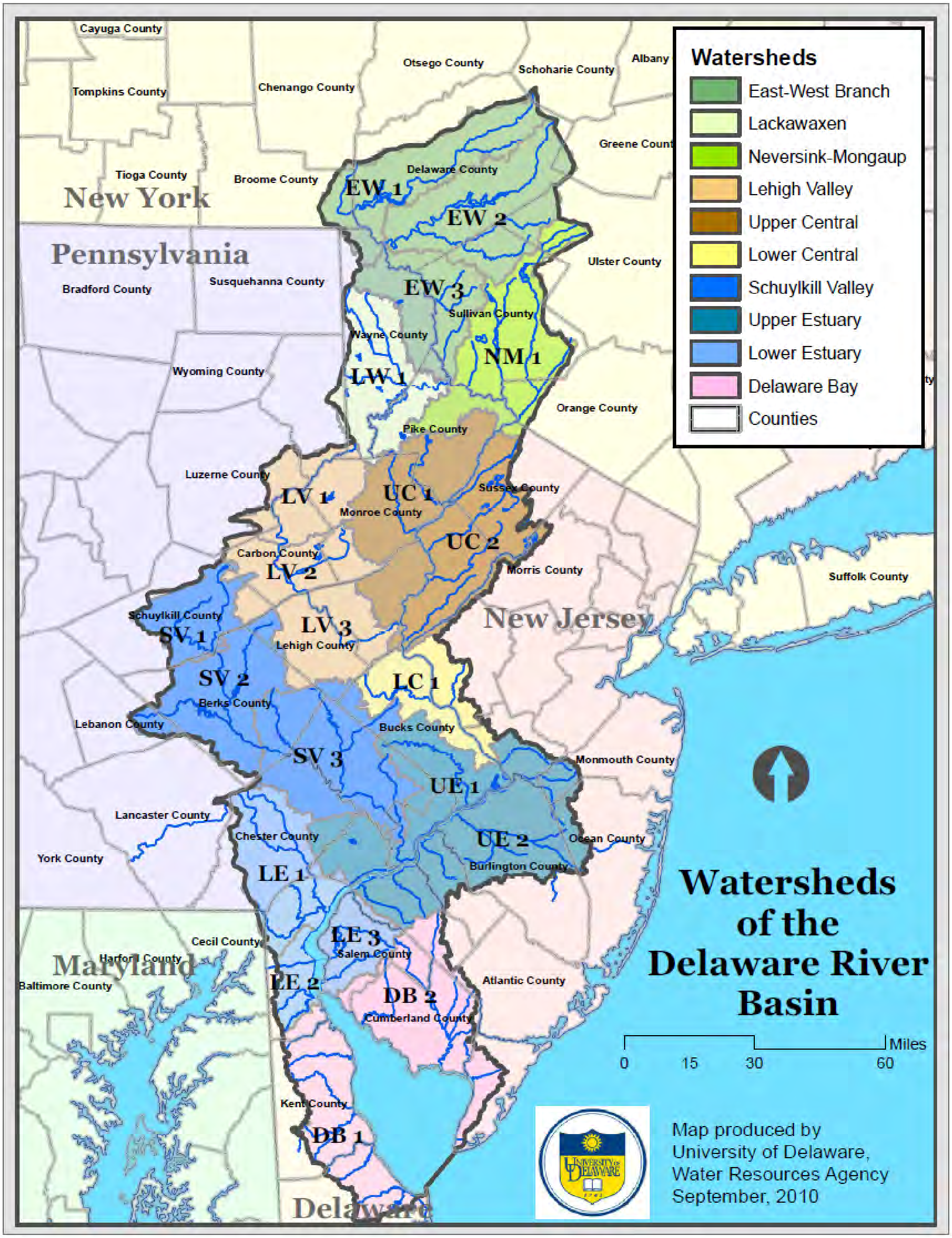


Figure 4. Watersheds in the Delaware River Basin (UDWRA 2010)

2. Methods

Valuation Techniques

The economic value of the Delaware River Basin in Delaware, New Jersey, New York, and Pennsylvania is derived from published studies and valuation methods such as:

Avoided Cost: Society sustains costs if certain ecosystems are not present or lost. For instance, the loss of wetlands may increase economic flood damages.

Replacement Cost: Natural services are lost and replaced by more expensive manmade systems, i.e. forests provide water filtration benefits that are replaced by costly water filtration plants.

Net Factor Income by Enhancement of Income: Improved water quality water enhances fisheries and crabbing industries and, in turn, boosts jobs and wages.

Travel Cost: Visitors are willing to pay to travel and visit ecosystems and natural resources for hunting, fishing, and birding.

Hedonic Pricing Process: Residents may be willing to pay more for property values that are higher along scenic bay and river coastlines.

Contingent Valuation: Valuation by survey of individual different preferences to preserve ecosystems. People may be willing to pay more in fees to preserve bay water quality.

Scope of Work

The socioeconomic value of the Delaware Basin was established by the following scope of work.

1. **Define and map area of interest:** The area of interest is defined as the Delaware River Basin from the headwaters in the Catskill Mountains of New York to the mouth of the bay at Cape Henlopen, Delaware. ArcGIS map layers of population census blocks, watershed boundaries, and land use/land cover were developed to perform the analysis.

2. **Literature review:** Gather a database of published literature and socioeconomic data relevant to the Delaware River Basin from the U. S. Census Bureau, U. S. Bureau of Labor Statistics, U.S. Department of Agriculture, U. S. Forest Service, and U. S. Fish and Wildlife Service.

3. **Economic activity:** Estimate the direct/indirect value of agriculture, water quality, water supply, fishing, hunting, recreation, boating, ecotourism, and navigation in the watershed from population, employment, industrial activity, and land use data. Total economic activity is defined as the sum of direct/indirect use, option, and non use values (Ingraham and Foster 2008). Direct use values are from natural goods such as drinking water, boating, recreation, and commercial fishing. Indirect values are benefits from ecosystems such as water filtration by forests and flood control/habitat protection from wetlands. Option demand is public willingness to pay for benefits from water quality or scenic value of the bay. Nonuse (existence) values accrue to a public who may never visit the resource but are willing to pay to preserve the existence of the resource.

4. Ecosystem Services: Tabulate the market value of natural resources (ecosystem services value) in the watershed for habitat such as wetlands, forests, farmland, and open water. Prepare GIS based data sets and mapping. Ecosystem services (ecological services) are provided by nature and represent benefits such as water filtration, flood reduction, and drinking water supply.

Using GIS, define ecosystem areas using 2006 NOAA Coastal Services Center land cover data in the following classifications: (a) Freshwater wetlands, (b) Marine, (c) Farmland, (d) Forest, (e) Barren, (f) Saltwater wetland, (g) Urban, (h) Beach/dune, (i) Open freshwater, and (j) Riparian buffer.

Search research studies and gather value ($/acre) data for ecosystem services: (a) carbon sequestration, (b) flood control, (c) drinking water supply, (d) water quality filtration, (e) waste treatment and assimilation, (f) nutrient regulation, (g) fish and wildlife habitat, (h) recreation and aesthetics. Ecosystem services were estimated using value (benefits) transfer where published data and literature are reviewed and applied in the context of the resource in question. Value transfer is used to estimate ecosystem goods and services for the Delaware River Basin.

Compute ecosystem services value by multiplying land use area (acres) by ecosystem value ($/ac). The value transfer techniques employed here involves selecting data from published literature from another watershed or study area and applying the $ per ac values to land use areas computed by GIS. While primary research data from the watershed in question (the Delaware Basin) is preferable and is used in this report, value transfer is the next best practical way to value ecosystems especially when in the absence of such data the worth of ecosystems have previously been deemed zero. Future economic valuation survey research is recommended to develop primary ecosystem service values for the Delaware Basin in particular.

4. Jobs and salaries: Obtain employment and wage data from the U. S. Department of Labor, U. S. Census Bureau, and National Ocean Economics Program. Calculate direct/indirect jobs in the Delaware Basin by North American Industry Classification System (NAICS) codes such as shipbuilding, marine transportation/ports, fisheries, recreation, minerals, trade, agriculture, and others. Total jobs and salaries were summarized for each county within the watershed based on population census block data. NAICS data were supplemented with farm jobs data from the USDA Agricultural Statistics Bureau, U. S. Fish and Wildlife Service ecotourism jobs data, and jobs provided by water purveyors and wastewater treatment utilities.

5. Report: Prepare a report and GIS mapping summarizing the direct and indirect economic values of goods and services provided by the Delaware River Basin updated to 2010 dollars.

3. Annual Economic Activity

Estimated annual economic value of the Delaware River Basin from recreation, fish and wildlife, public parks, water quality, navigation/ports, potential Marcellus Shale natural gas, agriculture, water supply, and forest activities is over $25 billion (Table 6 and Figure 5).

• Recreation	$1.22 billion
• Fish and Wildlife	$1.55 billion
• Public Parks	$1.83 billion
• Water Quality	$2.46 billion
• Navigation/Ports	$2.62 billion
• Marcellus Shale Natural Gas (potential)	$3.30 billion
• Agriculture	$3.37 billion
• Water Supply	$3.82 billion
• Forests	$5.13 billion

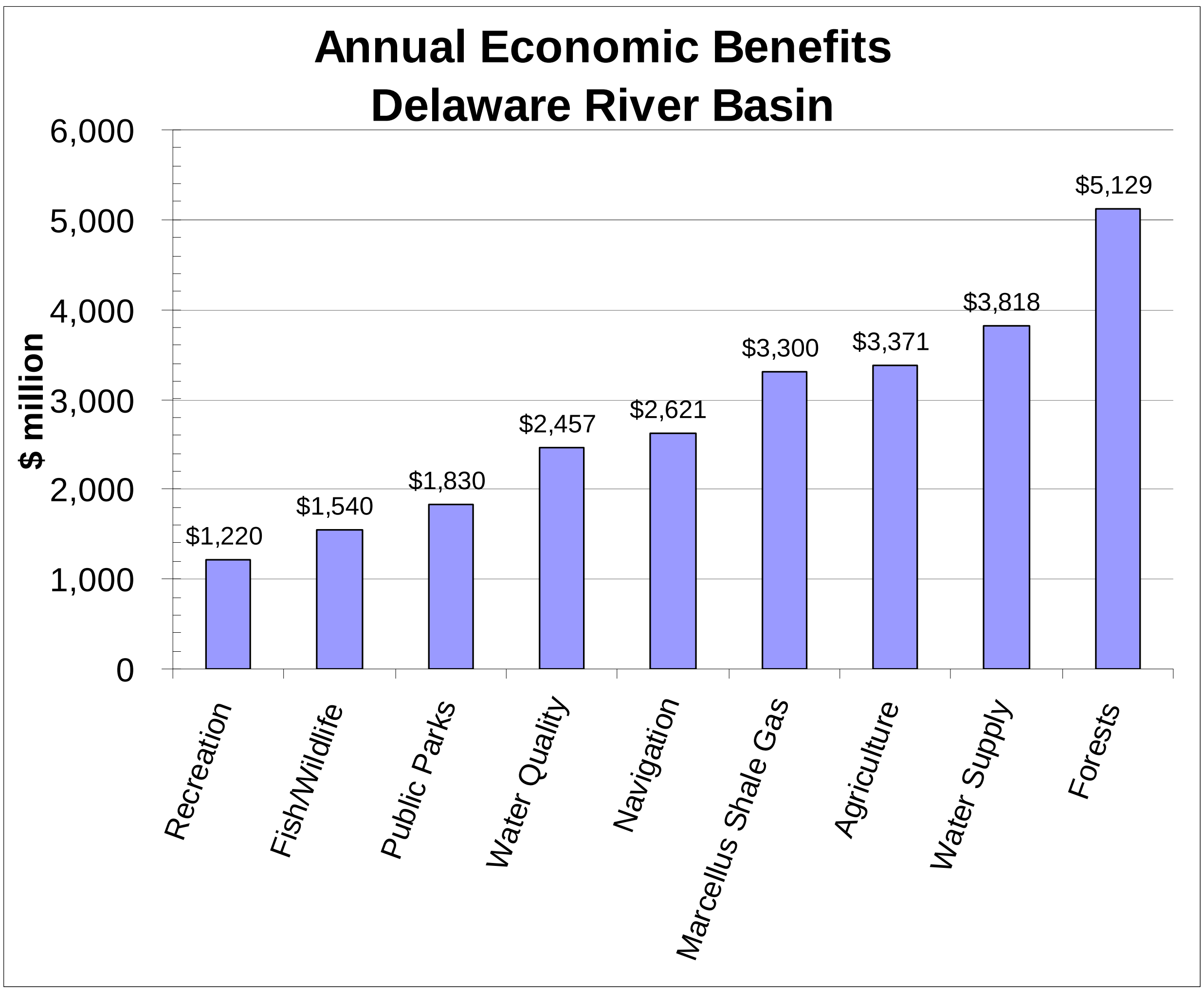


Figure 5. Annual economic activity related to the Delaware River Basin

Table 6. Annual economic activity in the Delaware River Basin, 2010

Activity	2010 ($ million)	Value Transfer Sources
Recreation (Boating, Fishing, Swimming)		
Clean Water Act Restoration		
Viewing/Aesthetics ($0.58/person)	5	University of Delaware (2003)
Boating ($0.76/person)	6	University of Delaware (2003)
Fishing ($2.95/person)	24	University of Delaware (2003)
Swimming ($6.88/person)	57	University of Delaware (2003)
Water Quality Based Recreation		
Swimming ($13.40/trip)	9	University of Rhode Island (2002)
Boating ($30/trip)	47	University of Rhode Island (2002)
Fishing ($62.79/trip)	52	University of Rhode Island (2002)
Wildlife/bird watching ($77.73/trip)	104	University of Rhode Island (2002)
Skiing (1.9 million ski-days @$45/day)	325	Pennsylvania Ski Areas Association (2010)
Paddling-based Recreation (620,860 paddlers)	362	Outdoor Industry Association(2006)
Del. Water Gap River Recreation (267,000 visitors)	41	U.S. Forest Service, U.S. Nat'l Park Service (1990)
Canoe/Kayak/Rafting (225,000 visits)	9	Canoe and Kayak Liveries (2010)
Powerboating (232,000 boat registrations)	395	National Marine Manufacturers Association (2010)
Water Quality		
Willing to Pay for Clean Water ($38-$121/user)	659	University of Maryland (1989)
Water Treatment by Forests ($96/mgd)	63	Trust for Public Land, AWWA (2004)
Wastewater Treatment ($4.00/1000 gal)	1,722	DRBC and USEPA
Increased Property Value (+8%)	13	EPA (1973), Brookings Institute (2010)
Water Supply		
Drinking Water Supply ($4.78/1000 gal)	3,145	UDWRA and DRBC (2010)
Reservoir Storage ($0.394/1000 gal)	145	UDWRA and DRBC (2010)
Irrigation Water Supply ($300/ac-ft)	32	Resources for the Future (1996), USDA (2007)
Thermoelectric Power Water Supply ($44/ac-ft)	297	EIA (2002), NETL (2009)
Industrial Water Supply ($200/ac-ft)	179	Resources for the Future (1996), DRBC (2010)
Hydropower Water Supply ($32/ac-ft)	20	Resources for the Future (1996), DRBC (2010)
Fish/Wildlife		
Commercial Fish Landings ($0.60/lb)	34	NMFS, Nat'l. Ocean Economics Program (2007)
Fishing (11-18 trips/angler, $17-$53/trip))	576	U. S. Fish and Wildlife Service (2001)
Hunting (16 trips/hunter, $16-50/trip)	340	U. S. Fish and Wildlife Service (2001)
Wildlife/Bird-watching (8-13 trip/yr, $15-$27/trip)	561	U. S. Fish and Wildlife Service (2001)
Shad Fishing (63,000 trips, $102/trip)	6	Pennsylvania Fish and Boat Commission (2011)
Wild Trout Fishing	29	Amer. Sportfishing Assn./Trout Unlimited (1998)
Agriculture		
Crop, poultry, livestock value ($1,180/ac)	3,371	USDA Census of Agriculture 2007 (2009)
Forests		
Carbon Storage ($827/ac)	3,592	U.S. Forest Service, Del. Ctr. Horticulture (2008)
Carbon Sequestration ($29/ac)	126	U.S. Forest Service
Air Pollution Removal ($266/ac)	1,155	U.S. Forest Service
Building Energy Savings ($56/ac)	243	U.S. Forest Service
Avoided Carbon Emissions ($3/ac)	13	U.S. Forest Service
Public Parks		
Health Benefits ($9,734/ac)	1,283	Trust for Public Land
Community Cohesion ($2,383/ac)	314	Trust for Public Land
Stormwater Benefit ($921/ac)	121	Trust for Public Land
Air Pollution ($88/ac)	12	Trust for Public Land
Del. Water Gap Natl. Rec. Area (4.9 million visits)	100	U.S. National Park Service (2002)
Marcellus Shale		
Natural Gas (7.3 trillion cf @ $11.21/1000 cf)	3,300	USGS (2011), EIA (2011)
Maritime Transportation		
Navigation ($15/ac-ft)	220	Resources for the Future (1996)
Port Activity	2,400	Economy League of Greater Philadelphia (2008)
Delaware River Basin	**≈$25 billion**	

Recreation

Clean Water Act Restoration

Parsons, Helm, and Bondelid (2003) from the University of Delaware measured the economic benefits of water quality improvements to recreational users in the northeastern states and found annual per person benefits for improvements due to the Clean Water Act ranged from $0.47 for viewing, $0.62 for boating, $2.40 for fishing, to $5.59 for swimming. Table 7 summarizes total water quality benefits to recreational users in the Delaware River Basin by transferring the benefits in $2003 to $2010 assuming an annual rate of 3% and then multiplying the $2010 benefits by the basin population. Total 2010 recreation benefits due to Clean Water Act water quality improvements in the Delaware Basin are $92 million per year or $11.17 per person. Swimming (62%) and fishing (26%) are the highest valued recreational benefits followed by boating (7%) and viewing (5%).

Table 7. Water quality benefits from Clean Water Act improvements in the Delaware River Basin

Recreational Benefit	$2003[1] (per person)	$2010[2] (per person)	Del. Basin Pop. 2010	Benefit/yr	% of Benefit
Viewing	$0.47	$0.58	8,255,013	$4,787,908	5%
Boating	$0.62	$0.76	8,255,013	$6,273,810	7%
Fishing	$2.40	$2.95	8,255,013	$24,352,288	26%
Swimming	$5.59	$6.88	8,255,013	$56,794,489	62%
Total	**$9.08**	**$11.17**	**8,255,013**	**$92,208,495**	**100%**

1. Parsons et al. 2003. 2. $2010 transferred from $2003 at annual rate of 3%.

Water Quality Based Recreation

Using travel cost demand methods, Johnston et al. (2002) from the University of Rhode Island computed the consumer surplus (economic use value per person) for swimming, boating, recreational fishing, and bird watching/wildlife viewing in the Peconic Estuary watershed on Long Island, New York. Swimming, boating, fishing, and wildlife viewing were valued at $8.59, $19.23, $40.25, and $49.83 per trip in $1995, respectively. Table 8 summarizes water quality benefits to recreational users of $211 million per year in the Delaware Basin (estuary only) by transferring unit values from the Peconic Estuary, converting $1995 to $2010 by an annual rate of 3%, and multiplying $2010 benefits by trips per year.

Table 8. Total annual value of recreational benefits in the Delaware River Basin

Recreational Benefit	$1995 Consumer surplus/trip[1]	$2010 Consumer surplus/trip[2]	Trips/year to Del. Estuary	Annual Value	% of Benefit
Swimming	$8.59	$13.40	670,000[3]	$8,978,000	4%
Boating	$19.23	$30.00	1,568,473[4]	$47,054,190	22%
Fishing	$40.25	$62.79	824,249[4]	$51,754,595	24%
Wildlife/bird watching	$49.83	$77.73	3,336,440[5]	$103,700,000	49%
Total				**$211,486,785**	**100%**

1. Johnston et al. 2002. 2. $2010 transferred from $1995 at 3%. 3. 10% of Delaware Estuary population swims. 4. NOEP 2009 for boating (16.8% of pop. and 1.4 trips/p./yr) and fishing (10.3% of pop. and 1.2 trips/p./yr). 5. USFWS 2006 wildlife/bird watching (Del. 427,500, NJ 2,070,900, & Pa. 838,000 trips/yr).

Skiing

In the Pocono Mountains of Pennsylvania, nine ski areas draw approximately 1 mgd from Delaware Basin water supplies for snowmaking on 1,005 skiable acres. The Pennsylvania Ski Areas Association (2009) estimated the economic value at 23 ski resorts statewide was $832,000,000. Prorating from PSAA statewide estimates, the economic value for 9 resorts in the Delaware Basin is $325,000,000. The nine ski resorts in the Delaware Basin have aggregate annual revenues of $87,655,063 from 1,908,228 skier visits based on a mid-week lift ticket rate of $45/day (Table 9).

Table 9. Revenues from ski resorts in the Delaware River Basin

Ski Resort	Ski Area (ac)	Annual Ski Visits	Lift Ticket ($/day)	Revenue ($)
Elk Mountain	235	446,203	$48	$21,417,722
Ski Big Bear	26	49,367	42	2,073,418
Ski Shawnee	125	237,342	43	10,205,696
Alpine Mountain	60	113,924	37	4,215,190
Camelback	160	303,797	48	14,582,278
Jack Frost	100	189,873	44	8,354,430
Big Boulder	55	104,430	44	4,594,937
Blue Mountain	158	300,000	49	14,700,000
Bear Creek	86	163,291	46	7,511,392
Total	**1,005**	**1,908,228**	**$45**	**$87,655,063**

Paddling-based Recreation

Canoeing, kayaking, and rafting are key drivers to the local economy along the Brandywine, Lehigh, Schuylkill, and middle/upper Delaware rivers in the Delaware Basin (Van Rossum, Carluccio, and Blankinship 2010). In the Mid-Atlantic census division (NY, NJ, PA), the Outdoor Industry Association (2006) estimates paddling-based recreation is practiced by 11% of the population and is responsible for 3,356,000 participants, $356 million in gear retail sales, $1.6 billion in trip related sales, and 22,844 jobs. Given the Delaware Basin is the home of 7,611,595 people in NJ, NY, and Pa. or 22% of New Jersey's population (1,951,047), 0.7% of New York State's population, (124,969), and 43% of Pennsylvania's population (5,533,254) or 18.5% of the three state's total population of 40,800,000 people, then prorated paddling-based recreation in the basin is responsible for 620,860 participants, $96 million in gear retail sales, $296 million in trip sales, and 4,226 jobs (Table 10).

Table 10. Economic value of paddling-based recreation in the Delaware River Basin

Paddling Based Recreation	States of NJ, NY, PA[1]	Del. Basin NJ, NY, PA[2]
Population	40,800,000	7,563,762
Participants	3,356,000	620,860
Gear retail sales	$356 million	$66 million
Trip related sales	$1.600 billion	$296 million
Total Sales	$1.956 billion	$362 million
Jobs	22,844	4,226

1. Outdoor Industry Association 2006. 2. Prorated by 18.5% given 40,800,000 people live in NJ, NY, and PA and 7,611,595 people live in these states in the Delaware Basin.

River Recreation

Cordel et al. (1990) from the U. S. Forest Service and U.S. National Park Service estimated river recreation along the Upper Delaware River and Delaware Water Gap was responsible for $13.3 million and $6.9 million in total economic output, respectively, in $1986 (Table 11). Adjusting for 3% annually, river recreation economic output along the Upper Delaware River and Delaware Water Gap is roughly $27.1 million and $14.1 million, respectively, or $41.2 million total in $2010.

Table 11. Economic impacts of river recreation along Upper Delaware and Delaware Water Gap

River	Participants	Jobs	Wages ($1986)	Economic Output ($1986)	Wages ($2010)	Economic Output ($2010)
Upper Delaware	232,000	292	5,582,800	13,351,000	11,408,000	$27,100,000
Del. Water Gap	135,400	156	3,246,300	6,929,000	6,633,743	$14,100,000
Total	**367,400**	**448**	**8,829,100**	**20,280,000**	**18,041,743**	**41,200,000**

1. Cordel et al. 1990. 2. Adjusted to $2010 at 3% annually.

Canoe/Kayak/Rafting

Thirty seven (37) canoe and kayak liveries along the Delaware, Lehigh, and Schuylkill, and Brandywine Rivers lease watercraft to approximately 225,000 visitors with earnings of $9 million per year assuming a daily rental fee of $40 per person (Table 12).

Table 12. Annual revenue from canoe and kayak liveries in the Delaware River Basin

Canoe/Kayak Livery	Address	Daily Rate ($)	Annual Visitors	Revenue ($)
Delaware River				
Adventure Sports Canoe/Raft	Marshalls Creek, PA	$40	9,000	$360,000
Bucks County River Country	Point Pleasant, PA	$40	13,500	$540,000
Catskill Mountain Canoe Rentals	Hankins, NY	$40	7,000	$280,000
Cedar Rapids Kayak/Canoe	Barryville, NY	$40	5,000	$200,000
Chamberlain Canoes Inc	Minisink Hills, PA	$40	5,000	$200,000
Delaware River Rafting/Canoeing	Delaware, NJ	$40	9,000	$360,000
Delaware River Tubing	Frenchtown, NJ	$40	7,000	$280,000
Driftstone on the Delaware	Mount Bethel, PA	$40	5,000	$200,000
GreenWave Paddling	Yardville, New Jersey	$40	3,000	$120,000
Indian Head Canoes & Rafts	Barryville, NY	$40	5,000	$200,000
Jerrys Three River Canoes	Pond Eddy, NY	$40	4,000	$160,000
Kayak East	East Stroudsburg, PA	$40	4,000	$160,000
Kittatinny Canoes, Inc.	Dingmanns Ferry, PA	$40	4,000	$160,000
Landers River Trips	Narrowsburg, NY	$40	15,000	$600,000
Lazy River Outpost	Phillipsburg, NJ	$40	4,000	$160,000
Pack Shack Adventures Inc	Delaware Water Gap, PA	$40	5,000	$200,000
Paint Island Canoe & Kayak	Bordentown, NJ	$40	4,000	$160,000
Portland Outfitters	Portland, PA	$40	5,000	$200,000
River Country	Point Pleasant, PA	$40	9,000	$360,000
Shawnee Canoe Trips	Shawnee on Delaware, PA	$40	12,000	$480,000
Silver Canoe Rentals	Port Jervis, NY	$40	4,000	$160,000
Upper Delaware Campgrounds	Callicoon, NY	$40	5,000	$200,000
Whitewater Willies Canoe Rentals	Pond Eddy, NY	$40	4,000	$160,000
Wild & Scenic River Tours/Rentals	Barryville, NY	$40	5,000	$200,000
Lehigh River				$0
Jim Thorpe River Adventures	Jim Thorpe, PA	$40	9,000	$360,000
Lehigh Rafting Rentals Inc	White Haven, PA	$40	9,000	$360,000
Lehigh River Bait and Bow	Allentown, PA	$40	3,000	$120,000
Northeast PA Kayak School	Lehighton, PA	$40	3,000	$120,000
Pocono Whitewater	Jim Thorpe, PA	$40	8,000	$320,000
Whitewater Challengers, Inc.	White Haven, PA	$40	9,000	$360,000
Whitewater Rafting Adventures Inc.	Nesquehoning, PA	$40	6,000	$240,000
Schuylkill				$0
Schuylkill River Outfitters	Birdsboro, PA	$40	4,500	$180,000
Brandywine River				$0
Brandywine Outfitters	Coatesville, PA	$40	3,000	$120,000
Northbrook Canoe	West Chester, PA	$40	9,000	$360,000
Wilderrness Canoe Trips	Wilmington, DE	$40	9,000	$360,000
Total			**225,000**	**9,000,000**

Powerboating

The National Marine Manufacturers Association (2010) announced that New York, Delaware, Pennsylvania, and New Jersey ranked 3rd, 7th, 17th, and 23rd in the U.S. respectively in total expenditures for new powerboats, outboard engines, boat trailers, and accessories. Table 13 summarizes powerboat expenditures by state and then prorated by percent population of each state within the Delaware Basin. Powerboat expenditures due to boating within the waters of the Delaware Basin are estimated at about $395 million/year

Table 13. Recreational powerboat expenditures in the Delaware River Basin (NMMA 2010)

State	Rank Expenditures	Total Powerboat Expenditures ($)	% Pop. of State in Basin	Del. Basin Powerboat Expenditures ($)
Delaware	7	343,743,963	74%	254,370,533
New Jersey	23	183,044,985	22%	40,269,897
New York	3	401,353,400	0.70%	2,809,474
Pennsylvania	17	226,281,490	43%	97,301,041
Total		**1,154,423,838**		**394,750,944**

New York, Pennsylvania, New Jersey, and Delaware are ranked 7th, 13th, 28th, and 40th in number of recreational boat registrations in 2009. The four states combined had just over $1 million boat registrations in 2009 with 232,000 registrations for boating in the Delaware River Basin (Table 14).

Table 14. Recreational boat registrations in the Delaware River Basin (NMMA 2010)

State	Rank Registrations	Total Boat Registrations	% Pop. of State in Basin	Del. Basin Boat Registrations
Delaware	40	61,523	0.74	45,527
New Jersey	28	173,994	0.22	38,279
New York	7	479,161	0.007	3,354
Pennsylvania	13	337,747	0.43	145,231
Total		**1,052,425**		**232,391**

Water Quality

Willingness to Pay for Clean Water

Bockstael, McConnell, and Strand (1989) from the University of Maryland estimated public annual willingness to pay for a moderate improvements in water quality of the Chesapeake Bay to be $10 to $100 million in 1984 dollars ($21.6 to $216 million in $2010 at 3% annually). The study found 43% of the respondents were users or visitors (boaters, fishermen) to the Chesapeake Bay and were willing to pay $121 per year to make the bay water quality "acceptable". About 57% of respondents were nonusers, those who do not visit or use the bay's resources but were willing to pay $38 per year to restore the bay. Transferring these values to the estuary watershed portion of the Delaware Basin (pop. 6,700,000) and using proportions of 10% users or visitors to the estuary and 90% nonusers, aggregate willingness to pay to make the Delaware Estuary water quality acceptable to the public is $658 million in $2010 or $99 per person.

Total willingness to pay for acceptable Delaware Estuary water quality
= (0.10)(6,700,000)($121/yr) + (0.90)(6,700,000)($38/yr)
= $310 million ($1984) = $659 million ($2010 at 3% annually).

Water Treatment

The Trust for Public Land and American Water Works Association (2004) found for every 10% increase in forested watershed land, drinking water treatment and chemical costs are reduced by approximately 20% (Table 15). The public drinking water supply is 1,803 mgd and forests cover 6,786 sq mi or 53% of the Delaware River Basin. Loss of these forests would increase drinking water treatment costs by $96 per mil gal ($139 per mil gal @ 0% forested minus $43 per mil gal @ 53% forested) or $173,088 per day for 1,803 mgd = $63,177,120 per year.

Table 15. Drinking water treatment and chemical costs based on percent of forested watershed (Trust for Public Land and AWWA 2004)

% of Watershed Forested	Water Treatment/ Chemical Costs (per mil gal)	% Change in Costs
0%	$139	21%
10%	$115	19%
20%	$93	20%
30%	$73	21%
40%	$58	21%
50%	$46	21%
60%	$37	19%

Wastewater Treatment

The waters of the Delaware Basin provide significant wastewater treatment, discharge, and assimilation services. In accordance with Federal Clean Water Act, DRBC, and state water quality regulations, NPDES municipal wastewater dischargers hold permits to discharge up to 1,180 million gallons per day to the Delaware River Basin or 106 mgd in Delaware, 218 mgd in New Jersey, 7 mgd in New York, and 849 mgd in Pennsylvania (Table 16). The average wastewater rate in the basin is $4.00 per 1000 gal. The fee for an average residence of 4 people @ 50 gpcd is $290 per year. The value of treated wastewater in the Delaware Basin is $4.7 million per day or $1.7 billion per year.

Table 16. Value of NPDES wastewater treatment discharges in the Delaware River Basin

NPDES ID	Facility	Location	State	Flow[1] (mgd)	Value[2] ($/day)	Wastewater Value ($/year)
DE0020338	Kent Co. Levy Court WWTR	Frederica	DE	15.0	60000	21900000
DE0021512	Lewes City POTW	Lewes	DE	0.8	3,200	1,168,000
DE0020320	Wilmington Wastewater Plant	Wilmington	DE	90.0	360,000	131,400,000
Delaware			**DE**	**105.8**	**423,200**	**154,468,000**

NJ0027481	Beverly City Sewer Auth. STP	Beverly	NJ	1.0	4,000	1,460,000
NJ0024678	Bordentown Sewerage Auth.	Bordentown	NJ	3.0	12,000	4,380,000
NJ0024651	Cumberland Co. Auth. WWTP	Bridgeton	NJ	7.0	28,000	10,220,000
NJ0024660	Burlington City STP	Burlington	NJ	2.7	10,800	3,942,000
NJ0021709	Burlington Twp. DPW	Burlington	NJ	1.6	6,400	2,336,000
NJ0026182	Camden County MUA	Camden	NJ	80.0	320,000	116,800,000
NJ0021601	Carneys Point Twp. WWTP	Carneys Point	NJ	1.3	5,200	1,898,000
NJ0024007	Cinnaminson Sewerage Auth.	Cinnaminson	NJ	2.0	8,000	2,920,000
NJ0023701	Florence Twp. DPW Sewer Auth.	Florence	NJ	2.5	10,000	3,650,000
NJ0026301	Hamilton Twp. DPW	Hamilton Twp.	NJ	16.0	64,000	23,360,000
NJ0020915	Lambertville City Sewer Auth.	Lambertville	NJ	1.5	6,000	2,190,000
NJ0024759	Ewing Lawrence Sewer WWTP	Lawrenceville	NJ	16.0	64,000	23,360,000
NJ0069167	Maple Shade Twp. Util, Authority	Maple Shade	NJ	3.4	13,600	4,964,000
NJ0026832	Medford Twp. Sewer Auth. STP	Medford	NJ	1.8	7,200	2,628,000
NJ0029467	Millville City Sewer Auth.	Millville	NJ	5.0	20,000	7,300,000
NJ0024996	Moorestown Twp. WWTP	Moorestown	NJ	3.5	14,000	5,110,000
NJ0024015	Mount Holly Twp. MUA	Mount Holly	NJ	7.7	30,800	11,242,000
NJ0020184	Newton Town DPW	Newton	NJ	1.4	5,600	2,044,000
NJ0024821	Pemberton Twp. MUA STP	Pemberton	NJ	2.5	10,000	3,650,000
NJ0024023	Penns Grove Sewerage Auth.	Penns Grove	NJ	0.8	3,200	1,168,000
NJ0021598	Pennsville Twp. Sewer Auth.	Pennsville	NJ	1.9	7,600	2,774,000
NJ0024716	Phillipsburg Town STP	Phillipsburg	NJ	3.5	14,000	5,110,000
NJ0022519	Riverside Twp. DPW	Riverside	NJ	1.0	4,000	1,460,000
NJ0024856	Salem WWTP Facility	Salem	NJ	1.4	5,600	2,044,000
NJ0024686	Gloucester Co. Util. Auth. STP	Thorofare	NJ	24.1	96,400	35,186,000
NJ0020923	Trenton City DPW Sewer Auth.	Trenton	NJ	20.0	80,000	29,200,000
NJ0023361	Willingboro Twp. MUA	Willingboro	NJ	5.2	20,800	7,592,000
New Jersey				**217.8**	**871,200**	**317,988,000**
NY0020265	Delhi WWTP	Delhi	NY	0.8	3,200	1,168,000
NY0030074	Liberty WWTF	Liberty	NY	1.6	6,400	2,336,000
NY0022454	Monticello STP	Monticello	NY	3.1	12,400	4,526,000
NY0029271	Sidney WWTP	Sidney	NY	1.7	6,800	2,482,000
New York				**7.2**	**28,800**	**10,512,000**
PA0026867	Abington Twp. STP	Abington	PA	3.9	15,600	5,694,000
PA0026000	Allentown City WWTP	Allentown	PA	40.0	160,000	58,400,000
PA0026042	Bethlehem City STP	Bethlehem	PA	90.0	360,000	131,400,000
PA0021181	Bristol Borough Water and Sewer	Bristol	PA	1.2	4,800	1,752,000
PA0027103	Delaware Co. Reg. Water Auth.	Chester	PA	44.0	176,000	64,240,000
PA0026859	Coatesville WWTP	Coatesville	PA	3.8	15,200	5,548,000
PA0026794	Conshohocken Borough Auth.	Conshohocken	PA	2.3	9,200	3,358,000
PA0026531	Downingtown Regional WPCC	Downingtown	PA	7.1	28,400	10,366,000
PA0026549	Borough of Doylestown WWTP	Doylestown	PA	28.5	114,000	41,610,000
PA0027235	Easton Area Joint Auth. WWTP	Easton, PA	PA	10.0	40,000	14,600,000
PA0029441	Upper Dublin Twp. MS4 UA	Ft. Washington	PA	1.1	4,400	1,606,000
PA0051985	Horsham Twp. STP	Horsham	PA	1.0	4,000	1,460,000
PA0024058	Kennett Square Borough WWTP	Kennett Square	PA	1.1	4,400	1,606,000
PA0026298	Whitemarsh STP	Lafayette Hill	PA	2.0	8,000	2,920,000
PA0026182	Lansdale Borough STP	Lansdale	PA	2.6	10,400	3,796,000
PA0039004	U. Gwynedd/Towamencin STP	Lansdale	PA	6.5	26,000	9,490,000
PA0026468	Morrisville Municipal Authority	Morrisville	PA	10.0	40,000	14,600,000
PA0027421	Norristown Borough WWTP	Norristown	PA	9.8	39,200	14,308,000
PA0020532	Upper Montgomery Joint Sewer	Pennsburg	PA	2.0	8,000	2,920,000

PA0026689	Northeast WPCP	Philadelphia	PA	210.0	840,000	306,600,000
PA0026662	Philadelphia Southeast POTW	Philadelphia	PA	112.0	448,000	163,520,000
PA0026671	SW Water Pollution Control	Philadelphia	PA	200.0	800,000	292,000,000
PA0020460	Quakertown WWTP	Quakertown	PA	4.3	17,200	6,278,000
PA0026549	Reading WWTP	Reading	PA	28.5	114,000	41,610,000
PA0020168	East Stroudsburg Filtration Plant	Stroudsburg	PA	2.3	9,200	3,358,000
PA0029289	Stroudsburg STP	Stroudsburg	PA	2.5	10,000	3,650,000
PA0027031	Goose Creek STP	West Chester	PA	1.7	6,800	2,482,000
PA0026018	West Chester Taylor Run STP	West Chester	PA	1.8	7,200	2,628,000
PA0028584	West Goshen STP	West Chester	PA	6.0	24,000	8,760,000
PA0023256	Upper Gwynedd Twp. WWTP	West Point	PA	5.7	22,800	8,322,000
PA0025976	Upper Moreland Hatboro Sewer	Willow Grove	PA	7.2	28,800	10,512,000
Pennsylvania			**PA**	**848.9**	**3,395,600**	**1,239,394,000**
Delaware Basin			**Basin**	**1,179.7**	**4,718,800**	**1,722,362,000**

1. DRBC and USEPA. 2. Value at @ $4.00/1000 gal

Increased Property Values

Several studies along rivers, estuaries, and coasts throughout the United States indicate that improved water quality can increase shoreline property values by 6% to 25% (Table 17). The EPA (1973) estimated that improved water quality can raise property values by up to 18% next to the water, 8% at 1000 feet from the water, 4% at 2000 feet from the water, and 1.5% at 3000 feet from the water. Leggett, et al. (2000) estimated that improved bacteria levels to meet state water quality standards along the western shore of the Chesapeake Bay in Maryland raised shoreline property values by 6%. The Brookings Institution (2007) projected that investments of $26 billion to restore the Great Lakes would increase shoreline property values by up to 10%. For this analysis, shoreline property values within 2000 feet of the waterways are estimated to increase by an average of 8% due to improved water quality in the Delaware Estuary.

Shoreline property values within 2000 feet of the water due to water quality improvements in the Delaware Estuary watershed will increase by $256 million (Table 18). The average riverfront property value in Philadelphia is $92,000 per acre. Multiply this value by the area of property within a 2,000 feet corridor along the Delaware Estuary shore between the C&D Canal and head of tide at Trenton. Multiply by increased property value of 8% due to improved water quality in the Delaware Estuary. Since the increase in property value is a one time benefit, the annual value over a 20 year period where water quality has improved in the Delaware Estuary is estimated as $13 million.

Table 17. Increased property values resulting from improved water quality

Study	Watershed	Increased Value
EPA (1973)	San Diego Bay, CA Kanawha, OH Willamette R., OR	
Next to water		18%
1000 ft from water		8%
2000 ft from water		4%
3,000 ft from water		1.5%
Leggett, et al. (2000)	Chesapeake Bay	6%
Brookings Institution (2007)	Great Lakes	10%

Table 18. Increased shore property value due to improved water quality in the Delaware Basin

State	Length of shoreline (ft)	Area 2000 ft of water (sf)	Area 2000 ft of water (ac)	Property Value @ $92,000/ac ($)	Increased Property Value @ 8% ($)
Delaware	114,048	228,096,000	5,236	481,745,455	38,539,636
New Jersey	357,456	714,912,000	16,412	1,509,915,152	120,793,212
Pennsylvania	285,648	571,296,000	13,115	1,206,593,939	96,527,515
Delaware Estuary	757,152	1,514,304,000	34,764	3,198,254,545	255,860,364

Water Supply

Drinking Water Supply

The Delaware Basin covers just 0.4% of the continental United States (12,769 sq mi/3,000,000 sq mi) yet supplies drinking water to 5% of the U.S. population (16,000,000/309,000,000 people). Delaware Basin aquifers and streams supply drinking water to over 8 million people within the basin to cities like Wilmington, Philadelphia, Allentown, Camden, and Trenton, NJ. Through interbasin transfers, the Delaware Basin also supplies drinking water to an additional 8 million people who live outside the basin by allocated diversions through the New York City Catskill Reservoir system (800 mgd) and the Delaware & Raritan Canal in New Jersey (100 mgd). Table 19 summarizes the economic benefits of groundwater reserve stock to generate ecosystem services (USEPA 1995).

Table 19. Groundwater services and effects (USEPA 2005)

Services	Effects
Drinking Water	Increase of decrease in availability of drinking water Change in human health or health risks
Water for Crop Irrigation	Change in value of crops or production costs Change in human health or health risks
Water for Livestock/Poultry	Change in Value of livestock products or production Change in human health or health risks

The Delaware Basin provides significant public drinking water supplies (1,804 mgd) with 44% in NY (800 mgd), 38% from Pa. (679 mgd), 16% from NJ (284 mgd), and 2% from Del. (40 mgd), Figure 6. The largest public water supply allocations in the Delaware Basin include United Water Delaware and Wilmington in Del.; Delaware & Raritan Canal diversion, New Jersey American, Trenton, and Camden in NJ; New York City, and Philadelphia and Aqua Pennsylvania in Pa. (Table 20). Figure 7 depicts public water supply service areas in the Delaware River Basin.

The annual value of raw (untreated) public water supply allocations in the Delaware Basin (1,803 mgd) is $658 million. When treated and delivered to customers the annual value of drinking water supplies is $3.14 billion (Table 21). Water purveyors in Delaware estimate the value of raw water supply is $1.00/1000 gallons according to cost of services studies for rate setting by the Public Service Commission. In FY13, the New Jersey Water Supply Authority plans to sell raw water supplies from the Manasquan Reservoir system for $1.02/1000 gallons (NJWSA 2011). The average value of treated drinking water based on rates set by public/private water purveyors in Del., NJ, Pa., and Md. is $4.78/1000 gallon (Corrozi and Seymour 2008).

Table 20. Public water supply allocations in the Delaware River Basin (DRBC 2010)

Water Purveyor	Supply (mgd)	Water Purveyor	Supply (mgd)	Water Purveyor	Supply (mgd)
Delaware	**40.10**				
United Water Del.	18.46	Harrington	0.36	Frederica Perkiomen	0.05
Wilmington	10.40	Camden-Wyoming	0.31		
Dover	4.74	Milton	0.17		
Newark	2.22	Milford	0.17		
Lewes BPW	0.98	Georgetown	0.13		
Tidewater Utilities	0.64	Frederica	0.08		
Dover AFB	0.44	Felton	0.08		
New Castle MSC	0.41	Delaware State Fair	0.05		
Smyrna	0.37	Magnolia	0.05		
New Jersey	**284.19**				
Del. & Raritan Canal	100.00	Hackettstown MUS	2.57	Medford Twp.	1.29
NJ American Western	39.37	Millville Water Dept	2.55	NJ American Oxford	1.20
Trenton	26.10	Moorestown	2.51	Florence Twp.	1.17
Camden	10.89	Bordentown	2.21	Salem City	1.12
Vineland	8.33	Burlington Twp.	2.00	Mantua Twp.	1.04
Merchant.-Pennsauken	6.05	Mt. Laurel	1.96	Pennsville Twp.	1.04
Washington Twp.	4.79	Glassboro	1.95	Pemberton Twp.	1.01
Willingboro MUA	4.65	Collingswood	1.93	Gloucester City	0.95
NJ American Mt. Holly	4.48	Maple Shade	1.64	Lower Twp MUA	0.95
Bridgeton	3.63	West Deptford	1.57	Sparta Twp.	0.94
Wildwood	3.59	Woodbury	1.55	Audubon Twp.	0.91
Aqua NJ Phillipsburg	3.46	Burlington City	1.47	Haddon Twp.	0.90
Aqua NJ Hamilton Sq.	3.39	Pennsgrove	1.42	Bellmawr Twp.	0.86
Aqua NJ Blackwood	2.96	Deptford Twp.	1.38	Haddonfield	0.82
Evesham MUA	2.82	Nesqehoning Boro	1.30	Greenwich Twp	0.82
				Misc. Water Purveyors	16.65
New York State	**800.03**				
New York City	800.00				
Pennsylvania	**679.30**				
Philadelphia	287.77	Easton Suburb.Water	4.47	Falls Twp.	2.66
Aqua PA Main System	102.18	Schuylkill Co. Auth.	4.36	Northampton Bucks	2.55
Forest Park	20.16	Muhlenberg Twp.	4.31	Warminster Twp.	2.54
Bethlehem	15.69	Lehigh County	4.22	Horsham Water/Sewer	2.30
Allentown	15.46	PA American Nazareth	4.13	Newtown Artesian	2.24
North Wales Water	15.09	Hazelton	4.12	Milford	1.88
Bucks Co. Water	14.99	PA Amer. Coatesville	4.07	Tamaqua MWA	1.87
Reading Area Auth.	14.31	Allentown City	4.02	Lehighton MWA	1.77
Bucks County SW	13.79	Northampton Boro.	3.74	Ambler Boro	1.75
PA Amer. Norristown	10.10	East Stroudsburg	3.69	Brodhead Cr. Auth.	1.73
Lower Bucks County	8.66	PA American Yardley	3.20	South Whitehall Twp.	1.71
North Penn Water	8.59	Phoenixville	3.01	Emmaus Munic. Water	1.49
Easton	7.13	Morrisville	2.89	Warrington Twp.	1.45
Schuylkill Co. Auth.	5.15	PA American Home	2.88	Wyomissing Boro	1.44
Pottstown Water Auth.	4.64	PA American Penn	2.76	Schuylkill Haven Boro.	1.42
				Misc. Water Purveyors	50.93

Table 21. Value of public drinking water supply allocations in the Delaware River Basin

State	Withdrawal (mgd)	Value/day untreated ($1.00/1000 gal)	Value/year untreated ($1.00/1000 gal)	Value/year treated ($4.78/1000 gal)
Delaware	40	40,000	14,600,000	69,788,000
New Jersey	284	284,000	103,660,000	495,494,800
New York	800	800,000	292,000,000	1,395,760,000
Pennsylvania	679	679,000	247,835,000	1,184,651,300
Delaware Basin	**1,803**	**1,803,000**	**658,095,000**	**3,145,694,100**

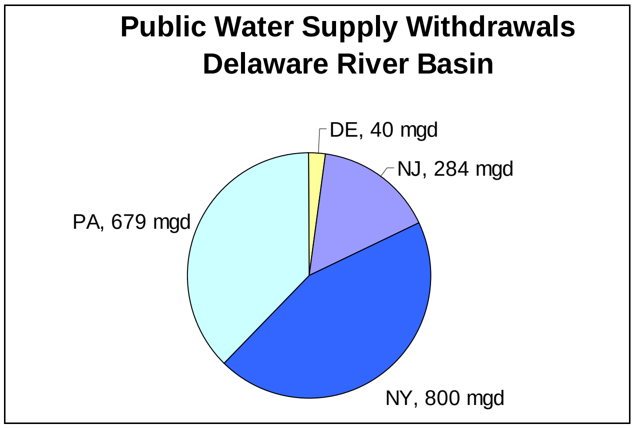


Figure 6. Public water supply withdrawals in the Delaware River Basin (DRBC)

Reservoir Storage

Almost 369 billion gallons of water is stored in reservoirs for interstate flow management and drinking water supply in the Delaware Basin (Table 22). The New Jersey Water Supply Authority operates a reservoir system and Delaware & Raritan Canal diversion from the Delaware River to New Jersey. The NJWSA delivers untreated water to public water purveyors from the Raritan River reservoir system at an estimated market price of $0.394/1,000 gallons (NJWSA 2011). Given the raw water value of drinking water before treatment) is $0.394/1000 gallons, the annual value of reservoir storage for flow management purposes in the Delaware Basin is $145 million.

Table 22. Economic value of reservoir storage in the Delaware River Basin

Reservoir	Storage (BG)	Value ($0.394/1000 gal)
Pepacton	140	55,160,000
Cannonsville	96	37,824,000
Neversink	35	13,790,000
Mongaup	15	5,910,000
Merrill Creek	16	6,304,000
Hoopes	2	788,000
Marsh Creek	4	1,576,000
Blue Marsh	6	2,561,000
Beltzville	13	5,122,000
F. E. Walter	11	4,334,000
L.Waullenpaupack	30	11,820,000
Total	**368**	**145,189,000**

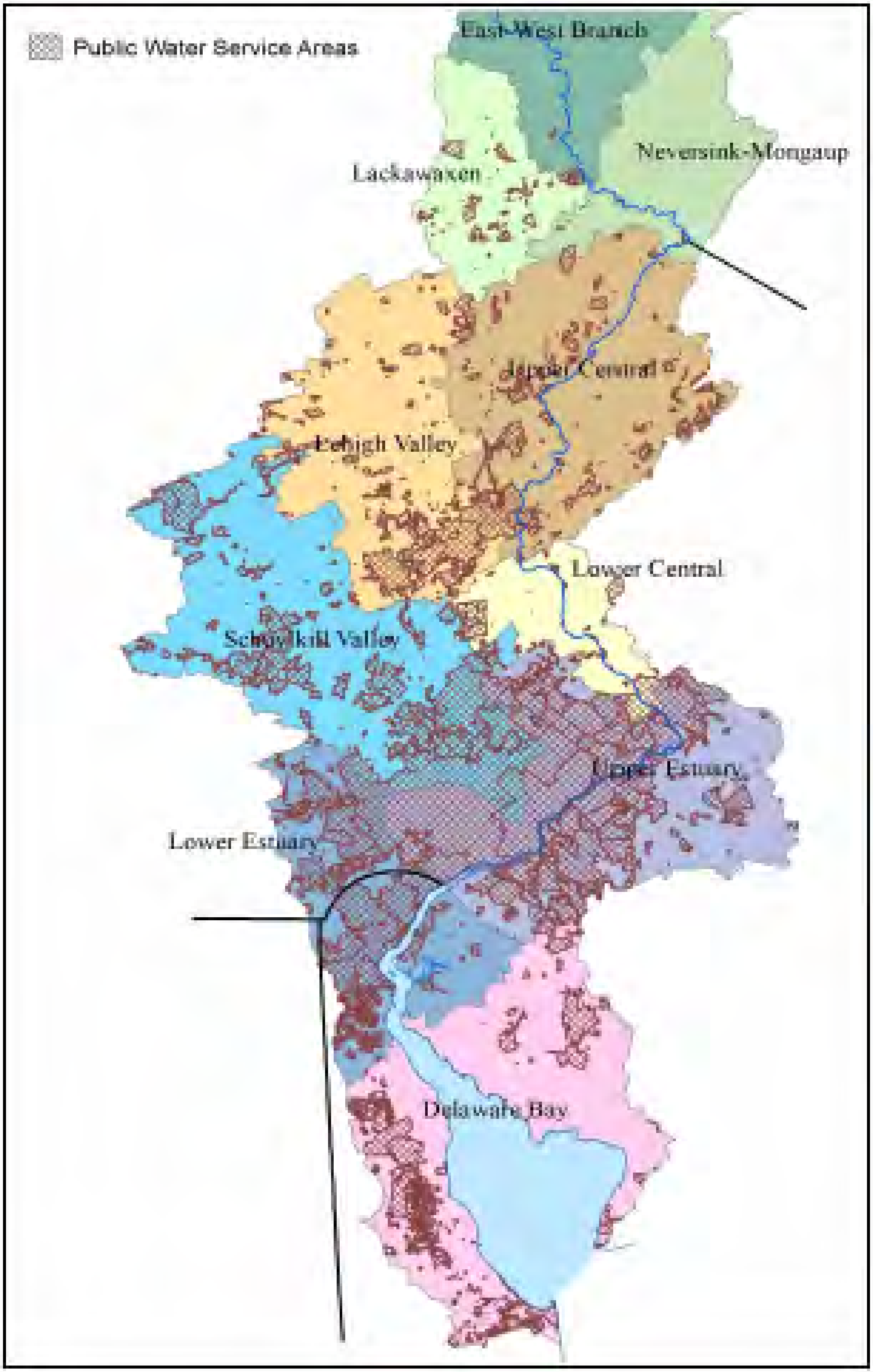


Figure 7. Public water supply service areas in the Delaware River Basin (DRBC 2011)

Irrigation Water Supply

Agricultural irrigation withdrawals allocated by DRBC total 36.5 mgd. The DRBC allocates groundwater withdrawals over 100,000 gpd therefore many small irrigation wells are not included in this total. Resources for the Future studied the economic value of freshwater in the U.S. estimated the median value of irrigation water withdrawals is $198/ac-ft in $1996 (Frederick et al. 1996) or $300/ac-ft ($0.92/1000 gal) in $2010 adjusting for 3% annually (Table 23). The value of irrigation withdrawals based on DRBC allocations is $33,630 per day or $12,275,000 per year (Table 24).

Table 23 Freshwater values in the United States by use

Use	2006 Median[1] ($/ac-ft)	2010 Median[2] ($/ac-ft)	2010 Median ($/1000 gal)
Hydropower	21	32	0.10
Industrial Process	132	200	0.61
Irrigation	198	300	0.92
Navigation	10	15	0.02
Thermoelectric Power	29	44	0.14

1. Frederick et al. 1996. 2. Adjusted to $2010 at 3% annually.

Table 24. Value of agricultural irrigation supply in the Delaware River Basin

Watershed	Withdrawal (mgd)	Irrigation Value/day ($0.92/1000 gal)	Irrigation Value/year ($0.92/1000 gal)
Upper Region	0.65	597	217,731
Upper Central	4.91	4,515	1,647,916
Lehigh Valley	0.20	184	67,118
Lower Central	1.51	1,389	507,084
Schuylkill Valley	0.02	23	8,358
Upper Estuary	4.15	3,819	1,394,036
Lower Estuary	7.58	6,976	2,546,164
Delaware Bay	17.53	16,128	5,886,540
Delaware Basin	**36.55**	**33,630**	**12,274,946**

Over 209,882 acres or 7% of cropland are irrigated in Delaware Basin counties (USDA 2009). About 1,926,524 acres or 24% of the basin is farmland, therefore, by proportion about 141,138 acres are irrigated (Table 25). Annual irrigation water needs from June - September are 9 inches for corn, soybeans, and grain (2,600 gpd/ac, 366 mgd). The economic value of water to irrigate 141,138 acres is $31.8 million, or $13.8 million in Del., $14.3 million in NJ, 0.9 million in NY, and $2.7 million in Pa.. The value of irrigation water demand = (9 in/12 in/ft)(141,138)($300/ac-ft) = $31,756,104/yr.

Table 25. Value of agriculture irrigation water demand in the Delaware River Basin

County	Cropland by county[1] (ac)	Irrigation by county[1] (ac)	Farmland in basin (ac)	Irrigated land in basin (ac)	Value of irrigation[2] @ $300/ac-ft
New Castle	51,913	2,711			
Kent	146,536	29,066			
Sussex	234,324	72,785			
Delaware	**432,773**	**104,562**	**254,143**	**61,403**	**$13,815,748**
Burlington	85,790	12,620			
Camden	8,760	2,647			
Cape May	7,976	2,342			
Cumberland	69,489	18,357			
Gloucester	46,662	12,891			
Hunterdon	100,027	1,501			
Mercer	21,736	1,028			
Monmouth	44,130	5,976			
Ocean	9,833	1,090			
Salem	96,530	18,001			
Sussex	65,242	454			
Warren	74,975	2,426			
New Jersey	**631,150**	**79,333**	**505,507**	**63,540**	**$14,296,541**
Broome	86,613	150			
Delaware	165,572	65			
Greene	44,328	735			
Orange	80,990	4,560			
Sullivan	50,443	75			
Ulster	75,205	4,707			
New York	**503,151**	**10,292**	**187,561**	**3,837**	**$863,230**
Berks	170,760	1,260			
Bucks	58,012	1,421			
Carbon	20,035	132			
Chester	117,145	1,659			
Delaware	1,646	36			
Lackawanna	39,756	258			
Lancaster	326,648	5,366			
Lebanon	89,566	1,276			
Lehigh	72,737	1,189			
Luzerne	66,577	60			
Monroe	29,165	97			
Montgomery	28,563	668			
Northampton	68,252	247			
Philadelphia	150	0			
Pike	27,569	12			
Schuylkill	81,276	1,896			
Wayne	99,939	118			
Pennsylvania	**1,297,796**	**15,695**	**979,313**	**11,843**	**$2,664,765**
Total	**2,864,870**	**209,882**	**1,926,524**	**141,138**	**$31,756,104**

1. Census of Agriculture 2007 (USDA 2009). 2. Frederick, VandenBerg, and Hansen 1996.

Thermoelectric Power Water Supply

Cooling water withdrawals for thermoelectric power plants in the Delaware Basin provide significant economic value. Over 89% of the energy in the United States is produced by thermoelectric power plants which evaporate water during cooling of condensate. The Delaware Basin provides 5,809 mgd of cooling water to run nuclear, coal, and gas fired power plants to generate 13,458 megawatts of electricity along the Delaware, Schuylkill, and Lehigh. About 95% of the cooling water returns to the river or bay (nonconsumptive use) and 5% evaporates (consumptive use). Table 26 lists power plants and associated cooling water withdrawals within the Delaware Basin obtained from U. S. Energy Information Administration (2002) and U.S. National Energy Technology Laboratory (2009) inventories of electric utility power plants and DRBC water allocation dockets.

Resources for the Future in a study of the economic value of freshwater in the United States estimated the median $1996 value of thermoelectric power water withdrawals is $29/ac-ft ($0.09/1000 gal) with a range of $9 to $63/ac-ft (Frederick et al. 1996). Adjusting for 3% annually, the median $2010 value of thermoelectric plant water withdrawals is $44 per ac-ft or $0.14/1000 gal. At $0.14/1000 gal, the value of thermoelectric water withdrawals in the Delaware Basin is $297 million/yr or $24 million/yr in Delaware, $196 million/yr in New Jersey, and $77 million/yr in Pennsylvania (Table 27).

Table 26. Thermoelectric power plant water withdrawals in the Delaware River Basin

State/Power Plant	Type	Capacity[1] (megawatts)	Withdrawal (mgd)	Value/day[2] ($0.14/1000 gal)[1]	Value/year ($0.14/1000 gal)
Delaware		**1,009**	**479**	**67,060**	**24,476,900**
Delmarva Delaware City		9	9		
Conectiv Edgemoor	Coal/Gas	1,000	470		
New Jersey		**4,920**	**3,830**	**536,200**	**195,713,000**
PSEG Salem 1 and 2	Nuclear	2,275	2,643		
PSEG Hope Creek	Nuclear	1,268	52		
Chambers Cogen. Salem	Coal	285			
Deepwater Station	Coal	82	219		
Logan Generating	Coal	242	38		
PSEG Mercer Trenton	Coal	768			
Pennsylvania		**7,529**	**1,500**	**210,000**	**76,650,000**
PECO Chester	Coal	56			
PECO Cromby	Coal	417			
PECO Croyden	Coal	546			
PECO Delaware (Phila.)	Coal	392			
PECO Eddystone	Coal	1,448			
PECO Fairless Hills	Coal	75			
PECO Falls	Coal	64			
PECO Limerick	Nuclear	2,230			
PECO Moser	Coal	64			
PECO Richmond (Phila.)	Coal	132			
PECO Schuylkill (Phila.)	Oil	233			
PECO Southwark (Phila.)	Coal	74			
PGE Northamp. Lehigh	Coal	134			
PPL Martins Creek	Coal	1,664	Shut 2007		
Delaware Basin		**13,458**	**5,809**	**813,260**	**296,839,900**

1. EIA 2002, NETL 2009, and DRBC. 2. Frederick et al. 1996 adjusted to $2010 at 3% annually.

Table 27. Value of thermoelectric power withdrawals in the Delaware River Basin

Watershed	Withdrawal [1] (mgd)	Value/day[2] ($0.14/1000 gal)	Value/year ($0.14/1000 gal)
Upper Region	0	0	0
Upper Central	394	55,160	20,133,400
Lehigh Valley	2	280	102,200
Lower Central	24	3,360	1,226,400
Schuylkill Valley	232	32,480	11,855,200
Upper Estuary	1,461	204,540	74,657,100
Lower Estuary	3,696	517,440	188,865,600
Delaware Bay	0	0	0
Delaware Basin	**5,809**	**813,260**	**296,839,900**

1. DRBC. 2. Frederick et al. 1996 adjusted to $2010 at 3% annually)

Industrial Water Supply

Industrial water withdrawals allocated by DRBC total 804 mgd in the Delaware River Basin (Table 28). A study of the economic value of freshwater in the U.S. indicates the median value of industrial withdrawals is $132/ac-ft in $1996 (Frederick et al. 1996) or $200/ac-ft ($0.61/1000 gal) in $2010 adjusting for 3% annually. The value of industrial withdrawals based on DRBC allocated supplies is $490,684 per day or $179,099,660 per year.

Table 28. Value of industry process water withdrawals in the Delaware River Basin

Watershed	Withdrawal [1] (mgd)	Industry Value/day[2] ($0.61/1000 gal)	Industry Value/year ($0.61/1000 gal)
Upper Region	0	0	0
Upper Central	31	18,727	6,835,355
Lehigh Valley	73	44,591	16,275,715
Lower Central	71	43,188	15,763,620
Schuylkill Valley	40	24,583	8,972,795
Upper Estuary	132	80,703	29,456,595
Lower Estuary	446	271,877	99,235,105
Delaware Bay	12	7,015	2,560,475
Delaware Basin	**804**	**$490,684**	**$179,099,660**

1. DRBC water allocations. 2. Frederick et al. 1996 adjusted to $2010 at 3% annually

Hydropower Water Supply

Hydropower water supply withdrawals allocated by DRBC total 539 mgd in the upper Delaware Basin at the Delaware Water Gap at Yards Creek and above Pt. Jervis (Table 29). A study of the economic value of freshwater in the U.S. indicates the median value of hydropower withdrawals is $21/ac-ft in $1996 (Frederick et al. 1996) or $32/ac-ft ($0.10/1000 gal) in $2010 adjusting for 3%

annually. The value of hydropower water withdrawals based on DRBC allocated supplies is $53,879 per day or $19,662,550 per year.

Table 29. Value of hydroelectric water supplies in the Delaware River Basin

Watershed	Withdrawal[1] (mgd)	Hydropower Value/day[2] ($0.10/1000 gal)	Hydropower Value/year ($0.10/1000 gal)
Upper Region	393	39,330	14,355,450
Upper Central	145	14,540	5,307,100
Lehigh Valley	0	0	0
Lower Central	0	0	0
Schuylkill Valley	0	0	0
Upper Estuary	0	0	0
Lower Estuary	0	0	0
Delaware Bay	0	0	0
Delaware Basin	**539**	**53,870**	**19,662,550**

1. DRBC water allocations. 2. Frederick et al. 1996 adjusted to $2010 at 3% annually

Fish/Wildlife

Fish Landings

The annual value of fish landings (Table 30) in the tidal Delaware River and Bay is $25.4 million in $2000 or $34.1 million in $2010 as reported to the National Marine Fisheries Service and tabulated by the National Ocean Economics Program (2007). Table 31 ranks the most lucrative fisheries in the Delaware Estuary as blue crab ($14.4 million/yr), summer flounder ($5.3 million/yr), Atlantic menhaden ($4.3 million/yr), eastern oyster ($3.7 million/yr), striped bass ($2.3 million/yr), and American eel ($0.8 million/yr). Figure 8 charts fish landings for Delaware Estuary species.

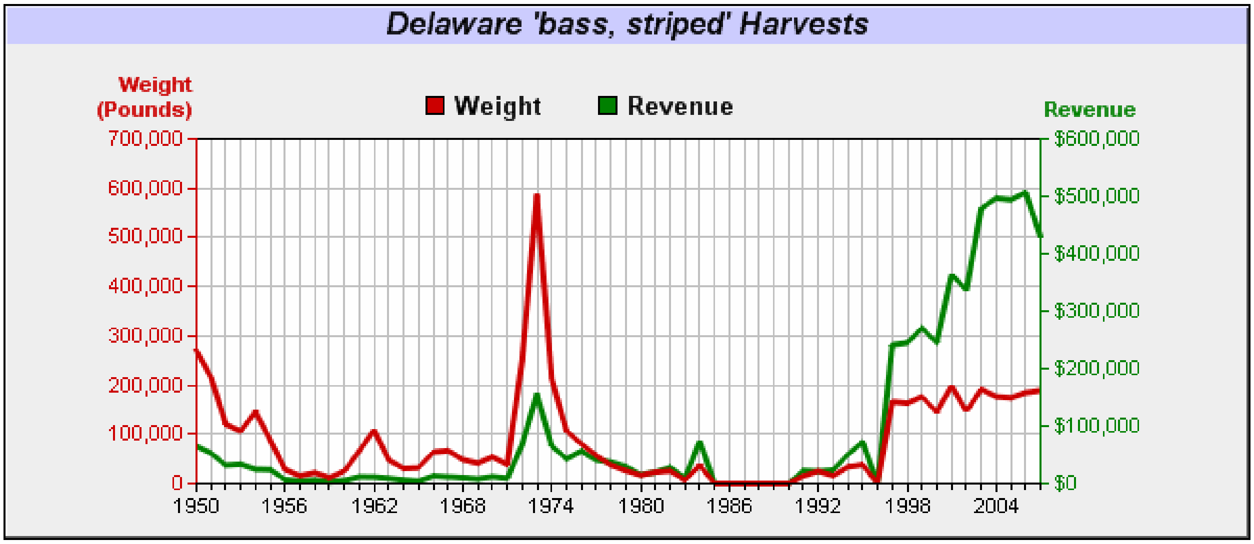
Table 30. Fish landings and landed value in the Delaware Estuary in $2000

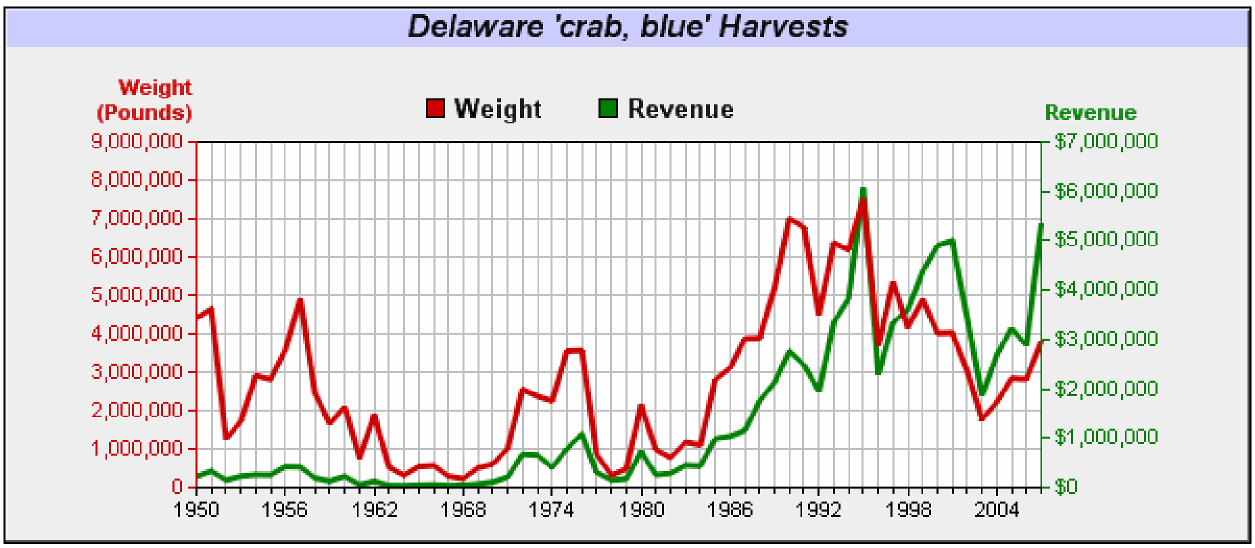
	Delaware		New Jersey		Pennsylvania		Delaware Estuary	
Delaware Estuary Species[1]	**Pounds**	**Value ($2000)**	**Pounds**	**Value ($2000)**	**Pounds**	**Value ($2000)**	**Pounds[2]**	**Value[2] ($2000)**
Bass, Striped	188,671	$429,994	564,000	$1,287,000	211	$378	752,882	$1,717,372
Bluefish	19,565	$8,075	1,403,717	$500,053			1,423,282	$508,128
Carp. Common	3,764	$865			6,724	$26,805	10,488	$27,670
Catfish, Channel	6,922	$3,929					6,922	$3,929
Crab, Blue	3,799,820	$5,329,182	4,636,368	$5,471,115			8,436,188	$10,800,297
Crab, Horseshoe	229,602	$48,978					229,602	$48,978
Drum, Black	37,712	$21,867	1,518	$444			39,230	$22,311
Eel, American	139,648	$315,094	159,292	$310,417			298,940	$625,511
Flounder, Summer	5,464	$11,119	1,697,513	$3,988,869			1,702,977	$3,999,988
Herring, Blueback	1,434	$609					1,434	$609
Herring, Atlantic			6,039,473	$563,083			6,039,473	$563,083
Menhaden, Atlantic	85,080	$6,635	37,634,929	$3,193,724			37,720,009	$3,200,359
Oyster, Eastern	79,933	$490,465	444,227	$2,230,835			524,160	$2,721,300
Perch, White	55,973	$46,865	27,527	$29,654	4,560	$7,981	88,060	$84,500
Perch, Yellow					20,527	$71,847	20,527	$71,847
Shad, American	71,445	$42,408	58,981	$77,015			130,426	$119,423
Shellfish	30,130	$76,119					30,130	$76,119
Snails (Conchs)			30,250	$59,016			30,250	$59,016
Weakfish	24,604	$36,177	164,506	$225,051			189,110	$261,228
Whelk,Chan'd/Knob	277,217	$511,172					277,217	$511,172
Total	**5,056,984**	**$7,379,553**	**52,862,301**	**$17,936,276**	**32,022**	**$107,011**	**57,951,307**	**$25,422,840**

1. Dove and Nyman 1995. 2. NMFS and National Ocean Economics Program 2007.

Table 31. Fish landings and value in the Delaware Estuary in $2010

Delaware Estuary Species[1]	Value ($2000)[2]	Value ($2010)[3]
Crab, Blue	$10,800,297	$14,472,398
Flounder, Summer	$3,999,988	$5,359,984
Menhaden, Atlantic	$3,200,359	$4,288,481
Oyster, Eastern	$2,721,300	$3,646,542
Bass, Striped	$1,717,372	$2,301,278
Eel, American	$625,511	$838,185
Herring, Atlantic	$563,083	$754,531
Bluefish	$508,128	$680,892
Whelk,Chan'd/Knob	$511,172	$684,970
Weakfish	$261,228	$350,046
Shad, American	$119,423	$160,027
Perch, White	$84,500	$113,230
Shellfish	$76,119	$101,999
Perch, Yellow	$71,847	$96,275
Snails (Conchs)	$59,016	$79,081
Crab, Horseshoe	$48,978	$65,631
Carp. Common	$27,670	$37,078
Drum, Black	$22,311	$29,897
Catfish, Channel	$3,929	$5,265
Herring, Blueback	$609	$816
Total	**$25,422,840**	**$34,066,606**





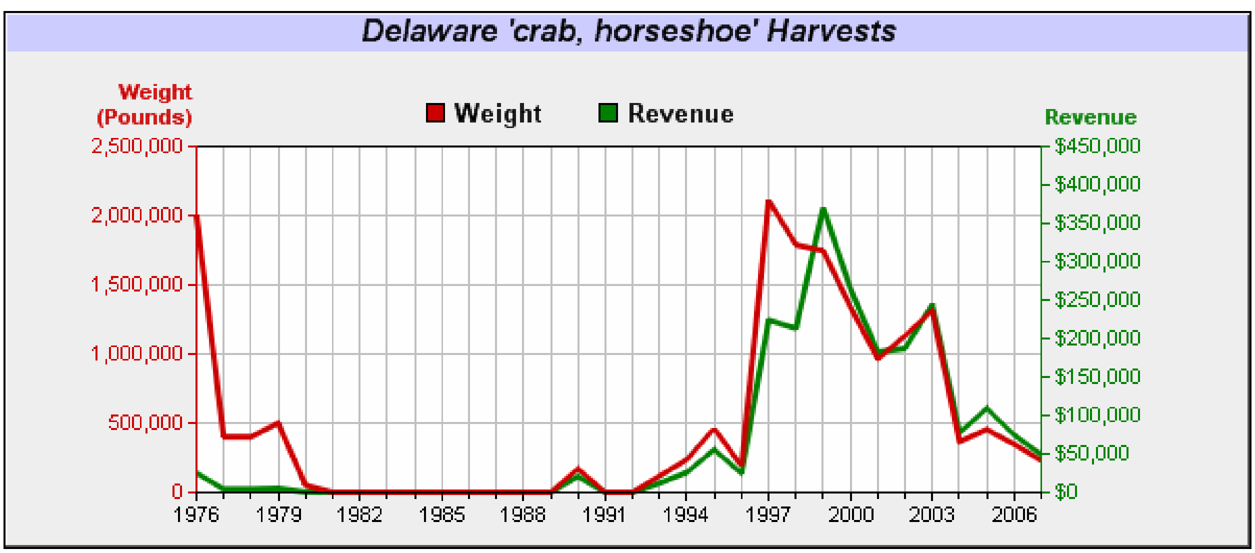
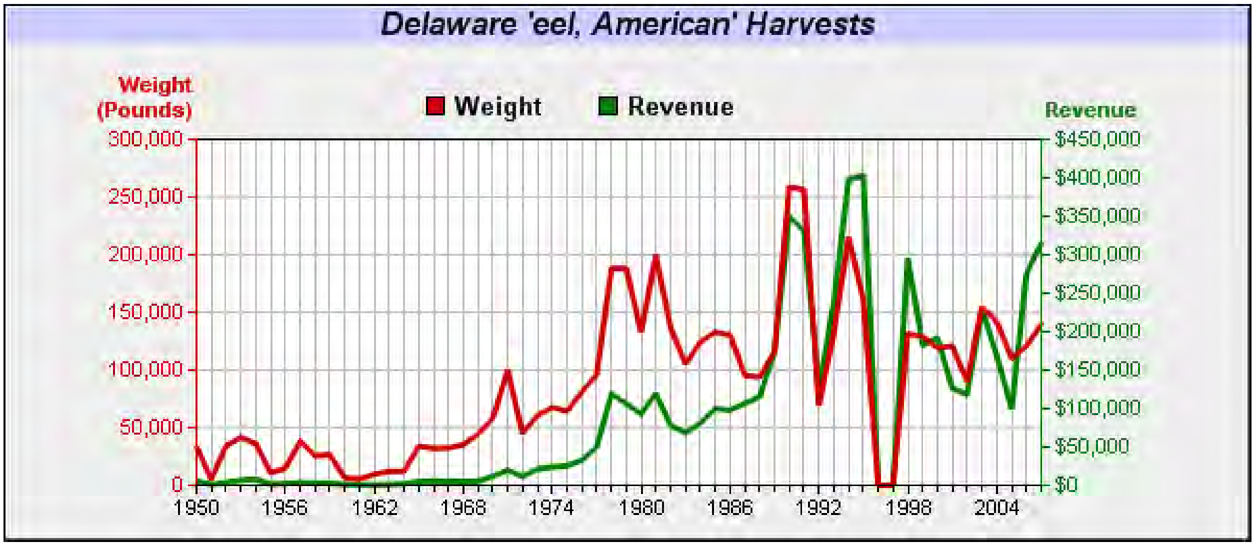
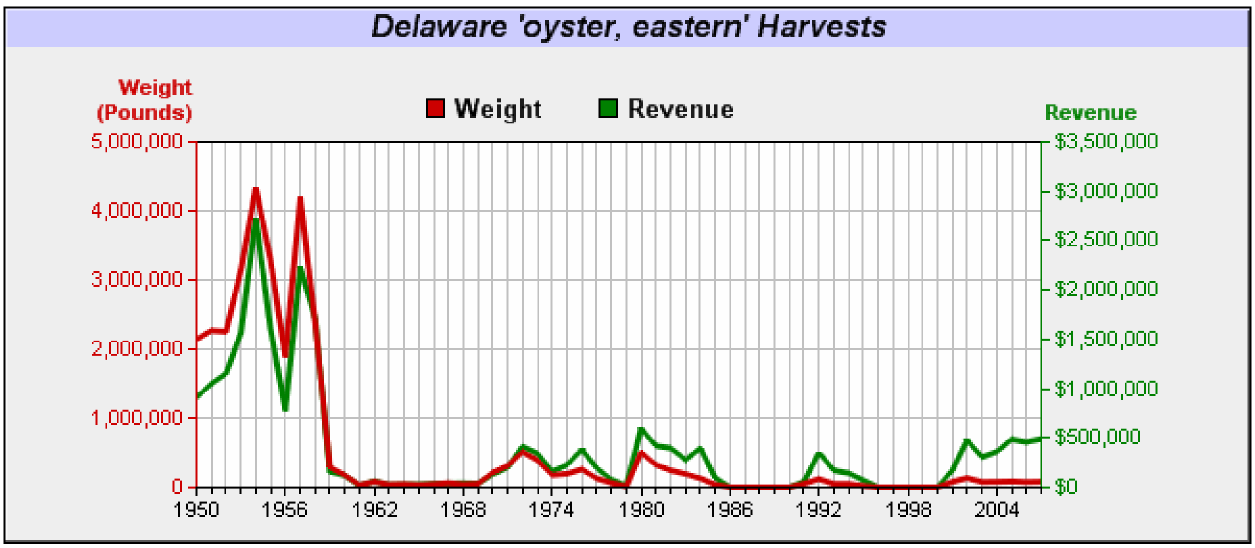


Figure 8. Fish landings in the Delaware Estuary (NMFS and NOEP 2007)





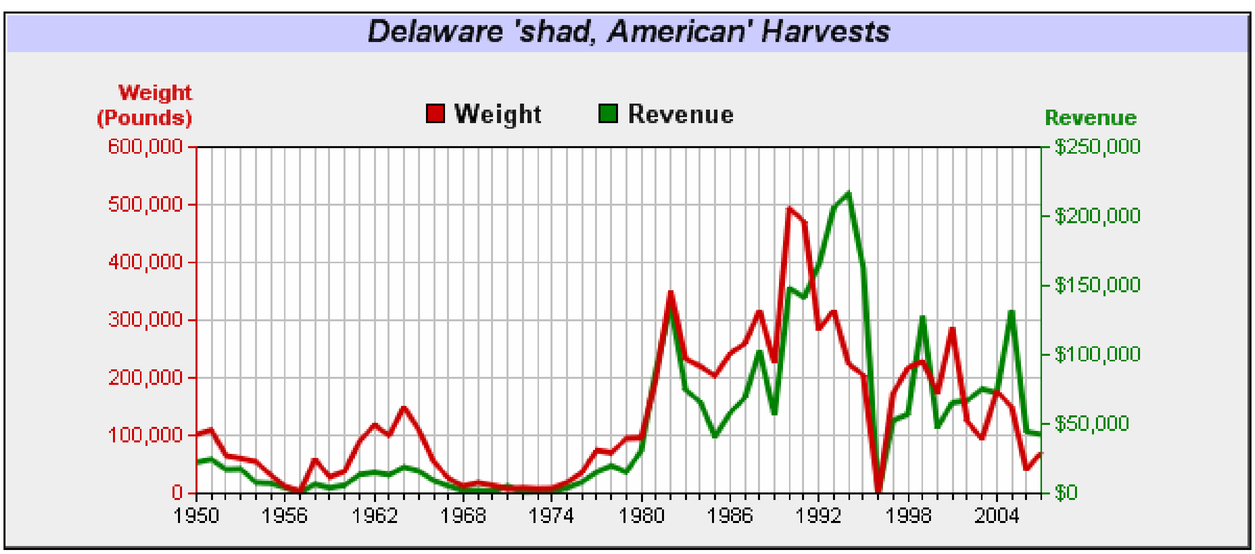
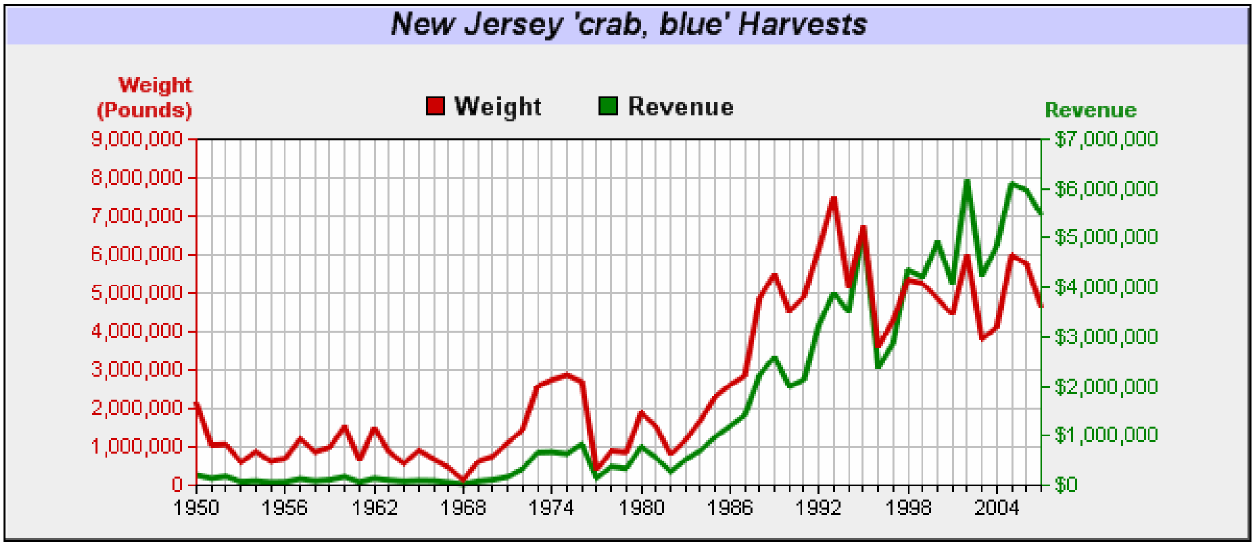
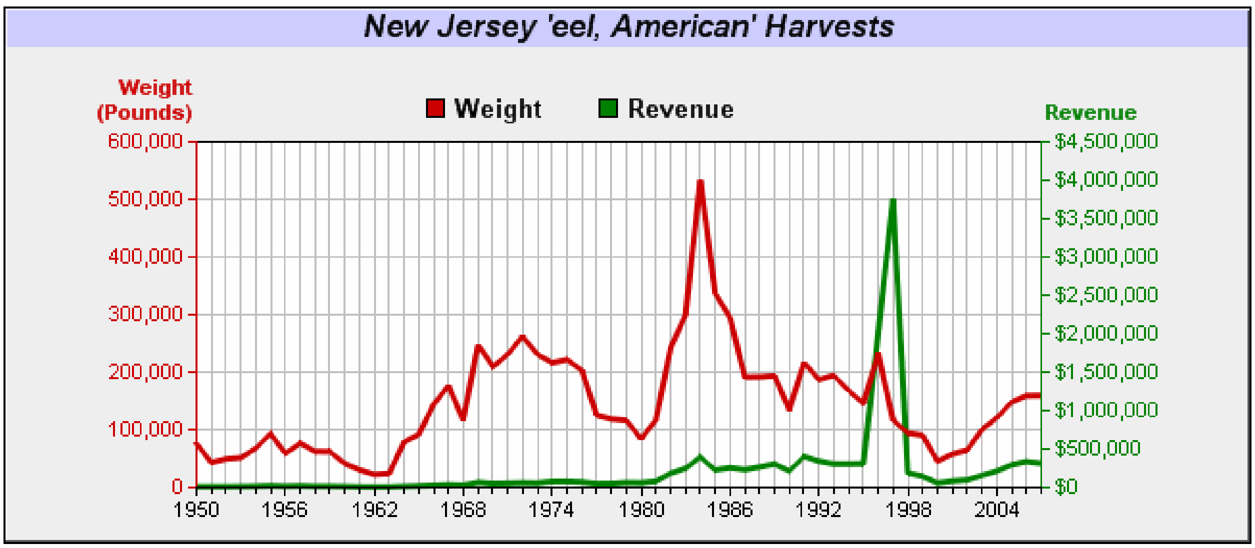


Figure 8. Fish landings in the Delaware Estuary, con't. (NMFS and NOEP 2007)





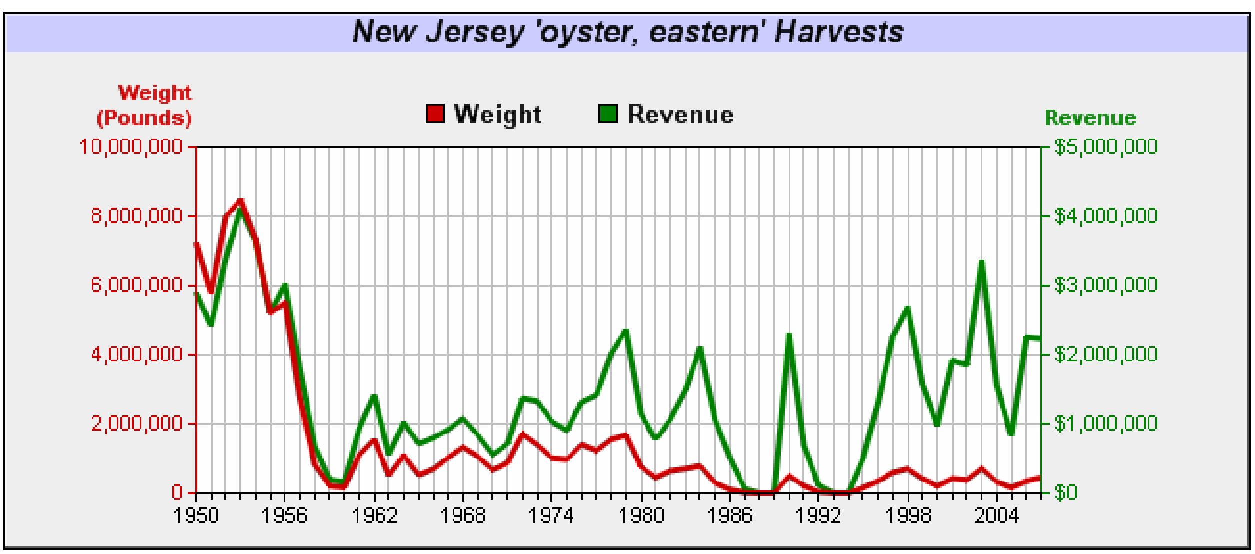
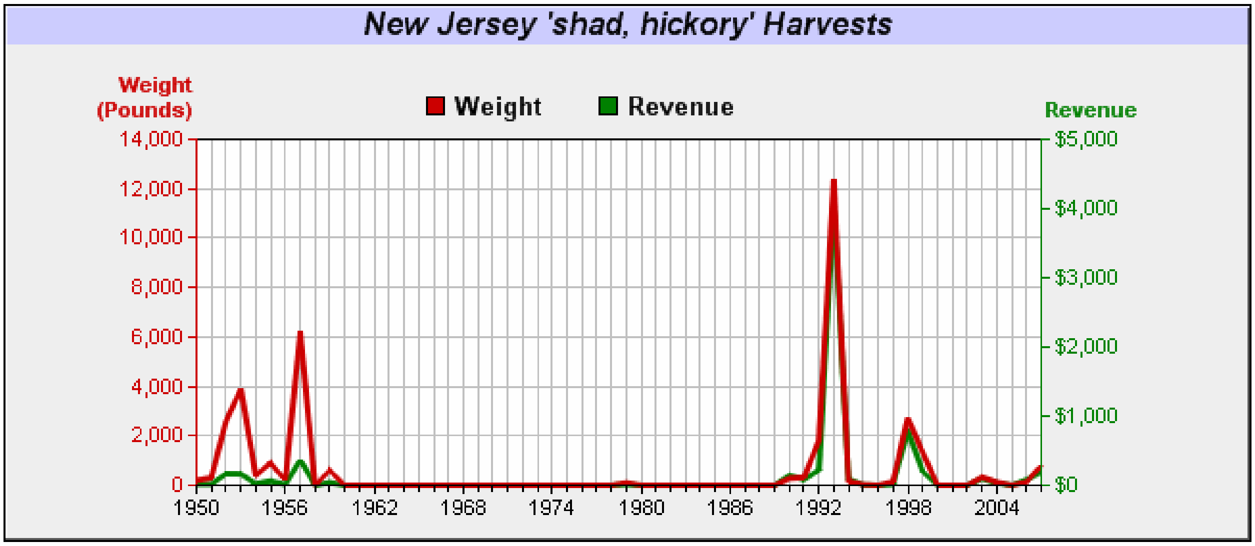
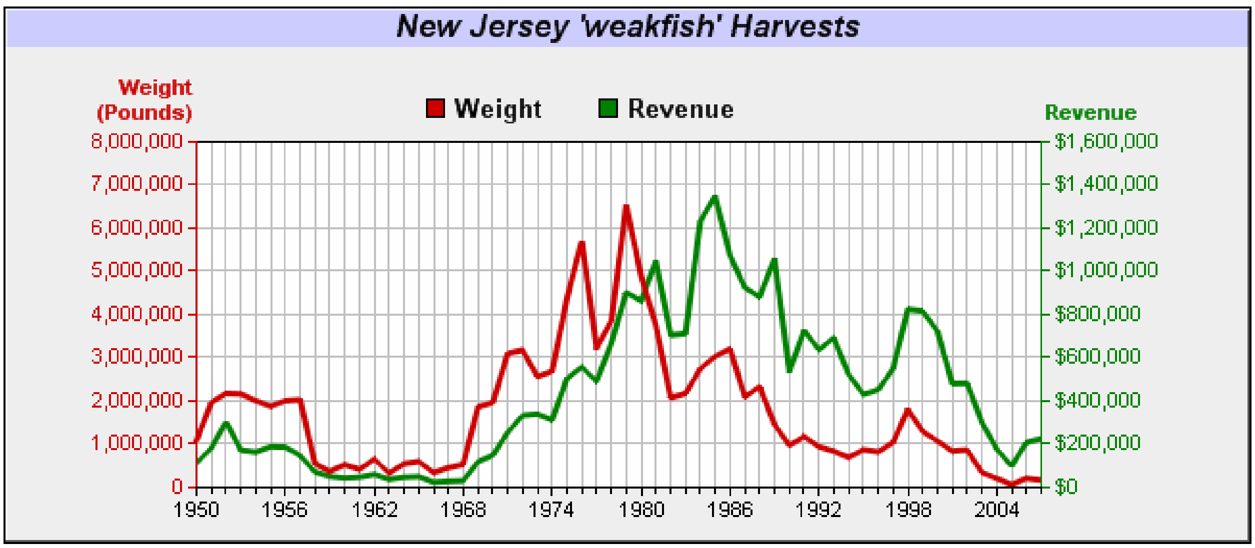


Figure 8. Fish landings in the Delaware Estuary, con't. (NMFS and NOEP 2007)





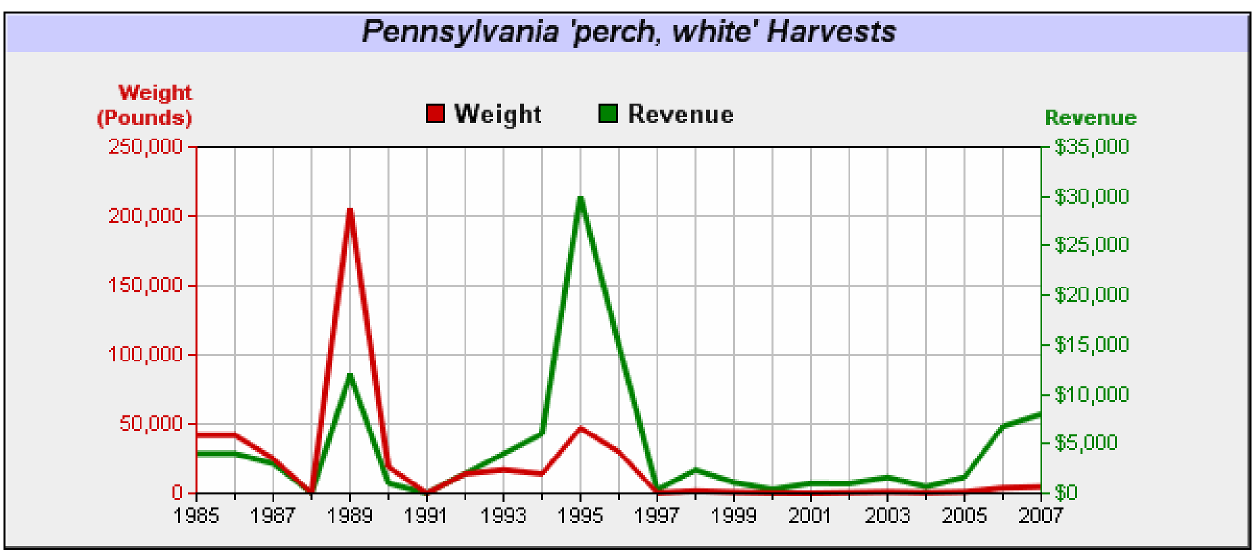


Figure 8. Fish landings in the Delaware Estuary, con't. (NMFS and NOEP 2007)

Fishing, Hunting, and Bird/Wild-life Watching

In Delaware, New Jersey, New York, and Pennsylvania, the U. S. Fish and Wildlife Service (2008) estimated the annual economic value of fishing, hunting, birding and wild-life/bird watching recreation was $9.2 billion in $2006. Trip-related expenditures include food and lodging, transportation, and hunting, fishing, and wildlife watching equipment. Most fishing, hunting, and birding/wildlife recreation occurs on farm, forest, wetlands, and open water ecosystems such as the Prime Hook and Bombay Hook National Wildlife Refuges in Delaware, the Cape May National Wildlife Refuge and Pine Barrens National Reserve in New Jersey, the Catskill Mountain Preserve in New York, the Delaware Water Gap National Recreation Area in Pennsylvania, and on the Delaware River and Bay and tributaries as well.

The Delaware Basin includes 50% of Delaware's land area, 40% of New Jersey's land area, 5% of New York State's land area, 14% of Pennsylvania's land area. Prorating based on the ratio of the area of the state within the basin to total state area, estimated economic value of fishing, hunting, and wild-life associated recreation in the Delaware Basin is $1,477 million/yr in $2006 or $134 million/yr in Delaware, $574 million/yr in New Jersey, $160 million/yr in New York, and $608 million/yr in Pennsylvania (Table 32).

Table 32. Value of fishing, hunting, and wildlife recreation in the Delaware River Basin

Recreation Activity	DE by state[1] ($M)	NJ by state[1] ($M)	NY by state[1] ($M)	PA by state[1] ($M)	DE in basin[2] ($M)	NJ in basin[2] ($M)	NY in basin[2] ($M)	PA in basin[2] ($M)	Del. Basin ($M)
Fishing	**97**	**752**	**926**	**1,291**	**48**	**301**	**46**	**181**	**576**
Trip Related	**49**	**471**	**585**	**299**	**24**	**188**	**29**	**42**	**284**
Equipment/other	**48**	**281**	**341**	**993**	**24**	**112**	**17**	**139**	**293**
Hunting	**41**	**146**	**716**	**1,609**	**21**	**58**	**36**	**225**	**340**
Trip-related	14	73	202	274	7	29	10	38	84
Equipment/other	28	73	514	1,335	14	29	26	187	256
Wildlife/Bird-watching	**131**	**537**	**1,568**	**1,443**	**65**	**215**	**78**	**202**	**561**
Trip Related	13	146	696	325	7	59	35	46	145
Equipment/other	118	391	872	1,118	59	156	44	156	415
Total	**269**	**1,436**	**3,209**	**4,343**	**134**	**574**	**160**	**608**	**1,477**

1. (USFWS 2008). Prorated by ratio of basin to state land area, Del. (50%), NJ (40%), NY (5%), and Pa. (14%).

Shad Fishing

The Pennsylvania Fish and Boat Commission (2011) published a fact sheet on the economic value of fishing and boating in Pennsylvania. A 1986 study of shad fishing on the Delaware River showed:

- Anglers spent an average of $25.40 per trip on gasoline, food, lodging, and tackle. Multiplied by 63,000 trips in 1986, anglers spent $1.6 million during a nine week season. Adjusting by 3% annually, the economic contribution by shad anglers would be about $3.2 million in $2010.
- The average shad angler was willing to pay $50 per day of shad fishing or $102 per day when adjusted to $2010 at 3% annually. Multiplied by 63,000 angler days, the annual economic value based on willingness to pay for the Delaware River shad fishery was $3.2 million in 1986 or $6.5 million adjusted to $2010.

Wild Trout Fishing

Releases from New York City reservoirs and excellent water quality in the forested Catskill watersheds contribute to a thriving cold water fishery in the upper Delaware Basin. Along the Beaverkill and East Branch, West Branch, and upper main stem of the Delaware River in New York, wild trout fishing contributes almost $18 million in annual business revenue, over $29 million in economic activity, and almost 350 jobs with $3.6 million in wages (Maharaj, McGurrin, and Carpenter, 1998).

Agriculture

In Delaware Basin counties, the USDA (2009) estimates the annual market value of agricultural products sold is $4.79 billion on 2,857,870 acres (4,465 sq mi) for crops (corn, wheat, oats, barley, soybeans, potatoes, and vegetables) and livestock and poultry (Table 33). On 1,926,524 acres (3,010 sq mi) of farmland within the Delaware Basin, the prorated annual market value of agricultural products sold is $3.37 billion or $1,750 per acre. The Delaware Basin covers 12,769 sq mi or just 13% of the combined land areas of Delaware (1,953 sq mi), New Jersey (7,417 sq mi), New York (47,214 sq mi), and Pennsylvania (44,816 sq mi) yet accounts for $3.37 billion or 27% of total annual farm products sold in the four states (Table 34).

Table 33. Farm products sold in the Delaware River Basin

State	State area (sq mi)	Area in Del. Basin (sq mi)	Ratio area basin/area state (%)	Farm products sold in state ($ million)	Farm products Del. Basin ($ million)	Products in basin/state (%)
Delaware	1,953	965	49%	1,083	636	59%
New Jersey	7,417	2,961	40%	987	603	61%
New York	47,214	2,555	5%	4,418	105	2%
Pennsylvania	44,816	6,280	14%	5,808	2,027	35%
Total	**101,400**	**12,761**	**13%**	**12,296**	**3,371**	**27%**

Table 34. Value of cropland and agriculture in the Delaware River Basin

County	Farmland by county[1] (ac)	Products sold by county[1] ($ million)	Products sold by county ($/ac)	Farmland in Del. Basin (ac)	Products sold in Del. Basin ($ million)
New Castle	51,913	45.7	880		
Kent	146,536	188.4	1,286		
Sussex	234,324	848.9	3,623		
Delaware	**432,773**	**1,083.0**	**2,502**	**254,143**	**636**
Burlington	85,790	86.3	1,006		
Camden	8,760	18.6	2,123		
Cape May	7,976	14.6	1,830		
Cumberland	69,489	156.9	2,258		
Gloucester	46,662	93.9	2,012		
Hunterdon	100,027	69.7	697		
Mercer	21,736	18.6	856		
Monmouth	44,130	105.4	2,388		
Ocean	9,833	11.5	1,170		
Salem	96,530	80.0	829		
Sussex	65,242	21.2	325		
Warren	74,975	75.5	1,007		
New Jersey	**631,150**	**752.2**	**1,192**	**505,507**	**602**
Broome	86,613	29.9	345		
Delaware	165,572	55.1	333		
Greene	44,328	16.4	370		
Orange	80,990	73.7	910		
Sullivan	50,443	42.1	835		
Ulster	75,205	65.6	872		
New York	**503,151**	**282.8**	**562**	**187,561**	**105**
Berks	170,760	367.8	2,154		
Bucks	58,012	70.6	1,217		
Carbon	20,035	8.9	444		
Chester	117,145	553.3	4,723		
Delaware	1,646	9.4	5,711		
Lackawanna	39,756	16.2	407		
Lancaster	326,648	1,072.1	3,282		
Lebanon	89,566	257.1	2,871		
Lehigh	72,737	72.1	991		
Luzerne	66,577	18.1	272		
Monroe	29,165	7.8	267		
Montgomery	28,563	30.0	1,050		
Northampton	68,252	31.8	466		
Philadelphia	150	0.5	3,333		
Pike	27,569	2.5	91		
Schuylkill	81,276	124.7	1,534		
Wayne	92,939	29.4	316		
Pennsylvania	**1,290,796**	**2,672.3**	**2,070**	**979,313**	**2,027**
Delaware Basin	**2,857,870**	**4,790.3**	**1,676**	**1,926,524**	**3,371**

1. Census of Agriculture 2007 (USDA 2009)

Forests

The U. S. Forest Service and Delaware Center for Horticulture (Nowak et al. 2008) estimated 7,137 acres of forests in New Castle County have a carbon storage benefit of $5.9 million ($827/ac) and air pollution removal of $1.9 million ($266/ac/yr). Applying these multipliers, Tables 35 and 36 indicate 4,343,190 (6,786 sq mi) of forests in the Delaware Basin have economic benefits from carbon storage ($3,591 million), air pollution removal ($1,155 million), building energy savings ($243 million), and carbon sequestration ($126 million).

Table 35. Economic benefits of forests in the Delaware River Basin

Forest Benefits	**New Castle County.**[1] ($/ac)	**Delaware. Basin**[2] ($ mil.)
Carbon storage	827	3,592
Carbon Sequestration	29	126
Air Pollution Removal	266	1,155
Building Energy Savings	56	243
Avoided Carbon Emissions	3	13

1. Nowak et al. 2008.
2. Computed for Delaware Basin forests (4,343,190 ac).

Table 36. Economic benefits of forests in the Delaware River Basin by state

Forest Benefits	**Del.** ($ mil.)	**NJ** ($ mil.)	**NY** ($ mil.)	**Pa.** ($ mil.)	**Del. Basin** ($ mil.)
Carbon Storage	78.8	564.8	1,147.5	1,800.8	3,592
Carbon Sequest.	2.8	19.8	40.2	63.1	126
Air Pollution Contr.	25.4	181.7	369.1	579.2	1,155
Energy Savings	5.4	38.2	77.7	121.9	243
Avoid Carbon Emiss.	0.3	2.0	4.2	6.5	13

Open Space

Public Parks

The Trust for Public Land (2009) found the 444-acre City of Wilmington park and recreation system provides annual economic value and savings to the public from health benefits from exercise in the parks ($9,734/ac), community cohesion benefit from people socializing in the parks ($2,383/ac), water pollution benefit from parks in treating stormwater ($921/ac), air pollution mitigation value from tree and shrub absorption ($88/ac).

Using value transfer from the data gathered for the City of Wilmington study, Table 37 indicates public parks (169 sq mi) within the Delaware Basin provide the following annual economic value:

- Health benefits from exercise in the parks ($1,283 million).
- Community cohesion benefit from people socializing in the parks ($314 million).
- Water pollution benefit from parks in treating stormwater ($121million).
- Air pollution mitigation value from tree and shrub absorption ($12 million).

Table 37. Value of public parks in the Delaware River Basin

State/county	Parks in Del. Basin (ac)	Health Benefits ($9,734/ac)	Community Cohesion ($2,383/ac)	Stormwater Benefit ($921/ac)	Air Pollution ($88/ac)
Kent	4,587	44,649,858	10,930,821	4,224,627	403,656
New Castle	12,440	121,090,960	29,644,520	11,457,240	1,094,720
Sussex	1,389	13,520,526	3,309,987	1,279,269	122,232
Delaware[1]	**18,416[1]**	**179,261,344**	**43,885,328**	**16,961,136**	**1,620,608**
Burlington	7,970	77,579,980	18,992,510	7,340,370	701,360
Camden	2,985	29,055,990	7,113,255	2,749,185	262,680
Cape May	2,911	28,335,674	6,936,913	2,681,031	256,168
Cumberland	2,640	25,697,760	6,291,120	2,431,440	232,320
Gloucester	4,868	47,385,112	11,600,444	4,483,428	428,384
Hunterdon	3,170	30,856,780	7,554,110	2,919,570	278,960
Mercer	8,283	80,626,722	19,738,389	7,628,643	728,904
Monmouth	105	1,022,070	250,215	96,705	9,240
Ocean	199	1,937,066	474,217	183,279	17,512
Salem	2,144	20,869,696	5,109,152	1,974,624	188,672
Sussex	2,961	28,822,374	7,056,063	2,727,081	260,568
Warren	5,563	54,150,242	13,256,629	5,123,523	489,544
New Jersey[2]	**31,800[2]**	**426,339,466**	**104,373,017**	**40,338,879**	**3,854,312**
Broome	389	3,786,526	926,987	358,269	34,232
Delaware	546	5,314,764	1,301,118	502,866	48,048
Orange	413	4,020,142	984,179	380,373	36,344
Sullivan	1,570	15,282,380	3,741,310	1,445,970	138,160
Ulster	50	486,700	119,150	46,050	4,400
New York[3]		**28,890,512**	**7,072,744**	**2,733,528**	**261,184**
Berks	3,979	38,731,586	9,481,957	3,664,659	350,152
Bucks	11,402	110,987,068	27,170,966	10,501,242	1,003,376
Carbon	2,820	27,449,880	6,720,060	2,597,220	248,160
Chester	12,020	117,002,680	28,643,660	11,070,420	1,057,760
Delaware	6,274	61,071,116	14,950,942	5,778,354	552,112
Lehigh	2,500	24,335,000	5,957,500	2,302,500	220,000
Luzerne	195	1,898,130	464,685	179,595	17,160
Monroe	875	8,517,250	2,085,125	805,875	77,000
Montgomery	14,138	137,619,292	33,690,854	13,021,098	1,244,144
Northampton	1,393	13,559,462	3,319,519	1,282,953	122,584
Philadelphia	9,689	94,312,726	23,088,887	8,923,569	852,632
Pike	125	1,216,750	297,875	115,125	11,000
Schuylkill	829	8,069,486	1,975,507	763,509	72,952
Wayne	350	3,406,900	834,050	322,350	30,800
Pennsylvania[4]	**58,331[3]**	**648,177,326**	**158,681,587**	**61,328,469**	**5,859,832**
Total	**108,547**	**1,282,668,648**	**314,012,676**	**121,362,012**	**11,595,936**

1. State, county, and municipal park land in Delaware from county and local comprehensive plans.
2. County and municipal park land from New Jersey State Comprehensive Outdoor Recreation Plan (SCORP).
3. County/municipal parks in New York from county and local comprehensive plans.
4. County/municipal parks in Pennsylvania from DVRPC 2007 & Berks/Schuylkill counties comprehensive plans.

Delaware Water Gap National Recreation Area

The Delaware Water Gap National Recreation Area (DWGNRA) preserves almost 109 square miles of forest and floodplain along 40 miles of the upper Delaware River and 29 miles of the Appalachian Trail. Stynes and Sun (2002) estimated the DWGNRA had 4,867,272 recreation visits in 2001 including 487,727 local day trips, 3,650,455 non-local day trips, 486,727 motel visits, and

243,364 camping overnights. Total visitor spending in the DWGNRA in 2001 was $100 million including $12.4 million for local day trips, $46.5 million for non-local day trips, $30.9 million for motels, and $10.3 million for camping overnights. In 2001, the DWGNRA generated $106 million in sales, and 7,563 direct/indirect jobs with $100 million in wages.

Marcellus Shale Natural Gas

The U.S. Geological Survey concluded that the Marcellus Shale Formation is a voluminous economic resource that lies under 4,700 square miles or 36% of the Delaware River Basin. Drilling for natural gas through the hydraulic fracturing process requires large quantities of water and has the potential to consume sizable tracts of land in the forested headwaters of the Delaware Basin (Figure 9). Hydraulic fracturing requires pumping water under high pressure to open fractures in the shale to allow natural gas to flow to the well. The hydrofracturing water must be recovered and treated before disposal to surface and ground waters. In forests, natural gas well drilling can require clearing of pads that range from 3 to 5 acres in area.

The DRBC is considering revisions to Article 7 of the Water Quality Regulations to protect the water resources of the Delaware Basin during construction and operation of natural gas projects with the following considerations:

- Gas drilling projects in the Marcellus Shale may reduce the flow in streams and aquifers.
- On-site drilling operations may potentially release pollutants into ground or surface water.
- The recovered hydrofracturing water must be treated and disposed of properly.

The Marcellus Shale Formation covers 54,000 square miles and lies up to a mile and a half below parts of Kentucky, New Jersey, New York, Ohio, Pennsylvania, and West Virginia (Figure 10). The Marcellus Shale lies under 4,700 square miles or 36% of the Delaware River Basin in New York, Pennsylvania, and a small tip of New Jersey (Figure 11). About 8.7% of the Marcellus Shale Formation lies within the Delaware River Basin (4,700 sq mi/54,000 sq mi).

The U.S. Geological Survey (Coleman et al. 2011) estimated the entire 54,000 square-mile Marcellus Shale Formation potentially contains a mean volume of 84 trillion cubic feet of recoverable natural gas with a range of 43 tcf (95 percentile) to 144 tcf (5 percentile). If the Delaware River Basin covers 4,700 sq mi or 8.7% of the Marcellus Shale, then by proportion approximately 7.3 trillion cubic feet of natural gas is potentially recoverable within the basin boundary (0.087 x 54,000). These estimates can vary as the thickness of Marcellus Shale in the Delaware Basin generally increases to the north toward the New York/Pennsylvania border and may range from 50 feet thick near Stroudsburg to more than 250 feet thick at Lackawaxen in Wayne County, Pennsylvania (Figure 12).

The U.S. Energy Information Administration (2011) reported the 2010 mean natural gas wellhead price was $4.16/1000 cf. The price of natural gas for residential customers was $11.21/1000 cf. At these unit prices, the estimated value of natural gas from the Marcellus Shale Formation within the Delaware River Basin is $30.4 billion at the wellhead and $81.8 billion when sold to residential customers (Tables 38 and 39).

Environmental economists classify natural gas as a nonrenewable resource with finite stock value over a defined time frame (say 25 or 50 years). Assuming the natural gas can be recovered within 25 years, the annual value of the Marcellus Shale gas recoverable from within the Delaware Basin is $1.2 billion/year at the wellhead and $3.3 billion/year when sold to residential customers.

Table 38. Wellhead value of Marcellus shale natural gas within the Delaware River Basin

State/Basin	Area Marcellus Shale (sq mi)	Wellhead Natural Gas Price[1] ($/1000 cf)	Volume Natural Gas[2] (tcf)	Wellhead Natural Gas Value ($ billion)	Wellhead Natural Gas Value[3] ($ billion/yr)
Pennsylvania	2,338	$4.16	3.6	$15.0	$0.6
New York	2,362	$4.16	3.7	$15.4	$0.6
Delaware Basin	**4,700**	**$4.16**	**7.3**	**$30.4**	**$1.2**

1. EIA 2010. 2. USGS 2011. 3. Assumes 25 year natural gas recovery period.

Table 39. Residential value of Marcellus shale natural gas within the Delaware River Basin

State/Basin	Area Marcellus Shale (sq mi)	Residential Natural Gas Price[1] ($/1000 cf)	Volume Natural Gas[2] (tcf)	Residential Natural Gas Value ($ billion)	Wellhead Natural Gas Value[3] ($ billion/yr)
Pennsylvania	2,338	$11.21	3.6	$40.4	$1.6
New York	2,362	$11.21	3.7	$41.5	$1.7
Delaware Basin	**4,700**	**$11.21**	**7.3**	**$81.8**	**$3.3**

1. EIA 2010. USGS 2011. 3. Assumes 25 year natural gas recovery period.

On a per volume basis, the value of untreated drinking water in streams and wells (at $7.48/1000 cf or $1.00/1000 gal) exceeds the value of natural gas at the wellhead (at $4.16/1000 cf) in the Delaware Basin. The total value of untreated drinking water from streams/wells (1,803 mgd) in the Delaware Basin is $0.7 billion/year, less than the estimated value of natural gas recoverable at the wellhead ($1.2 billion/year). The value of treated drinking water in the basin (at $35.70/1000 cf or $4.78/1000 gal) is $3.1 billion/year which is comparable to the total natural gas value sold to residential customers or $3.3 billion/year (Table 40).

Table 40. Value of Marcellus shale gas compared to drinking water in the Delaware River Basin

Price/ Value	Natural Gas	Drinking Water
Quantity	7.3 trillion cf	1,803 mgd
Unit Price Wellhead Gas or Untreated Drinking Water	$4.16/1000 cf	$7.48/1000 cf
Total Value Wellhead Gas or Untreated DrinkingWater	$1.2 billion/yr	$0.7 billion/yr
Unit Price Residential Gas or Treated Drinking Water	$11.21/1000 cf	$35.70/1000 cf
Total Value Residential Gas or Treated Drinking Water	$3.3 billion/yr	$3.1 billion/yr

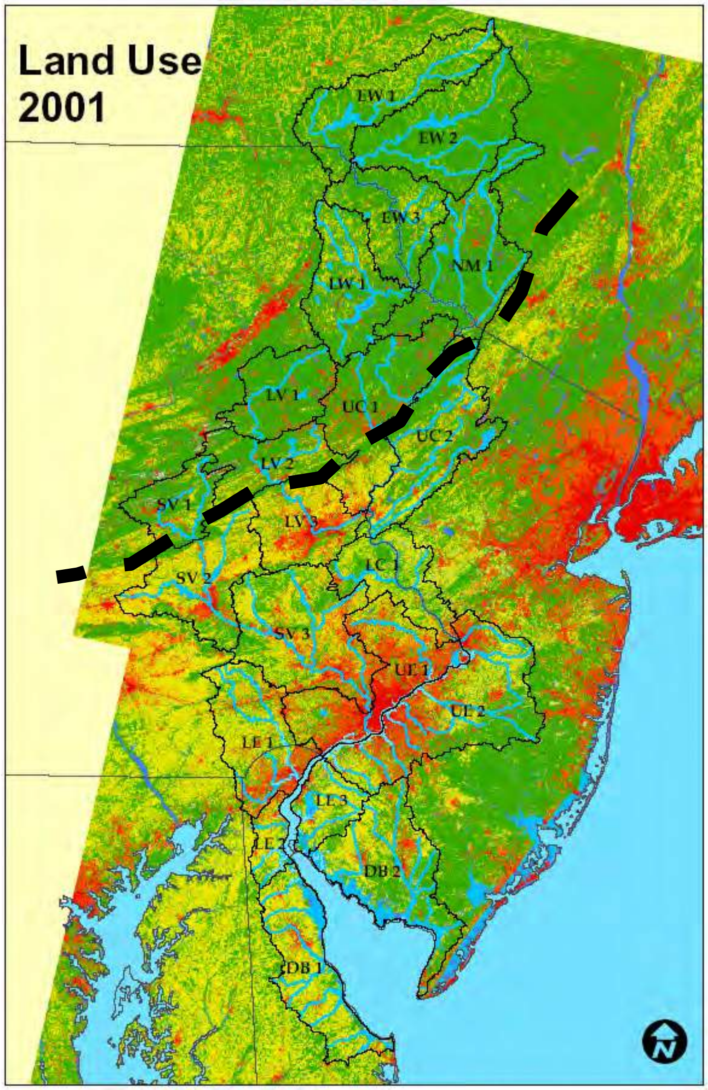


Figure 9. Land use including forested headwaters in the Delaware Basin (Marcellus Shale southerly boundary delineated as dashed line).

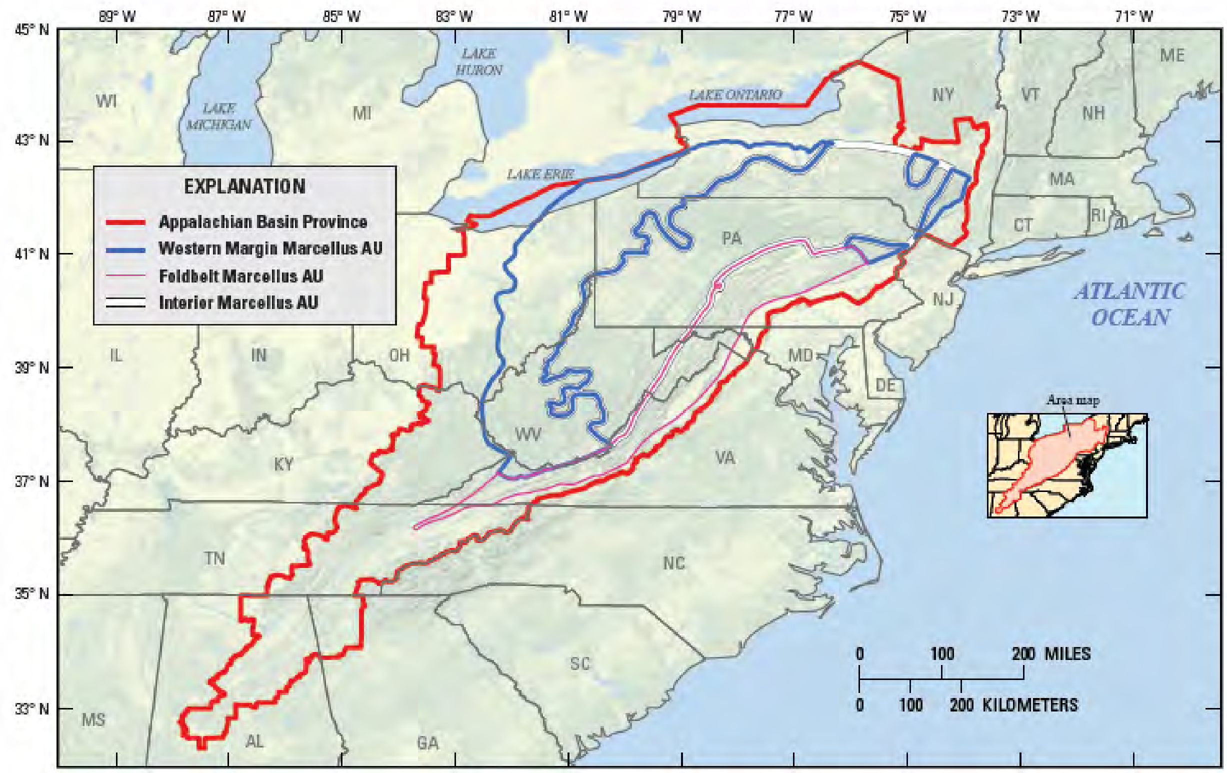


Figure 10. Marcellus Shale Formation in the Appalachian Basin Province (USGS 2011)

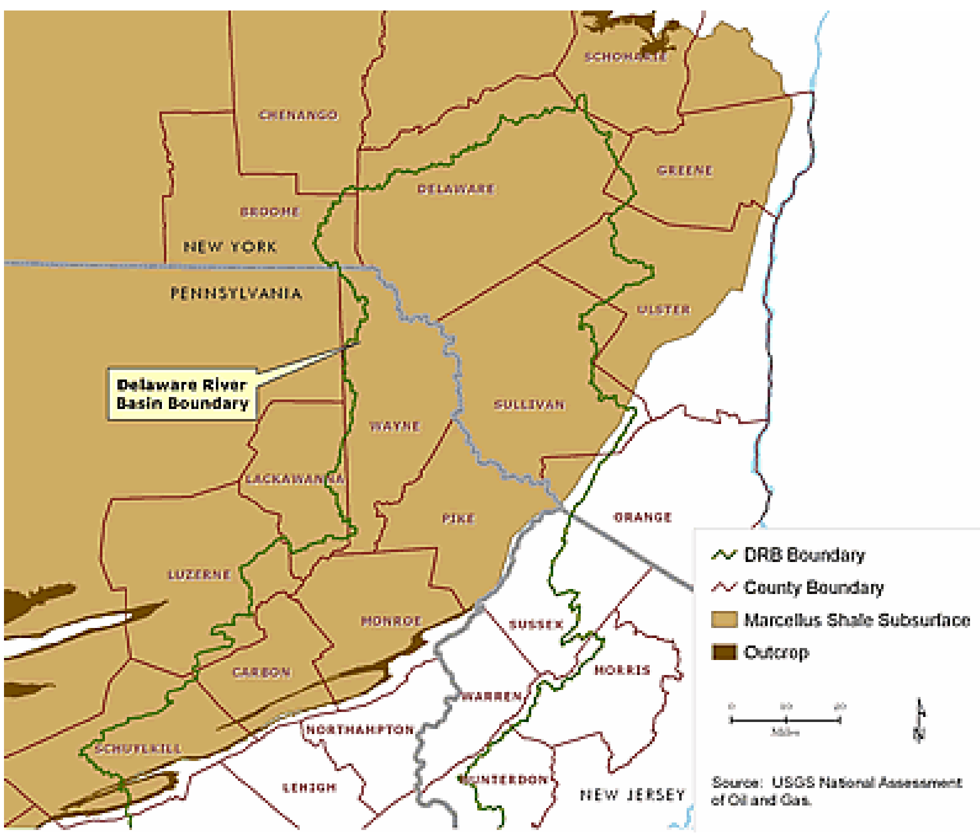


Figure 11. Marcellus Shale Formation within the Delaware River Basin (USGS)

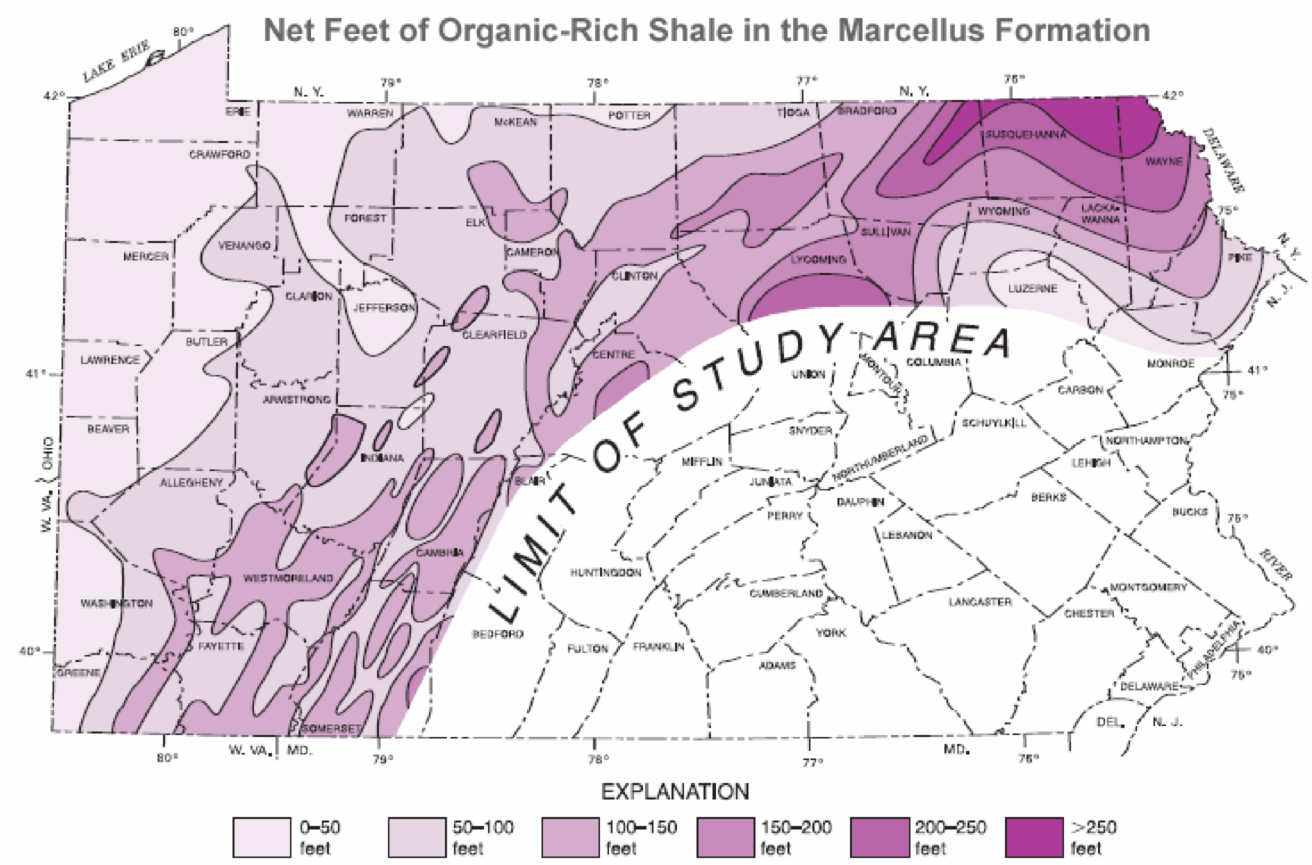


Figure 12. Thickness of Marcellus shale in Pennsylvania
(Pennsylvania Geological Survey)

Maritime Transportation

Navigation

The 130-mile long Delaware River and Bay ship channel from Cape Henlopen to the head of navigation at Trenton has significant instream navigation use value. The Delaware River port from Wilmington to Chester, Paulsboro, Camden, and Philadelphia is the 6th largest port in the U.S. based on imports. The volume of the 720 square mile Delaware Estuary at mean depth of 32 feet is 14.7 million ac-ft or 4.8 trillion gallons. A study of the economic value of freshwater in the U.S. estimated the median value of instream navigation uses is $10/ac-ft in $1996 (Frederick et al. 1996) or $15/ac-ft in $2010 based on 3% annually. Accordingly, the instream navigation value of the Delaware River and Bay (14.7 million ac-ft) from the ocean to head of tide at Trenton is $220 million.

C&D Canal

The 35-feet deep Chesapeake & Delaware Canal is a valuable commercial conduit that flows through the Delaware Basin in Delaware and carries 40% of all ship traffic to/from the Port of Baltimore. The C&D Canal trims 300 miles from the trip for ships that would otherwise sail up the Chesapeake Bay to Baltimore from the ocean. Normally 6 to 35 ships per day sail through the C&D Canal.

The Port of Baltimore is responsible for 16,700 direct jobs and $3.7 billion in wages (Maryland Port Administration 2010). Of 360 ports in the U.S., Baltimore is No. 1 in forest product, gypsum, and sugar imports and No. 2 in automobile exports. In 2009, the Port of Baltimore was 11th among all U.S. port districts with $10.8 billion in exports after Seattle (9th) and San Francisco (10th). Baltimore was 12th in the U.S. with $19.4 billion in imports after Norfolk (10th) and Port Arthur, Texas (11th). If 40% of all Baltimore-bound ship traffic sails through the C&D Canal, then 40% of the economic activity generated by the port can be indirectly attributed to this avenue of commerce that cuts through Delaware River Basin in Delaware (Table 41).

Table 41. Economic activity generated by Port of Baltimore through the C&D Canal

Activity	Port of Baltimore[1]	C&D Canal[2]
Jobs	16,700	6,700
Wages	$3.7 billion	$1.5 billion
Imports	$19.4 billion	$7.8 billion
Exports	$10.8 billion	$4.3 billion

1. Maryland Port Authority 2010. 40% of Baltimore-bound shipping sails through C&D Canal.

Port Activity

For over 300 years since the time of William Penn, the Delaware River has been an economic engine that is now the largest freshwater port in the world. The Economy League of Greater Philadelphia (2008) concluded that Delaware River ports from Wilmington to Philadelphia to Trenton:

- Collectively is the largest freshwater port in the world with $2.4 billion in total economic output.
- Generate $81 million in tax revenues to Delaware, Pennsylvania, New Jersey (Table 42).
- Import 1/2 of the nation's cocoa beans, 1/3 of the bananas, and 1/4 of all fruit and nuts.
- Rank 5th among ports in the USA in import cargo value and 20th in export value.
- In Chester, Philadelphia, Wilmington, Camden and Paulsboro handled 16% of container trade in the U.S. and 51% of container trade value nationwide.
- Biggest commodity is petroleum that accounts for 65% of the port's imports while fruits and nuts account for 4%.

Table 42. Tax revenues from Delaware River ports, 2005
(Economy League of Greater Philadelphia 2008)

Type	DE	NJ	PA	Total
Individual Income Tax	$2,538,803	$6,679,380	$13,102,579	$22,320,762
Sales and Use Tax		5,326,255	13,851,735	$19,177,990
Corporate Income Tax	888,055	1,988,447	3,632,195	$6,508,697
Selective Tax	1,075,499	2,674,104	7,807,469	$11,557,072
Other State Tax, License, Fees	2,536,226	1,597,420	5,199,444	$9,333,090
Total State and Local Tax	**7,038,582**	**18,266,605**	**55,974,357**	**$81,279,544**

The Economy League reports that nearly 2,900 ships (8 per day) docked at Delaware River ports in 2006, up 10% from 1995. Most shipping traffic were tankers, containers, bulk, refrigerated (meat/fruits/vegetables) and auto transport vessels (Table 43).

Table 43. Delaware River port vessel calls, 1996-2000 (Economy League of Greater Philadelphia 2008)

Year	General	Container	Roll on	Refrg	Bulk	Tanker	Chem	Auto	Passengr	Total
1995	304	368	84	333	405	812	138	110	16	2,570
2006	248	581	78	373	402	861	144	121	39	2,847
change	-56	213	-6	40	-3	49	6	11	23	277
% change	-18%	-58%	-7%	12%	-1%	6%	4%	10%	144%	11%

Top Delaware River port exports (Table 44) are motor vehicles (31% and petroleum products (12%) and top imports are petroleum (65%) and iron and steel (7%).

Table 44. Top exports and imports at Delaware River ports (Economy League 2008)

Cargo	Exports	Imports
Motor Vehicles	31%	
Petroleum	12%	65%
Precious stones/Metals	7%	
Industrial Machinery	6%	2%
Plastics	6%	
Iron and Steel		7%
Fruits and Nuts		4%
Meat		3%

In 2005, Delaware River ports at Philadelphia, Chester, and Camden were the 6th, 35th, and 37th largest ports in the U.S. based on imports of goods and cargo (Table 45). The five ports along the Delaware River had combined imports of $41 billion, the 5th largest port in the U.S. after Los Angeles, Newark (NJ), Houston, and Long Beach (CA) and ahead of Seattle, Norfolk (VA), and Baltimore. The five ports along the Delaware had combined exports of $6.4 billion making it the 20th largest port in the USA after Oakland (CA) and Baltimore but ahead of Charleston (SC).

Table 45. Rank of Delaware River imports/exports in United States by value of goods, 2005

Imports Rank in U.S.	Port	Imports ($))
6	Philadelphia	$29,500,000,000
35	Chester	$5,700,000,000
37	Wilmington	$5,500,000,000
79	Paulsboro	$250,000,000
103	Camden	67,000,000
5	**Delaware R.**	**$41,017,000,000**
Exports Rank in U.S.	**Port**	**Exports ($)**
22	Philadelphia	$2,400,000,000
24	Wilmington	$2,200,000,000
32	Chester	$1,600,000,000
74	Camden, NJ	$150,000,000
84	Paulsboro, NJ	$89,000,000
20	**Delaware R.**	**$6,439,000,000**

4. Ecosystem Services

Other Studies

Data from the following studies were examined to estimate the value of ecosystem services in the Delaware River Basin in Delaware, New Jersey, New York, and Pennsylvania:

- Cecil County green infrastructure study by the Conservation Fund, Annapolis, Md (2007).
- New Jersey Department of Environmental Protection with the University of Vermont (2007)
- Ecosystem services value of forests by the Wilderness Society (2001)
- Ecosystem services value of Peconic Estuary watershed by University of Rhode Island (2002)
- U.S. National Wildlife Refuge System by Univ. of Maryland and Nature Conservancy (2008)
- Economic value of ecosystem services in Massachusetts by the Audubon Society (2003).

Ecosystem services include air filtration, water filtration, recycling nutrients, soil conservation, pollinating crops and plants, climate regulation, carbon sequestration, flood/stormwater control, and hydrologic cycle regulation. Ecological resources provide marketable goods and services such as timber, fish and wildlife recreation, hiking, and boating/kayaking. A Cecil County, Md. study by the Conservation Fund (Table 46) found the largest ecosystem services values result from stormwater/flood control, water supply, and clean water functions (Weber 2007).

Table 46. Ecosystem services values for Cecil County, Maryland (Weber 2007)

Ecosystem Service	Upland Forest ($/ac/yr)	Riparian Forest Wetlands ($/ac/yr)	Nonriparian Wetlands ($/ac/yr)	Tidal Marsh ($/ac/yr)
Carbon sequestration	31	65	65	65
Clean air	191	191	191	
Soil and peat formation	17	946	450	1,351
Stormwater/flood control	679	32,000	32,000	1,430
Water supply	8,630	8,630	8,630	
Clean water	1,100	1,925	1,100	11,000
Erosion/sediment control	151	3,418	151	12,700
Water temperature regulation		4,450		
Pest control	50	50	50	
Pollination	75	75	75	
Wood products	142			
Recreation, fish, wildlife habitat	486	534	534	544
Community services savings	439	439	439	439
Increase in property values	42	42		
Total	**12,033**	**52,765**	**43,685**	**28,146**

The New Jersey Department of Environmental Protection (2007) partnered with the University of Vermont and estimated the value of New Jersey's natural capital was $20 billion/year plus or minus

$9 billion/year in $2004 with a net present value of $681 billion based on a discount rate of 3% calculated in perpetuity (over 100 years in the future). Natural capital is the sum of goods (commodities like water, crops, and timber that can be sold) and services (functions like flood control, water filtration, and wildlife/fisheries habitat) provided by watershed ecosystems such as wetlands, forests, farms, and open water. In addition to these direct benefits, ecosystems also provide indirect benefits such as ecotourism by hunters, fishermen, boaters, and hikers who spend money to visit natural sites and realize value from improved water quality and habitat. Table 47 summarizes total ecosystem goods and services in New Jersey. Farm products, fish, minerals, and water supply provide the most ecosystem goods. Nutrient cycling, soil disturbance regulation, water regulation, habitat, aesthetic/recreational, waste treatment, and water supply provide the greatest ecosystem services.

Table 47. Ecosystem goods and services provided by New Jersey natural capital (NJDEP 2007)

Ecosystem	$ million/yr	%
Natural Goods	**$5,864**	**100%**
Farm products	3,676	63%
Commercial/recreational fish	958	16%
Minerals	587	10%
Raw Water	381	7%
Saw timber	147	3%
Fuelwood	95	2%
Game/fur animals	21	1%
Ecoservices	**$19,803**	**100%**
Nutrient cycling	5,074	26%
Disturbance regulation	3,383	17%
Water regulation	2,433	12%
Habitat	2,080	11%
Aesthetic/recreational	1,999	10%
Waste treatment	1,784	9%
Water supply	1,739	9%
Cultural//spiritual	778	4%
Gas/climate regulation	246	1%
Pollination	243	1%
Biological control	35	<1%
Soil formation	8	<1%

The Wilderness Society (Krieger 2001) concluded forest ecosystem services values from climate regulation, water supply, water quality, and recreation benefits totaled $392/ac in $1994 or $631/ac in $2010 at a 3% annual discount rate (Table 48).

Table 48. Forest ecosystem service values for U.S. temperate forests (Krieger 2001)

Ecosystem Good or Service	1994 Value ($/ac)	2010 Value[1] ($/ac)
Climate regulation	57.1	91.9
Disturbance regulation	0.8	1.3
Water regulation	0.8	1.3
Water supply	1.2	1.9
Erosion and sediment control	38.8	62.5
Soil formation	4.0	6.4
Nutrient cycling	146.1	235.2
Waste Treatment	35.2	56.7
Biological Control	0.8	1.3
Food Production	17.4	28.0
Raw Materials	55.8	89.8
Genetic Resources	6.5	10.5
Recreation	26.7	43.0
Cultural	0.8	1.3
Total	**392.1**	**631.3**

1. $2010 computed at 3% annually.

A contingent value study by University of Rhode Island economists found natural resources values in the Peconic Estuary watershed in Suffolk County on Long Island New York ranged from $6,560/ac for wetlands to $9,979/ac for farmland in $1995 (Johnston et al. 2002). The University of Maryland studied the National Wildlife Refuge System and determined ecosystem values of freshwater wetlands and forests were $6,268/ac and $845/ac, respectively (Ingraham and Foster 2008). The Audubon Society found the economic value of ecosystems in Massachusetts ranged from $984/ac for forests to $15,452/ac for saltwater wetlands (Breunig 2003).

According to the 2007 USDA Census of Agriculture (2009) the market value of agricultural crops, poultry, and livestock sold from 1,926,524 acres of farmland in the Delaware River Basin was $3.37 billion or $1,676/ac. The market value of agriculture from 254,143 acres of farmland in Delaware in the basin was $636 million or $2,502/ac. The market value of agriculture from 505,507 acres of farmland in New Jersey was $602 million or $1,192/ac. The market value of agriculture from 187,561 acres of farmland in New York in the basin was $105 million or $562/ac.
The market value of agriculture from 979,313 acres of farmland in Pennsylvania counties in the basin was $2.0 billion or $2,070/ac.

Table 49 compares ecosystem services values ($/acre) from other studies. Data from the NJDEP/University of Vermont study are used for value transfer since the Delaware Basin includes New Jersey ecosystems and two adjacent states in the watershed (Del. and Pa.) share a similar climate (humid continental) at 40 degrees north in latitude, similar physiographic provinces (Piedmont/Coastal Plain) and similar aquifers, soils, and ecosystems. Farmland natural goods values are estimated from market values from the 2007 USDA Census of Agriculture. Cecil County, Maryland occupies a small sliver of the Delaware Basin and utilized higher ecosystem values on a per acre basis for forests and wetlands than the other studies. The NJDEP ecosystem service estimates ($/ac) are lower than Cecil County values for wetlands/forests and Mass Audubon values for wetlands but higher than Wilderness Society values for forests and U. S. Wildlife Refuge values for freshwater wetlands and forests. Values from previous studies were adjusted to $2010 based on 3% annually. Net present values were calculated based on an annual discount rate of 3% in perpetuity (over 100 years in the future).

Table 49. Comparison of ecosystem service value studies

Ecosystem	Cecil Co. Maryland 2006 ($/ac/yr)	New Jersey DEP 2004 ($/ac/yr)	Wilderness Society 2001 ($/ac/yr)	Peconic Estuary 1995 ($/ac/yr)	US Wildlife Refuge 2008 ($/ac/yr)	Mass Audubon 2003 ($/ac/yr)	USDA Census[1] 2007 ($/ac/yr)
Freshwater wetland	43,685	11,802			6,268	15,452	
Marine		8,670					
Farmland		6,229		9,979		1,387	1,676
Forest land	12,033	1,714	641		845	984	
Saltwater wetland	28,146	6,269		$6,560		12,580	
Undeveloped				$2,080			
Urban		296					
Beach/dune		42,149					
Open freshwater		1,686			217	983	
Riparian buffer	52,765	3,500					
Shellfish areas				$4,555			

1. Value of goods only as measured by agricultural crops, livestock, and poultry sold.

Delaware Basin

The estimated value of natural goods and services provided by ecosystems in the Delaware River Basin (12,742 sq mi) is $21 billion ($2010) with a net present value (NPV) of $683 billion (Table 50). The ecosystems services value of the Delaware portion of the Delaware Basin (965 sq mi) is $2.5 billion ($2010) with a NPV of $81.4 billion (Figure 13). The ecosystems services value of the New Jersey portion of the Delaware Basin (2,960 sq mi) is $6.6 billion ($2010) with a NPV of $213.4 billion. The ecosystems services value of the New York portion of the Delaware Basin (2,556 sq mi) is $3.5 billion ($2010) with a NPV of $113.6 billion. The ecosystems services value of the Pennsylvania portion of the basin (6,290 sq mi) is $8.6 billion ($2010) with a NPV of $279.6 billion. NPV is based on an annual discount rate of 3% over a perpetual life time (>100 years).

Natural goods are commodities that can be sold such as water supply, farm crops, fish, timber, and minerals). Natural services provide ecological benefits to society such as flood control by wetlands, water filtration by forests, and fishery habitat by beach and marine areas. Ecosystems within the Delaware Basin are comprised of forests (53%), farmland (24%), freshwater wetlands (5%), saltwater wetlands (2%), and open water/marine (1%). Over 15% of the Delaware Basin is urban (Figure 14).

Farms, freshwater wetlands, forests, and saltwater wetlands provide the highest total ecosystems goods and services values (Table 51 and Figures 15 and 16). Ecosystems that provided the highest natural good values are farmland ($3.2 billion or $1,676/ac/ yr), followed by forest ($1.2 billion or $275/ac), and freshwater wetlands ($114 million or $270/ac). The highest natural ecosystem services values are provided by forests ($7.4 billion or $1,703/ac) followed by freshwater wetlands

($5.6 billion or $13,351/ac), farmland ($1.6 billion or $827/ac), and saltwater wetlands ($1.0 billion or $7,076/ac).

The DB2 Delaware Bay ($2,497,635,761), UE2 New Jersey Coastal Plain ($2,093,235,974), DB1 Delaware Bay ($1,922,732,778), NM1 Neversink R. ($1,212,219,295), EW2 West Branch Del. R. ($1,137,547,038), UC1 Pocono Mt. ($1,106,108,992), UC2 NJ Highlands ($1,072,263,808), SV3 Schuylkill above Philadelphia ($1,098,758,690), and LW1 Lackawaxen R. ($1,006,865,455) watersheds each provide over $1 billion in annual ecosystem services value (Table 52 and Figure 17).

Watersheds with the highest value of annual ecosystem services per acre include the DB2 Delaware Bay ($4,991/ac), DB1 Delaware Bay ($4,797/ac), LE3 Salem River ($4,288/ac), LE2 C&D Canal ($3,941/ac), UE2 New Jersey Coastal Plain ($3,205/ac), LW1 Lackawaxen R. ($2,631/ac), NM1 Neversink R. ($2,321/ac), SV2 Schuylkill above Valley Forge ($2,276/ac), and LV1 Lehigh River above Lehighton ($2,263/ac) as these systems have high amounts (over 75%).of forests, wetlands, and farm habitat (Figure 18).

The above estimates do not include the ecosystem services value of open water (720 sq mi) in the tidal Delaware River and Bay between the shores of Delaware, Pennsylvania, and New Jersey. The ecosystem services value of open water habitat in the river and bay is $61 billion or $1,946/ac.

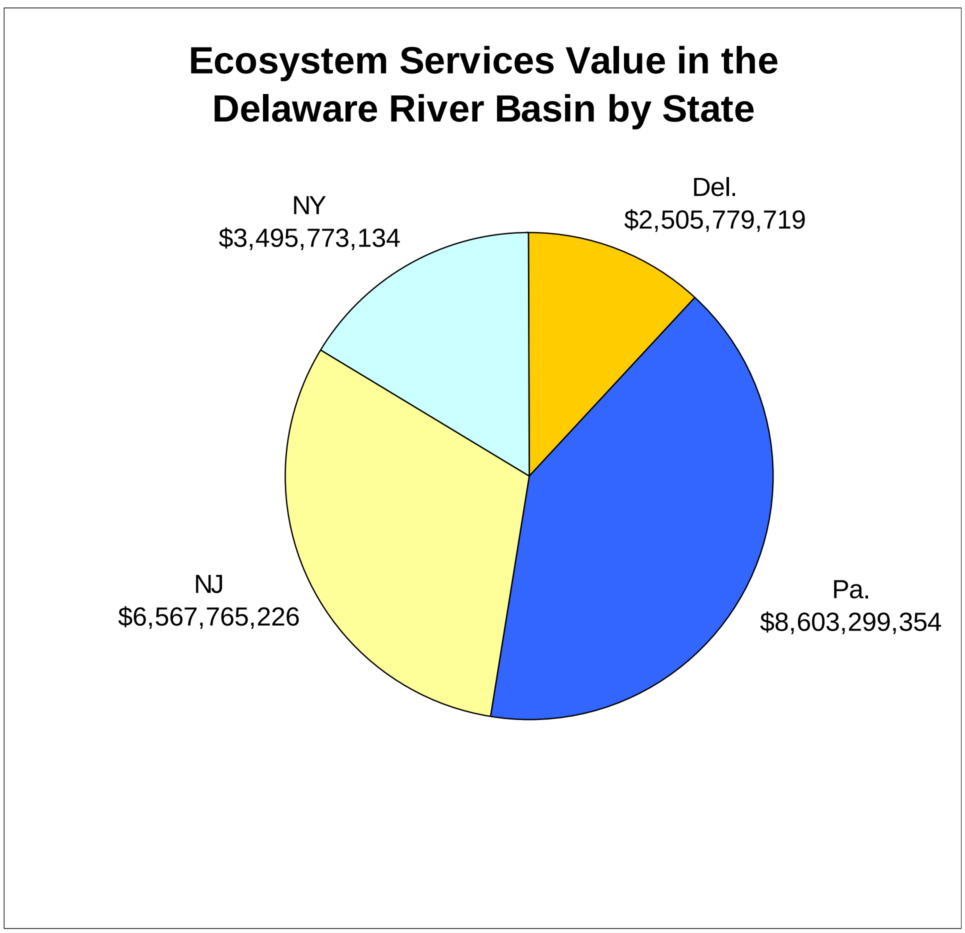


Figure 13. Ecosystem service value in the Delaware Basin by state

Table 50. Ecosystem services values in the Delaware River Basin by state

Ecosystem	Area (ac)	$/ac/yr 2010	PV 2010 $	NPV $
Delaware Basin				
Freshwater wetlands	422,838	13,621	5,759,329,048	187,178,194,067
Marine	16,588	10,006	165,982,947	5,394,445,767
Farmland	1,926,524	2,503	4,823,030,404	156,748,488,136
Forest land	4,343,190	1,978	8,591,367,360	279,219,439,184
Saltwater wetland	145,765	7,235	1,054,617,851	34,275,080,170
Urban	1,206,504	342	412,157,579	13,395,121,322
Beach/dune	900	48,644	43,758,633	1,422,155,566
Open water	92,615	1,946	180,210,703	5,856,847,857
Total	**8,154,924**		**$21,030,454,525**	**$683,489,772,069**
Delaware				
Freshwater wetlands	58,390	13,621	795,317,362	25,847,814,257
Marine	16,274	10,006	162,840,906	5,292,329,460
Farmland	254,143	3,329	846,164,877	27,500,358,509
Forest land	95,346	1,978	188,605,634	6,129,683,090
Saltwater wetland	61,617	7,235	445,802,585	14,488,584,028
Urban	123,048	342	42,034,778	1,366,130,274
Beach/dune	256	48,644	12,429,832	403,969,529
Open water	6,467	1,946	12,583,745	408,971,719
Total	**615,541**		**$2,505,779,719**	**$81,437,840,867**
New Jersey				
Freshwater wetlands	246,857	13,621	3,362,352,134	109,276,444,364
Marine	314	10,006	3,142,040	102,116,307
Farmland	505,507	2,019	1,020,866,015	33,178,145,495
Forest land	682,931	1,978	1,350,922,709	43,904,988,032
Saltwater wetland	83,563	7,235	604,583,594	19,648,966,813
Urban	321,090	342	109,688,612	3,564,879,893
Beach/dune	499	48,644	24,253,858	788,250,378
Open water	47,259	1,946	91,956,264	2,988,578,571
Total	**1,888,020**		**6,567,765,226**	**213,452,369,853**
New York				
Freshwater wetlands	34,792	13,621	473,886,107	15,401,298,475
Marine	0	10,006	0	0
Farmland	187,561	1,389	260,613,634	8,469,943,113
Forest land	1,387,514	1,978	2,744,673,732	89,201,896,298
Saltwater wetland	0	7,235	0	0
Urban	20,806	342	7,107,761	231,002,225
Beach/dune	0	48,644	0	0
Open water	4,878	1,946	9,491,900	308,486,749
Totalac	**1,635,551**		**3,495,773,134**	**113,612,626,859**
Pennsylvania				
Freshwater wetlands	82,799	13,621	1,127,773,445	36,652,636,971
Marine	0	10,006	0	0
Farmland	979,313	2,897	2,837,548,786	92,220,335,530
Forest land	2,177,399	1,978	4,307,165,285	139,982,871,763
Saltwater wetland	585	7,235	4,231,672	137,529,329
Urban	741,560	342	253,326,429	8,233,108,930
Beach/dune	145	48,644	7,074,943	229,935,659
Open freshwater	34,011	1,946	66,178,794	2,150,810,818
Total	**4,015,812**		**8,603,299,354**	**279,607,229,001**

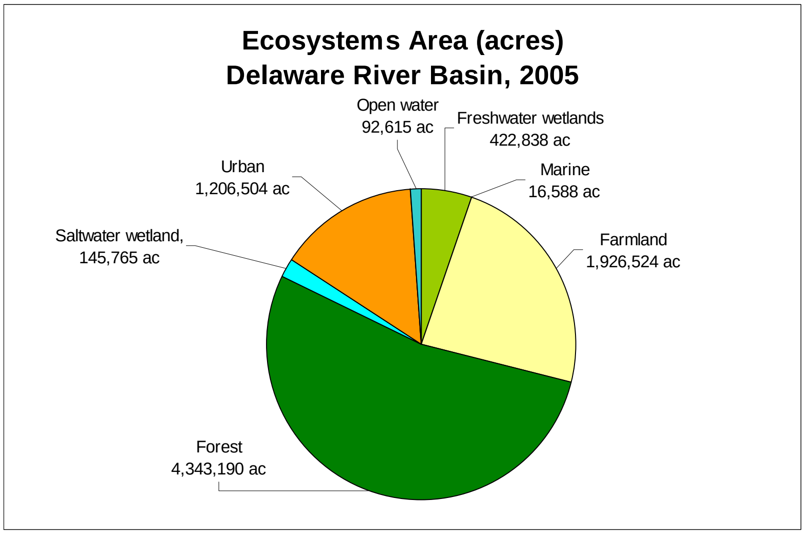


Figure 14. Ecosystem service areas within the Delaware River Basin

Table 51. Value of ecosystem goods and services in the Delaware River Basin

Natural Goods						
Ecosystem	**Area (ac)**	**$/ac/yr 2004**	**$/yr 2004**	**$/ac/yr 2010**	**$/yr 2010**	**NPV $**
Freshwater wetlands	422,838	234	98,943,997	270	114,191,069	3,711,209,745
Marine	16,588	1,125	18,661,829	1,298	21,537,580	699,971,336
Farmland	1,926,524	1,676	3,228,854,342	1,676	3,228,854,342	104,937,766,110
Forest land	4,343,190	238	1,033,679,112	275	1,192,966,996	38,771,427,378
Saltwater wetland	145,765	139	20,261,377	160	23,383,615	759,967,482
Urban	1,206,504	13	15,684,557	15	18,101,515	588,299,247
Beach/dune	900	0	0	0	0	0
Open water	92,615	921	85,298,217	1,063	98,442,502	3,199,381,302
Total	**8,154,924**		**4,501,383,431**		**4,697,477,618**	**152,668,022,601**
Natural Services						
Ecosystem	**Area (ac)**	**$/ac/yr 2004**	**$/yr 2004**	**$/ac/yr 2010**	**$/yr 2010**	**NPV $**
Freshwater wetlands	422,838	11,568	4,891,385,289	13,351	5,645,137,979	183,466,984,322
Marine	16,588	7,544	125,142,079	8,707	144,426,223	4,693,852,233
Farmland	1,926,524	717	1,381,317,758	827	1,594,176,062	51,810,722,026
Forest land	4,343,190	1,476	6,410,547,773	1,703	7,398,400,363	240,448,011,806
Saltwater wetland	145,765	6,131	893,687,073	7,076	1,031,402,464	33,520,580,080
Urban	1,206,504	283	341,440,730	327	394,056,064	12,806,822,075
Beach/dune	900	42,149	37,915,873	48,644	43,758,633	1,422,155,566
Open water	92,615	765	70,850,311	883	81,768,202	2,657,466,554
Total	**8,154,924**		**14,152,286,885**		**16,333,125,990**	**530,826,594,663**
Goods & Services						
Ecosystem	**Area (ac)**	**$/ac/yr 2004**	**$/yr 2004**	**$/ac/yr 2010**	**$/yr 2010**	**NPV $**
Freshwater wetlands	422,838	11,802	4,990,329,286	13,621	5,759,329,048	187,178,194,067
Marine	16,588	8,670	143,820,496	10,006	165,982,947	5,394,445,767
Farmland	1,926,524	2,503	4,823,030,404	2,503	4,823,030,404	156,748,488,136
Forest land	4,343,190	1,714	7,444,226,885	1,978	8,591,367,360	279,219,439,184
Saltwater wetland	145,765	6,269	913,802,685	7,235	1,054,617,851	34,275,080,170
Urban	1,206,504	296	357,125,287	342	412,157,579	13,395,121,322
Beach/dune	900	42,149	37,915,873	48,644	43,758,633	1,422,155,566
Open water	92,615	1,686	156,148,527	1,946	180,210,703	5,856,847,857
Total	**8,154,924**		**18,866,399,443**		**21,030,454,525**	**683,489,772,069**

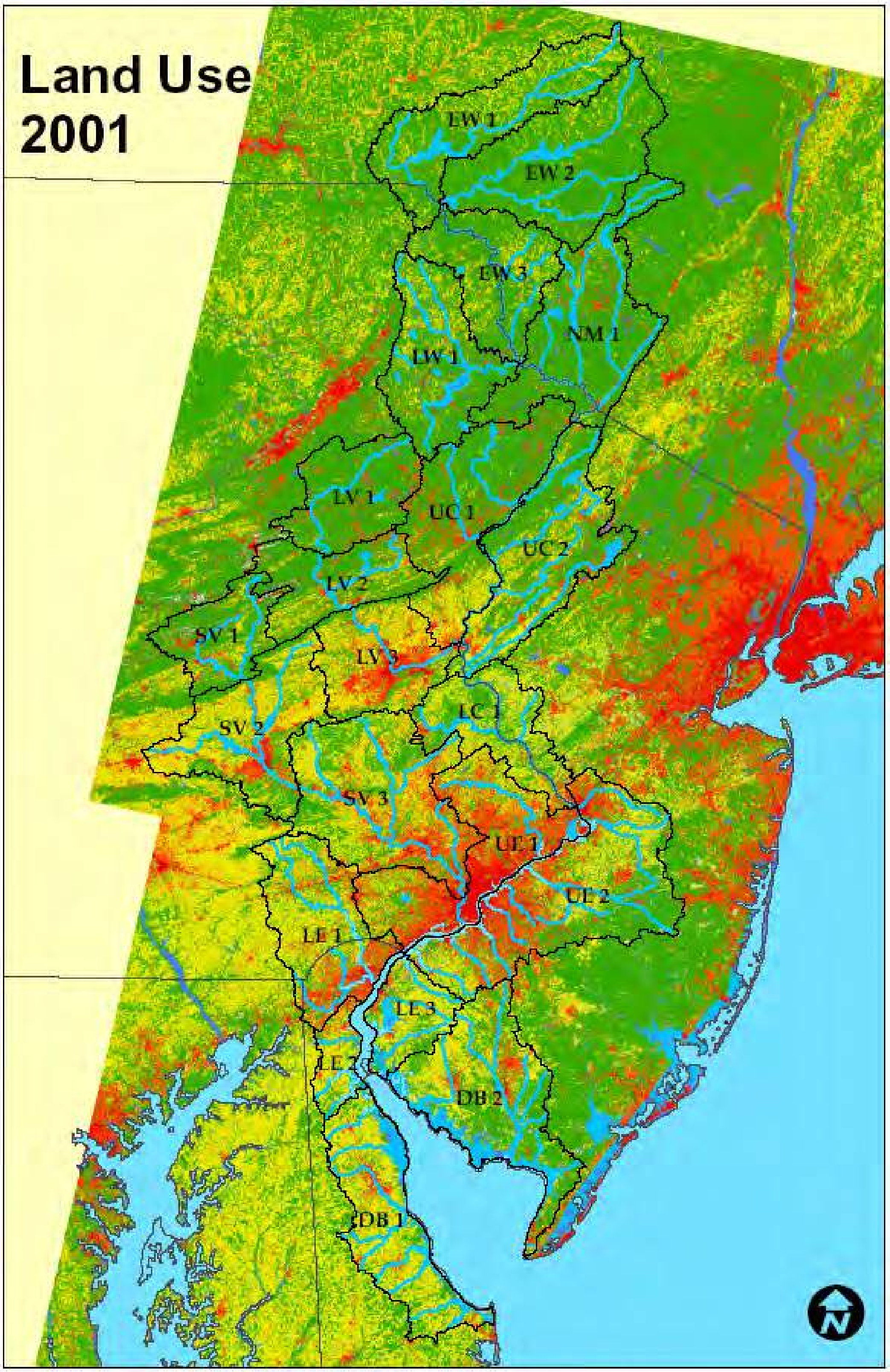


Figure 15. Land cover in the Delaware River Basin
(NOAA CSC 2001)

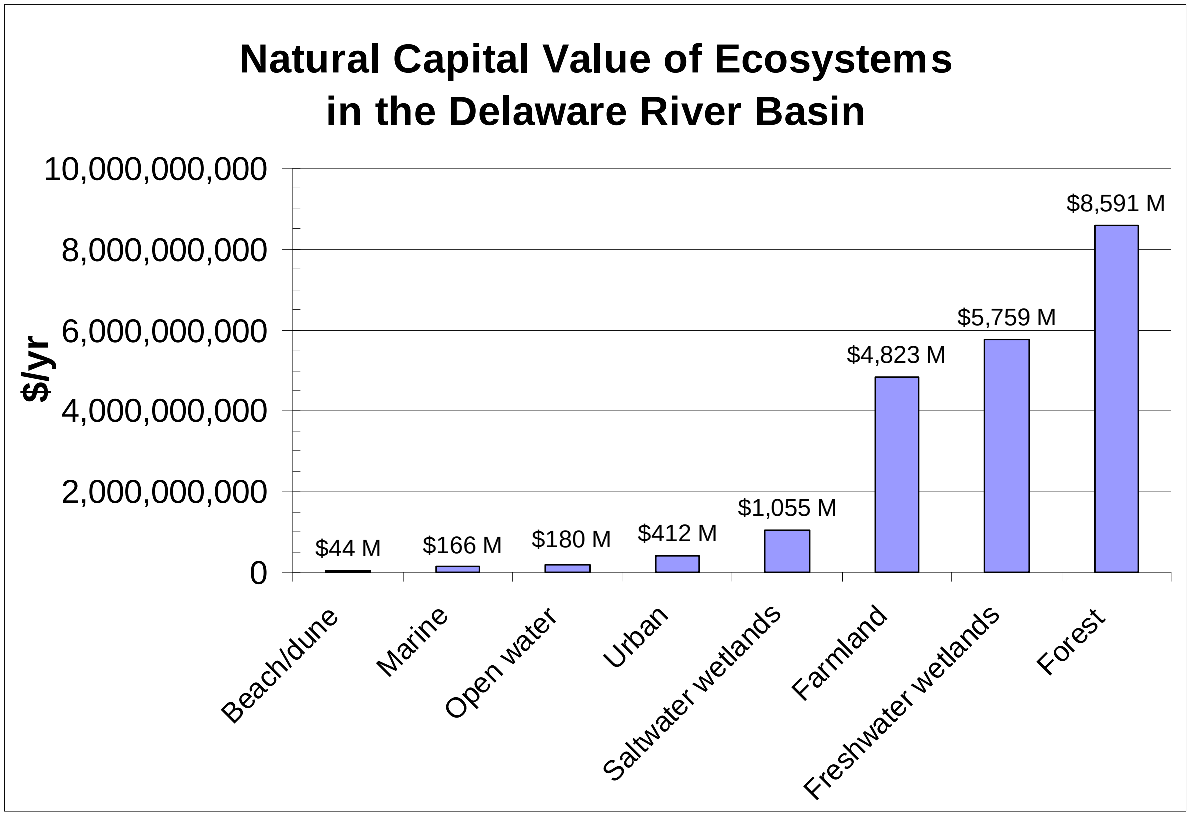


Figure 16. Ecosystem service value ($2010) of habitat within the Delaware River Basin

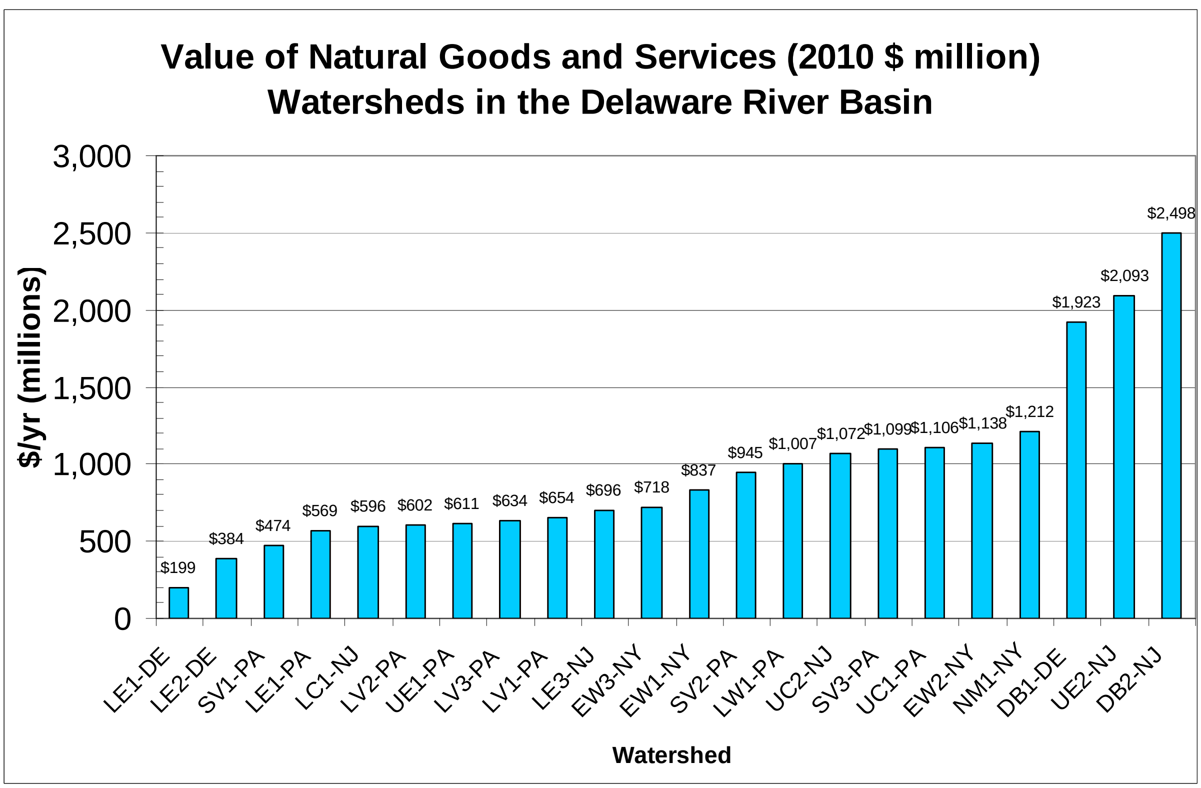


Figure 17. Ecosystem services values of watersheds within the Delaware River Basin

Table 52. Ecosystem services value of watersheds in the Delaware River Basin

Watershed	Area (sq mi)	2010 $/yr	2010 $/ac/yr
LE1 Brandywine/Christina	187	199,035,649	1,664
LE2 C&D Canal	152	384,011,292	3,941
DB1 Delaware Bay	626	1,922,732,778	4,797
Delaware	**962**	**2,505,779,719**	**4,071**
UC2 NJ Highlands	745	1,072,263,808	2,248
LC1 Del. R. above Trenton	159	208,902,978	2,053
UE2 New Jersey Coastal Plain	1,021	2,093,235,974	3,205
LE3 Salem River	254	695,858,091	4,288
DB2 Delaware Bay	782	2,497,635,761	4,991
New Jersey	**2,950**	**6,567,765,226**	**3,479**
EW1 East Branch Del. R.	666	836,579,484	1,963
EW2 West Branch Del. R.	841	1,137,547,038	2,114
EW3 Del. R. above Pt. Jervis	314	430,101,000	2,142
NM1 Neversink R.	734	1,076,794,000	2,321
New York	**2,556**	**3,495,773,134**	**2,137**
EW3 Del. R. above Pt. Jervis	210	287,647,100	2,142
NM1 Neversink R.	82	135,425,000	2,321
LW1 Lackawaxen R.	598	1,006,865,455	2,631
UC1 Pocono Mt.	779	1,106,108,992	2,219
LV1 Lehigh River above Lehighton	451	653,896,676	2,263
LV2 Lehigh River above Jim Thorpe	430	601,508,831	2,183
LV3 Lehigh River above Bethlehem	480	633,649,592	2,064
LC1 Del. R. above Trenton	295	387,587,286	2,053
SV1 Schuylkill above Reading	348	474,099,567	2,126
SV2 Schuylkill above Valley Forge	649	945,100,081	2,276
SV3 Schuylkill above Philadelphia	874	1,098,758,690	1,965
UE1 Penna Fall Line	693	611,041,618	1,377
LE1 Brandywine/Christina	401	568,524,810	2,216
Pennsylvania	**6,275**	**8,603,299,354**	**2,142**
Delaware Basin	**12,742**	**21,030,454,525**	**2,579**

Estimates of ecosystem services in the Delaware River Basin using the NJDEP/University of Vermont values coupled with market values from the USGS Census of Agriculture ($21.0 billion or $683.5 billion NPV) are conservative and in the lower end of the range. If lower per acre estimates of ecosystem services value from other studies were used instead of the NJDEP values, the total value of natural resources in the Delaware Basin would be $9.6 billion or NPV = $311 billion (Table 53). If higher per acre estimates of ecosystem services value from other studies were used, the total value of natural resources in the Delaware Basin would be $94.7 billion or NPV = $3.1 trillion (Table 54).

Estimate	PV $B	NPV $B
Low	9.6	311
NJDEP/USDA	21.0	683
High	94.7	3,100

Table 53. Low range estimate of ecosystem services in the Delaware River Basin

Ecosystem	Area (ac)	$/ac/yr	PV $	NPV $
Freshwater wetlands	422,838	6,268[5]	2,650,346,040	86,136,246,300
Marine	16,588	8,670[2]	143,820,496	4,674,166,116
Farmland	1,926,524	1,387[6]	2,672,088,886	86,842,888,779
Forest land	4,343,190	641[3]	2,783,984,500	90,479,496,255
Saltwater wetland	145,765	6,269[2]	913,802,685	29,698,587,269
Barren land	18,630	0	0	0
Urban	1,206,504	296[2]	357,125,287	11,606,571,818
Beach/dune	900	42,149[2]	37,915,873	1,232,265,862
Open water	92,615	217[5]	20,097,408	653,165,771
Total acres	**8,173,554**		**9,579,181,174**	**311,323,388,171**
sq mi	**12,771**			

Table 54. High range estimate of ecosystem services in the Delaware River Basin

Ecosystem	Area (ac)	$/ac/yr	PV $	NPV $
Freshwater wetlands	422,838	43,685[1]	18,471,660,300	600,328,959,736
Marine	16,588	8,670[2]	143,820,496	4,674,166,116
Farmland	1,926,524	9,979[4]	19,224,783,698	624,805,470,173
Forest land	4,343,190	12,033[1]	52,261,599,829	1,698,501,994,444
Saltwater wetland	145,765	28,146[1]	4,102,710,221	133,338,082,193
Barren land	18,630	0	0	0
Urban	1,206,504	296[2]	357,125,287	11,606,571,818
Beach/dune	900	42,149[2]	37,915,873	1,232,265,862
Open water	92,615	1,686[2]	156,148,527	5,074,827,144
Total acres	**8,173,554**		**94,755,764,230**	**3,079,562,337,486**
sq mi	**12,771**			

1. Cecil Co., Md. 2006. 2. NJDEP 2007. 3. Wilderness Society 2001. 4. Peconic Estuary 1995. 5. U. S. Nat'l. Wildlife Refuge 2008. 6. Mass Audubon Society 2003. 7. USDA Agric. Census 2007.

5. Jobs and Wages

The Delaware River Basin is a jobs engine that supports 600,000 direct and indirect jobs with $10 billion in annual wages in the coastal, farm, ecotourism, water/wastewater, recreation, and port industries (Table 55).

Table 55. Direct and indirect jobs and wages related to the Delaware River Basin

Sector	Jobs	Wages ($ million)	Data Source
Direct Basin Related	240,621	4,900	U.S. Bureau of Labor Statistics, 2009
Indirect Basin Related	288,745	4,000	U.S. Census Bureau, 2009
Coastal	44,658	947	National Coastal Economics Program, 2009
Farm	45,865	1,880	USDA Census of Agriculture, 2007
Fishing/Hunting/Birding	44,941	1,476	U.S. Fish and Wildlife Service, 2008
Water Supply Utilities	8,750	485	UDWRA and DRBC, 2010
Wastewater Utilities	1,298	61	UDWRA and DRBC, 2010
Watershed Organizations	201	10	UDWRA and DRBC, 2010
Ski Area Jobs	1,753	$88	Penna. Ski Areas Association
Paddling-based Recreation	4,226		Outdoor Industry Association (2006
River Recreation	448	$9	U. S. Forest Service/Nat'l. Park Service, 1990
Canoe/Kayak/Rafting	225		Canoe Liveries and UDWRA, 2010
Wild Trout Fishing	350	$4	Maharaj, McGurrin, and Carpenter, 1998
Del. Water Gap Nat'l. Rec. Area	7,563	101	Stynes and Sun, 2002
Port Jobs	12,121	772	Economy League of Greater Phila., 2008
Delaware Basin Total	**> 600,000**	**>$10 billion**	

Jobs and salaries in the Delaware Basin were obtained from U. S. Bureau of Labor Statistics (2009) and U. S. Census Bureau (2009) data bases for the following scenarios (Tables 56-58):

1. Total number of jobs in each county within the Delaware Basin with jobs determined by NAICS industry code (formerly SIC code) and then grouped by census tract.
2. Direct Delaware Basin-related jobs such as water and sewer construction, living resources, maritime, tourism/recreation, ports, environmental services, and water/wastewater management determined for each NAICS code by state and county within the basin boundary.
3. Indirect jobs/wages provided by purchases of goods and services by direct jobs earners within the Delaware Basin in the interlinked regional economy. Indirect jobs were estimated by a multiplier of 2.2 applied to direct jobs and 1.8 to direct wages (Latham and Stapleford 1990), i.e., 100 direct jobs fund 120 indirect jobs and direct wages of $1,000 provide $800 indirect wages.

Within the Delaware Basin are 3,480,483 jobs earning $172.6 billion in annual wages including:

- Delaware (316,014 jobs, $16.5 billion wages)
- New Jersey (823,294 jobs, $38.1 billion wages)
- New York (69,858 jobs, $2.5 billion wages)
- Pennsylvania (2,271,317 jobs, $115.5 billion wages)

Jobs directly associated with the Delaware River Basin (such as water/sewer construction, water utilities, fishing, recreation, tourism, and ports) employ 240,621 with $4.9 billion in wages including:

- Delaware (15,737 jobs, $340 million wages)
- New Jersey (62,349 jobs, $1.3 billion wages)
- New York (32,171 jobs, $550 million wages)
- Pennsylvania (130,364 jobs, $2.8 billion wages)

Jobs indirectly related to the waters of the Delaware Basin (based on multipliers of 2.2 for jobs and 1.8 for salaries) employ 288,745 people with $4.0 billion in wages including:

- Delaware (18,884 jobs, $270 million wages)
- New Jersey (74,819 jobs, $1.0 billion in wages)
- New York (38,605 jobs, $400 million in wages)
- Pennsylvania (156,437 jobs, $2.2 billion in wages)

National Coastal Economy Report

The National Ocean Economic Program (2009) published a report that summarized the coastal economy in the United States that includes 6 industrial sectors:

- Marine Transportation
- Tourism and Recreation
- Living Marine Resources
- Marine Construction
- Ship and Boat Building
- Mineral Extraction.

According to the National Ocean Economic program (2009), the coastal counties within the Delaware Basin boundary contribute 44,658 coastal jobs with $947 million in annual wages with contributions of $1.8 billion toward the GDP. Table 59 summarizes employment, wages, and employment within the Delaware Basin obtained by multiplying the 2009 NOEP report county-wide values by the ratios of coastal county area within the basin by total coastal county area within the state which are 80% for Delaware, 5% for New Jersey and 86% for Pennsylvania. Using these ratios, 80%, 5%, and 86% of the employment and wages for coastal counties in Delaware, New Jersey, and Pennsylvania from the NOEP report are within the Delaware Basin boundary.

Table 56. Direct basin-related jobs within the Delaware River Basin by state, 2009

Sector	Industry	1997 NAICS Code	DE Jobs	DE Wages x$1,000	NJ Jobs	NJ Wages $1,000	NY Jobs	NY Wages $1,000	PA Jobs	PA Wages x$1,000
Construction	Marine Related	237120			81	4,532			923	58,999
	Water and Sewer	23711	529	21,838	2,485	109,527	551	36,387	3,138	211,691
	Construction	237990	126	5,678	318	19,547			306	16,427
Living Resources	Fish Hatcheries	112511								
	Aquaculture	112512								
	Fishing/Forestry	11411			50	2,028	21	424	67	2,485
	Finfish Fishing	114111			111	5,591				
	Shellfish Fishing	114112			28	995				
	Seafood Markets	445220	39	1,447	81	1,550			283	6,348
	Seafood Process.	31171			97	6,734				
	Comm. Fisheries		0	0	0	0			0	0
Minerals	Sand & Gravel	212321			166	8,109				
		212322	0	0	81	3,865				
	Oil & Gas	541360	16	752					39	3,802
Ship/Boat Building	Boat Bldg. Repair	336612								
	Ship Bldg. Repair	336611								
	Shipbuilding		0	0	0	0			0	0
Tourism/Recreation	Recreation	487990			52	1,184				
		611620	64	513	305	5,301			675	12,270
		532292			50	774				
	Amusement	713990	250	4,102	2,426	35,967	11,537	162,246	2,008	31,251
	Misc. Recreation				0	0	1,100	16,574	0	0
	Boat Dealers	441222	198	7,489	157	5,945				
	Restaurants	722110	3,714	173,787	26,512	415,604	17,029	264,832	59,217	974,264
		722211	6,797	4,102	14,697	190,314			31,766	422,438
		722212	265	3,876	312	4,717			1,138	18,281
		722213	942	13,509	2,388	32,495			7,628	119,695
	Hotels & Lodging	721110	650	11,673	2,323	52,310			6,965	243,253
		721191			92	1,583				
	Marinas	713930			202	6,410				
	RV Park/Camps	721211	105	3,611	339	11,894			39	494
	Scenic Tours	487210	18	393	37	748				
	Sporting Good	339920	0	0	245	5,287	702	9,972	245	3,780
	Zoos, Aquaria	712130							55	1,959
		712190			58	3,411			466	28,459
Transportation	Deep Sea Freight	483111								
	Marine Transport.	483112	954	32,378	1,823	71,222			904	43,155
	Search/Navigation	334511	39	2,856					716	61,370
	Warehousing	493110	313	13,739	2,396	95,952			8,477	336,427
		493120			361	14,120			337	14,571
	Ports		0	0	0	0			0	0
	Dredging/Disposal		0	0	0	0			0	0
Education/Research	Environ.organizations	813312	83	2,976	61	2268	103	1,221	682	23,574
	Environ. consulting	54162	205	10,745	1,193	61,107	133	7,700	1,441	895
Water/Wastewater	Water/sewage systms	2213	267	20,004	679	8,169	23	1,101	203	774
	Waste management	562	146	6,028	1,928	92,495	882	41,649	2,372	113,437
	Septic tank services	562991	17	644	215	10,381	90	4,173	274	10,145
Total			**15,737**	**342,140**	**62,349**	**1,292,136**	**32,171**	**546,279**	**130,364**	**2,760,244**

Table 57. Jobs and wages directly and indirectly related to the Delaware River Basin, 2009

State/County	(1) Total Jobs	(2) Basin Jobs	(3) Direct Jobs	(4) Indirect Jobs	(1) Total Wages $ billion	(2) Basin Wages $ billion	(3) Direct Wages $ billion	(4) Indirect Wages $ billion
Delaware	**390,900**	**316,014**	**15,737**	**18,884**	**19.5**	**16.5**	**0.34**	**0.27**
Kent	60,100	50,412			2.4	2.0		
New Castle	264,600	252,534			14.7	14.1		
Sussex	66,200	13,068			2.4	0.5		
New Jersey	**1,362,200**	**823,294**	**62,349**	**74,819**	**61.6**	**38.1**	**1.3**	**1.0**
Burlington	194,500	187,758			9.1	8.8		
Camden	196,800	169,909			8.7	7.5		
Cape May	47,500	14,545			1.4	0.4		
Cumberland	62,000	61,868			2.5	2.5		
Gloucester	99,100	89,183			3.9	3.6		
Hunterdon	47,300	23,650			2.8	1.4		
Mercer	222,900	178,320			12.4	9.9		
Monmouth	246,600	9,864			11.4	0.5		
Ocean	149,900	7,495			5.5	0.3		
Salem	21,900	21,900			1.0	1.0		
Sussex	38,200	23,302			1.4	0.9		
Warren	35,500	35,500			1.5	1.5		
New York	**341,300**	**69,858**	**32,171**	**38,605**	**12.8**	**2.5**	**0.55**	**0.4**
Broome	94,100	11,292			3.4	0.4		
Delaware	16,000	14,240			0.6	0.5		
Greene	14,300	572			0.5	19.9		
Orange	130,700	10,456			5.2	0.4		
Sullivan	26,300	25,511			0.9	0.9		
Ulster	59,900	7,787			2.2	0.3		
Pennsylvania	**2,596,260**	**2,271,317**	**130,364**	**156,437**	**126.5**	**115.5**	**2.8**	**2.2**
Berks	159,106	150,665			6.2	5.9		
Bucks	244,453	244,453			10.6	10.6		
Carbon	16,730	16,730			0.5	0.5		
Chester	231,368	212,996			13.6	12.5		
Delaware	201,208	201,208			10.1	10.1		
Lackawanna	96,604	4,830			3.2	0.2		
Lebanon	45,826	2,750			1.5	0.1		
Lehigh	166,932	166,932			7.4	7.4		
Luzerne	134,574	8,074			4.6	0.3		
Monroe	56,025	56,025			2.1	2.1		
Montgomery	453,962	453,771			27.7	27.7		
Northampton	96,536	96,536			3.8	3.8		
Philadelphia	619,396	619,396			33.3	33.3		
Pike	9,874	9,874			0.3	0.3		
Schuylkill	49,116	27,077			1.6	0.9		
Wayne	14,550	14,114			0.5	0.4		
Delaware Basin	**4,690,660**	**3,480,483**	**240,621**	**288,745**	**220.3**	**172.6**	**4.9**	**4.0**

Table 58. Direct basin-related and indirect jobs within the Delaware River Basin, 2009

Sector	Industry	1997 NAICS Codes	Direct Jobs	Direct Wages (x$1,000)	Indirect Jobs[1]	Indirect Wages[2] (x$1,000)
Construction	Marine Related	237120	1,004	63,531	1,205	50,825
	Water and Sewer	23711	6,703	379,443	8,044	303,554
	Construction	237990	750	41,652	900	33,322
Living Resources	Fish Hatcheries	112511	0	0	0	0
	Aquaculture	112512	0	0	0	0
	Fishing/Foresty	11411	138	4,937	166	3,950
	Finfish Fishing	114111	111	5,591	133	4,473
	Shellfish Fishing	114112	28	995	34	796
	Seafood Markets	445220	403	9,345	484	7,476
	Seafood Process.	31171	97	6,734	116	5,387
	Comm. Fisheries		0	0	0	0
Minerals	Sand & Gravel	212321	166	8,109	199	6,487
		212322	81	3,865	97	3,092
	Oil & Gas	541360	55	4,554	66	3,643
Ship/Boat Building	Boat Bldg. Repair	336612	0	0	0	0
	Shipbuilding		0	0	0	0
Tourism/Recreation	Recreation	487990	52	1,184	62	947
		611620	1,044	18,084	1,253	14,467
		532292	50	774	60	619
	Amusement	713990	16,221	233,566	19,465	186,853
	Misc. Recreation		1,100	16,574	1,320	13,259
	Boat Dealers	441222	355	13,434	426	10,747
	Restaurants	722110	106,472	1,828,487	127,766	1,462,790
		722211	53,260	616,854	63,912	493,483
		722212	1,715	26,874	2,058	21,499
		722213	10,958	165,699	13,150	132,559
	Hotels & Lodging	721110	9,938	307,236	11,926	245,789
		721191	92	1,583	110	1,266
	Marinas	713930	202	6,410	242	5,128
	RV Park/Camps	721211	483	15,999	580	12,799
	Scenic Tours	487210	55	1,141	66	913
	Sporting Good	339920	1,192	19,039	1,430	15,231
	Zoos, Aquaria	712130	55	1,959	66	1,567
		712190	524	31,870	629	25,496
Transportation	Deep Sea Freight	483111	0	0	0	0
	Marine Transport.	483112	3,681	146,755	4,417	117,404
	Search/Navigation	334511	755	64,226	906	51,381
	Warehousing	493110	11,186	446,118	13,423	356,894
		493120	698	28,691	838	22,953
	Ports		0	0	0	0
	Dredging/Disposal		0	0	0	0
Education/Research	Environ.organizations	813312	929	30,039	1,115	24,032
	Environ. consulting	54162	2,972	80,447	3,566	64,357
Water/Wastewater	Water/sewage systms	2213	1,172	30,048	1,406	24,038
	Waste management	562	5,328	253,609	6,394	202,887
	Septic tank services	562991	596	25,343	715	20,275
Total			**240,621**	**4,940,799**	**288,745**	**3,952,639**

1. Direct jobs are directly related to the Delaware Basin. 2. Indirect jobs/salaries are derived from purchases of goods and services calculated by multipliers of 2.2 for jobs and 1.8 for wages.

Table 59. Coastal employment, wages, and GDP within the Delaware River Basin (National Ocean Economic Program 2009)

Sector	Employment	Wages ($ million)	GDP ($ million)
Delaware	**12,139**	**$214**	**$392**
Marine Construction			
Living Resources	354	$8	$15
Offshore Minerals			
Tourism & Recreation	10,398	$151	$299
Marine Transportation	1,744	$53	$72
Ship and Boat Building			
New Jersey	**4,423**	**$140**	**$235**
Marine Construction			$9
Living Resources			$7
Offshore Minerals			$1
Tourism & Recreation	2,939		$110
Marine Transportation			$104
Ship and Boat Building			$4
Pennsylvania	**28,096**	**$593**	**$1,204**
Marine Construction			$4
Living Resources			$172
Offshore Minerals			$13
Tourism & Recreation	**20,093**		$538
Marine Transportation			$383
Ship and Boat Building			$68
Delaware Basin	**44,658**	**$947**	**$1,831**
Marine Construction			$12
Living Resources	354	$8	$195
Offshore Minerals			$14
Tourism & Recreation	33,430	$151	$947
Marine Transportation	1,744	$53	$560
Ship and Boat Building			$72

Farm Jobs

In 2007 there were 30,455 farms in Delaware Basin counties or 21,840 farms within the basin boundary (30,455 x 0.67 = 21,840). The USDA estimates each farm employs 2.1 full time equivalent jobs. Farming provides 45,865 jobs with $1.9 billion in wages in the Delaware Basin (Table 60).

Table 60. Farm jobs in the Delaware River Basin

County	Farmland by County[1] (ac)	Farmland in Del. Basin (ac)	Ratio Farmland County/Basin	Farms in County[1]	No. of Farms in Basin	Farm jobs in Basin (2.1 jobs/farm)
New Castle	51,913			825		
Kent	146,536			347		
Sussex	234,324			1,374		
Delaware	**432,773**	**254,143**	**59%**	**2,546**	**1,495**	**3,140**
Burlington	85,790			922		
Camden	8,760			225		
Cape May	7,976			201		
Cumberland	69,489			615		
Gloucester	46,662			669		
Hunterdon	100,027			1,623		
Mercer	21,736			311		
Monmouth	44,130			932		
Ocean	9,833			255		
Salem	96,530			759		
Sussex	65,242			1,060		
Warren	74,975			933		
New Jersey	**631,150**	**505,507**	**80%**	**8,505**	**6,812**	**14,305**
Broome	86,613			580		
Delaware	165,572			747		
Greene	44,328			286		
Orange	80,990			642		
Sullivan	50,443			323		
Ulster	75,205			501		
New York	**503,151**	**187,561**	**37%**	**3,079**	**1,148**	**2,410**
Berks	170,760			1,980		
Bucks	58,012			934		
Carbon	20,035			207		
Chester	117,145			1,733		
Delaware	1,646			79		
Lackawanna	39,756			417		
Lancaster	326,648			5,462		
Lebanon	89,566			1,193		
Lehigh	72,737			516		
Luzerne	66,577			610		
Monroe	29,165			349		
Montgomery	28,563			719		
Northampton	68,252			486		
Philadelphia	150			17		
Pike	27,569			54		
Schuylkill	81,276			966		
Wayne	92,939			603		
Pennsylvania	**1,290,796**	**979,313**	**76%**	**16,325**	**12,386**	**26,010**
Total	**2,857,870**	**1,926,524**	**67%**	**30,455**	**21,840**	**45,865**

Census of Agriculture 2007 (USDA 2009)

Fishing/Hunting/Bird and Wildlife Recreation Jobs

The 2007 NJDEP study estimates the average annual salary per ecotourism job is $32,843 using figures from the U.S. Fish and Wildlife Service (2001) report on fishing, hunting, and wildlife associated recreation. If fishing, hunting, and bird/wildlife associated recreation in the Delaware

River Basin accounts for $1.5 billion in annual economic activity ($2006), then ecotourism provides for 44,941 jobs (Table 61).

Table 61. Jobs from fishing, hunting, and wildlife recreation in the Delaware River Basin

Recreation Activity[1]	DE in Basin[2] (2006 $M)	NJ in Basin[2] (2006 $M)	NY in Basin[2] (2006 $M)	PA in Basin[2] (2006 $M)	Delaware Basin (2006 $M)
Fishing	48	301	46	181	576
Hunting	21	58	36	225	340
Wildlife/Bird-watching	65	215	78	202	560
Total	**134**	**574**	**160**	**608**	**1,476**
	DE Jobs @ $32,843	**NJ Jobs** @ $32,843	**NY Jobs** @ $32,843	**PA Jobs** @ $32,843	**Del. Basin Jobs** @ $32,843
Fishing	1,461	9,165	1,401	5,511	17,538
Hunting	639	1,766	1,096	6,851	10,352
Wildlife/Bird-watching	1,979	6,546	2,375	6,150	17,051
Total	**4,080**	**17,477**	**4,872**	**18,512**	**44,941**

1. (USFWS 2008). 2. Prorated by ratio of basin area within state to state land area: Delaware (50%), New Jersey (40%), New York (5%) and Pennsylvania (14%).

Water Utility Jobs

Over 300 public and private water utilities (including the City of New York with 5,600 employees and the City of Philadelphia with over 800 water system employees) withdraw up to 1,800 mgd of drinking water from surface water and groundwater supplies in the Delaware River Basin. According to the American Water Works Association, the average salary of a water system employee is $55,407. Therefore, water utilities in the Delaware River Basin employ at least 8,750 jobs with annual wages of $485 million (Table 62).

Wastewater Utility Jobs

Over 60 wastewater utilities discharge almost 1.2 billion gallons per day of treated wastewater to the Delaware River Basin. These wastewater utilities employ 1,298 employees who earn $61 million in annual wages (Table 63).

Table 62. Public water supply jobs in the Delaware River Basin (DRBC and UDWRA 2010)

Water Purveyor	Jobs	Salaries
Delaware	**141**	**7,812,387**
United Water Delaware	55	3,047,385
City of Wilmington	31	1,717,617
City of Dover	14	775,698
City of Newark	7	387,849
City of Milford	6	332,442
Lewes Board of Public Works	5	277,035
Tidewater Utilities	5	277,035
Dover Air Force Base	1	55,407
New Castle Mun. Services Comm.	1	55,407
Town of Smyrna	1	55,407
Harrington	1	55,407
Camden-Wyoming Water Authority	1	55,407
Town of Milton	1	55,407
Other	12	664,884
New Jersey	**823**	**45,599,961**
Delaware and Raritan Canal	123	6,815,061
NJ American Water Co.	118	6,538,026
City of Trenton	78	4,321,746
City of Camden	33	1,828,431
City of Vineland	25	1,385,175
Aqua New Jersey	31	1,717,617
Merchantville-Pennsauken Water	18	997,326
Washington Twp. MUA	14	775,698
Willingboro Twp. MUA	14	775,698
Mount Holly Water	13	720,291
City of Bridgeton	11	609,477
City of Wildwood	11	609,477
Evesham Twp. MUA	8	443,256
Millville City Water Dept.	8	443,256
Evesham MUA	7	387,849
Hackettstown MUS	7	387,849
Millville Water Dept	8	443,256
Moorestown	8	443,256
Bordentown	7	387,849
Burlington Twp.	6	332,442
Mt. Laurel	6	332,442
Glassboro	6	332,442
Collingswood	6	332,442
Mapleshade	6	332,442
West Deptford	5	277,035
Woodbury	5	277,035
Burlington City	5	277,035
Pennsgrove	5	277,035
Deptford Twp.	5	277,035
Nesqehoning Boro Auth.	5	277,035
Medford Twp.	5	277,035
NJ American Mansfield/Oxford	5	277,035
Florence Twp.	5	277,035
Salem City	5	277,035
Other	201	11,136,807

New York	**5,600**	**310,279,200**
New York City	5,600	310,279,200
Pennsylvania	**2,186**	**121,119,702**
City of Philadelphia	863	47,816,241
Aqua Pennsylvania, Inc.	307	17,009,949
Forest Park/Point Pleasant Diversion	50	2,770,350
Bethlehem	46	2,548,722
Allentown	45	2,493,315
North Wales Water Authoriity	45	2,493,315
Bucks Co. Water and Sewer Auth.	45	2,493,315
Reading Area Water Authority	43	2,382,501
Bucks Co. Water and Sewer Auth.	41	2,271,687
Penna. American Water Co.	30	1,662,210
North Penn Water	26	1,440,582
Easton	24	1,329,768
Pennsylvania-American Water Co.	22	1,218,954
Schuylkill Co. Municipal. Authority	15	831,105
Pottstown Water Authority	14	775,698
Schuylkill Co. MUA	13	720,291
Muhlenberg Twp.	12	664,884
Lehigh County	12	664,884
PA American Nazareth	12	664,884
Hazelton	12	664,884
PA American Coatesville	12	664,884
Allentown City	12	664,884
Phoenixville Mun. Waterworks	12	664,884
Northampton Boro.	10	554,070
East Stroudsburg	10	554,070
PA American Yardley	10	554,070
Phoenixville	10	554,070
Morrisville	10	554,070
PA American Home District	10	554,070
PA American Penn District	10	554,070
Falls Twp.	10	554,070
Northampton Bucks Co. Auth.	10	554,070
Warminster Twp. MUA	10	554,070
Horsham Water and Sewer Auth.	10	554,070
Newtown Artesian Water	10	554,070
Milford	7	387,849
Tamaqua MWA	7	387,849
Lehighton MWA	7	387,849
Ambler Boro	7	387,849
Brodhead Creek Reg. Auth.	7	387,849
South Whitehall Twp. Auth.	7	387,849
Emmaus Munic. Water	7	387,849
Warrington Twp.	7	387,849
Wyomissing Boro	7	387,849
Schuylkill Haven Boro.	7	387,849
PA American Water Glen Alsace	7	387,849
Palmerton Mun. Auth.	7	387,849
Quakertown Mun. Water	6	332,442
Other	263	14,572,041
Delaware Basin	**8,750**	**484,811,250**

Table 63. Jobs and salaries at wastewater utilities in the Delaware River Basin

NPDES ID	Facility	Location	State	Jobs	Salaries
DE0020338	Kent Co. Levy Court WWTR	Frederica	DE	15	705,000
DE0021512	Lewes City POTW	Lewes	DE	3	141,000
DE0020320	Wilmington Wastewater Plant	Wilmington	DE	90	4,230,000
Delaware				**108**	**5,076,000**
NJ0027481	Beverly City Sewer Auth. STP	Beverly	NJ	3	141,000
NJ0024678	Bordentown Sewerage Auth.	Bordentown	NJ	5	235,000
NJ0024651	Cumberland Co. Utility Auth.	Bridgeton	NJ	7	329,000
NJ0024660	Burlington City STP	Burlington	NJ	5	235,000
NJ0021709	Burlington Twp. DPW	Burlington	NJ	4	188,000
NJ0026182	Camden County MUA	Camden	NJ	80	3,760,000
NJ0021601	Carneys Point Twp. Sewer Auth	Carneys Point	NJ	3	141,000
NJ0024007	Cinnaminson Sewerage Auth.	Cinnaminson	NJ	4	188,000
NJ0023701	Florence Twp. Sewer Auth.	Florence	NJ	5	235,000
NJ0026301	Hamilton Twp. DPW WWTP	Hamilton.	NJ	16	752,000
NJ0020915	Lambertville City Sewer Auth.	Lambertville	NJ	4	188,000
NJ0024759	Ewing Lawrence Sewer Auth.	Lawrenceville	NJ	16	752,000
NJ0069167	Maple Shade Util, Authority	Maple Shade	NJ	5	235,000
NJ0026832	Medford Twp. Sewer Auth. STP	Medford	NJ	2	94,000
NJ0029467	Millville City Sewer Auth.	Millville	NJ	7	329,000
NJ0024996	Moorestown Twp. Utilities Auth	Moorestown	NJ	6	282,000
NJ0024015	Mount Holly Twp. MUA	Mount Holly	NJ	8	376,000
NJ0020184	Newton Town DPW	Newton	NJ	4	188,000
NJ0024821	Pemberton Twp. MUA STP	Pemberton	NJ	5	235,000
NJ0024023	Penns Grove Sewerage Auth.	Penns Grove	NJ	3	141,000
NJ0021598	Pennsville Twp. Sewer Auth.	Pennsville	NJ	4	188,000
NJ0024716	Phillipsburg Town STP	Phillipsburg	NJ	5	235,000
NJ0022519	Riverside Twp. DPW	Riverside	NJ	3	141,000
NJ0024856	Salem WWTP Facility	Salem	NJ	3	141,000
NJ0024686	Gloucester Co. Util. Auth. STP	Thorofare	NJ	24	1,128,000
NJ0020923	Trenton City DPW Sewer Auth.	Trenton	NJ	20	940,000
NJ0023361	Willingboro Twp. MUA	Willingboro	NJ	6	282,000
New York				**257**	**12,079,000**
NY0020265	Delhi WWTP	Delhi	NY	4	188,000
NY0030074	Liberty WWTF	Liberty	NY	4	188,000
NY0022454	Monticello STP	Monticello	NY	6	282,000
NY0029271	Sidney WWTP	Sidney	NY	6	282,000
New Jersey				**20**	**940,000**
PA0026867	Abington Twp. STP	Abington	PA	6	282,000
PA0026000	Allentown City WWTP	Allentown	PA	45	2,115,000
PA0026042	Bethlehem City STP	Bethlehem	PA	95	4,465,000
PA0021181	Bristol Borough Water/Sewer	Bristol	PA	3	141,000
PA0027103	Delaware Co. Reg. Water Auth.	Chester	PA	44	2,068,000
PA0026859	Coatesville WWTP	Coatesville	PA	6	282,000
PA0026794	Conshohocken Borough Auth.	Conshohocken	PA	4	188,000
PA0026531	Downingtown Regional WPCC	Downingtown	PA	7	329,000
PA0026549	Borough of Doylestown WWTP	Doylestown	PA	29	1,363,000
PA0027235	Easton Area Joint Auth. WWTP	Easton, PA	PA	14	658,000
PA0029441	Upper Dublin Twp. MS4 UA	Ft. Washington	PA	3	141,000
PA0051985	Horsham Twp. STP	Horsham	PA	3	141,000
PA0024058	Kennett Square Borough WWTP	Kennett Sq.	PA	3	141,000

PA0026298	Whitemarsh STP	Lafayette Hill	PA	4	188,000
PA0026182	Lansdale Borough STP	Lansdale	PA	5	235,000
PA0039004	Upper Gwynedd Towam. STP	Lansdale	PA	7	329,000
PA0026468	Morrisville Mun. Auth. Water	Morrisville	PA	10	470,000
PA0027421	Norristown Borough WWTP	Norristown	PA	10	470,000
PA0020532	Upper Montgomery Joint Sewer	Pennsburg	PA	4	188,000
PA0026689	Northeast WPCP	Philadelphia	PA	210	9,870,000
PA0026662	Philadelphia Southeast POTW	Philadelphia	PA	112	5,264,000
PA0026671	SW Water Pollution Control	Philadelphia	PA	200	9,400,000
PA0020460	Quakertown WWTP	Quakertown	PA	10	470,000
PA0026549	Reading WWTP	Reading	PA	29	1,363,000
PA0020168	East Stroudsburg Filtration Plant	Stroudsburg	PA	10	470,000
PA0029289	Stroudsburg STP	Stroudsburg	PA	10	470,000
PA0027031	Goose Creek STP	West Chester	PA	4	188,000
PA0026018	West Chester Taylor Run STP	West Chester	PA	4	188,000
PA0028584	West Goshen STP	West Chester	PA	8	376,000
PA0023256	Upper Gwynedd Twp. WWTP	West Point	PA	7	329,000
PA0025976	Upper Moreland Hatboro Sewer	Willow Grove	PA	7	329,000
Pennsylvania				**913**	**42,911,000**
Del. Basin				**1,298**	**61,006,000**

Watershed Jobs

Over 100 nonprofit watershed and environmental organizations employ at least 200 staff who earn at least 9.5 million in wages on programs to restore the watersheds in the Delaware Basin (Table 64).

Table 64. Watershed organization jobs and salaries in the Delaware River Basin

Watershed Organization	Town	State	Jobs	Salaries
Christina Conservancy, Inc.	Wilmington	DE	1	48,000
Coalition for Natural Stream Valleys	Newark	DE		0
Delaware Audubon Society	Wilmington	DE	1	48,000
Delaware Nature Society	Hockessin	DE	20	960,000
Fairfield Watershed Association	Newark	DE		0
Friends of Bombay Hook	Smyrna	DE	1	48,000
Friends of White Clay Creek State Park	Newark	DE	1	48,000
Naamans Creek Watershed Association	Arden	DE		0
Nature Conservancy of Delaware	Wilmington	DE	2	96,000
Partnership for the Delaware Estuary, Inc.	Wilmington	DE	10	480,000
Save Wetlands and Bays	Millsboro	DE		0
St. Jones River Greenway Commission	Magnolia	DE		0
St. Jones River Watershed Association	Dover	DE	1	48,000
Waterfront Watch of Wilmington	Wilmington	DE	1	48,000
White Clay Creek Watershed Mgmt. Committee	Newark	DE	1	48,000
Delaware			**39**	**1,872,000**
Cape May County Watershed Area 16	Cape May Ct. Hse.	NJ	1	48,000
Citizens United to Protect the Maurice River	Millville	NJ	1	48,000
Cooper River Watershed Association	Haddonfield	NJ		0
Crafts Creek Spring Hill Brook Watershed	Bordentown	NJ		0
Crosswicks Creek Watershed Association	Yardville	NJ	1	48,000
Crosswicks-Doctors Creeks Watershed Association	New Egypt	NJ	1	48,000
Delaware River Greenway Partnership	Burlington	NJ	1	48,000
Fairview Lake & Watershed Conservation Foundation	West Caldwell	NJ		0
Friends Hamilton-Trenton-Bordentown Marsh	Robbinsville	NJ		0

Hunterdon Land Trust Alliance	Flemington	NJ	2	96,000
Mantua/Woodbury Creeks Watershed Association	Glassboro	NJ	1	48,000
Musconetcong Watershed Association	Asbury	NJ	1	48,000
New Jersey Coalition of Lake Associations	Sparta	NJ	1	48,000
Newton Creek Watershed Association	Collingswood	NJ	1	48,000
Oldmans Creek Watershed Association.	Mullica Hill	NJ	1	48,000
Paulinskill-Pequest Watershed Association	Blairstown	NJ	1	48,000
Phillipsburg Riverview Organization	Phillipsburg	NJ	3	144,000
Pinelands Preservation Alliance	Southampton	NJ	1	48,000
Pinelands Watershed Alliance	Tuckerton	NJ	1	48,000
Pohatcong Creek Watershed Association	Phillipsburg	NJ	1	48,000
Pompeston Creek Watershed Association	Cinnaminson	NJ	1	48,000
Raccoon Creek Watershed Association, Inc.	Mullica Hill	NJ	1	48,000
Rancocas Conservancy	Vincentown	NJ	2	96,000
Salem County Watershed Task Force	Woodstown	NJ		0
South Jersey Land and Water Trust	Glassboro	NJ	2	96,000
Upper Maurice River Watershed Association	Franklinville	NJ	1	48,000
New Jersey			**26**	**1,248,000**
Neversink River Program/The Nature Conservancy	Cuddebackville	NY	3	144,000
New York			3	
Aquashicola/Pohopoco Watershed Conservancy	Kresgeville	PA	1	48,000
Berks County Conservancy	Reading	PA	5	240,000
Bertsch-Hokendauqua-Catasauqua Watershed Assoc.	Bethlehem	PA	1	48,000
Brandywine Valley Association	West Chester	PA	8	384,000
Brodhead Forest & Stream Association	Stroudsburg	PA	1	48,000
Brodhead Watershed Association	Henryville	PA	1	48,000
Bushkill Stream Conservancy	Tatamy	PA	1	48,000
Chester Creek Watershed Association	Glen Mills	PA	1	48,000
Chester-Ridley-Crum Watersheds Association	Media	PA	5	240,000
Cooks Creek Watershed Association	Springtown	PA	1	48,000
Crum Creek Watershed Partnership	Swarthmoore	PA	1	48,000
Darby Cobbs Watershed Partnership	Philadelphia	PA	1	48,000
Darby Creek Valley Association	Drexel Hill	PA	1	48,000
Delaware River Shad Fishermen's Association	Bethlehem	PA	1	48,000
Delaware Riverkeeper Network	Bristol	PA	13	624,000
French and Pickering Creeks Conservation Trust	Valley Forge	PA	7	336,000
Friends of Cherry Valley	Stroudsburg	PA	1	48,000
Friends of Cobbs Creek Park	Philadelphia	PA	1	48,000
Friends of Crum Creek	Philadelphia	PA	1	48,000
Friends of Lake Afton	Yardley	PA	1	48,000
Friends of Mingo Creek	Royersford	PA	1	48,000
Friends of Poquessing Watershed, Inc.	Philadelphia	PA	1	48,000
Friends of Tacony Creek Park	Philadelphia	PA	1	48,000
Friends of the Del. Water Gap Nat'l. Recreation Area	Bushkill	PA	1	48,000
Friends of the Manayunk Canal	Philadelphia	PA	1	48,000
Friends of the Pennypack Park	Philadelphia	PA	1	48,000
Friends of the Wissahickon	Philadelphia	PA	1	48,000
Fry's Run Watershed Association	Easton	PA		0
Greater Pottstown Watershed Alliance	Pottstown	PA		0
Green Valleys Association	Pottstown	PA	3	144,000
Hay Creek Watershed Association	Geigertown	PA	1	48,000
Lackawaxen River Conservancy	Rowland PA	PA	1	48,000
Lake Wallenpaupack Watershed Association	Paupack	PA	2	96,000
Little Schuylkill Conservation Club	Delano	PA		0
Lower Merion Conservancy	Gladwyne	PA	6	288,000

Maiden Creek Watershed Association	Kempton	PA		0
Martins-Jacoby Watershed Association	Martins Creek	PA	1	48,000
Mid-Atlantic Council of Watershed Associations	West Chester	PA		0
Middle Anthracite Watershed Association	Sybertsville	PA	1	48,000
Mill Creek Council, Inc.	Philadelphia	PA	1	48,000
Monocacy Creek Watershed Association, Inc.	Bethlehem	PA	1	48,000
Neshaminy Creek Watershed Association	Rushland	PA	1	48,000
North Branch Watershed Association	Doylestown	PA	1	48,000
North Pocono CARE	Thornhurst	PA	2	96,000
Palisades Region Watershed Partnership	Pipersville	PA		0
Paunacussing Watershed Association	Carversville	PA		0
Pennsylvania Organization Watersheds and Rivers	Harrisburg	PA	3	144,000
Pennypack Ecological Restoration Trust	Huntington Valley	PA	8	384,000
Pennypack Watershed Partnership	Philadelphia	PA	1	48,000
Perkiomen Watershed Conservancy	Schwenksville	PA	4	192,000
Poquessing Watershed Partnership	Philadelphia	PA		0
Red Clay Valley Association	West Chester	PA	4	192,000
Saucon Creek Watershed Association	Bethlehem	PA	1	48,000
Schuylkill Action Network	Philadelphia	PA	2	96,000
Schuylkill Canal Association	Oaks	PA	1	48,000
Schuylkill Headwaters Association	Pottsville	PA	2	96,000
Schuylkill River Greenway Association	Pottstown	PA	1	48,000
Southampton Watershed Association	Southampton	PA	1	48,000
Springton Lake/Crum Creek Conservancy	Newtown Square	PA	1	48,000
Stony Creek Watershed Committee	Norristown	PA	1	48,000
Swarthmore College's Watershed Projects	Swarthmore	PA	2	96,000
Tinicum Conservancy	Erwinna	PA	4	192,000
Tinicum Creek Watershed Association	Upper Black Eddy	PA	2	96,000
Tobyhanna/Tunkhannock Creek Watershed Association	Pocono Lake	PA	1	48,000
Tohickon Creek Watershed Association	Pipersville	PA	1	48,000
Tookany/Tacony - Frankford Watershed Partnership	Philadelphia	PA	1	48,000
Upper Perkiomen Watershed Coalition	Palm	PA	1	48,000
Water Resources Association Delaware River Basin	Exton	PA	1	48,000
White Clay Watershed Association	Landenberg	PA	1	48,000
Wildlands Conservancy	Emmaus	PA	5	240,000
Wissahickon Restoration Volunteers	Philadelphia	PA	1	48,000
Wissahickon Valley Watershed Association	Ambler	PA	1	48,000
Wissahickon Watershed Partnership	Philadelphia	PA	1	48,000
Pennsylvania			**133**	**6,384,000**
Delaware Basin			**201**	**9,504,000**

Ski Area Jobs

In the Pocono Mountains of Pennsylvania, 9 ski resorts employ 1,753 direct jobs in the Delaware Basin from aggregate annual revenues of $87,655,063 from 1,908,228 skier visits based on an average mid-week lift ticket rate of $45/day.

Paddling-based Recreation

In the Mid-Atlantic census division (NY, NJ, PA), the Outdoor Industry Association (2006) estimates that paddling-based recreation is practiced by 11% of the population and is responsible for 3,356,000 participants and 22,844 jobs. Given the Delaware Basin is the home of 18.5% of the three state's total population of 40,800,000 people, then the prorated paddling-based recreation in the basin is responsible for 620,860 participants and 4,226 jobs.

River Recreation

Cordel et al. (1990) from the U. S. Forest Service and U.S. National Park Service estimated river recreation along the Upper Delaware River and Delaware Water Gap was responsible for 448 jobs with wages of $8.8 million in $1986.

Canoe/Kayak/Rafting

The 37 canoe and kayak liveries along the Delaware, Lehigh, and Schuylkill, and Brandywine Rivers employ 225 people to lease watercraft to approximately 225,000 visitors with earnings of $9 million per year assuming a daily rental fee of $40 per person.

Wild Trout Fishing

Along the Beaverkill, East Branch, West Branch and upper main stem of the Delaware River in New York, wild trout fishing provides for 350 jobs with $3.6 million in wages.

Delaware Water Gap National Recreation Area

Stynes and Sun (2002) estimated the Delaware Water Gap Nat'l. Recreation Area recorded 4,867,272 visits in 2001 that generated $106 million in sales, 7,563 direct/indirect jobs, and $100 million wages.

Port Jobs

The Economy League of Greater Philadelphia (2008) reported that Delaware River ports:

- Employ 4,056 workers earning $326 million in wages (Table 65).
- Indirectly support an additional two jobs each in port activity and employee spending for a total of 12,121 port jobs with $772 million wages and $2.4 billion annual economic output.
- Most of the 4,056 direct port jobs are in cargo handling and warehousing with petroleum port jobs adding up to less than 10% of employment.
- Provide good jobs, the average salary of a port employee (with benefits) is over $80,000.

Table 65. Jobs at Delaware River ports
(Economy League of Greater Philadelphia 2008)

Employment Type	Jobs
Direct	**4056**
Cargo Handling	1,911
Warehousing	987
Federal Government	553
Construction	318
State/Local Government	152
Security	99
Wholesale	36
Indirect (Industry)	**4,655**
Induced (Worker Spending)	**3,410**
Total	**12,121**

6. References

Austin, J. C., S. Anderson, P. N. Courant, and R. E. Litan, 2007. America's North Coast: A Benefit Cost Analysis of a Program to Protect and Restore the Great Lakes. Brookings Institute, Great Lakes Economic Initiative.

Austin, J. C., S. Anderson, P. N. Courant, and R. E. Litan, 2007. Healthy Waters, Strong Economy: The Benefits of Restoring the Great Lakes Ecosystem. The Brookings Institution. 16 pp.

Bockstael, N. E., K. E. McConnell, and I. E. Stroud, 1989. Measuring the Benefits of Improvements in Water Quality: the Chesapeake Bay. Marine Resource Economics. 6:1-18.

Breunig, K., 2003. Losing Ground: At What Cost? Changes in Land Use and Their Impact on Habitat, Biodiversity, and Ecosystem Services in Massachusetts. Mass Audubon. 43 pp.

Chesapeake Bay Watershed Blue Ribbon Finance Panel, 2003. Saving a National Treasure: Financing the Cleanup of the Chesapeake Bay. A Report to the Chesapeake Executive Council.

Coleman, J. L., R. C. Milici, T.A. Cook, R. R. Charpentier, M. Kirshbaum, T.R. Klett, R. M. Pollastro, and C.J. Schenk, 2011, Assessment of Undiscovered Oil and Gas Resources of the Devonian Marcellus Shale of the Appalachian Basin Province, USGS Fact Sheet 2011–3092, 2 pp.

Cordell, H. K., J. C. Bergstrom, G. A. Ashley, and J. Karish, 1990. Economic Effects of River Recreation on Local Economies. Water Resources Bulletin American Water Resources Association. 26(1), 53-60.

Corrozi, M. and M. Seymour, 2008. Water Rates in Delaware and Surrounding States. University of Delaware Institute for Public Administration-Water Resources Agency.

Dove, L. E. and R. M. Nyman eds., 1995. Living Resources of the Delaware Estuary. Delaware Estuary Program. 529 pp.

Economic League of Greater Philadelphia, 2008. Maritime Commerce in Greater Philadelphia: Assessing Industry Trends and Growth Opportunities for Delaware River Ports. 78 pp.

McCormick, B., 2010. Measuring the Economic Benefits of America's Everglades Restoration. The Everglades Foundation. 173 pp.

National Ocean Economics Program, 2009. State of the U.S. Ocean and Coastal Economies, Coastal and Ocean Economic Summaries of the Coastal States. 62 pp.

Frederick, K. D., T.VandenBerg, and J. Hansen, 1996. Economic Value of Freshwater in the United States. Discussion Paper 97-03. Resources for the Future. Washington, D. C. 37 pp.

Greeley-Polhemus Group, 1993. Final Report: Assessment of Selected Delaware Estuary Economic and Resource Values. Delaware Estuary Program Science & Tech. Advisory Committee. 117 pp.

Ingraham, M. and S. G. Foster, 2008. The Value of Ecosystem Services Provided by the U. S. National Wildlife Refuge System in the Contiguous U. S. Ecological Economics. 67:608-818.

Johnston, R. J., T. A. Grigalunas, J. J. Opaluch, Marisa Mazzotta, and J. Diamantedes, 2002. Valuing Estuarine Resource Services Using Economic and Ecological Models: The Peconic Estuary System Study. Coastal Management. 30:47-65.

Latham, W. R. and J. E. Stapleford, 1987. Economic Impacts of the Delaware Estuary. Delaware Sea Grant College Program. No. DEL-SG-02-87. 12 pp.

Leggett, C. G. and N. E. Bockstael, 2000. Evidence of the Effects of Water Quality on Residential Land Prices. Journal of Environmental Economics and Management. 39:2, 121-144.

Maharaj, V., J. McGurrin, and J. Carpenter, 1998. The Economic Impact of Trout Fishing on the Delaware River Tailwaters in New York. American Sportfishing Association and Trout Unlimited.

National Marine Manufacturers Association, 2010. 2010 Recreational Boating Statistical Abstract. Chicago, Illinois. 94 pp.

New Jersey Department of Environmental Protection, 2007. Valuing New Jersey's Natural Capital: An Assessment of the Economic Value of the State's Natural Resources.

New Jersey Water Supply Authority, 2011. New Jersey Water Supply Authority Basis and Background Statement. Accessed October 4, 2011. http://www.njwsa.org/html/publications/html.

Nowak, D. J., R. E. Hoehn, J. Wang, A. Lee, V. Krishnamurthy, and G. Schwetz, 2008. Urban Forest Assessment in Northern Delaware. Delaware Center for Horticulture and U. S. Forest Service.

Outdoor Industry Association, 2006. The Active Outdoor Recreation Economy. 20 pp.

Parsons, G. R., E. C. Helm, and T. Bondelid, 2003. Measuring the Economic Benefits of Water Quality Improvements to Recreational Users in Six Northeastern States: An Application of the Random Utility Maximization Model. For the EPA Office of Policy Economics and Innovation

Pennsylvania Fish and Boat Commission, 2011. Economic Value of Fishing and Boating in Pennsylvania. Accessed June 6, 2011. http://www.fish.state.pa.us/promo/funding/fact_economic_impact.htm.

Pennsylvania Geological Survey, 2010. Map of Marcellus Shale Thickness in Pennsyvania.

Pennsylvania Ski Areas Association, 2009. Accessed June 6, 2011. http://www.skipa.com

Stynes, D. J. and Y. Sun, 2002. Economic Impacts of Selected National Parks, Update to Year 2001. 10 pp.

Trust for Public Land and American Water Works Association, 2004. Protecting the Source: Land Conservation and the Future of America's Drinking Water. 51 pp.

Trust for Public Land, 2009. How Much Value Does the City of Wilmington Receive from its Park and Recreation System? 20 pp.

U. S. Census Bureau, 2010. Property Value: 2008-2009. American Community Survey Briefs. 4 pp.

U. S. Department of Agriculture, 2009. 2007 Census of Agriculture. Delaware State & County Data.

U. S. Department of Agriculture, 2010. Land Values and Cash Rents 2010 Summary. National Agricultural Statistics Service.

U. S. Department of the Interior, Fish and Wildlife Service, 2002. 2001 National Survey of Fishing, Hunting, and Wildlife-Associated Recreation.

U. S. Department of the Interior, Fish and Wildlife Service, 2008. 2006 National Survey of Fishing, Hunting, and Wildlife-Associated Recreation.

U. S. Energy Information Administration, 2002. Inventory of Electric Utility Power Plants in the United States 2000. U. S. Department of Energy. Washington, D. C. 339 pp.

U.S. Energy Information Administration, 2010. Natural Gas Weekly Update. ResidentialNatural Gas Prices. Accessed October 5, 2011. http://205.254.135.24/oog/info/ngw/ngupdate.asp

U. S. Environmental Protection Agency. 1973. Benefit of Water Pollution Control on Property Values. EPA-600/5-73-005, October 1973.

U. S. Environmental Protection Agency, 1995. A Framework for Measuring the Economic Benefits of Groundwater. Office of Water. Washington, D. C.

U. S. Nat'l. Energy Tech. Laboratory, 2009. Impact of Drought on U. S. Steam Electric Power Plant Cooling Water Intakes & Related Water Resource Management Issues. Washington, D. C. 191 pp.

Van Rossum, M. K., T. Carluccio, and S. Blankinship, 2010. River Values the Value of a Clean and Healthy Delaware River. Delaware Riverkeeper Network. 76 pp.

Weber, T., 2007. Ecosystem Services in Cecil County's Green Infrastructure. The Conservation Fund. Annapolis, Maryland.

Appendix A

Economic Value (Potential) of Marcellus Shale Natural Gas in the Delaware River Basin

The U.S. Geological Survey (Coleman et al. 2011) estimated the entire 54,000 square-mile Marcellus Shale Formation from Kentucky and Ohio to Pennsylvania and New York potentially contains a mean volume of 84 trillion cubic feet of natural gas with a range of 43 tcf (95th percentile) to 144 tcf (5th percentile). If the Delaware River Basin covers 4,700 square miles or 8.7% of the Marcellus Shale, then by proportion a mean volume of 7.3 tcf of natural gas is potentially recoverable within the basin boundary (0.087 x 84 tcf) with a range of 3.7 tcf (95^{th} percentile) to 12.5 tcf (5th percentile). These estimates may vary as the thickness of Marcellus Shale in the Delaware Basin increases to the northeast toward the New York/Pennsylvania border ranging from 50 feet thick near Stroudsburg to more than 250 feet thick under Lackawaxen in Wayne County, Pennsylvania.

In 2010, the U.S. Energy Information Administration reported the mean natural gas wellhead price was $4.16/1000 cf, down from a peak of $7.97/1000 cf in 2008. The residential customer price of natural gas was $11.21/1000 cf, down two dollars from the 2008 peak. Table A1 lists fluctuating annual wellhead and residential consumer prices of natural gas in the U.S. from 2006 through 2010.

Table A1. Wellhead and residential prices of natural gas in the United States, 2006-2010 (EIA)

Year	Wellhead Price ($/1000 cf)	Residential Price ($/1000 cf)
2006	6.39	13.73
2007	6.25	13.08
2008	7.97	13.89
2009	3.67	12.14
2010	4.16	11.21

At the 2010 wellhead unit price (Table A2), the mean value of potentially recoverable natural gas from the Marcellus Shale Formation within the Delaware River Basin is projected to be $30.4 billion with a range of $15.4 billion ($95^{th}$ percentile) to $52.0 billion (5th percentile). Assuming the natural gas can be recovered within 25 years, the mean annual wellhead value of Marcellus Shale gas within the Delaware Basin is potentially $1.2 billion/year with a range of $0.6 billion/year ($95^{th}$ percentile) to $2.0 billion/year (5th percentile). Figures A1 and A2 project total and annual wellhead value of natural gas recoverable from the Delaware Basin based on variable prices from 2006 to 2010.

At the 2010 residential consumer unit price (Table A3), the mean value of natural gas from the Marcellus Shale Formation within the Delaware River Basin is $81.8 billion with a range of $41.5 billion ($95^{th}$ percentile) to $140.1 billion (5th percentile). Assuming the natural gas can be recovered within 25 years, the mean annual residential consumer value of Marcellus Shale gas within the Delaware Basin is $3.3 billion/year with a range of $1.7 billion/year ($95^{th}$ percentile) to $5.6 billion/year (5th percentile). Figures A3 and A4 project total and annual residential consumer value of natural gas recoverable from the Delaware Basin based on prices from 2006 to 2010.

Table A2. Wellhead value of Marcellus Shale natural gas within the Delaware River Basin

State/Basin	Area Marcellus Shale (sq mi)	Wellhead Natural Gas Price[1] ($/1000 cf)	Volume Natural Gas[2] (tcf)	Wellhead Natural Gas Value ($ billion)	Wellhead Natural Gas Value[3] ($ billion/yr)
Mean					
Pennsylvania	2,338	$4.16	3.6	$15.0	$0.6
New York	2,362	$4.16	3.7	$15.4	$0.6
Delaware Basin	4,700	$4.16	7.3	$30.4	$1.2
95th Percentile					
Pennsylvania	2,338	$4.16	1.8	$7.5	$0.3
New York	2,362	$4.16	1.9	$7.9	$0.3
Delaware Basin	4,700	$4.16	3.7	$15.4	$0.6
5th Percentile					
Pennsylvania	2,338	$4.16	6.2	$25.8	$1.0
New York	2,362	$4.16	6.3	$26.2	$1.0
Delaware Basin	4,700	$4.16	12.5	$52.0	$2.0

1. EIA 2010. 2. USGS 2011. 3. Assumes 25 year natural gas recovery period.

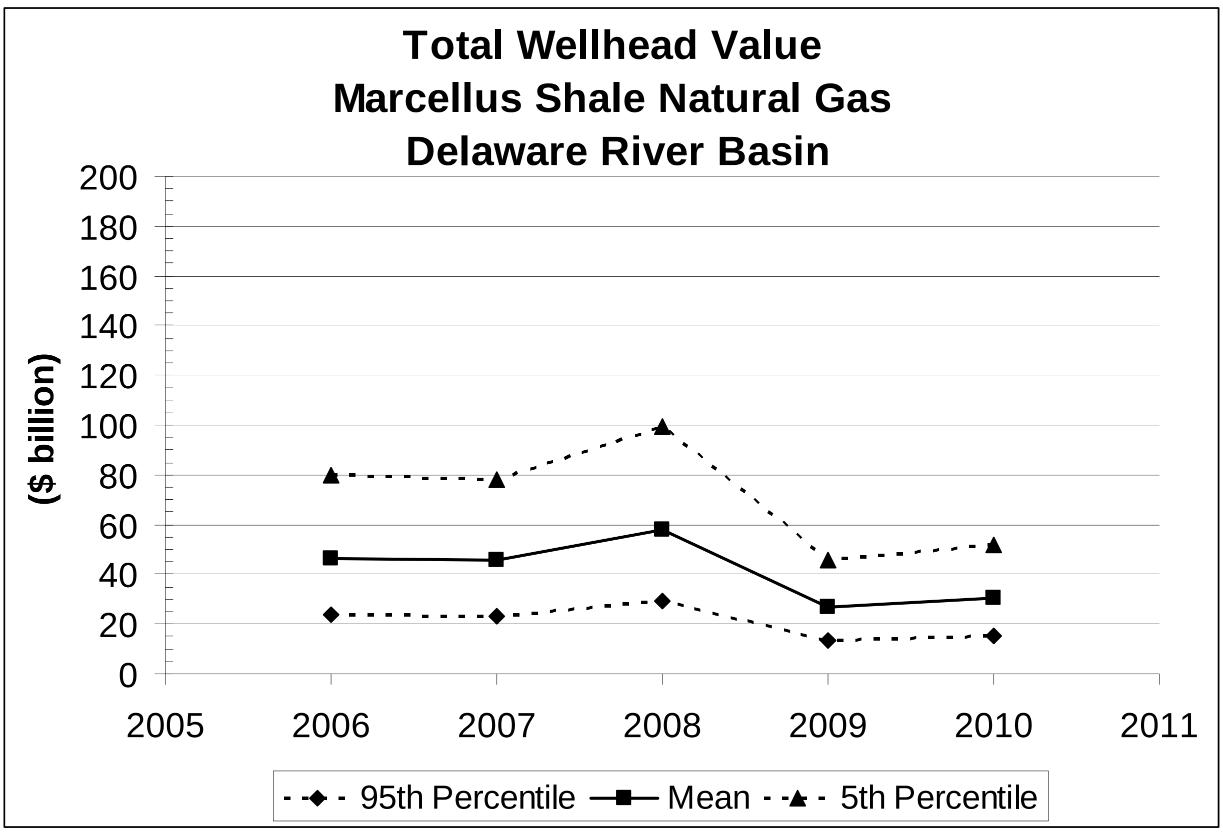


Figure A1. Total wellhead value of Marcellus shale natural gas in the Delaware River Basin Assumes mean volume of 7.3 tcf of natural gas potentially recoverable within basin boundary with a range of 3.7 tcf (95th percentile) to 12.5 tcf (5th percentile) as per Coleman et al. 2011 from the USGS. From EIA (2011), natural gas prices at wellhead ($/1000 cf): 2006 ($6.39), 2007 ($6.25), 2008 ($7.97), 2009 ($3.67), and 2010 ($4.16).

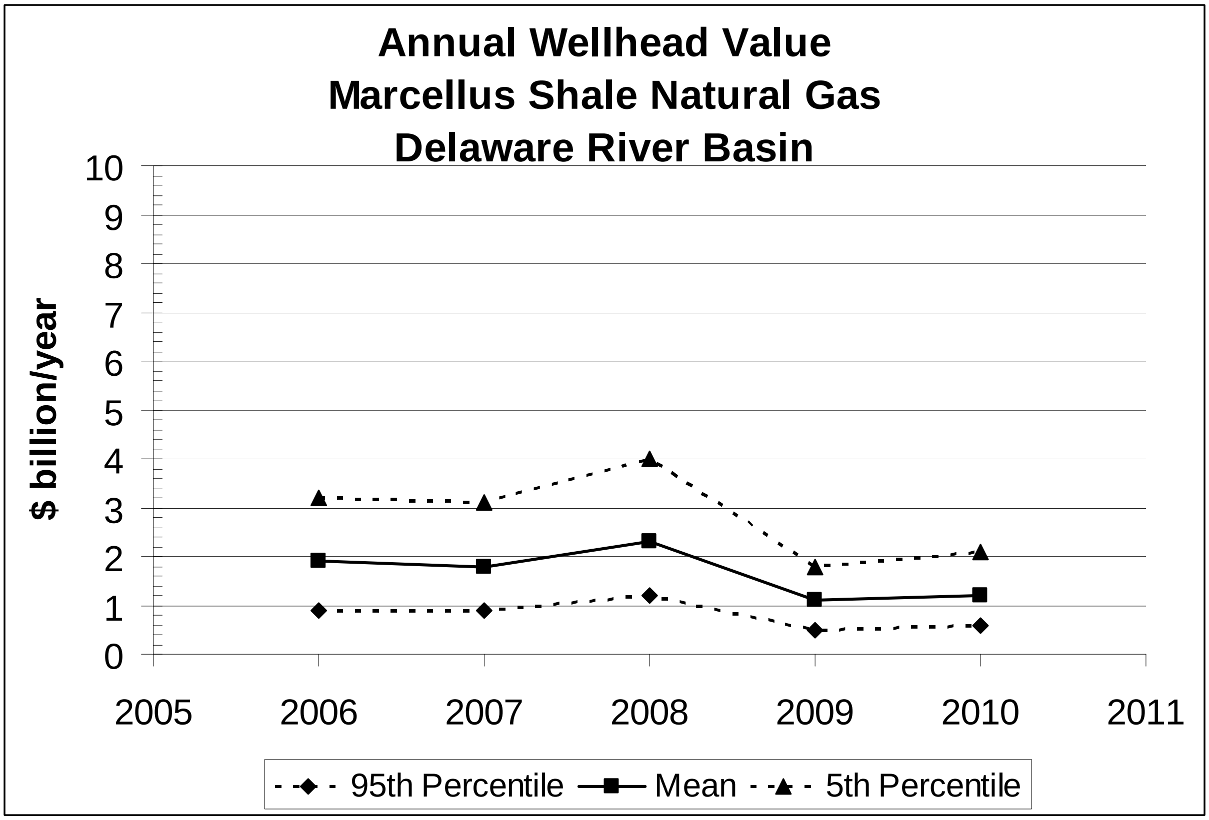


Figure A2. Total wellhead value of Marcellus shale natural gas in the Delaware River Basin Assumes mean volume of 7.3 tcf of natural gas potentially recoverable within basin boundary with a range of 3.7 tcf (95th percentile) to 12.5 tcf (5th percentile) as per Coleman et al. 2011 from the USGS. From EIA (2011), natural gas prices at wellhead ($/1000 cf): 2006 ($6.39), 2007 ($6.25), 2008 ($7.97), 2009 ($3.67), and 2010 ($4.16). Assumes 25 year natural gas recovery period.

Table A3. Residential value of Marcellus Shale natural gas within the Delaware River Basin

State/Basin	Area Marcellus Shale (sq mi)	Residential Natural Gas Price[1] ($/1000 cf)	Volume Natural Gas[2] (tcf)	Residential Natural Gas Value ($ billion)	Residential Natural Gas Value[3] ($ billion/yr)
Mean					
Pennsylvania	2,338	$11.21	3.6	$40.4	$1.6
New York	2,362	$11.21	3.7	$41.5	$1.7
Delaware Basin	4,700	$11.21	7.3	$81.8	$3.3
95th Percentile					
Pennsylvania	2,338	$11.21	1.8	$20.2	$0.8
New York	2,362	$11.21	1.9	$21.3	$0.9
Delaware Basin	4,700	$11.21	3.7	$41.5	$1.7
5th Percentile					
Pennsylvania	2,338	$11.21	6.2	$69.5	$2.8
New York	2,362	$11.21	6.3	$70.6	$2.8
Delaware Basin	4,700	$11.21	12.5	$140.1	$5.6

1. EIA 2010. 2. USGS 2011. 3. Assumes 25 year natural gas recovery period.

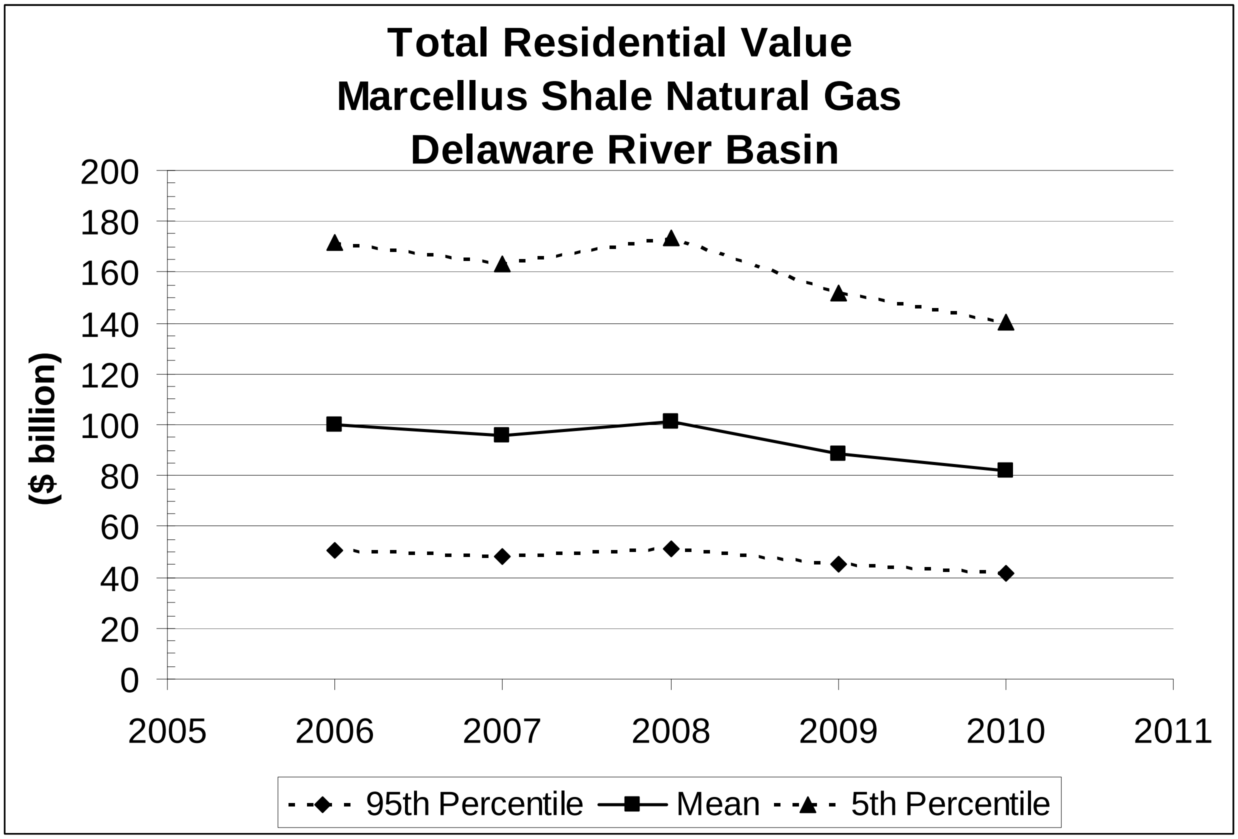


Figure A3. Total residential value of Marcellus shale natural gas in the Delaware River Basin Assumes mean volume of 7.3 tcf of natural gas potentially recoverable within basin boundary with a range of 3.7 tcf (95^{th} percentile) to 12.5 tcf (5th percentile) from Coleman et al. 2011 (USGS). From EIA (2011), natural gas sold to residential consumers ($/1000 cf): 2006 ($13.73), 2007 ($13.08), 2008 ($13.89), 2009 ($12.14), and 2010 ($11.21).

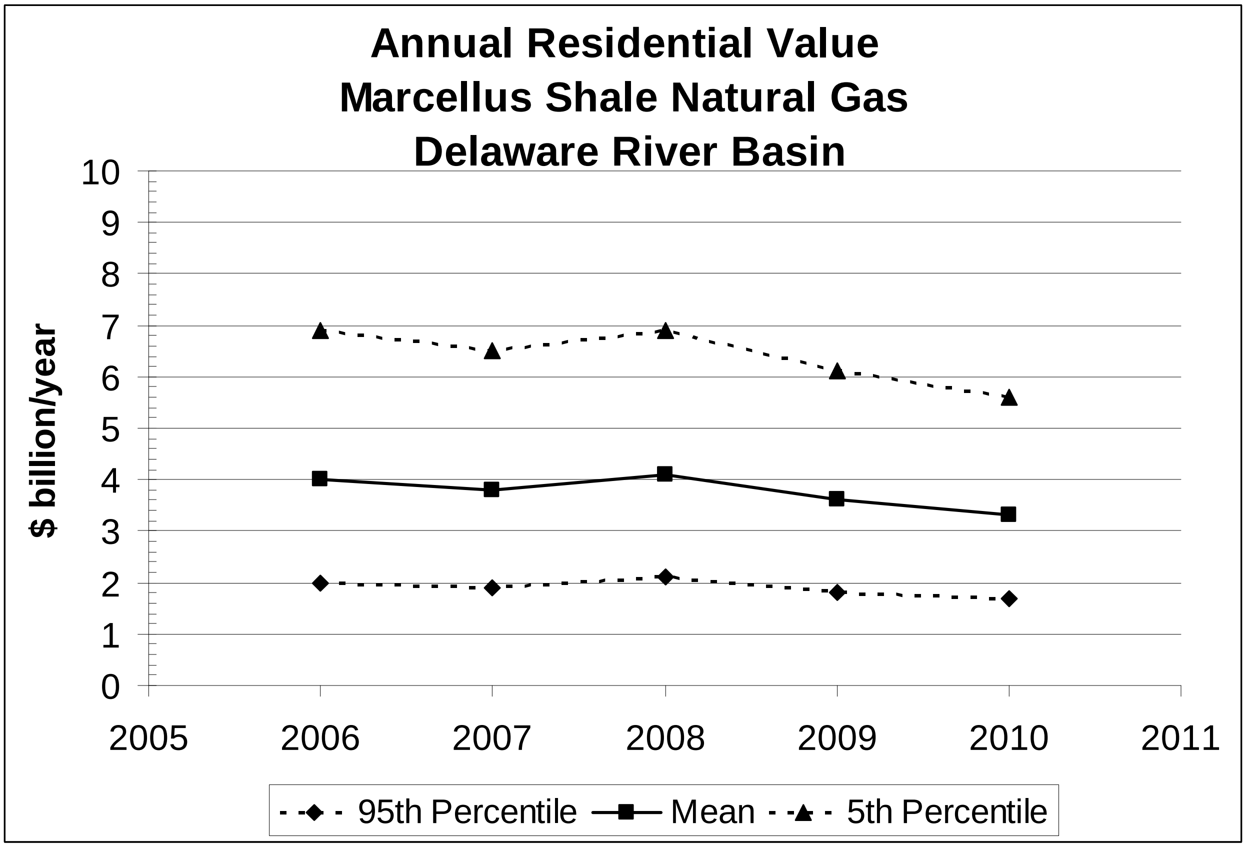


Figure A4. Annual residential value of Marcellus shale natural gas in the Delaware River Basin Assumes mean volume of 7.3 tcf of natural gas potentially recoverable within basin boundary with a range of 3.7 tcf (95th percentile) to 12.5 tcf (5th percentile) from Coleman et al. 2011 (USGS). From EIA (2011), natural gas sold to residential consumers ($/1000 cf): 2006 ($13.73), 2007 ($13.08), 2008 ($13.89), 2009 ($12.14), and 2010 ($11.21). Assumes 25 year natural gas recovery period.

Appendix B
Employment Codes by Industry, 2009
(U. S. Bureau of Labor Statistics)

Industry			NAICS Code
Agriculture, Forestry, Fishing and Hunting			11
	Crop Production		111
	Animal Production		112
		Aquaculture	1125
	Forestry and Logging		113
	Fishing, Hunting and Trapping		114
		Fishing	1141
	Support Activities for Agriculture and Forestry		115
Mining, Quarrying, and Oil and Gas Extraction			21
	Oil and Gas Extraction		211
	Mining (except Oil and Gas)		212
		Nonmetallic Mineral Mining and Quarrying	2123
	Support Activities for Mining		213
Utilities			22
	Utilities		221
		Electric Power Generation, Transmission and Distribution	2211
		Natural Gas Distribution	2212
		Water, Sewage and Other Systems	2213
Construction			23
	Construction of Buildings		236
		Residential Building Construction	2361
		Nonresidential Building Construction	2362
	Heavy and Civil Engineering Construction		237
		Land Subdivision	2372
		Highway, Street, and Bridge Construction	2373
		Other Heavy and Civil Engineering Construction	2379
	Specialty Trade Contractors		238
Manufacturing			31
	Food Manufacturing		311
		Seafood Product Preparation and Packaging	3117
	Beverage and Tobacco Product Manufacturing		312
	Textile Mills		313
	Textile Product Mills		314
	Apparel Manufacturing		315
		Apparel Knitting Mills	3151
	Leather and Allied Product Manufacturing		316
	Wood Product Manufacturing		321
	Paper Manufacturing		322
	Petroleum and Coal Products Manufacturing		324
	Chemical Manufacturing		325
		Basic Chemical Manufacturing	3251
		Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments Manufacturing	3252
		Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	3253
		Pharmaceutical and Medicine Manufacturing	3254
		Paint, Coating, and Adhesive Manufacturing	3255
		Soap, Cleaning Compound, and Toilet Preparation Manufacturing	3256
		Other Chemical Product and Preparation Manufacturing	3259
	Plastics and Rubber Products Manufacturing		326

	Nonmetallic Mineral Product Manufacturing		327
		Cement and Concrete Product Manufacturing	3273
		Lime and Gypsum Product Manufacturing	3274
		Other Nonmetallic Mineral Product Manufacturing	3279
	Primary Metal Manufacturing		331
	Fabricated Metal Product Manufacturing		332
	Machinery Manufacturing		333
	Computer and Electronic Product Manufacturing		334
		Computer and Peripheral Equipment Manufacturing	3341
		Communications Equipment Manufacturing	3342
		Audio and Video Equipment Manufacturing	3343
		Semiconductor and Other Electronic Component Manufacturing	3344
		Navigational, Measuring, Electromedical, and Control Instruments Manufacturing	3345
		Manufacturing and Reproducing Magnetic and Optical Media	3346
	Electrical Equipment, Appliance, and Component Manufacturing		335
	Transportation Equipment Manufacturing		336
		Motor Vehicle Manufacturing	3361
		Motor Vehicle Body and Trailer Manufacturing	3362
		Motor Vehicle Parts Manufacturing	3363
		Aerospace Product and Parts Manufacturing	3364
		Railroad Rolling Stock Manufacturing	3365
		Ship and Boat Building	3366
		Other Transportation Equipment Manufacturing	3369
	Furniture and Related Product Manufacturing		337
	Miscellaneous Manufacturing		339
Wholesale Trade			42
	Merchant Wholesalers, Durable Goods		423
	Merchant Wholesalers, Nondurable Goods		
	Wholesale Electronic Markets and Agents and Brokers		425
Retail Trade			44
	Motor Vehicle and Parts Dealers		441
	Furniture and Home Furnishings Stores		442
	Electronics and Appliance Stores		443
		Electronics and Appliance Stores	4431
	Building Material and Garden Equipment and Supplies Dealers		444
	Food and Beverage Stores		445
	Health and Personal Care Stores		446
	Gasoline Stations		447
	Clothing and Clothing Accessories Stores		448
	Sporting Goods, Hobby, Book, and Music Stores		451
	General Merchandise Stores		452
	Miscellaneous Store Retailers		453
	Nonstore Retailers		454
Transportation and Warehousing			48
	Air Transportation		481
		Scheduled Air Transportation	4811
		Nonscheduled Air Transportation	4812
	Rail Transportation		482
		Rail Transportation	4821
	Water Transportation		483
		Deep Sea, Coastal, and Great Lakes Water Transportation	4831
		Inland Water Transportation	4832
			4883
	Truck Transportation		484
		General Freight Trucking	4841

		Specialized Freight Trucking		4842
	Transit and Ground Passenger Transportation			485
		Urban Transit Systems		4851
		Interurban and Rural Bus Transportation		4852
		Taxi and Limousine Service		4853
		School and Employee Bus Transportation		4854
		Charter Bus Industry		4855
		Other Transit and Ground Passenger Transportation		4859
	Pipeline Transportation			486
		Pipeline Transportation of Crude Oil		4861
Information				51
	Publishing Industries (except Internet)			511
	Motion Picture and Sound Recording Industries			512
	Broadcasting (except Internet)			515
	Telecommunications			517
	Data Processing, Hosting, and Related Services			518
	Other Information Services			519
Finance and Insurance				52
	Monetary Authorities-Central Bank			521
	Credit Intermediation and Related Activities			522
	Securities, Commodity Contracts, and Other Financial Investments and Related Activities			523
	Insurance Carriers and Related Activities			524
	Funds, Trusts, and Other Financial Vehicles			525
Real Estate and Rental and Leasing				53
	Real Estate			531
	Rental and Leasing Services			532
	Lessors of Nonfinancial Intangible Assets (except Copyrighted Works)			533
Professional, Scientific, and Technical Services				54
	Professional, Scientific, and Technical Services			541
		Management, Scientific, and Technical Consulting Services		5416
		Scientific Research and Development Services		5417
Management of Companies and Enterprises				55
	Management of Companies and Enterprises			551
Administrative and Support and Waste Management and Remediation Services				56
	Administrative and Support Services			561
		Travel Arrangement and Reservation Services		5615
	Waste Management and Remediation Services			562
Educational Services				61
	Educational Services			611
		Colleges, Universities, and Professional Schools		6113
		Technical and Trade Schools		6115
		Educational Support Services		6117
Health Care and Social Assistance				62
	Ambulatory Health Care Services			621
	Hospitals			622
	Nursing and Residential Care Facilities			623
	Social Assistance			624
Arts, Entertainment, and Recreation				71
	Performing Arts, Spectator Sports, and Related Industries			711
	Museums, Historical Sites, and Similar Institutions			712
	Amusement, Gambling, and Recreation Industries			713
		Other Amusement and Recreation Industries		7139
Accommodation and Food Services				72
	Accommodation			721
		Traveler Accommodation		7211

		RV (Recreational Vehicle) Parks and Recreational Camps	7212
		Rooming and Boarding Houses	7213
	Food Services and Drinking Places		722
Other Services (except Public Administration)			81
	Repair and Maintenance		811
	Personal and Laundry Services		812
	Religious, Grantmaking, Civic, Professional, and Similar Organizations		813
		Social Advocacy Organizations	8133
		Business, Professional, Labor, Political, and Similar Organizations	8139
	Private Households		814
Public Administration			92
	Executive, Legislative, and Other General Government Support		921
	Justice, Public Order, and Safety Activities		922
	Administration of Human Resource Programs		923
	Administration of Environmental Quality Programs		924
	Administration of Housing Programs, Urban Planning, Community Development		925
	Administration of Economic Programs		926
	Space Research and Technology		927
	National Security and International Affairs		928

Ann. N.Y. Acad. Sci. ISSN 0077-8923

ANNALS OF THE NEW YORK ACADEMY OF SCIENCES
Issue: *The Year in Ecology and Conservation Biology*

Risks to biodiversity from hydraulic fracturing for natural gas in the Marcellus and Utica shales

Erik Kiviat

Hudsonia, Annandale, New York

Address for correspondence: Erik Kiviat, Hudsonia, P.O. Box 5000, Annandale, NY 12504. kiviat@bard.edu

High-volume horizontal hydraulic fracturing (HVHHF) for mining natural gas from the Marcellus and Utica shales is widespread in Pennsylvania and potentially throughout approximately 280,000 km^2 of the Appalachian Basin. Physical and chemical impacts of HVHHF include pollution by toxic synthetic chemicals, salt, and radionuclides, landscape fragmentation by wellpads, pipelines, and roads, alteration of stream and wetland hydrology, and increased truck traffic. Despite concerns about human health, there has been little study of the impacts on habitats and biota. Taxa and guilds potentially sensitive to HVHHF impacts include freshwater organisms (e.g., brook trout, freshwater mussels), fragmentation-sensitive biota (e.g., forest-interior breeding birds, forest orchids), and species with restricted geographic ranges (e.g., Wehrle's salamander, tongue-tied minnow). Impacts are potentially serious due to the rapid development of HVHHF over a large region.

Keywords: Appalachian Basin; biodiversity; forest fragmentation; hydraulic fracturing; salinization; shale gas

Introduction

High-volume horizontal hydraulic fracturing (HVHHF) occurs at increasing density across potentially 280,000 km^2 of the eastern United States underlain at depth by the natural gas–bearing Marcellus and Utica shales. These industrial installations and their edge effects alter as much as 80% of local landscapes.[1] The predicted intensity, speed, and extent of industrialization of the landscape have engendered concern about human health but little discussion of the effects on biodiversity,[2–4] although HVHHF has been identified as a global conservation issue.[5] Although the biota of the eastern United States is relatively well studied, many of the rare organisms potentially susceptible to industrial impacts are not. For example, the woodland salamanders (*Plethodon*) are diverse and sensitive to landscape and soil conditions; many species have only been described in recent decades; and as a group they are declining.[6–8] Although a direct survey of many taxa may be infeasible, indicator taxa may not effectively represent overall diversity.[9] In general, various taxa use different micro- and macrohabitats and have different conservation needs; one taxon may not predict the occurrence or sensitivity to impacts of another taxon.[10] This review focuses on the physical and chemical impacts of HVHHF on habitats, taxa, and guilds, and suggests which organisms have particular sensitivities that may put them at risk.

The Marcellus–Utica region

Conservatively, 9.5% of the conterminous United States is underlain by gas shales;[11] Canada, southern South America, Europe, South Africa, North Africa, China, India, and Australia also have exploitable formations.[12] The most extensive resources in the eastern United States are the Marcellus and Utica shales, underlying the Appalachian Basin from approximately the Mohawk and Hudson rivers in New York, through extensive areas of Pennsylvania and Ohio, most of West Virginia, and into small parts of Maryland, Virginia, and Ontario (Fig. 1).[13] Much of the region is forested, with dominant trees that include oaks (*Quercus* spp.), hickories (*Carya* spp.), sugar maple (*Acer saccharum*), American beech (*Fagus grandifolia*), and yellow birch (*Betula allegheniensis*).[14] Elevations range

doi: 10.1111/nyas.12146

Figure 1. Map of the Marcellus–Utica shale region. Reprinted with the permission of Cambridge University Press.[8]

from less than 100 m near the Hudson River to more than 1500 m in north-central Pennsylvania.

The Marcellus and Utica shales are organic-rich, marine shales deposited during the Middle Devonian and Middle Ordovician periods, respectively. The formations vary from exposed (in small areas) to overlain by 3 km or more of other bedrock strata, with the Utica underlying the Marcellus and extending farther west and southwest. Some of the organic matter is methane, the principal constituent of natural gas, tightly bound in microscopic pores.

Hydraulic fracturing

Horizontal drilling and hydraulic fracturing were developed in recent decades to mine gas from deep strata. In a typical installation, one to several wells are drilled from a single wellpad. Each well descends vertically 1.5 km or more to the target shale stratum, and then continues horizontally as much as 1.5 km. Fracturing fluid (water, chemicals, and sand) is forced under high pressure into the shale to open and prop spaces that let gas flow into the well.[13]

After fracturing, the gas and a portion of the fracturing fluid ascend the well and are collected. The gas is cleaned, compressed, and piped via collector lines to transmission pipelines.

Each HVHHF installation constitutes a wellpad, an access road, storage areas for water, chemicals, sand, and wastewater, a compressor station, and a collector pipeline. Installations often require extensive cut-and-fill, and some are on steep slopes.[15] In Pennsylvania in 2008, half of the installations were in forests and used, on average, 3.56 ha, thereby affecting approximately 15 ha of forest per installation.[1] An estimated 60,000 new wells will be in place by 2030.[16] A well is fractured at intervals of several years during its projected 40- to 50-year life, and each wellpad may support several wells. Each fracturing episode, per well, uses $4–12 \times 10^6$ L of water, which is usually trucked from a lake or river (the amount per episode may be as high as $15–25 \times 10^6$ L).[17] The portion of water and chemicals that returns to the surface as wastewater has been estimated at 9–100%.[18] More than 600 synthetic chemicals are used in HVHHF, including methanol, napthalene, xylene, acetic acid, ammonia, and #2 fuel oil,[2] but those used in any given well are unidentified. These chemicals constitute about 0.5% of the fracturing fluid; because of the large volume of fluids, 1×10^6 L of chemicals may be injected with a portion returning to the surface.[4,13] The wastewater, either return water during the fracturing operation or produced water afterward,[4] also contains substances from the shale, especially sodium, chloride, bromide, arsenic, barium, other heavy metals, organic compounds, and radionuclides.[13] Wastewater is often stored in lined, open ponds near wellpads, apparently to concentrate it, then trucked to treatment plants (including municipal plants not designed to remove salinity or radionuclides, and discharging effluent that has sometimes led to high salinity or total dissolved solids in rivers).[13,18] Wastewater is also reused for fracturing, disposed of by deep injection, spread on roads for dust control, or concentrated by evaporation and buried.[2,15,18]

Assessing biodiversity risk

Water and soil pollutants

Many spills or leaks of raw chemicals, fracturing fluids, or wastewater have been documented, involving volatile and gaseous organic chemicals, diesel fuel, surfactants, metals, sodium chloride, acidic water, and other substances.[2,3,19–21] In one instance, the median chloride content of wastewater was 56,900 mg L^{-1}.[18] At a West Virginia site, wastewater with approximately 4,000–14,000 mg L^{-1} chloride was sprayed on ground and vegetation, killing trees and other plants.[15] Four northeastern amphibian species have been shown to be adversely affected by approximately 50–1,000 mg L^{-1} chloride, depending on the species and life stage,[22] suggesting that small amounts of HVHHF wastewater could render breeding habitats unsuitable. Many lichens,[23–25] liverworts,[26] sphagnum mosses,[27–29] conifers,[30,31] aquatic plants,[32,33] and bog plants[34] are also sensitive to salt; numerous streams are already salinized from road deicing.[35] Furthermore, lichens[36–40] and stoneworts[41–43] can be harmed by heavy metals. Wastewater ponds contain highly toxic synthetic chemicals[2] and could potentially be ecological traps for water birds, muskrat, turtles, frogs, and aquatic insects. Mixtures of these chemicals will have effects that cannot be predicted by knowledge of individual chemicals.[3]

Sediment pollution of streams and other habitats may be caused by heavy equipment on rural roads mobilizing mineral particles in runoff or airborne dust,[13] or by inadequate erosion control at HVHHF sites.[21] In an HVHHF region of Arkansas, stream turbidity was correlated with well density.[3] Suspended sediment additions to higher order streams could potentially harm benthic invertebrates and fish; native brook trout and freshwater mussels are among the most vulnerable taxa. Dust from roads can harm nearby plants and pollute streams.[35]

Forest loss and fragmentation

Loss of forest cover and change in the spatial pattern of cover are often confounded, but cause different responses.[44] Edge effects on forest biota range from 10 m for trees to as much as 500 m for certain birds.[45] Forest fragmentation, which affects dispersal, pollination, herbivory, and predation, is a major conservation concern in HVHHF landscapes;[1,16,46] 20% or more of the forest cover may be removed for the establishment of HVHHF installations, and more than 80% of the land may be affected if a 100-m edge effect is considered.[1] This loss and fragmentation of forest would result in the warming and drying of the remaining forest, with greater penetration by nonnative plants, songbird nest predators, and the brood-parasitic brown-headed cowbird (*Molothrus ater*). Several forest amphibians occur at lower abundances in forest within 25–35 m of clearcut edges,[47] and juvenile forest amphibians have trouble dispersing across open habitats.[48,49] At five conventional gas well sites in West Virginia, three salamander species were more abundant closer to the forest edge, but less so in the drier southwestern aspect than in the moister northeastern aspect; edge effect was offset by rock and coarse woody debris (CWD) microhabitats.[50] Organisms sensitive to forest fragmentation include lichens and bryophytes,[51] orchids,[52] other herbs,[53] the West Virginia white butterfly (*Pieris virginiensis*),[54] amphibians,[8,48,55] and birds.[56–59] Orchids are among the taxa most sensitive to habitat change in that many orchid species occur in small, isolated populations and depend on narrow ranges of soil moisture, organic matter, light, and nutrients; they also have complex obligate relationships with mycorrhizal fungi and pollinators.[60] In addition, drying of air and soils near forest edges can degrade habitat for certain grape ferns (*Botrychium*).[61]

Pennsylvania forests serve as habitat reserves for many species.[46] Forest fragmentation and loss threaten populations of several breeding birds of conservation concern in Pennsylvania and West Virginia, including wood thrush (*Hylocichla mustelina*), cerulean warbler (*Setophaga cerulea*), and summer tanager (*Piranga rubra*).[62–64] Concern has been raised about potential HVHHF impacts on breeding populations of area-sensitive forest interior songbirds, such as black-throated blue warbler (*Setophaga caerulescens*) and a wide-ranging forest raptor, the northern goshawk (*Accipiter gentilis*).[1] In a 5-year study of breeding birds at 469 sampling points in forest patches ranging from 0.1 to 3,000 ha in Maryland, Pennsylvania, West Virginia, and Virginia, the percentages of forest cover within 2 km and the forest patch area were significant habitat variables for 40 and 38 species, respectively, of 75 species studied; 26 birds were considered area sensitive.[56]

It may take 75–100 years, or more, for cleared forests to regenerate and mature. Forest floor species such as salamanders[65] and herbaceous plants[66] have limited dispersal ability and may take as many additional years to recolonize regrown forests.[67] The guild of forest herbs, often diverse and abundant in mature Appalachian forests, contains many species vulnerable to environmental changes.[66] Logging or clearing reduces herb diversity, and the herb stratum may take several decades to recover. Herbivory by white-tailed deer (*Odocoileus virginianus*) is harmful to many forest herbs; it is possible that clearing for wellpads, roads, and pipelines may create a landscape that will support more deer and may subject forest herb populations to more intense grazing. One study reported that forests that are less than 70 years old supported fewer rare lichens and bryophytes than older forests;[51] this observation may pertain to young forests that develop following abandonment of HVHHF installations.

Roads and pipelines

Roads act as corridors for the spread of nonnative weeds.[35,68,69] Nonnative or weedy native plants will colonize disturbed soils at roads,[35,70] wellpads, compressor stations, and pipelines, and spread from there into forests and other habitats. This has occurred at energy development sites in western North America.[71] Among possible nonnative weeds that could colonize eastern HVHHF sites are common reed (nonnative haplotype of *Phragmites australis*), stiltgrass (*Microstegium vimineum*), Japanese knotweed (*Polygonum cuspidatum*), spotted knapweed (*Centaurea stoebe*), mugwort (*Artemisia vulgaris*), angelica tree (*Aralia elata*), autumn-olive (*Elaeagnus umbellata*), tree-of-heaven (*Ailanthus altissima*), and empress tree (*Paulownia tomentosa*). These plants thrive on habitats resulting from cut-and-fill, and are colonizing recent disturbances from surface mining, roads, and gas pipelines in the Catskill Mountains and Hudson Highlands of New York and other eastern regions.[72] Common reed disperses along roads, and from there, into adjoining undisturbed habitats,[73,74] where it may adversely affect plant and animal assemblages. The combination of disturbed roadside habitat and salinization from deicing salts is favorable for common reed. Vegetation of pipeline rights-of-way is managed by mowing or spraying herbicide; runoff or spray drift may affect rare native plants in adjoining habitats.

Many forest songbirds avoid roads, trails, pipelines, and human activities.[75] In western Canada, territories of the ovenbird (*Seiurus aurocapillus*) straddled 3-m-wide cleared seismic exploration lines, but did not straddle 8-m-wide lines, leading to local population declines.[75] In another example, red-backed salamander (*Plethodon cinereus*) was less abundant near gravel roads in mature forests in Virginia; this influence of roads on red-backed salamander appeared to be due to dessication of soils.[76] Some access roads and pipelines cross wetlands and streams, potentially creating barriers to movement of water and organisms. It takes an estimated 6,800 truck trips to fracture a single well.[77] Many amphibians, reptiles, birds, and mammals are vulnerable to road mortality; in Ontario, numbers of dead frogs increased, and nearby breeding choruses decreased in intensity, in proportion to the amount of traffic on roads.[78]

Hydrological alteration

Many organisms of streams, wetlands, and temporary ponds require certain patterns of water levels and flows through the year (the hydropattern).[79] Hydrological changes, including the withdrawal of surface waters, and increases in runoff caused by deforestation and impervious surfaces of wellpads and access roads, presumably affect the hydropatterns of streams,[80] floodplains, wetlands, intermittent pools (vernal pools), springs, seeps, shallow groundwater, and karst complexes. Withdrawals from lakes and rivers for fracturing wells might reduce minimum instream flows in the summer. Stream fishes, including brook trout (*Salvelinus fontinalis*), and aquatic invertebrates that must remain in water during summer, such as crayfishes and stoneflies, may be adversely affected by reduced summer flows.[81] Reduced flows may also decrease dissolved oxygen, increase deposition of fine sediment, and increase water temperatures, causing macroinvertebrate species richness to decrease and community composition to shift toward forms tolerant of these conditions.[82] Other species that could potentially be affected include freshwater mussels (Unionoidea), diverse in the Marcellus–Utica region, that are sensitive to hydrology, water quality, and siltation of rivers.[83,84] Hellbender (*Cryptobranchus alleganiensis*), a giant aquatic salamander, requires cool, well-oxygenated, swift streams and is also sensitive to siltation and pollution.[85–87]

In addition, withdrawal and disposal of water could potentially affect groundwater tables and flows, changing groundwater inputs to streams or wetlands. Impacts may be greater during droughts, or where there are competing uses of water, such as in agriculture.[3,13] At a threshold of 10–20% cover by impervious surfaces in a watershed, water quality and species diversity decrease in streams;[80,88–90] in some HVHHF landscapes, wellpads and access roads cover more than 10%.[1] Because of the density of HVHHF infrastructure on the landscape, and other impacts from siltation and chemical pollution, there may be cumulative impacts to wetlands and streams. Reduction of forest cover in watersheds may also have long-lasting effects on stream biodiversity.[91]

Noise

At HVHHF installations, diesel compressors run 24 h/day, and the noise can be heard from long distances.[20] Continuous loud noise from, for example, transportation networks, motorized recreation, and urban development can interfere with acoustic communication of frogs, birds, and mammals, and cause hearing loss, elevated stress hormone levels, and hypertension in various animals.[92] One study showed that gas compressor station noise in Alberta reduced ovenbird pairing success.[93] In pinyon-juniper woodland of New Mexico, breeding bird species richness was greater, species composition different, and overall nest density similar near gas wellpads without compressors compared to wellpads with compressors, but daily nest survival was higher near pads with compressors due to less predation by western scrub jays (*Aphelocoma californica*).[94] In a comparison of breeding birds near wellpads with and without compressors in the boreal forest, total density and densities of one-third of the individual species were lower at the compressor sites.[95] Bats avoid continuous loud noise and it may impair foraging efficiency.[96–100]

Light

Installations are brightly lit at night,[20] especially wellpads during drilling and fracturing and compressor stations continuously. Artificial night lighting variably affects different taxa; for example, adult moths and aquatic insects may be attracted and killed, whereas various species of bats may be harmed or benefited.[96,101,102] Night lighting potentially disrupts populations of stream insects, in turn affecting food webs and ecosystem function.[103] Mortality, reproduction, and foraging of many other animals are affected negatively or positively.[101] Polarized light pollution from artificial surfaces, especially smoother, darker surfaces including pavement, vehicles, and waste oil, creates another visual disturbance.[104] Animals that orient to polarized light, including many invertebrate and vertebrate taxa, may be killed or have their reproduction disrupted. This potential impact of HVHHF installations has not been studied.

Air quality

Air emissions, including diesel exhaust from compressors and trucks, volatile organics from fracturing fluids, ground-level ozone resulting from their interaction, and road dust, affect air quality around HVHHF sites.[105] Diesel smoke contains mutagenic and carcinogenic polycyclic aromatic hydrocarbons (PAHs)[106] that could affect animal health. In a relevant study, nitrogen oxides from vehicles affected mosses within 50–100 m of roads in England;[107] trees were adversely affected within the same distances, but the haircap moss *Polytrichum commune* showed a decline in frequency with distance from heavily traveled roads.[108] It is possible that diesel exhaust at HVHHF sites could produce similar effects. Lichens are especially sensitive to sulfur dioxide and other air pollutants,[36,39,109,110] and are harmed by road dust, as are sphagnum mosses.[111]

Range-restricted species

A species that has a large part of its geographic range in the Marcellus–Utica region may potentially be at risk of extinction from HVHHF impacts (especially in combination with other widespread environmental change). A recent study[8] analyzed 15 plants, butterflies, fish, amphibians, and mammals with geographic ranges overlapping the Marcellus–Utica region by 36–100% (Figs. 2 and 3). Although most of these species are considered sensitive to forest fragmentation, habitat alteration, or water quality degradation, lungless salamanders (Plethodontidae; eight species analyzed) seemed especially at risk. Many species of invertebrates, higher plants, and cryptogams whose ranges have not been mapped in detail may be quasi-endemic to the region.

Species with larger geographic ranges may nonetheless have important population components or seasonal habitats within the Marcellus–Utica region. The Virginia big-eared bat (*Corynorhinus townsendii virginianus*) occupies 15 limestone caves, 11 of which are in West Virginia.[112] Limestones are often highly porous to water pollution; therefore, cave species could potentially be at greater risk of being affected by HVHHF.

In each state, because of historic, political, social, and economic differences, and genetic differences within many species, environmental impacts on, and management of, rare species differ. Therefore, a species that is restricted to the Marcellus–Utica region within one state could potentially be at higher risk. In Pennsylvania, all known populations of the green salamander (*Aneides aeneus*), and 73% of populations of the snow trillium (*Trillium nivale*), are in localities with a high probability of HVHHF.[1] In New York, bluebreast darter (*Etheostoma camurum*), spotted darter (*E. maculatum*), banded darter (*E. zonale*), and variegate darter (*E. variatum*) are apparently confined to the Marcellus region;[113] these stream fishes are likely to be sensitive to salt and sediment pollution.[114,115]

Species potentially benefiting from HVHHF

Many native organisms use habitats created by construction or abandonment of industrial facilities, such as forest edges or bare soil. Some native bees and wasps dig nest burrows in bare soil, and reptiles often lay eggs in disturbed soils of road and railroad verges. Snakes, including timber rattlesnake (*Crotalus horridus*), are attracted by warm pavement in cooling weather. Several birds nest on bare or sparsely vegetated soil, including mallard (*Anas platyrhynchos*), common nighthawk (*Chordeiles minor*), killdeer (*Charadrius vociferus*), and spotted sandpiper (*Actitis macularia*), and many birds dust bathe on bare soils. White-tailed deer have been shown to be attracted to soils where HVHHF wastewater had been land-applied;[15] porcupine (*Erethizon dorsatum*)[116] and many butterflies[117] would also be attracted to salt. Metal-tolerant vascular plants and mosses could grow in these situations.[118] Postindustrial sites in England are important habitats for beetles, including rare species.[119]

Species of southern affinities would be attracted to wellpads and their peripheries due to solar warming. For example, water-filled wheel ruts and rain pools would serve as larval mosquito habitats; in Wyoming, there was a 75% increase in 5 years in potential mosquito larval habitats in ponds holding wastewater from coal bed gas drilling.[120] Access roads with numerous, long-lasting rain pools might support the globally rare feminine clam shrimp (*Cyzicus gynecia*).[121] It is possible that some grassland and shrubland species might colonize decommissioned facilities if they are extensive or adjoin other nonforested habitats. Most organisms able to colonize active or abandoned installations may be

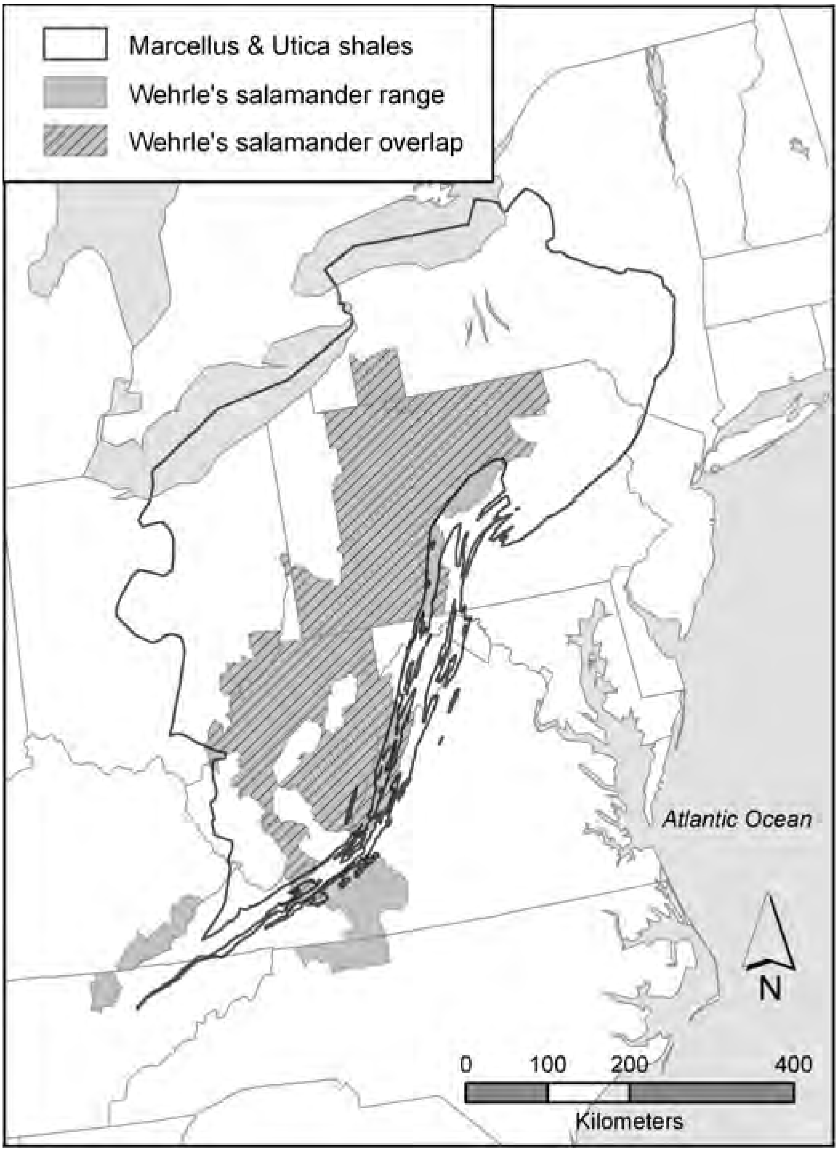


Figure 2. **Distribution of Wehrle's salamander (*Plethodon wehrlei*) in relation to the Marcellus–Utica shale region. Reprinted with the permission of Cambridge University Press.[8]**

common species and ecological generalists. Rare or sensitive species that are small or require only small habitat patches (e.g., land snails, millipedes, certain insects) may persist in forest patches between wellpads, and some organisms might escape predators or competitors in fragments.

Cumulative impacts

In the Marcellus–Utica region, HVHHF constitutes landscape- and regional-scale activities and impacts. Many thousands of wellpads will be distributed across the 280,000 km^2 region. Each wellpad will likely be drilled several times, and successful wells will be fractured multiple times during their 40- to 50-year life span.

Widespread environmental changes other than those produced by HVHHF also affect eastern biodiversity,[6,122] including coal mining, logging, agriculture, urban sprawl, accelerated climate change, acidification, eutrophication, chemical

Figure 3. Distribution of tongue-tied minnow (*Exoglossum laurae*) in relation to the Marcellus–Utica shale region. Reprinted with the permission of Cambridge University Press.[8]

contamination, altered fire regimes, emerging pathogens and parasites, and nonnative species spread. For example, most tree species are not shifting latitudinal ranges to keep pace with climate warming, and the ranges of many species are shrinking.[123] Such large-scale changes could potentially interact synergistically with the HVHHF impacts on forest biota as they accumulate across space and time. One study suggested that the effects of HVHHF on stream water quality will accumulate across watersheds.[3] In a meta-analysis of the effects of roads, power lines, and wind turbines on birds and mammals, bird populations were reduced as far as 1 km, and mammal populations were reduced as far as 5 km, from roads and infrastructure.[124] If this finding applies to the wellpads, gas compressors, and roads associated with HVHHF, the corresponding buffers around each installation needed to protect birds and mammals (3.1 km^2 and 78.5 km^2) are larger than the current spacing units for well density in Pennsylvania (1–2.5 km^2) and those projected for New York (2.6 km^2).[16]

Discussion and conclusions

Biodiversity impacts of HVHHF are similar to the impacts of many industries, although the chemical complexity and geographic extent are unusual. The major, long-term effects on biota likely to propagate through landscapes are habitat loss and fragmentation, chemical pollution, degradation of water quality, and hydrological alteration; other impacts, including noise, light, and air quality, may be more local and short-term. Biota vulnerable to HVHHF impacts include many native organisms that are important either for subsistence or in broader markets, such as medicinal plants (e.g., goldenseal (*Hydrastis canadensis*)),[125] edible fungi, brook trout and other sport fishes,[1] game birds and mammals (e.g., wood duck (*Aix sponsa*)), furbearers (American mink (*Mustela vison*), river otter (*Lontra canadensis*), common muskrat (*Ondatra zibethicus*)), and "watchable" wildlife (e.g., many forest-breeding birds). For example, studies suggest that HVHHF may affect trout habitats via water temperature increase, siltation, and heavy metals.[126,127]

Many of the biodiversity impacts of HVHHF might be reduced by zero-loss management of chemicals, wastewater, soil, and other pollutants, but this is a challenge considering the record of leaks, spills, fugitive emissions, and disposal. Water use and truck traffic can be reduced by reusing more wastewater, but similar amounts of pollutants will require disposal. If it eventually becomes possible to drill horizontally several kilometers, fewer wellpads would be needed, thus reducing fragmentation, and allowing more wells to be sited next to highways or on derelict lands, such as abandoned strip mines. However, pipelines would still fragment forests and impinge on sensitive habitats.

Forest loss and fragmentation are considered among the most serious threats to biodiversity.[128,129] Many forest species, particularly birds, require extensive tracts of continuous forest to maintain viable breeding populations. Inasmuch as the eastern United States was extensively deforested during the 1800s, one might ask whether current deforestation and fragmentation matter to biodiversity. At a maximum, only half of the east was deforested at once because clearing was not concurrent across the region; asynchronous deforestation probably prevented extinction of many species.[129] Yet deforestation contributed greatly to the extinction of the passenger pigeon (*Ectopistes migratorius*)[130] and the temporary loss or rarity of red-shouldered hawk (*Buteo lineatus*), wild turkey (*Meleagris gallopavo*), pileated woodpecker (*Dryocopus pileatus*), American beaver, black bear (*Ursus americanus*), fisher (*Martes pennanti*), and white-tailed deer from most of New York State and probably large regions elsewhere in the eastern United States.[131] Most of these species have recovered with the redevelopment of extensive forests, even to the point of overabundance of deer, bear, and turkey. Forest cover in the east is decreasing again,[132] and forests of the conterminous United States are fragmented to the degree that edge effects occur throughout most forested landscapes.[133] Fragmentation also affects grasslands and their breeding birds.[16,134] The many other stressors affecting freshwater organisms[135] may be compounded by water pollution and hydrological alteration from HVHHF.

Biotas are impoverished in industrial and urban areas, although many species thrive, including some rare species.[136–138] Few empirical data are available on biodiversity impacts of eastern HVHHF, although activities are already widespread and potentially will occur throughout 280,000 km^2. HVHHF is also intensive, causing great changes to habitats at HVHHF installations and to the intervening landscapes. Consideration of a broad spectrum of taxa and guilds suggests potential HVHHF risks to biodiversity, particularly organisms that are specialized in their habitat, require unpolluted freshwater with natural hydropatterns, or have small geographic ranges concentrated in the Appalachian Basin. Impoverishment of species assemblages likely will lead to diminution of ecosystem functions and services.[139]

It is expected that an HVHHF installation will be decommissioned and the site restored after 40–50 years; procedures may include regrading, removing roads and impoundments, restoring topsoil, and native planting.[21] Restoration will accomplish more if it is targeted at habitats and species of conservation concern, rather than simply restoring forest or grassland. For example, CWD is important for salamanders, snakes, invertebrates, bryophytes, and lichens. Coarse woody debris could be stockpiled when a site is cleared and used for restoration of a nearby site that is being decommissioned. Construction, operation, and decommissioning of HVHHF facilities, if viewed as a mosaic across the landscape, could be better managed to reduce impacts on biodiversity. Most research on wild organisms is restricted in space and time; thus, we are not well equipped to understand and conserve on large scales.[140] Most regulation of HVHHF has occurred at the level of the individual wellpad; however, to protect biodiversity and ecosystem services, it may be necessary to plan and regulate at the level of the whole Marcellus–Utica region.

Acknowledgments

I am grateful for discussions with Jennifer Gillen, Kristi MacDonald, Cody Mellott, Karen Schneller-McDonald, Gretchen Stevens, and Kristin Westad. The maps were prepared by Maxine Segarnick and Jordan Michael Kincaid, and edited by Kristen Bell Travis, who also edited the manuscript. This work is a Bard College Field Station—Hudsonia contribution.

Conflicts of interest

The author declares no competing financial interest.

References

1. Johnson, N. 2010. Pennsylvania energy impacts assessment. Report 1: Marcellus shale natural gas and wind. Nature Conservancy, Pennsylvania Chapter. Harrisburg, PA. Accessed: September 8, 2012. http://www.nature.org/media/pa/pa_energy_assessment_report.pdf.
2. Colborn, T., C. Kwiatkowski, K. Schultz & M. Bachran. 2011. Natural gas operations from a public health perspective. *Hum. Ecol. Risk Assess.* **17:** 1039–1056.
3. Entrekin, S., M. Evans-White, B. Johnson & E. Hagenbuch. 2011. Rapid expansion of natural gas development poses a threat to surface waters. *Front. Ecol. Environ.* **9:** 503–511.
4. Schmidt, C.W. 2011. Blind rush? Shale gas boom proceeds amid human health questions. *Environ. Health Persp.* **119:** 348–353.
5. Sutherland, W.J., S. Bardsley, L. Bennun, *et al.* 2011. Horizon scan of global conservation issues for 2011. *Trends Ecol. Evol.* **26:** 10–16.
6. Wyman, R.L. 1991. "Multiple threats to wildlife: climate change, acid precipitation, and habitat fragmentation." In *Global Climate Change and Life on Earth.* R.L. Wyman, Ed.: 134–155. New York, NY: Routledge, Chapman and Hall.
7. Highton, R. 2005. "Declines of eastern North American woodland salamanders (*Plethodon*)." In *Amphibian Declines.* M.J. Lannoo, Ed.: 34–46. Berkeley, CA: University of California Press.
8. Gillen, J. & E. Kiviat. 2012. Hydraulic fracturing threats to species with restricted geographic ranges in the eastern United States. *Environ. Pract.* **14:** 320–331. DOI: 10.10170S1466046612000361.
9. Lindenmayer, D.B. & G.E. Likens. 2011. Direct measurement versus surrogate indicator species for evaluating environmental change and biodiversity loss. *Ecosystems* **14:** 47–59.
10. Raphael, M.G. & R. Molina. 2005. *Conservation of Rare or Little-Known Species.* Washington, DC: Island Press.
11. US EIA (U.S. Energy Information Administration). 2012. What is shale gas and why is it important? U.S. Energy Information Administration. Washington, DC. Accessed September 23, 2012. http://www.eia.gov/energy_in_brief/about_shale_gas.cfm.
12. ARI (Advanced Resources International). 2011. World shale gas resources: an initial assessment of 14 regions outside the United States. U.S. Energy Information Administration. Washington, DC. Accessed September 23, 2012. http://www.eia.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf.
13. Soeder, D.J. & W.M. Kappel. 2009. Water resources and natural gas production from the Marcellus shale. U.S. Geological Survey Fact Sheet 2009-3032. Accessed September 16, 2012. http://pubs.usgs.gov/fs/2009/3032/pdf/FS2009-3032.pdf.
14. Bailey, R.G. 1995. *Description of the Ecoregions of the United States*, 2nd ed. Washington, DC: U.S. Forest Service Miscellaneous Publication 1391 (revised).
15. Adams, M.B., M.W. Ford, T.M. Schuler & M. Thomas-Van Gundy. 2011. Effects of natural gas development on forest ecosystems. Proceedings of the 17th Central Hardwood Forest Conference GTR-NRS-P-**78:** 219–226.
16. Davis, J.B. & G.R. Robinson. 2012. A geographic model to assess and limit cumulative ecological degradation from Marcellus shale exploitation in New York, USA. *Ecol. Soc.* **17:** article 25.
17. Collins, E.A. 2010. New withdrawals, new impairments as Pennsylvania develops the Marcellus shale. 2010 Eastern Water Resources Conference. Orlando, FL. May 20–21, 2010. University of Pittsburgh Legal Studies Research Paper 2010–34. Accessed September 19, 2012. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1699731.
18. Rozell, D.J. & S.J. Reaven. 2012. Water pollution risk associated with natural gas extraction from the Marcellus Shale. *Risk Anal.* **32:** 1382–1393.
19. Michaels, C., J. Simpson & W. Wegner. 2010. Fractured communities: case studies of the environmental impacts of industrial gas drilling. Riverkeeper. Ossining, NY. Accessed September 16, 2012. http://www.riverkeeper.org/wp-content/uploads/2010/09/Fractured-Communities-FINAL-September-2010.pdf.
20. Mellott, C. 2011. Natural gas extraction from the Marcellus formation in Pennsylvania: environmental impacts and possible policy responses for state parks. Annandale, NY: M.S. Thesis, Bard College Center for Environmental Policy.
21. Mitchell, A.L. & E.A. Casman. 2011. Economic incentives and regulatory framework for shale gas well site reclamation in Pennsylvania. *Environ. Sci. Technol.* **45:** 9506–9514.
22. Karraker, N.E. 2008. "Impacts of road deicing salts on amphibians and their habitats." In *Urban Herpetology*. J.C.

Mitchell, R.E.J. Brown & B. Bartholomew, Eds.: 211–223. Salt Lake City, UT: Society for the Study of Amphibians and Reptiles.

23. Nash, T.H. & O.L. Lange. 1988. Responses of lichens to salinity: concentration and time-course relationships and variability among Californian species. *N. Phytol.* **109:** 361–367.
24. Matos, P., J. Cardoso-Vilhena, R. Figueira & A. Jorge Sousa. 2011. Effects of salinity stress on cellular location of elements and photosynthesis in *Ramalina canariensis* Steiner. *Lichenologist* **43:** 155–164.
25. Pisani, T., S. Munzi, L. Paoli, *et al.* 2011. Physiological effects of mercury in the lichens *Cladonia arbuscula* subsp. *mitis* (Sandst.) Ruoss and *Peltigera rufescens* (Weiss) Humb. *Chemosphere* **82:** 1030–1037.
26. Hill M.O., C.D. Preston, S.D.S. Bosanquet & D.B. Roy. 2007. BRYOATT: attributes of British and Irish mosses, liverworts and hornworts. NERC Centre for Ecology and Hydrology and Countryside Council for Wales. Accessed: December 27, 2012. http://nora.nerc.ac.uk/1131/1/BRYOATT.pdf.
27. Wilcox, D.A. 1984. The effects of NaCl deicing salts on *Sphagnum recurvum* P. Beauv. *Environ. Exp. Bot.* **24:** 295–301, 303–304.
28. Wilcox, D.A. & R.E. Andrus. 1987. The role of *Sphagnum fimbriatum* in secondary succession in a road salt impacted bog. *Can. J. Botany.* **65:** 2270–2275.
29. Richburg, J.A., W.A. Patterson III & F. Lowenstein. 2001. Effects of road salt and *Phragmites australis* invasion on the vegetation of a western Massachusetts calcareous lake-basin fen. *Wetlands* **21:** 247–255.
30. Roth, D. & G. Wall. 1976. Environmental effects of highway deicing salts. *Ground Water* **14:** 286-289.
31. Bryson, G.M. & A.V. Barker. 2002. Sodium accumulation in soils and plants along Massachusetts roadsides. *Commun. Soil Sci. Plan.* **33:** 67–78.
32. Smith, M.J., K.M. Ough, M.P. Scroggie, *et al.* 2009. Assessing changes in macrophyte assemblages with salinity in non-riverine wetlands: a Bayesian approach. *Aquat. Bot.* **90:** 137–142.
33. Thouvenot, L., J. Haury & G. Thiébaut. 2012. Responses of two invasive macrophyte species to salt. *Hydrobiologia* **686:** 213–223.
34. Wilcox, D.A. 1986. The effects of deicing salts on vegetation in Pinhook Bog, Indiana. *Can. J. Bot.* **64:** 865–874.
35. Trombulak, S.C. & C.A. Frissell. 2000. Review of ecological effects of roads on terrestrial and aquatic communities. *Conserv. Biol.* **14:** 18–30.
36. Wetmore, C.M. 1988. "Lichen floristics and air quality." In *Lichens, Bryophytes and Air Quality*. (Bibliotheca Lichenologica) T.H. Nash, III & V. Wirth, Eds.: 55–65. Berlin, Germany: J. Cramer.
37. Branquinho, C., D.H. Brown, C. Máguas & F. Catarino. 1997. Lead (Pb) uptake and its effects on membrane integrity and chlorophyll fluorescence in different lichen species. *Environ. Exp. Bot.* **37:** 95–105.
38. Garty, J., Y. Cohen, N. Kloog & A. Karnieli. 1997. Effects of air pollution on cell membrane integrity, spectral reflectance and metal and sulfur concentrations in lichens. *Environ. Toxicol. Chem.* **16:** 1396–1402.
39. Brodo, I.M., S.D. Sharnoff & S. Sharnoff. 2001. *Lichens of North America.* New Haven, CT: Yale University Press.
40. Bačkor, M., B. Pawlik-Skowrońska, J. Tomko, *et al.* 2006. Response to copper stress in aposymbiotically grown lichen mycobiont *Cladonia cristatella*: uptake, viability, ergosterol and production of non-protein thiols. *Mycol. Res.* **110:** 994–999.
41. Heumann, H.G. 1987. Effects of heavy metals on growth and ultrastructure of *Chara vulgaris. Protoplasma* **136:** 37–48.
42. Gosek, A., M. Kwiatkowska & R. Duszyński. 1997. The effect of cadmium on growth of vegetative thallus and development of generative organs of *Chara vulgaris* L. after short time of cultivation. *Acta Soc. Bot. Pol.* **66:** 67–72.
43. Bibi M.H., T. Asaeda & E. Azim. 2010. Effects of Cd, Cr, and Zn on growth and metal accumulation in an aquatic macrophyte, *Nitella graciliformis. Chem. Ecol.* **26:** 49–56.
44. Long, J.A., T.A. Nelson & M.A. Wulder. 2010. Characterizing forest fragmentation: distinguishing change in composition from configuration. *Appl. Geogr.* **30:** 426–435.
45. Zipperer, W.C. 1993. Deforestation patterns and their effects on forest patches. *Landscape Ecol.* **8:**177–184.
46. Drohan, P.J., M. Brittingham, J. Bishop & K. Yoder. 2012. Early trends in landcover change and forest fragmentation due to shale gas development in Pennsylvania: a potential outcome for the northcentral Appalachians. *Environ. Manage.* **49:** 1061–1075.
47. Demaynadier, P.G. & M.L. Hunter, Jr. 1998. Effects of silvicultural edges on the distribution and abundance of amphibians in Maine. *Conserv. Biol.* **12:** 340–352.
48. Rothermel, B.B. & R.D. Semlitsch. 2006. Consequences of forest fragmentation for juvenile survival in spotted (*Ambystoma maculatum*) and marbled (*Ambystoma opacum*) salamanders. *Can. J. Zool.* **84:** 797–807.
49. Popescu, V.D. & M.L. Hunter, Jr. 2011. Clear-cutting affects habitat connectivity for a forest amphibian by decreasing permeability to juvenile movements. *Ecol. Appl.* **21:** 1283–1295.
50. Moseley, K.R., W.M. Ford & J.W. Edwards. 2009. Local and landscape scale factors influencing edge effects on woodland salamanders. *Environ. Monit. Assess.* **151:** 425–435.
51. Rudolphi, J. & L. Gustafsson. 2011. Forests regenerating after clear-cutting function as habitat for bryophyte and lichen species of conservation concern. *PLoS One* **6:** e18639.
52. Swarts, N.D. & K.W. Dixon. 2009. Terrestrial orchid conservation in the age of extinction. *Ann. Bot.-Lond.* **104:** 543–556.
53. Brunet, J., K. Valtinat, M.L. Mayr, *et al.* 2011. Understory succession in post-agricultural oak forests: habitat fragmentation affects forest specialists and generalists differently. *Forest Ecol. Manag.* **262:** 1863–1871.
54. NYNHP (New York Natural Heritage Program). 2009. Online conservation guide for *Pieris virginiensis.* Accessed: January 9, 2013. http://acris.nynhp.org/guide.php?id=7830.
55. Gibbs, J.P. 1998. Distribution of woodland amphibians along a forest fragmentation gradient. *Landscape Ecol.* **13:** 263–268.

56. Robbins, C.S., D.K. Dawson & B.A. Dowell. 1989. Habitat area requirements of breeding forest birds of the middle Atlantic states. *Wildlife Monogr.* **103:** 3–34.
57. Rolstad, J. 2008. Consequences of forest fragmentation for the dynamics of bird populations: conceptual issues and the evidence. *Biol. J. Linn. Soc.* **42:** 149–163.
58. Smith, A.C., L. Fahrig & C.M. Francis. 2011. Landscape size affects the relative importance of habitat amount, habitat fragmentation, and matrix quality on forest birds. *Ecography* **34:** 103–113.
59. Cox, W.A., F.R. Thompson, B. Root & J. Faaborg. 2012. Declining brown-headed cowbird (*Molothrus ater*) populations are associated with landscape-specific reductions in brood parasitism and increases in songbird productivity. *PloS One* **7:** e47591.
60. McCormick, M.K. & D.F. Whigham. 2012. Using the complexities of orchid life histories to target conservation efforts. *Native Orchid Conf. J.* **9:** 14–23.
61. Johnson-Groh, C.L. & J.M. Lee. 2002. Phenology and demography of two species of *Botrychium* (Ophioglossaceae). *Am. J. Bot.* **89:** 1624–1633.
62. Brauning, D.W., Ed. 1992. *Atlas of Breeding Birds in Pennsylvania.* Pittsburgh, PA: University of Pittsburgh Press.
63. Buckelew, A.R., Jr. & G.A. Hall. 1994. *The West Virginia Breeding Bird Atlas.* Pittsburgh, PA: University of Pittsburgh Press.
64. Steele, M.A., M.C. Brittingham, T.J. Maret & J.F. Merritt. 2010. *Terrestrial Vertebrates of Pennsylvania: A Complete Guide to Species of Conservation Concern.* Baltimore, MD: Johns Hopkins University Press.
65. Green, D.M. 2005. "Biology of amphibian declines." In *Amphibian Declines: The Conservation Status of United States Species.* M. Lannoo, Ed.: 28–33. Berkeley, CA: University of California Press.
66. Jolls, C.L. 2003. "Populations of and threats to rare plants of the herb layer." In *The Herbaceous Layer in Forests of Eastern North America.* F.S. Gilliam & M.R. Roberts, Eds.:105–159. Oxford, UK: Oxford University Press.
67. Bratton, S.P. & A.J. Meier. 1998. Restoring wildflowers and salamanders in southeastern deciduous forests. *Restor. Manage. Notes* **16:** 158–165.
68. Thiele, J., U. Schuckert & A. Otte. 2008. Cultural landscapes of Germany are patch-corridor-matrix mosaics for an invasive megaforb. *Landscape Ecol.* **23:** 453–465.
69. Mortensen, D.A., E.S.J. Rauschert, A.N. Nord & B.P. Jones. 2009. Forest roads facilitate the spread of invasive plants. *Invas. Plant Sci. Manage.* **2:** 191–199.
70. Forman, R.T.T. & L.E. Alexander. 1998. Roads and their major ecological effects. *Annu. Rev. Ecol. Syst.* **29:** 207–231.
71. Evangelista, P.H., A.W. Crall & E. Bergquist. 2011. "Invasive plants and their response to energy development." In *Energy Development and Wildlife Conservation in Western North America.* D.E. Naugle, Ed.: 115–129. Washington, DC: Island Press.
72. Kiviat, E. unpublished data.
73. Catling, P.M. & S. Carbyn. 2006. Recent invasion, current status and invasion pathway of European common reed, *Phragmites australis* subspecies *australis*, in the southern Ottawa district. *Can. Field Nat.* **120:** 307–312.
74. Jodoin, Y., C. Lavoie, P. Villeneuve, *et al.* 2008. Highways as corridors and habitats for the invasive common reed *Phragmites australis* in Quebec, Canada. *J. Appl. Ecol.* **45:** 459–466.
75. Bayne, E.M. & B.C. Dale. 2011. "Effects of energy development on songbirds." In *Energy Development and Wildlife Conservation in Western North America.* D.E. Naugle, Ed.: 95–114. Washington, DC: Island Press.
76. Marsh, D.M. & N.G. Beckman. 2004. Effects of forest roads on the abundance and activity of terrestrial salamanders. *Ecol. Appl.* **14:** 1882–1891.
77. Garti, A.M. 2012. The illusion of the blue flame: water law and unconventional gas drilling in New York State. *Environ. Law N.Y.* **23:** 159–165.
78. Fahrig, L., J.H. Pedlar, S.E. Pope, *et al.* 1995. Effect of road traffic on amphibian density. *Biol. Conserv.* **73:** 177–182.
79. Batzer, D.P. & R.R. Sharitz. 2006. *Ecology of Freshwater and Estuarine Wetlands.* Berkeley, CA: University of California Press.
80. Klein, R.D. 1979. Urbanization and stream quality impairment. *Water Resour. Bull.* **15:** 948–963.
81. Orth, D.J. & O.E. Maughan. 1982. Evaluation of the incremental methodology for recommending instream flows for fishes. *T. Am. Fish. Soc.* **111:** 413–445.
82. Dewson, Z.S., A.B.W. James & R.G. Death. 2007. A review of the consequences of decreased flow for instream habitat and macroinvertebrates. *J. N. Am. Benthol. Soc.* **26:** 401–415.
83. Lydeard, C., R.H. Cowie, W.F. Ponder, *et al.* 2004. The global decline of nonmarine mollusks. *BioScience* **54:** 321–330.
84. Baldigo, B.P., A.G. Ernst, G.E. Schuler & C.D. Apse. 2008. Relations of environmental factors with mussel-species richness in the Neversink River, New York. U.S. Geological Survey Open-File Report 2007–1283.
85. Williams, R.D., J.E. Gates, C.E. Hocutt & G.J. Taylor. 1981. The hellbender: a nongame species in need of management. *Wildlife Soc. B.* **9:** 94–100.
86. Nickerson, M.A., K.L. Krysko & R.D. Owen. 2002. Ecological status of the hellbender (*Cryptobranchus alleganiensis*) and the mudpuppy (*Necturus maculosus*) salamanders in the Great Smoky Mountains. *J. N.C. Acad. Sci.* **118:** 27–34.
87. Hopkins, W.A. & S.E. DuRant. 2011. Innate immunity and stress physiology of eastern hellbenders (*Cryptobranchus alleganiensis*) from two stream reaches with differing habitat quality. *Gen. Comp. Endocr.* **174:** 107–115.
88. Schueler, T.R. 1994. The importance of imperviousness. *Watershed Protect. Tech.* **1:** 100–111.
89. Arnold, C.L. & C.J. Gibbons. 1996. Impervious surface coverage: the emergence of a key environmental indicator. *J. Am. Plann. Assoc.* **62:** 243–258.
90. NRC (National Research Council). 2008. *Urban Stormwater Management in the United States.* Washington, DC: National Academies Press.
91. Harding, J.S., E.F. Benfield, P.V. Bolstad., *et al.* 1998. Stream biodiversity: the ghost of land use past. *Proc. Natl. Acad. Sci. USA* **95:** 14843–14847.
92. Barber, J.R., K.R. Crooks & K.M. Fristrup. 2010. The costs of chronic noise exposure for terrestrial organisms. *Trends Ecol. Evol.* **25:**180–189.

93. Habib, L., E.M. Bayne & S. Boutin. 2007. Chronic industrial noise affects pairing success and age structure of ovenbirds *Seiurus aurocapilla*. *J. Appl. Ecol.* **44:** 176–184.
94. Francis C.D., C.P. Ortega & A. Cruz. 2009. Noise pollution changes avian communities and species interactions. *Curr. Biol.* **19:** 1415–1419.
95. Bayne, E.M., L. Habib & S. Boutin. 2008. Impacts of chronic anthropogenic noise from energy-sector activity on abundance of songbirds in the boreal forest. *Conserv. Biol.* **22:** 1186–1193.
96. Legakis, A., C. Papadimitriou, M. Gaethlich & D. Lazaris. 2000. Survey of the bats of the Athens metropolitan area. *Myotis* **38:** 41–46.
97. Jones, G. 2008. Sensory ecology: noise annoys foraging bats. *Curr. Biol.* **18:** 1098–1100.
98. Schaub, A., J. Ostwald & B.M. Siemers. 2008. Foraging bats avoid noise. *J. Exp. Biol.* **211:** 3174–3180.
99. Siemers, B.M. & A. Schaub. 2011. Hunting at the highway: traffic noise reduces foraging efficiency in acoustic predators. *Proc. R. Soc. B.-Biol. Sci.* **278:** 1646–1652.
100. Francis, C.D., N.J. Kleist, C.P. Ortega & A. Cruz. 2012. Noise pollution alters ecological services: enhanced pollination and disrupted seed dispersal. *Proc. R. Soc. B.-Biol. Sci.* **279:** 2727–2735.
101. Rich, C. & T. Longcore, Eds.: 2006. *Ecological Consequences of Artificial Night Lighting*. Covelo, CA: Island Press.
102. Stone, E.L., G Jones & S. Harris. 2009. Street lighting disturbs commuting bats. *Curr. Biol.* **19:** 1123–1127.
103. Perkin, E.K., F. Hölker, J.S. Richardson, *et al.* 2011. The influence of artificial light on stream and riparian ecosystems: questions, challenges, and perspectives. *Ecosphere* **2:** 1–16.
104. Horváth, G., G. Kriska, P. Malik & B. Robertson. 2009. Polarized light pollution: a new kind of ecological photopollution. *Front. Ecol. Environ.* **7:** 317–325.
105. Colborn, T., K. Schultz, L. Herrick & C. Kwiatkowski. 2012. An exploratory study of air quality near natural gas operations. *Hum. Ecol. Risk Assess.* DOI: 10.1080/10807039.2012.749447.
106. Courter, L.A., C. Pereira & W.A. Baird. 2007. Diesel exhaust influences carcinogenic PAH-induced genotoxicity and gene expression in human breast epithelial cells in culture. *Mutat. Res.* **625:** 72–82.
107. Bignal, K.L., M.R. Ashmore & A.D. Headley. 2008. Effects of air pollution from road transport on growth and physiology of six transplanted bryophyte species. *Environ. Pollut.* **156:** 332–340.
108. Bignal, K.L., M.R. Ashmore, A.D. Headley, *et al.* 2007. Ecological impacts of air pollution from road transport on local vegetation. *Appl. Geochem.* **22:** 1265–1271.
109. Seaward, M.R.D. 1993. Lichens and sulphur dioxide air pollution: field studies. *Environ. Rev.* **1:** 73–91.
110. Lisowska, M. 2011. Lichen recolonisation in an urban-industrial area of southern Poland as a result of air quality improvement. *Environ. Monit. Assess.* **179:** 177–190.
111. Farmer, A.M. 1993. The effects of dust on vegetation—a review. *Environ. Pollut.* **79:** 63–75.
112. Wilcove, D., S. Roble & G. Hammerson. 2011. Virginia big-eared bat *(Corynorhinus townsendii virginianus)*. NatureServe Explorer. An online encyclopedia of life. Version 7.1. NatureServe. Arlington, VA. Accessed September 17, 2012. http://www.natureserve.org/explorer/servlet/NatureServe?searchName=Corynorhinus+townsendii+virginianus.
113. Smith, C.L. 1985. *The Inland Fishes of New York State*. Albany, NY: New York State Department of Environmental Conservation.
114. Cañedo-Argüelles, M., B.J. Kefford, C. Piscart, *et al.* 2013. Salinisation of rivers: an urgent ecological issue. *Environ. Pollut.* **173:** 157–167.
115. NatureServe. 2013. NatureServe Explorer: an online encyclopedia of life [web application]. Version 7.1. NatureServe, Arlington, Virginia. Accessed April 11, 2013. http://www.natureserve.org/explorer.
116. Roze, U. 1989. *The North American Porcupine*. Washington, D.C: Smithsonian Institution Press, 261.
117. Molleman, F. 2009. Puddling: from natural history to understanding how it affects fitness. *Entomol. Exp. Appl.* **134:** 107–113.
118. Salemaa, M., I. Vanha-Majamaa & J. Derome. 2001. Understorey vegetation along a heavy-metal pollution gradient in SW Finland. *Environ. Pollut.* **112:** 339–350.
119. Eyre, M.D., M.L. Luff & J.C. Woodward. 2003. Beetles (Coleoptera) on brownfield sites in England: an important conservation resource? *J. Insect Conserv.* **7:** 223–231.
120. Zou, L., S.N. Miller & E.T. Schmidtmann. 2006. Mosquito larval habitat mapping using remote sensing and GIS: implications of coalbed methane development and West Nile virus. *J. Med. Entomol.* **43:** 1034–1041.
121. Schmidt, R.E. & E. Kiviat. 2007. State records and habitat of clam shrimp, *Caenestheriella gynecia* (Crustacea: Conchostraca), in New York and New Jersey. *Can. Field-Naturalist* **121:** 128–132.
122. Root, T.L., J.T. Price, K.R. Hall, S.H. Schneider, *et al.* 2003. Fingerprints of global warming on wild animals and plants. *Nature* **421:** 57–60.
123. Zhu, K., C.W. Woodall & J.S. Clark. 2012. Failure to migrate: lack of tree range expansion in response to climate change. *Glob. Change Biol.* **18:** 1042–1052.
124. Benítez-López, A., R. Alkemade & P.A. Verweij. 2010. The impacts of roads and other infrastructure on mammal and bird populations: a meta-analysis. *Biol. Conserv.* **143:** 1307–1316.
125. Sanders, S.E. & J.B. McGraw. 2005. Harvest recovery of goldenseal, *Hydrastis canadensis* L. *Am. Midl. Nat.* **153:** 87–94.
126. Harper, D.D., A.M. Farag, C. Hogstrand & E. MacConnell. 2009. Trout density and health in a stream with variable water temperatures and trace element concentrations: does a cold-water source attract trout to increased metal exposure? *Environ. Toxicol. Chem.* **28:** 800–808.
127. Siitari, K.J., W.W. Taylor, S.A.C. Nelson & K.E. Weaver. 2011. The influence of land cover composition and groundwater on thermal habitat availability for brook charr (*Salvelinus fontinalis*) populations in the United States of America. *Ecol. Freshw. Fish.* **20:** 431–437.
128. Wilcox, B.A. & D.D. Murphy. 1985. Conservation strategy: the effects of fragmentation on extinction. *Am. Nat.* **125:** 879–887.

129. Pimm, S.L. & R.A. Askins. 1995. Forest losses predict bird extinctions in eastern North America. *Proc. Natl. Acad. Sci. USA* **92:** 9343–9347.
130. Blockstein, D.E. 2002. "Passenger pigeon *(Ectopistes migratorius)*." In *The Birds of North America.* A. Poole & F. Gill, Eds.: 611. Philadelphia, PA: Academy of Natural Sciences.
131. Foster, D.R., G. Motzkin, D. Bernardos & J. Cardoza. 2002. Wildlife dynamics in the changing New England landscape. *J. Biogeogr.* **29:** 1337–1357.
132. Drummond, M.A. & T.R. Loveland. 2010. Land-use pressure and a transition to forest cover loss in the eastern US. *BioScience* **60:** 286–298.
133. Riitters, K.H., J.D. Wickham, R.V. O'Neill, *et al.* 2002. Fragmentation of continental United States forests. *Ecosystems* **5:** 815–822.
134. Ribic, C.A., R.R. Koford, J.R. Herkert, *et al.* 2009. Area sensitivity in North American grassland birds: patterns and processes. *Auk* **126:** 233–244.
135. Strayer, D. 2006. Challenges for freshwater invertebrate conservation. *J. N. Am. Benthol. Soc.* **25:** 271–287.
136. Gilbert, O.L. 1989. *The Ecology of Urban Habitats.* London, UK: Chapman & Hall.
137. Savard, J.-P.L., P. Clergeau & G. Mennechez. 2000. Biodiversity concepts and urban ecosystems. *Landscape Urban Plan.* **48:** 131–142.
138. Kiviat, E. & K. MacDonald. 2004. Biodiversity patterns and conservation in the Hackensack Meadowlands, New Jersey. *Urban Habitats* **2:** 28–61.
139. Loreau, M. 2010. Linking biodiversity and ecosystems: towards a unifying ecological theory. *Philos. Trans. R. Soc. B.* **365**: 49–60.
140. May, R.M. 1994. "The effects of spatial scale on ecological questions and answers." In *Large-scale Ecology and Conservation Biology*. P.J. Edwards, R.M. May & N.R. Webb, Eds.: 1–17. Oxford, U.K: Blackwell Science.

Hydraulic Fracturing Threats to Species with Restricted Geographic Ranges in the Eastern United States

Jennifer L. Gillen, Erik Kiviat

High-volume horizontal hydraulic fracturing (*fracking*) is a new technology that poses many threats to biodiversity. Species that have small geographic ranges and a large overlap with the extensively industrializing Marcellus and Utica shale-gas region are vulnerable to environmental impacts of fracking, including salinization and forest fragmentation. We reviewed the ranges and ecological requirements of 15 species (1 mammal, 8 salamanders, 2 fishes, 1 butterfly, and 3 vascular plants), with 36%–100% range overlaps with the Marcellus-Utica region to determine their susceptibility to shale-gas activities. Most of these species are sensitive to forest fragmentation and loss or to degradation of water quality, two notable impacts of fracking. Moreover, most are rare or poorly studied and should be targeted for research and management to prevent their reduction, extirpation, or extinction from human-caused impacts.

Environmental Practice Page 1 of 12

The new technology of high-volume horizontal hydraulic fracturing to extract natural gas, known as *fracking*, has gained attention in the past few years. Fracking is the process of drilling vertically and then horizontally through deeply buried shale beds, and pumping water, sand, and chemicals at high pressures into the shales to release the natural gas. Part of this chemical and water mixture returns to the surface as *frack water*, which contains toxicants such as benzene and toluene from the fracking fluids, as well as radium and salt from the shales (Rowan et al., 2011; Schmidt, 2011). Although the impacts of fracking in the eastern states on drinking-water supplies and public health have been discussed extensively, little attention has been paid to the effects of toxic chemicals, salt, habitat fragmentation, truck traffic, air pollution, noise, night lighting, and water withdrawals on ecosystems and their wild animals and plants (Davis and Robinson, 2012; Entrekin et al., 2011; Kiviat and Schneller-McDonald, 2011) The great spatial extent of industrialization and the rapid pace of development of shale-gas resources associated with fracking in the eastern United States (US) may result in environmental impacts disproportionate to economic benefits (Davis and Robinson, 2012). Many serious impacts of gas and oil mining on biodiversity have been documented in the US and Canadian West (Naugle, 2011). For example, compressor noise from gas-drilling installations was found to interfere with ovenbird (*Seiurus aurocapilla*) pairing success and alter population age structure (Habib, Bayne, and Boutin, 2007). In the Marcellus shale-gas region, it is expected that fracking will exacerbate the natural migration of salt from the deep shale beds into shallow aquifers (Warner et al., 2012), which could adversely affect wild species adapted to strictly fresh groundwaters or to surface waters into which groundwaters discharge.

The largest occurrence of commercially exploitable gas shales—the Marcellus and Utica shale-gas region—extends beneath approximately 285,000 km^2 of the Appalachian Basin (calculated from the US agency maps cited in this article's Methods section). This region supports high species diversity and many endemic species with small geographic ranges and narrow habitat affinities. The Appalachian region is a global megadiversity region for salamanders, stream fishes, freshwater mussels, and crayfishes, and is home to more than 150 imperiled species (Stein, Kutner, and Adams, 2000). Because organisms with geographic ranges concentrated in shale-gas regions are at greater risk from fracking impacts (Kiviat and Schneller-McDonald, 2011), we reviewed the potential impacts of fracking on animal and plant species with ranges substantially restricted to areas underlain by the Marcellus and Utica shale-gas region.

Affiliation of authors: Jennifer L. Gillen, Environmental and Urban Studies Program, Bard College, Annandale, New York. Erik Kiviat, PhD, Executive Director, Hudsonia Ltd., Annandale, New York.

Address correspondence to: Erik Kiviat, Executive Director, Hudsonia Ltd., PO Box 5000, Annandale, NY 12504; (phone) 845-758-7273; (fax) 845-758-7033; (e-mail) kiviat@bard.edu.

doi:10.1017/S1466046612000361

Methods

We focused on species that have geographic ranges of which 35% or more is underlain by the Marcellus and Utica shale-gas region; we refer to these species as *quasi-endemic* to the Marcellus-Utica region. The cutoff of 35% has precedent in conservation science and is considered a high percentage overlap in the Natural Capital Project's habitat risk assessment model (Arkema, Bernhardt, and Verutes, 2011). By reviewing publicly available range maps, we selected 15 species that met the 35% criterion and are currently accepted as full species in standard taxonomic treatments [e.g., US Department of Agriculture (USDA), 2012].

We then studied each species' natural history, habitat needs, and legal status for indications of vulnerability to the physical and chemical effects of fracking. For example, eight species are salamanders in the family Plethodontidae. These lungless salamanders are particularly sensitive to environmental changes because they respire through their skin and require constant contact with moisture (Welsh and Droege, 2001). After selecting species, geographic information system (GIS) software was used to calculate the percentage overlap with the gas shales. We obtained geographic range data for mammals and amphibians from the International Union for Conservation of Nature (IUCN) Red List Spatial Data Download website (2012), for plants from the USDA (2012), for fishes from NatureServe (2011), and for butterflies from Butterflies and Moths of North America (BAMONA, 2012). We combined digital maps of the Marcellus and Utica shale formations obtained from the US Energy Information Administration (2012) and the US Geological Survey (2002) to create a single map layer showing the region underlain by both formations. We used ArcMap 10.0 (ESRI, Redlands, CA) to establish the overlap between each species' range and the shale boundary, to calculate the percentage overlap, and to create the maps depicting the species ranges in relation to the Marcellus and Utica shale-gas region.

Various federal agency maps indicate that the area of the combined Marcellus and Utica shales is in the range of 268,000 to 340,000 km^2. We use the conservative figure of 285,000 km^2 for our analyses.

One of the selected species, Bailey's sedge, extends northward into a small area of Québec, yet we have analyzed only the US portion of its range. Because Canadian and US practices differ with regard to managing this rare species, and the species undoubtedly varies genetically in different portions of its range, we believe it is important to protect this plant within the US regardless of its status in Canada. Another species, northern blue monkshood, which occurs in small areas of Wisconsin, Iowa, Ohio, and New York (USDA, 2012), may be part of a widespread western species, Columbian monkshood (*Aconitum columbianum*; Cole and Kuchenreuther, 2001). However, because there is a disjunction of 800 km between the Ohio and Wisconsin populations, suggesting the potential for evolutionary divergence, we have included only the Ohio–New York populations in our analysis. Evolutionary potential must also be considered when determining the ecological effects of fracking. We assessed potential impacts at the species level, but genetic variation below the species level may have an even higher overlap with the shales.

Results and Discussion

We reviewed 15 species with restricted geographic ranges having 35%–100% overlap with the Marcellus and Utica shale-gas region (Table 1 and Figure 1). Of the 15 species selected, there are 8 plethodontid salamanders, 2 stream fishes, 1 mammal, 1 butterfly, and 3 plants. The total geographic range size varies from 3 to 292,261 km^2, with a mean of 91,075.3 km^2 and median of 59,988 km^2. The mean overlap with the shale-gas region is 64.4%, and the median is 68%. Ten species have 50% or greater overlaps with the shales, and four have 40%–49% overlap. These overlap figures indicate the potential for impacts to occur over large portions of these species' ranges and, given the cumulative impacts of other intensive land uses such as coal mining, agriculture, residential development, and logging, raise substantial concerns about species survival. The sensitivities of these species to habitat degradation at the landscape and regional levels are suggested by the data in Table 1. Of the 15 species, 4 are listed as endangered or threatened at the federal level or in at least one state where the species occurs. Of the 15 species, 11 are stated to depend on good water quality, 10 to be sensitive to habitat fragmentation, 13 are either stenotopic (have narrow habitat affinities) or are sensitive to changes in habitat, and 11 are threatened by deforestation (Table 1).

Species with smaller geographic ranges are more vulnerable to extinction than are species with larger ranges (Payne and Finnegan, 2007), and species with smaller populations (numbers of individuals) are more vulnerable than are species with larger populations (Noss and Cooperrider, 1994; Slobodkin, 1986). Thus, reductions in range size are expected to make a species more vulnerable to extinction. Reductions in

Table 1. Selected species of animals and plants with restricted geographic ranges and a high degree of overlap with the combined Marcellus and Utica shale-gas region.

Species	Range (km²)[a]	Shale (%)[b]	Status[c]	Water quality[d]	Fragmentation[e]	Stenotopic[f]	Forest[g]	References
Appalachian cottontail (*Sylvilagus obscurus*)	94,345	46			X		X	Barry and Lazell, 2008
Allegheny mountain dusky salamander (*Desmognathus ochrophaeus*)	292,261	70		X	X	X	X	Duncan et al., 2011 Gibbs et al., 2007 Welsh and Droege, 2001
West Virginia spring salamander (*Gyrinophilus subterraneus*)	3	100	E (WV)	X	X	X	X	Welsh and Droege, 2001
Wehrle's salamander (*Plethodon wehrlei*)	114,481	82		X	X	X	X	Duncan et al., 2011 Hammerson, 2004 Welsh and Droege, 2001 Wyman, 2003
Valley and ridge salamander (*Plethodon hoffmani*)	59,988	68		X	X	X	X	Duncan et al., 2011 Welsh and Droege, 2001 Wyman, 2003
Cheat Mountain salamander (*Plethodon nettingi*)	1,286	100	T (federal)	X	X	X	X	Duncan et al., 2011 Welsh and Droege, 2001 Wyman, 2003
White-spotted salamander (*Plethodon punctatus*)	11,143	45		X	X	X	X	Duncan et al., 2011 Welsh and Droege, 2001 Wyman, 2003
Shenandoah Mountain salamander (*Plethodon virginia*)	2,472	77		X	X	X	X	Duncan et al., 2011 Welsh and Droege, 2001 Wyman, 2003
Northern ravine salamander (*Plethodon electromorphus*)	113,396	58		X	X	X	X	Duncan et al., 2011 Welsh and Droege, 2001 Wyman, 2003
Tonguetied minnow (*Exoglossum laurae*)	31,622	67		X		?		USEPA, 2010
Bluebreast darter (*Etheostoma camurum*)	75,917	51	C (NY) I (OH, VA)	X		X		Losey, Roble, and Hammerson, 2011
Appalachian azure (*Celastrina neglectamajor*)	244,038	36			X	X	X	NYNHP, 2011
Shale-barrens pimpernel (*Taenidia montana*)	29,310	42	E (PA)			X		USDA, 2012 Walton, Ormes, and Morse, 2012
Bailey's sedge (*Carex baileyi*)	279,581	44		?	?	X	?	MNHESP, 2009
Northern blue monkshood (*Aconitum noveboracense*)	16,281	81	E (OH) T (federal, NY)	X		X	X	Edmondson et al., 2009 ONHP, 2007

[a] Total area of geographic range (calculations do not account for the fragmented ranges of some species, thus area occupied may be smaller than the figures shown).
[b] Percentage of geographic range that overlaps the Marcellus-Utica shale-gas region.
[c] E (endangered) or T (threatened) listing by federal or state agencies; C (critically imperiled) or I (imperiled) ranking by NatureServe (see references cited).
[d] Reported as sensitive to water quality (see references cited).
[e] Reported as sensitive to habitat fragmentation (see references cited).
[f] Reported as having narrow habitat affinities or as sensitive to habitat change (see references cited).
[g] Reported as dependent on forested environments or sensitive to deforestation (see references cited).
MNHESP, Massachusetts Natural Heritage and Endangered Species Program; NYNHP, New York Natural Heritage Program; ONHP, Ohio Natural Heritage Program; USDA, US Department of Agriculture; USEPA, US Environmental Protection Agency.

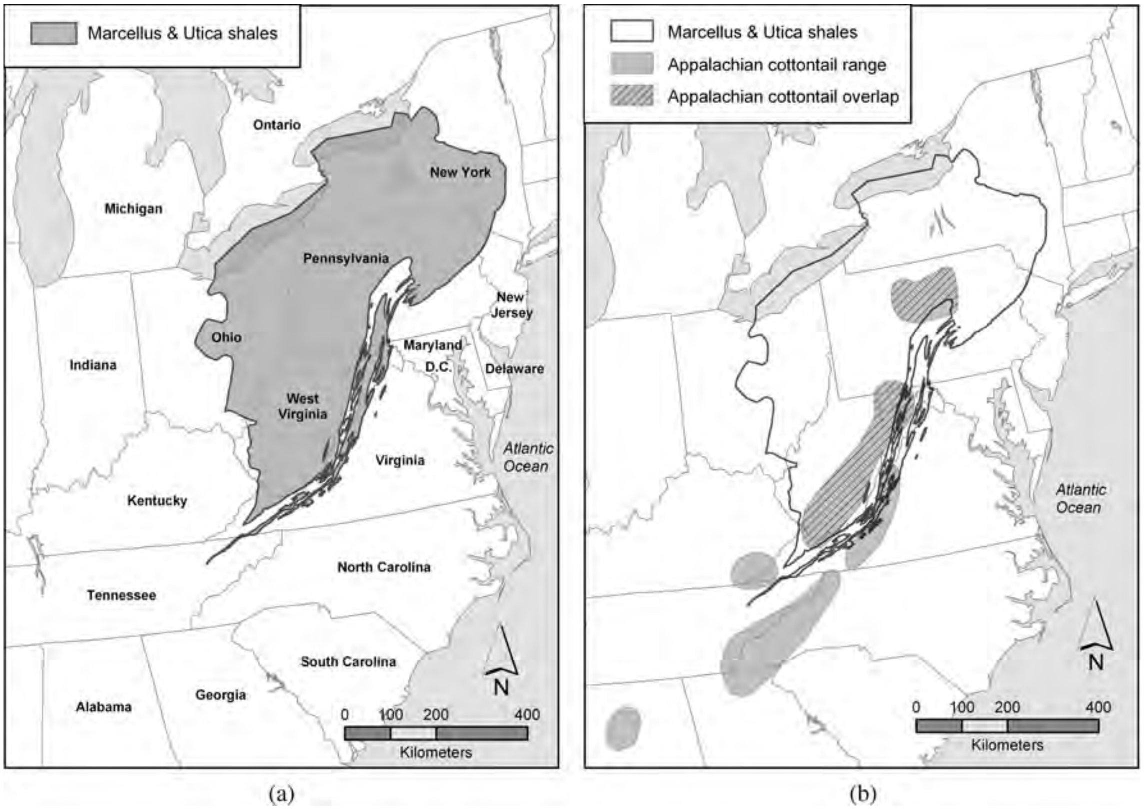


Figure 1. Maps showing the area underlain collectively by the Marcellus and Utica shale-gas region, the geographic ranges of selected species, and the overlap between shales and species: (**a**) Marcellus–Utica Shale outline, (**b**) Appalachian cottontail, (**c**) Allegheny mountain dusky salamander, (**d**) West Virginia spring salamander, (**e**) Wehrle's salamander, (**f**) valley and ridge salamander, (**g**) Cheat Mountain salamander, (**h**) white-spotted salamander, (**i**) Shenandoah Mountain salamander, (**j**) northern ravine salamander, (**k**) tonguetied minnow, (**l**) bluebreast darter, (**m**) Appalachian azure, (**n**) shale-barrens pimpernel, (**o**) Bailey's sedge, and (**p**) northern blue monkshood. Range maps for species are from the International Union for Conservation of Nature (2011), the US Department of Agriculture (2012), and Butterflies and Moths of North America (2012). See Table 1 for calculated areas of the geographic ranges and percentage overlaps with the shales.

forest area may result in great reductions of the number of species (Drakare, Lennon, and Hillebrand, 2006), and most of the species in our sample are closely associated with forests. The remainder of this discussion addresses the ecological requirements of the various groups of organisms that may make them vulnerable to fracking impacts.

Mammals

The Appalachian cottontail, recently separated by systematists from the New England cottontail, is found in mixed-oak forests with ericaceous (heath family) shrub cover (Bunch et al., 2012) and has a highly fragmented range, extending from Pennsylvania to Alabama (Barry and Lazell, 2008). Habitat needs are most likely different from those of the New England cottontail, but because this is not known, the species cannot yet be managed in a targeted way (Bunch et al., 2012). The Appalachian cottontail is declining and the number of local populations is decreasing due to habitat destruction, fragmentation, and forest maturation (Barry and Lazell, 2008; Harnishfeger, 2010). Fracking uses large areas of land for drill pads and pipelines, and roads must be constructed to enable truck traffic back and forth from drill sites. An average of 8.8 acres of forest is cleared for each Marcellus drill site and, with an additional indirect impact (through edge effects) on 21.2 acres, an average of 30 acres of forest is impacted at each site (Johnson, 2010). For a species that is threatened by habitat destruction and fragmentation, fracking could further reduce population and cause endangerment. The IUCN lists the Dolly Sods Wilderness Area, West Virginia, as a major source population for smaller populations of Appalachian cottontails

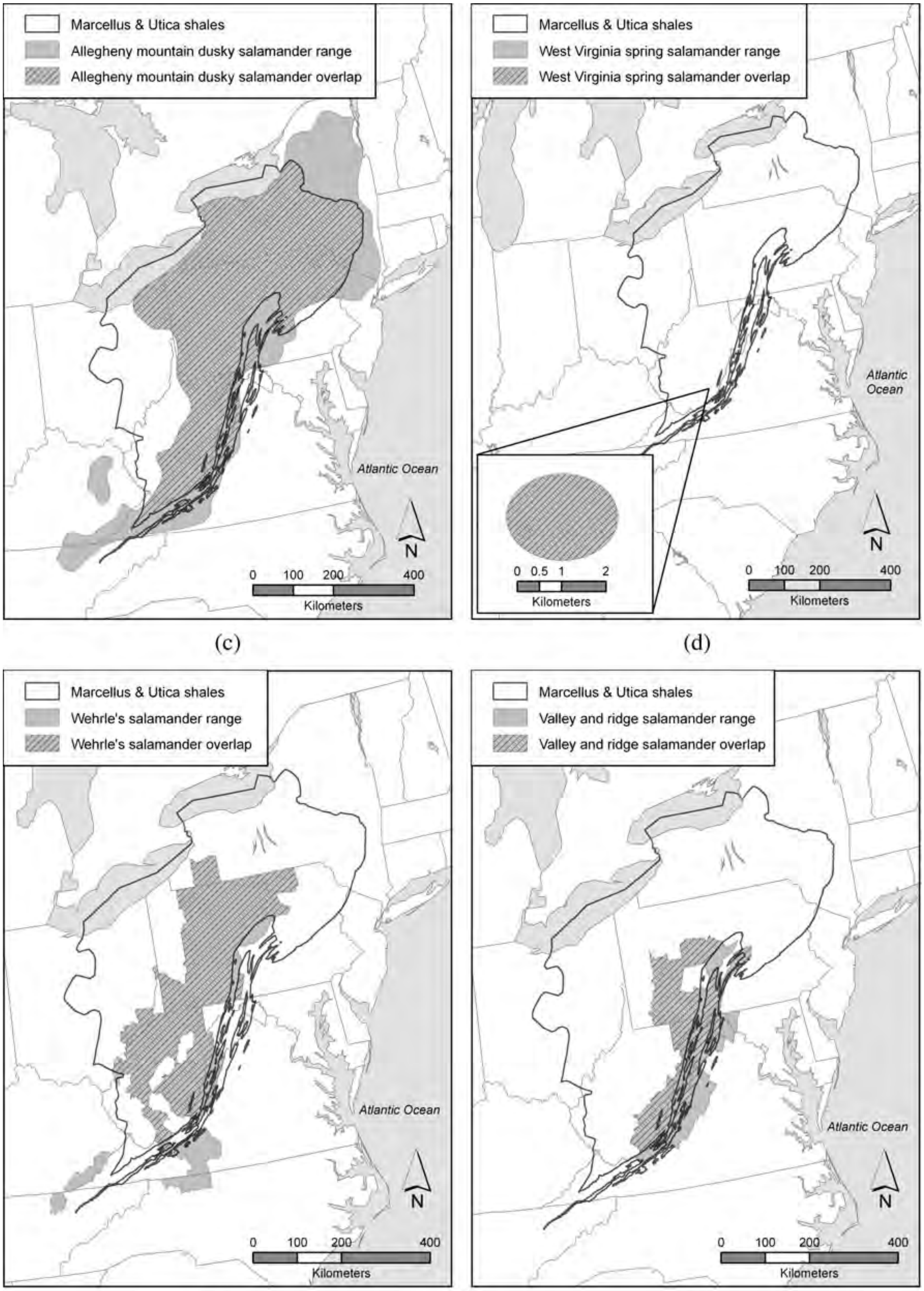


Figure 1. *Continued*

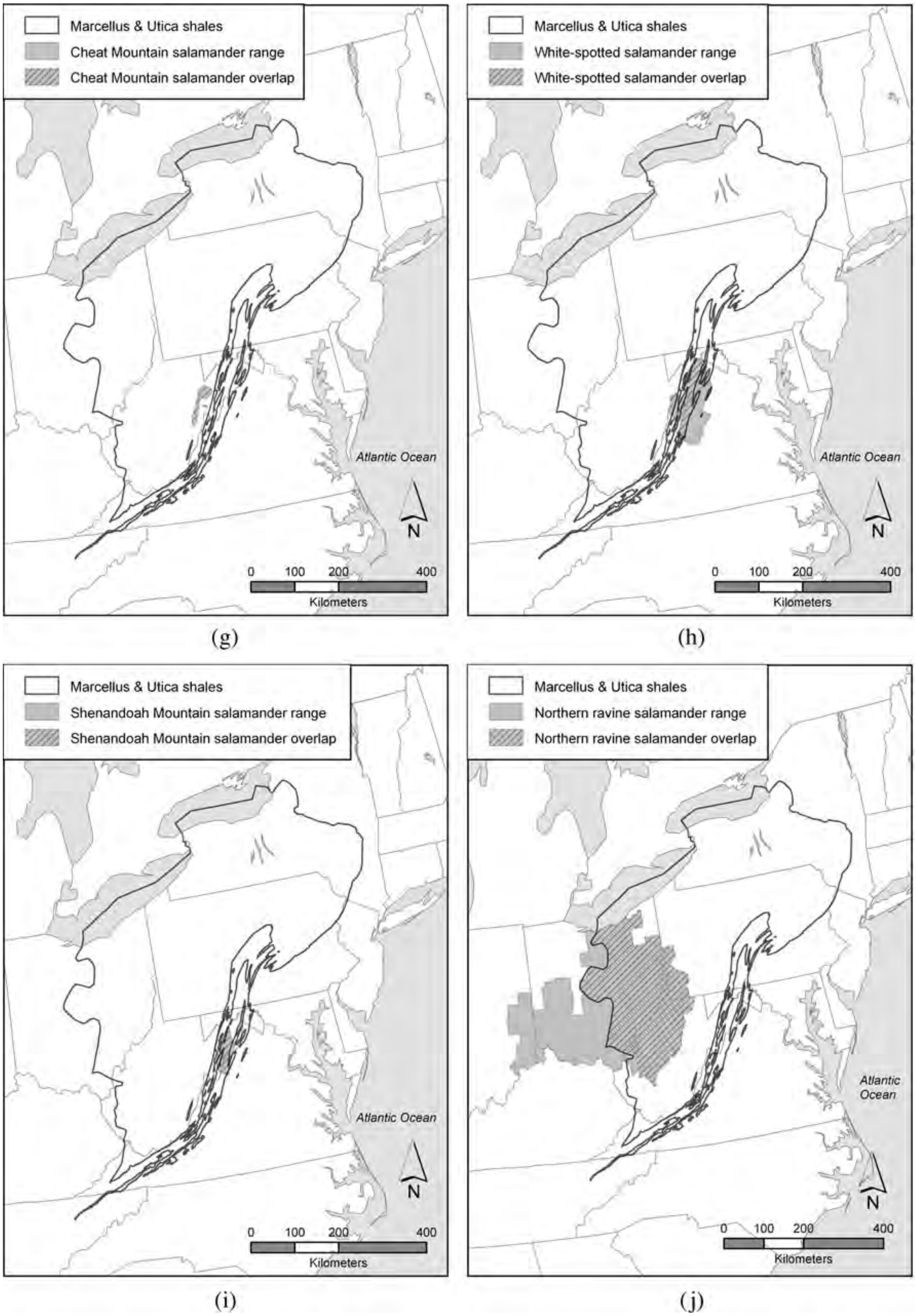


Figure 1. *Continued*

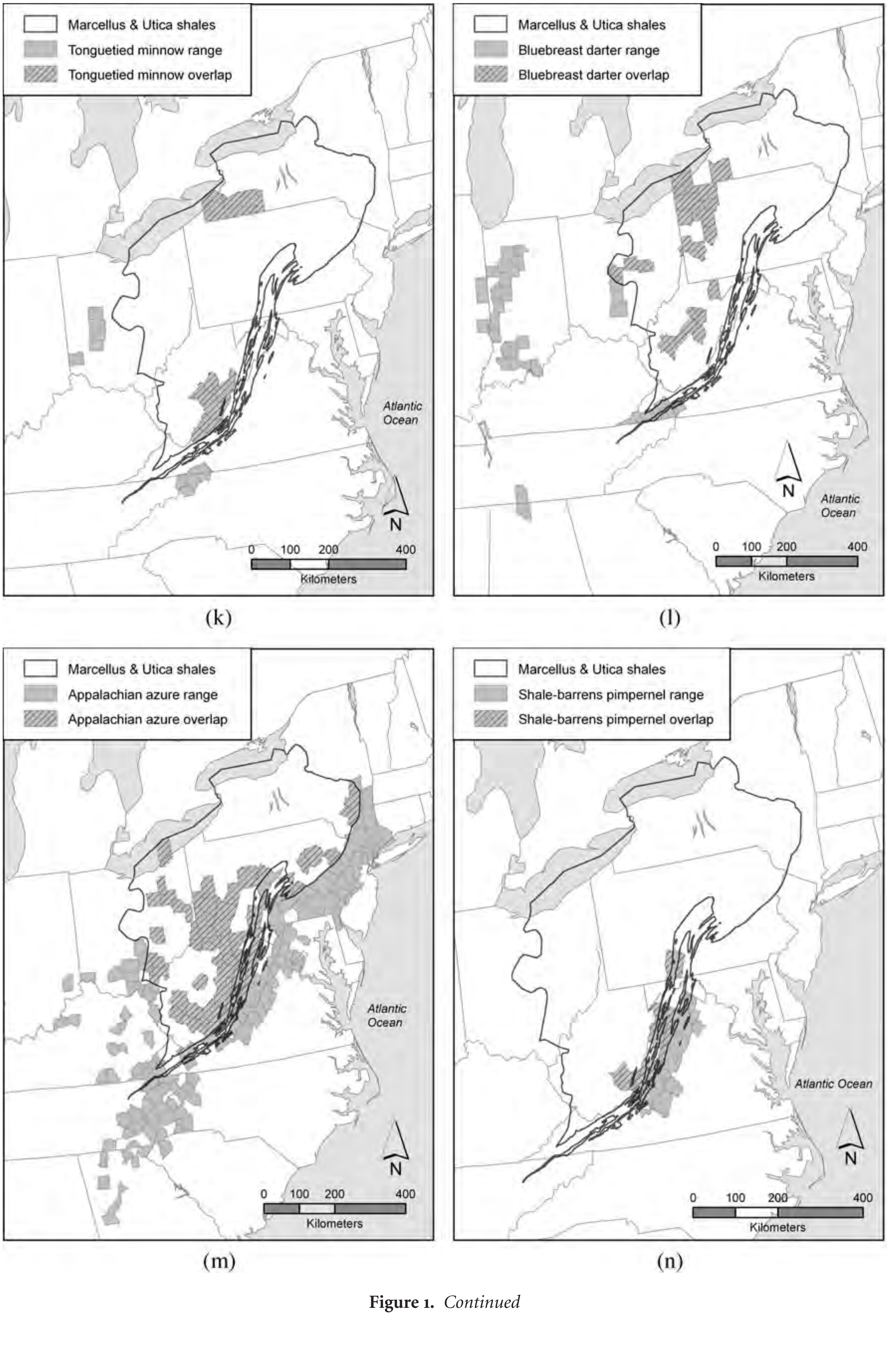


Figure 1. *Continued*

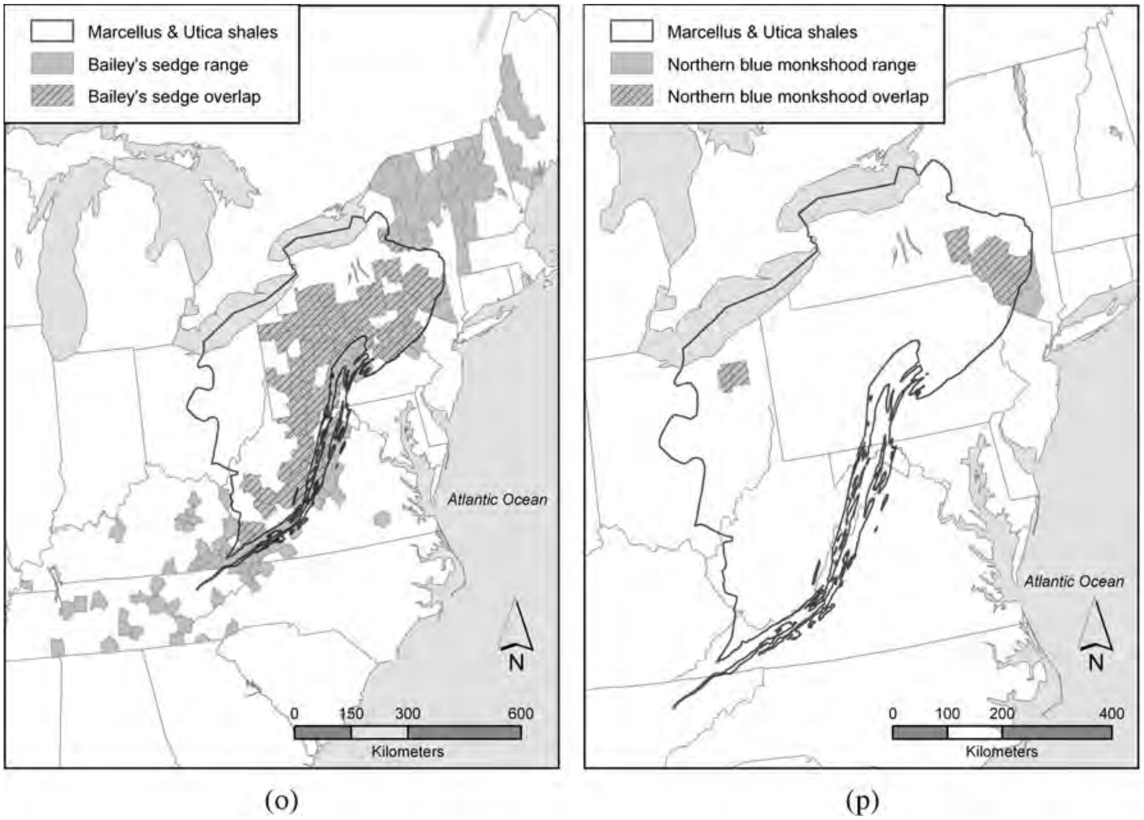


Figure 1. *Continued*

(Barry and Lazell, 2008), and if this population were severely affected by habitat destruction or fragmentation caused by fracking, those populations that depend on Dolly Sods for gene flow would be negatively impacted.

Salamanders

The Plethodontidae, which is the largest family of salamanders, represents significant diversity (Petranka, 1998). Plethodontids are rapidly evolving, and too little is known about 43% of species to manage them successfully (Wyman, 2003). Many plethodontids, such as the Shenandoah Mountain salamander and the northern ravine salamander (Table 1), have only recently been recognized as species, and their habitat requirements and management needs are poorly understood (Highton, 1999). There is especially a lack of knowledge about the vulnerable juvenile terrestrial plethodontids (Wyman, 2003).

Terrestrial salamanders have difficulty crossing roads, and roads may reduce both their abundance and genetic diversity. Roads not only fragment habitats but may also be obstacles to salamanders (Wyman, 2003). Forest roads have been shown to reduce terrestrial salamander movement by 51%, and multiple roads could reduce dispersal by up to 97%. Although roads may not have major implications for species with large ranges and high abundances, species with limited ranges and low abundances may be severely affected by new roads because they are already impacted by fragmentation, logging, and other human activities (Marsh, Gorham, and Beckman, 2005). Plethodontids such as the white-spotted salamander and the Cheat Mountain salamander have small distributions and are currently affected by fragmentation and deforestation (Hammerson, 2004; Hammerson and Mitchell, 2004); multiple roads and truck traffic, when compounded with many other destructive factors, could imperil these species' survival. After clear-cutting, salamander communities take decades to recover from the drying of soils in logged areas, changes in the prey community, and the difficulty many salamander species have in crossing nonforested habitats (e.g., Ash, 1997; Bratton and Meier, 1998; Mitchell, Wicknick, and Anthony, 1996; Petranka, Eldridge, and Haley, 1993). The perforation of forests by well pads, access roads, and pipeline rights-of-way, with associated microclimatic drying, salinization, and other changes, presumably reduces or eliminates local populations of many salamander species in fracking landscapes, and this could contribute cumulatively to a decline or loss of species over large areas.

The wastewater from fracking installations is another potential threat to salamanders. After well fracking is completed, 30%–70% of the water injected into the well returns to the surface with contaminants from the shales and the fracking chemicals (Schmidt, 2011). In Pennsylvania and West Virginia, frack water has been sprayed on land, diluted in municipal sewage treatment plants, stored in open pits, partially reused, leaked, and spilled (Kiviat and Schneller-McDonald, 2011). Preliminary data from Pennsylvania streams indicate that conductivity was higher and biotic diversity (including salamanders) was lower in small watersheds where fracking had occurred (Anonymous, 2010). Saline wastewater can pollute streams and other bodies of water, and many stream-dwelling and water-dependent organisms are salt sensitive. Salamanders, especially those with aquatic larvae, are sensitive to water quality (Duncan et al., 2011). The West Virginia spring salamander has been found in a single cave in Greenbrier County, West Virginia; the adults reside in the mud banks next to the stream passage, and the aquatic larvae develop in the stream (Besharse and Holsinger, 1977). Fewer than 250 mature individuals of this species exist, and all of these salamanders are dependent on the stream that runs through the General Davis Cave (Hammerson and Beachy, 2004)—if this stream were to be polluted by salt or fracking chemicals, the species would be in danger of extinction. Although much of the toxicological research has been conducted on frogs rather than salamanders, amphibians in general are vulnerable to many contaminants, including organic chemicals, heavy metals, and metalloids (Herfenist et al., 1989).

Fishes

There is a high probability of water pollution from spills of fracking wastewater (Rozell and Reaven, 2012), and stream fishes are vulnerable to this impact. The tonguetied minnow is intolerant of water pollution (US Environmental Protection Agency, 2010), although there is not enough information on this species to determine how it would be affected by fracking. The bluebreast darter is critically imperiled in New York, imperiled in both Ohio and Virginia, and vulnerable in West Virginia and requires good water quality (Losey, Roble, and Hammerson, 2011; Pennsylvania Natural Heritage Program, 2012), making it particularly vulnerable to fracking activities.

Butterflies

The Appalachian azure inhabits deciduous forests, and its larval food plant is black cohosh (*Actaea racemosa*). The butterfly is scarce and has difficulty moving between forest fragments. Black cohosh is potentially threatened by nonnative plants and white-tailed deer (*Odocoileus virginianus*) (New York Natural Heritage Program, 2011), both of which are likely to benefit from fracking.

Plants

Plants will also be affected by fracking through fragmentation, increased salinity levels, and pollution by toxic chemicals. The northern wild monkshood is a federally threatened plant at risk of soil contamination, drying due to canopy loss, and nonnative plants. The monkshood occurs in only four states, of which New York and Ohio overlap with the Marcellus and Utica shale-gas region. Monkshood has narrow habitat affinities, grows slowly, is very sensitive to disturbance, and there is probably little gene flow among the isolated populations (Edmondson et al., 2009; Ohio Natural Heritage Program, 2007); forest fragmentation and increased salinity caused by fracking could imperil an already threatened species. Forest fragmentation is known to facilitate the spread of nonnative, potentially invasive, plants (e.g., Yates, Levia, and Williams, 2003).

Potential Benefits to Biodiversity

Fracking may benefit some species as well as harm others. Industrial activity creates habitats that may be used by rare or economically important species. For example, Noel et al. (1998) documented caribou (*Rangifer tarandus*) using gravel pads associated with oil drilling for insect relief habitat. Schmidt and Kiviat (2007) found a globally rare clam shrimp [*Cyzicus* (*Caenestheriella*) *gynecia*] in rain pools on a gas pipeline road in New Jersey. However, artificial industrial habitats tend to support common species that are ecological generalists (E. Kiviat, personal observations) rather than species of conservation concern. We expect that fracking installations will provide habitats for a few noteworthy species while degrading the environment for many others. Appalachian cottontail is known to use shrublands and several-year-old clear-cuts (Cannings and Hammerson, 2012); thus, gas-pipeline rights-of-way and abandoned well pads might provide acceptable habitat. Undoubtedly, other species of conservation concern could be managed for in fracking landscapes, and research to provide the basis for such management is urgently needed. Forest fragmentation in fracking landscapes, because of the dispersed character of the industry, cannot be avoided.

Summary

Hydraulic fracturing poses serious threats to a diverse group of species, including plants, butterflies, fishes, and salamanders, that have restricted geographic ranges overlapping substantially with the Marcellus and Utica gas shales. Of the 15 species we reviewed, many are so little known that targeted management would be based on insufficient evidence. Of these, 13 have narrow habitat affinities and 11 are dependent on good water quality (Table 1), making them particularly vulnerable to fracking effects such as elevated salinity and other pollution.

Conclusions

Although fracking will likely be permitted in most states underlain with gas shales, if biodiversity and human impacts are well studied, appropriate regulations can be implemented. Because New York has not yet permitted high-volume horizontal hydraulic fracturing, there is an opportunity to protect the quasi-endemic species whose ranges extend into New York, including northern blue monkshood, Wehrle's salamander, Allegheny mountain dusky salamander, and Appalachian azure. Many organisms are undergoing poleward range shifts caused by climate change, but because changes in range limits are species specific and subject to many biological and abiotic interactions (Wyman, 1991), we cannot know whether overlap percentages with gas shales will increase or decrease. Range contraction (local or regional extirpation) due to other causes may increase the percentage overlap of the remaining range with the Marcellus-Utica region, thus cumulatively increasing the risk posed by fracking; the Allegheny woodrat (*Neotoma magister*; LoGiudice, 2003) may be an example.

We reviewed species for which range maps are available; there are many more species with no range maps or so little ecological information that it would be impossible to assess how fracking may affect them. There are almost certainly many species of invertebrates, plants, lichens, and other organisms that are quasi-endemic to the Marcellus-Utica region, but lack of access to range maps and ecological information prohibited their inclusion in our study. The species selected in this study may actually have a much greater overlap with the shales (because habitat range maps are generalized or out of date), and thus potential effects of fracking could be greater than the percentages in Table 1 suggest. Also, ecological impacts like mountaintop-removal mining, logging, climate change, and other industrial activities will compound the effects of fracking, making these species vulnerable to decline and extinction. Future studies should include a broader range of taxa and field research that can measure the impacts of fracking while considering how these impacts may be compounded by other threats to biodiversity.

Biodiversity at all levels, from genes to ecosystems, constitutes many important values to human society and ecosystem functions, as well as the intrinsic importance of each species (Wilson, 1992). Conserving biodiversity is important because each species has unique compounds, behaviors, and other information that we may be able to use to improve human health, biotechnology, and enjoyment. Biodiversity is also of great value to the function of ecosystems—and we do not know how the elimination of certain species will affect ecosystem function. Many of the species selected not only have restricted geographic ranges, but live in small, isolated populations that would be negatively affected by further fragmentation. A number of these species are also recently described species, and most are little known ecologically. Intensive industrial activities such as fracking that potentially affect an almost 300,000-km^2 region need to be thoroughly studied so that researchers and natural resource managers can assess impacts on biodiversity and humanity.

Acknowledgments

We are grateful to Felicia Keesing (Bard College) for discussions and comments on a draft. Karen Schneller-McDonald (Hickory Creek Consulting) also discussed the subject with us. Maxine Segarnick and Jordan Michael Kincaid (Bard College Center for Environmental Policy) prepared the maps and calculated the areas of the geographic ranges and the percentage overlaps with the shales. Prototype maps were drafted earlier by Robyn Glenney and Laura Steadman, with assistance from Gretchen Stevens, and Kristen Bell Travis edited the maps for publication. This is a Bard College Field Station–Hudsonia Contribution.

References

Anonymous. 2010. Academy of Natural Sciences: Marcellus Shale Needs Scientific Study to Set Guidelines. *PA Environment Digest*, October 18, 2010. http://www.paenvironmentdigest.com/newsletter/default.asp?NewsletterArticleID=17078 (accessed May 1, 2012).

Arkema, K., J. Bernhardt, and G. Verutes. 2011. *Habitat Risk Assessment*. Natural Capital Project, Stanford University, Stanford, CA. Available at http://stanford.edu/~woodsp/natcap/invest/docs/21/habitat_risk_assessment.html (accessed May 1, 2012).

Ash, A.N. 1997. Disappearance and Return of Plethodontid Salamanders to Clearcut Plots in the Southern Blue Ridge Mountains. *Conservation Biology* 11(4):983–989.

Barry, R., and J. Lazell. 2008. *Sylvilagus obscurus*. IUCN Red List of Threatened Species Version 2011.2, http://www.iucnredlist.org/details/41301/0 (accessed April 18, 2012).

Besharse, J.C., and J.R. Holsinger. 1977. *Gyrinophilus subterraneus*, a New Troglobitic Salamander from Southern West Virginia. *Copeia*, 2007(4): 624–634.

Bratton, S.P., and A.J. Meier. 1998. Restoring Wildflowers and Salamanders in Southeastern Deciduous Forests. *Restoration & Management Notes* 16(2):158–165.

Bunch, M., R. Davis, S. Miller, and R. Harrison. 2012. *Appalachian Cottontail: Sylvilagus obscurus*. South Carolina Department of Natural Resources, Columbia, 7 pp. Available at http://www.dnr.sc.gov/cwcs/pdf/AppalachianCottontail.pdf (accessed April 10, 2012).

Butterflies and Moths of North America (BAMONA). 2012. Montana State University, Bozeman. http://www.butterfliesandmoths.org/species/ (accessed May 1, 2012).

Cannings, S., and G. Hammerson. 2012. *Sylvilagus obscurus*. NatureServe Explorer, Arlington, VA. http://www.natureserve.org/explorer/servlet/NatureServe?searchName=Sylvilagus+obscurus (accessed August 25, 2012).

Cole, C.T., and M.A. Kuchenreuther. 2001. Molecular Markers Reveal Little Genetic Differentiation among *Aconitum noveboracense* and *A. columbianum* (Ranunculaceae) Populations. *American Journal of Botany* 88(2):337–347.

Davis, J.B., and G.R. Robinson. 2012. A Geographic Model to Assess and Limit Cumulative Ecological Degradation from Marcellus Shale Exploitation in New York, USA. *Ecology and Society* 17(2):art. 25. Available at http://dx.doi.org/10.5751/ES-04822-170225 (accessed August 21, 2012).

Drakare, S., J.J. Lennon, and H. Hillebrand. 2006. The Imprint of the Geographic, Evolutionary and Ecological Context on Species-Area Relationships. *Ecology Letters* 9(2):215–227.

Duncan, M.B., S.E. DuRant, B.J.K. Ostby, J.H. Roberts, and J.D. Willson. 2011. A Multi-taxa Biological Survey of Passage Creek, Virginia. *Northeastern Naturalist* 18(3):357–369.

Edmondson, L., L. Morse, C. Russell, S. Gottlieb, J. Pearson, K. Maybury, S. Neid, and L. Oliver. 2009. *Aconitum noveboracense*. NatureServe Explorer, Arlington, VA. http://www.natureserve.org/explorer/ (accessed May 1, 2012).

Entrekin, S., M. Evans-White, B. Johnson, and E. Hagenbuch. 2011. Rapid Expansion of Natural Gas Development Poses a Threat to Surface Waters. *Frontiers in Ecology and the Environment* 9(9):503–511.

Gibbs, J.P., A.R. Breisch, P.K. Ducey, G. Johnson, J.L. Behler, and R.C. Bothner. 2007. *The Amphibians and Reptiles of New York State: Identification, Natural History, and Conservation*. Oxford University Press, Oxford, UK, 422 pp.

Habib, L., E.M. Bayne, and S. Boutin. 2007. Chronic Industrial Noise Affects Pairing Success and Age Structure of Ovenbirds *Seiurus aurocapilla*. *Journal of Applied Ecology* 44(1):176–184.

Hammerson, G. 2004. *Plethodon nettingi*. IUCN Red List of Threatened Species Version 2011.2, http://www.iucnredlist.org (accessed May 3, 2012).

Hammerson, G., and C. Beachy. 2004. *Gyrinophilus subterraneus*. IUCN Red List of Threatened Species Version 2011.2, http://www.iucnredlist.org (accessed March 25, 2012).

Hammerson, G., and J. Mitchell. 2004. *Plethodon punctatus*. IUCN Red List of Threatened Species Version 2011.2, http://www.iucnredlist.org (accessed May 5, 2012).

Harnishfeger, R. 2010. Appalachian Cottontail. In *Terrestrial Vertebrates of Pennsylvania: A Complete Guide to Species of Conservation Concern*, M.A. Steele, M.C. Brittingham, T.J. Maret, and J.F. Merritt, eds. Johns Hopkins University Press, Baltimore, MD, 354–358.

Herfenist, A., T. Power, K.L. Clark, and D.B. Peakall. 1989. *A Review and Evaluation of the Amphibian Toxicological Literature*. Canadian Wildlife Service [CWS] Technical Report Series 61. CWS, Ottawa, Canada, 222 pp.

Highton, R. 1999. Geographic Protein Variation and Speciation in the Salamanders of the *Plethodon cinereus* Group with the Description of Two New Species. *Herpetologica* 55(1):43–90.

International Union for Conservation of Nature (IUCN). 2011. IUCN Red List of Threatened Species Version 2011.2, http://www.iucnredlist.org (accessed April 25, 2012).

Johnson, N. 2010. *Pennsylvania Energy Impacts Assessment: Report 1—Marcellus Shale Natural Gas and Wind*. The Nature Conservancy–Pennsylvania Chapter, Harrisburg, 46 pp. Available at http://www.nature.org/media/pa/pa_energy_assessment_report.pdf (accessed April 20, 2012).

Kiviat, E., and K. Schneller-McDonald. 2011. Fracking and Biodiversity: Unaddressed Issues in the New York Debate. *News from Hudsonia* 25(1–2):1–3, 8–10.

LoGiudice, K. 2003. Trophically Transmitted Parasites and the Conservation of Small Populations: Raccoon Roundworm and the Imperiled Allegheny Woodrat. *Conservation Biology* 17(1):258–266.

Losey, J., S. Roble, and G. Hammerson. 2011. *Etheostoma camurum*. NatureServe Explorer, Arlington, VA. http://www.natureserve.org/explorer/ (accessed August 22, 2012).

Marsh, D.M., N.P. Gorham, and N.G. Beckman. 2005. Forest Roads as Partial Barriers to Terrestrial Salamander Movement. *Conservation Biology* 19(6):2004–2008.

Massachusetts Natural Heritage and Endangered Species Program (MNHESP). 2009. *Bailey's Sedge (Carex baileyi)*. MNHESP, Massachusetts Division of Fish & Wildlife, Westborough, 2 pp. http://www.mass.gov/dfwele/dfw/nhesp/species_info/nhfacts/carex_baileyi.pdf (accessed May 5, 2012).

Mitchell, J.C., J.A. Wicknick, and C.D. Anthony. 1996. Effects of Timber Harvesting Practices on Peaks of Otter Salamander (*Plethodon hubrichti*) Populations. *Amphibian & Reptile Conservation* 1(1):15–19.

NatureServe. 2012. *NatureServe Explorer: An Online Encyclopedia of Life*. NatureServe, Arlington, VA. http://www.natureserve.org/explorer/ (accessed October 13, 2012).

Naugle, D.E. 2011. *Energy Development and Wildlife Conservation in Western North America*. Island Press, Washington, DC, 305 pp.

New York Natural Heritage Program (NYNHP). 2011. *Online Conservation Guide for Celastrina neglectamajor*. NYNHP, Albany. http://www.acris.nynhp.org/guide.php?id=7871 (accessed April 19, 2012).

Noel, L.E., R.H. Pollard, W.B. Ballard, and M.A. Cronin. 1998. Activity and Use of Active Gravel Pads and Tundra by Caribou, *Rangifer tarandus granti*, within the Prudhoe Bay Oil Field, Alaska. *Canadian Field-Naturalist* 112(3):400–409.

Noss, R.F., and A.Y. Cooperrider. 1994. *Saving Nature's Legacy: Protecting and Restoring Biodiversity*. Island Press, Washington, DC, 416 pp.

Ohio Natural Heritage Program (ONHP). 2007. *Aconitum noveboracense*. Division of Wildlife, Ohio Department of Natural Resources, Columbus. http://ohiodnr.com/Portals/3/Abstracts/Abstract_pdf/A/Aconitum_noveboracense.pdf (accessed April 20, 2012).

Payne, J.L., and S. Finnegan. 2007. The Effect of Geographic Range on Extinction Risk During Background and Mass Extinction. *Proceedings of the National Academy of Sciences, USA* 104(25):10506–10511.

Pennsylvania Natural Heritage Program (PNHP). 2012. *Bluebreast Darter (Etheostoma camurum)*. PNHP, Harrisburg. 2 pp. http://www.naturalheritage.state.pa.us/factsheets/11411.pdf (accessed April 25, 2012).

Petranka, J.W. 1998. *Salamanders of the United States and Canada*. Smithsonian Institution Press, Washington, DC, 587 pp.

Petranka, J.W., M.E. Eldridge, and K.E. Haley. 1993. Effects of Timber Harvesting on Southern Appalachian Salamanders. *Conservation Biology* 7(2):363–370.

Rowan, E.L., M.A. Engle, C.S. Kirby, and T.F. Kraemer. 2011. *Radium Content of Oil- and Gas-Field Produced Waters in the Northern Appalachian Basin (USA): Summary and Discussion of Data*. US Geological Survey Scientific Investigations Report 2011–5135. US Geological Survey, Reston, VA, 31 pp. Available at http://pubs.usgs.gov/sir/2011/5135/ (accessed October 14, 2012).

Rozell, D.J., and S.J. Reaven. 2012. Water Pollution Risk Associated with Natural Gas Extraction from the Marcellus Shale. *Risk Analysis* 32(8):1382–1393.

Schmidt, C.W. 2011. Blind Rush? Shale Gas Boom Proceeds Amid Human Health Questions. *Environmental Health Perspectives* 119(8):a348–a353.

Schmidt, R.E., and E. Kiviat. 2007. State Records and Habitat of Clam Shrimp, *Caenestheriella gynecia* (Crustacea: Conchostraca), in New York and New Jersey. *Canadian Field-Naturalist* 121(2):128–132.

Slobodkin, L.B. 1986. On the Susceptibility of Different Species to Extinction: Elementary Instructions for Owners of a World. In *The Preservation of Species*, B.G. Norton, ed. Princeton University Press, Princeton, NJ, 226–242.

Stein, B.A., L.S. Kutner, and J.S. Adams. 2000. *Precious Heritage: The Status of Biodiversity in the United States*. Oxford University Press, Oxford, UK, 339 pp.

US Department of Agriculture (USDA). 2012. *Plants Database*. USDA, Washington, DC. http://plants.usda.gov/java/ (accessed May 5, 2012).

US Energy Information Administration (US EIA). 2012. http://www.eia.gov (accessed October 13, 2012).

US Environmental Protection Agency (USEPA). 2010. *Biological Indicators of Watershed Health: Minnows (Cyprinidae)*. USEPA, Washington, DC. http://www.epa.gov/bioiweb1/html/fish_minnows.html (accessed August 21, 2012).

US Geological Survey (USGS). 2002. http://www.usgs.gov (accessed October 13, 2012).

Walton, D., M. Ormes, and L. Morse. 2012. *Taenidia montana*. NatureServe Explorer, Arlington, VA. http://www.natureserve.org/explorer/servlet/NatureServe?searchName=Taenidia+montana (accessed August 21, 2012).

Warner, N.R., R.B. Jackson, T.H. Darrah, S.G. Osborn, A. Down, K. Zhao, A. White, and A. Vengosh. 2012. Geochemical Evidence for Possible Natural Migration of Marcellus Formation Brine to Shallow Aquifers in Pennsylvania. *Proceedings of the National Academy of Sciences, USA* 109(30):11961–11966.

Welsh, H.H., Jr., and S. Droege. 2001. A Case for Using Plethodontid Salamanders for Monitoring Biodiversity and Ecosystem Integrity of North American Forests. *Conservation Biology* 15(3):558–569.

Wilson, E.O. 1992. *The Diversity of Life*. Harvard University Press, Cambridge, MA, 424 pp.

Wyman, R.L. 1991. Multiple Threats to Wildlife: Climate Change, Acid Precipitation, and Habitat Fragmentation. In *Global Climate Change and Life on Earth*, R.L. Wyman, ed. Routledge, Chapman and Hall, New York, 134–155.

Wyman, R.L. 2003. Conservation of Terrestrial Salamanders with Direct Development. In *Amphibian Conservation*, R.D. Semlitsch, ed. Smithsonian Institution Press, Washington, DC, 37–52.

Yates, E.D., D.F. Levia Jr., and C.L. Williams. 2003. Recruitment of Three Nonnative Invasive Plants into a Fragmented Forest in Southern Illinois. *Forest Ecology and Management* 190(2–3):119–130.

Submitted May 18, 2012; revised August 6, 2012; accepted August 27, 2012.

NEW SOLUTIONS
A Journal of Environmental and Occupational Health Policy
Volume 23, No. 1 — 2013

Credit for Cover Graphics: Michelle Bamberger
Cover Art: The New Silo, Illustration by Michelle Bamberger

Special Issue

SCIENTIFIC, ECONOMIC, SOCIAL, ENVIRONMENTAL, AND HEALTH POLICY CONCERNS RELATED TO SHALE GAS EXTRACTION

Guest editors: Robert Oswald and Michelle Bamberger

CONTENTS

NEW SOLUTIONS, Vol. 23(1) 1-5, 2013

Editorial

AN ENERGY POLICY THAT PROVIDES CLEAN AND GREEN POWER

CRAIG SLATIN
CHARLES LEVENSTEIN

The oil and gas industry's current promise of cheap natural gas supplies for the next century sounds remarkably like the promises of the 1950s about nuclear power. We were to gain cheap, abundant, and safe electricity for our homes, to expand industry for jobs, and to advance modern living. Nuclear electricity generation, however, has brought us the burden of subsidizing the high cost of nuclear facility construction and liability insurance, denial of ongoing radioactive releases, additional cancer burden, decades of fights over the transport and disposal of radioactive wastes, secrecy and lies from the industry and its government regulators, and multiple actual and near meltdowns.

Now shale gas extraction conducted through the technological process commonly referred to as "fracking" is touted by the oil and gas industry as the next great energy boon. They tell us that gas will be so plentiful that it will answer all of our energy-related problems. Best yet, it will end the unemployment crisis that lingers past the Great Recession, leading to millions of jobs over the next several decades. Its promoters claim that we can have energy independence and a fuel that burns cleaner than coal—while they spread denial that the threat of catastrophic climate change is real or has much to do with human activity.

Let's not be deceived: shale gas extraction will neither fulfill the prophesies nor be useful in the transition to just, democratic, and ecologically sustainable economies across the globe. It is business as usual [1]. It is owned and operated by industries with more than a century's legacy of greed, corruption, war provocation, pollution, illness, injury and death, environmental degradation, and a steady stream of propaganda and lobbying to limit its regulation by

doi: http://dx.doi.org/10.2190/NS.23.1.a
http://baywood.com

governments. The U.S. Energy Information Agency (EIA) had touted the Marcellus Shale deposit as containing an estimated 410 trillion cubic feet of recoverable natural gas. In 2011, however, the U.S. Geological Survey (USGS) reported that the deposit "contains about 84 trillion cubic feet of undiscovered, technically recoverable natural gas and 3.4 billion barrels of undiscovered, technically recoverable natural gas liquids" [2]. Though an increase from the 2002 USGS estimates, this figure was 80 percent less than the EIA estimate that the industry had used to sell expansion of the shale gas extraction projects. This revision came while some members of the U.S. Congress were calling for investigation of the EIA's use of consultants with ties to industry to produce estimates of shale gas [3].

The subterfuges are likely to continue. In December 2012, the *Boston Globe* reported that Phil Flynn, a Chicago commodities trader for Price Futures Group, was confident that shale gas extraction was a key to U.S. energy independence. He stated that it would create:

> . . . millions upon millions of jobs for the next 10 to 30 years. What is going to drive us in this next decade? What is going to create good, high-paying jobs? Really fracking and natural gas have been an answer to our prayers, so hopefully we're going to embrace it and move in that direction [4].

In response to a journalist's question about whether or not abundant natural gas could jeopardize development of renewable technologies, he replied:

> If they can't compete, maybe they shouldn't. Fracking and new production have made a lot of these other technologies obsolete. You can throw billions of dollars at some of these technologies and they'll never be able to compete, unless you're going to subsidize them for the next 50 to 100 years. We've got over 100 years of [natural gas] supply, maybe more [4].

Keep in mind that this interview was reported at a time when the gas industry sought to obtain permission to establish a pipeline from the Marcellus Shale to New England, which it hopes will be a prime consuming region of this gas. Mr. Flynn neglected to note that U.S. oil and gas industries have received federal government subsidies dating back to 1916 [5]. The point isn't for renewable energy technologies to compete with natural gas. Rather, it is to replace gas and all fossil fuels if we are to have any chance of avoiding catastrophic climate change.

Another end-of-2012 news report from Bloomberg.com criticized U.S. Senator Ron Wyden (D–OR) for suggesting that the U.S. government should ". . . direct trade in energy according to its determination of the national interest" [6]. The editorial criticized Wyden for "protectionism" because of his suggestion that liquefied natural gas exports would lead to domestic gas price increases. Bloomberg.com stated:

> Natural gas is hardly a private product, in Wyden's understanding, but rather a national resource whose price, quantity and use are best determined by the federal government. What's so troubling about Wyden's view, however, is the potentially enormous cost to economic efficiency from substituting market mechanisms with political decision-making.
>
> Wyden is wrong: The federal government should not be exercising a heavy hand in this case. Liberal capitalist democracies [*sic*] should not allocate resources through regulatory determinations of the national interest. They should encourage free trade. If the domestic manufacturing and chemical industries require natural gas, they should place competitive bids for it [6].

Pennsylvania, a prime area above the Marcellus Shale and a state that produces a significant percentage of the nation's shale gas, passed Act 13 in early 2012. The law imposed a tax, an impact fee, on shale gas production. Although it toughened some safety standards to protect the environment and public health, the limited fee is primarily to compensate communities for the prior and ongoing damages that result from shale gas extraction operations. Several pro-industry provisions of the law are being challenged in the courts, including limitations on local zoning of drilling operations and protection of industry chemical use disclosure. These are hardly reasonable trade-offs for limited reparations funding, but "[b]y October (2012), $204 million from gas industry payments were being distributed to state agencies and counties and municipalities that host gas wells" [7]. Pennsylvania and Ohio have both passed laws allowing state institutions of higher education to receive a percentage of revenues from shale gas sales when gas companies are given the right to set up wells on school premises [8]. Shale gas extraction fees/taxes will increasingly be proposed to offset the impact of 30 years of cutting taxes at all levels of government and the resultant reduction and privatization of public services and infrastructure. In the case of public higher education facilities, these revenues will also create disincentives against critical examination of the consequences of using shale gas for fuel. This will be the latest phase of the blackmail of working-class communities—the offer of jobs and public services at the cost of safe and clean natural resources of water and air that sustain good health.

Since its inception, *New Solutions* has been a forum for discussions of a "just transition" toward ecologically sustainable modes of production and consumption. The well-being of workers and communities is at stake when industries and operations that threaten environmental and ecological destruction as well as human illness and injury are closed and in some cases transformed. Communities long suffering environmental injustices and often poverty due to racist and classist policies that placed polluting facilities in their midst must be made whole and provided priority status in this planned transition. Yes, planned, not the free market model of "liberal capitalist democracies" touted by Bloomberg.com.

With this special issue of *New Solutions*, so excellently organized by guest editors Robert Oswald and Michelle Bamberger, we address a range of social, economic, environmental, and public health risks that have emerged from energy companies' push to extract shale gas. The industry claims that the benefits of shale gas extraction far outweigh the costs, and that harms are mostly imagined by the usual collection of NIMBY environmentalists and public health police. We believe, however, that enough evidence has been provided in support of taking extraordinary caution during all phases of shale gas operations. Though this special issue barely addresses the health and safety concerns for workers in this industry, the hazardous exposures involved in this work are another key factor that requires taking extraordinary caution. We can no longer afford to have industry use deeply hazardous technologies—with government encouragement—while public health is consigned to surveillance of the sick and dead.

Whatever short-term assistance the American economy gains from the continued use of fossil fuels, the highest priority must be placed on establishing a national energy policy, coordinated with an international set of energy policies, that aims for immediate measures to avert catastrophic climate change and establish a transition toward producing and delivering clean, green, and sufficient energy as part of the foundation for sustainable development. Attention to the health and welfare of workers and communities affected by these changes must be an essential priority of this new energy policy.

AUTHORS' BIOGRAPHIES

CHARLES LEVENSTEIN is Editor Emeritus of *New Solutions*; Professor Emeritus of Work Environment at the University of Massachusetts Lowell; and Adjunct Professor of Occupational Health at Tufts University School of Medicine. Write him at chuck_lev@comcast.net

CRAIG SLATIN is a professor in the Department of Community Health and Sustainability, University of Massachusetts Lowell. He is an editor of *New Solutions: A Journal of Environmental and Occupational Health Policy*. His book, *Environmental Unions: Labor and the Superfund,* was published in 2009 by Baywood Publishing Co., Inc. He is the principal investigator of The New England Consortium, a hazardous waste worker/emergency responder health and safety training network supported by the National Institute of Environmental Health Sciences' Worker Education and Training Program. Contact him at craig_slatin@uml.edu+

NOTES

1. Ian Urbina, "New York Times Drilling Down Series," 2012, http://www.nytimes.com/interactive/us/DRILLING_DOWN_SERIES.html (accessed December 31, 2012).

2. U.S. Geological Survey, "USGS Releases New Assessment of Gas Resources in the Marcellus Shale, Appalachian Basin," August 23, 2011, http://www.usgs.gov/newsroom/article.asp?ID=2893 (accessed December 31, 2012).
3. Ian Urbina, "Geologists Sharply Cut Estimate of Shale Gas," *New York Times,* August 24, 2011, http://www.nytimes.com/2011/08/25/us/25gas.html (accessed December 31, 2012).
4. Erin Ailworth, "Fracking May Hold Key to Energy Independence," *Boston Globe,* December 31, 2012, http://bostonglobe.com/business/2012/12/30/hot-seat-with-energy-trader-phil-flynn/Z69dYLQMMSv0gwrMn4HJgK/story.html (accessed 12/31/12).
5. Molly F. Sherlock, Congressional Research Service, *Energy Tax Policy: Historical Perspectives on and Current Status of Energy Tax Expenditures* (R41227), 2011.
6. Evan Soltas, "U.S. Natural Gas Doesn't Need Protectionism," *Bloomberg.com,* December 28, 2012, http://www.bloomberg.com/news/2012-12-28/u-s-natural-gas-doesn-t-need-protectionism.html (accessed December 31, 2012).
7. Kevin Begos, "Marcellus Natural Gas Production Expanded in 2012," *San Francisco Chronicle,* 2012, http://www.sfgate.com/business/energy/article/Marcellus-natural-gas-production-expanded-in-2012-4145125.php#ixzz2GGmyWa00 (accessed December 31, 2012).
8. Sydney Brownstone, "Pennsylvania Fracking Law Opens Up Drilling on College Campuses," *Mother Jones,* October 12, 2012, http://www.motherjones.com/politics/2012/10/pennsylvania-fracking-law-opens-drilling-college-campuses (accessed December 31, 2012).

Direct reprint requests to:

Craig Slatin
Department of Community Health and Sustainability
University of Massachusetts Lowell
205 Riverside St.
Pinanski Hall, Room 301
Lowell, MA 01854
e-mail: craig_slatin@uml.edu

NEW SOLUTIONS, Vol. 23(1) 7-12, 2013

Introduction

SCIENCE AND POLITICS OF SHALE GAS EXTRACTION

MICHELLE BAMBERGER
ROBERT E. OSWALD

ABSTRACT- Please supply 50-100 word abstract

Keywords: Please supply 3-5 key words

Although humans have exploited natural resources to produce energy throughout recorded history, the modern age of fossil fuels didn't begin until the first half of the 19th century, when oil and natural gas wells were used to extract hydrocarbons for heating in China and for illumination in the northeast United States. Our addiction to oil and gas began in earnest with the introduction of the internal combustion engine for cars and trucks, and the switch from coal to gas in heating our homes in the 1950s. In the 1940s, hydraulic fracturing was introduced to stimulate the production of gas and oil trapped in rocks with

doi: http://dx.doi.org/10.2190/NS.23.1.b
http://baywood.com

limited porosity; such stimulation opened up a whole new avenue for the extraction of oil and gas. Conventional wells were drilled to search for pockets of hydrocarbons buried deep within the earth; with hydraulic fracturing, oil and gas could be coaxed out of even very dense rock, such as shales. The initial applications for hydraulic fracturing were on vertical wells where relatively small quantities of water and comparatively low pressures were used to stimulate the flow of oil or gas. The problem with this is that the shale layers are relatively thin (50 to 200 feet in thickness), so that even with hydraulic fracturing, only a small amount of hydrocarbons could be extracted from vertical wells. The solution was to drill down and then turn the bit horizontally and continue drilling. The horizontal length of the well can then be hydraulically fractured, and much more oil or gas can be extracted. This process requires much larger quantities of water (approximately 5 million gallons for each fracturing), which contains sand to keep the fractures open (i.e., sand is used as proppant) and a variety of chemicals, some benign and some highly toxic. The transition from a conventional vertical well to a horizontal well that is hydraulically fractured is a huge step from a relatively minor insult to the rural landscape to major industrialization of the landscape.

Although concerns about this process had been raised in Colorado [1] and Alberta [2], among other places, the realization [3] that a large portion of the heavily populated and farmed areas of the eastern United States rests above large deposits of shale oil and gas (the Marcellus and Utica Shales) has sparked an enormous interest in the consequences of drilling near homes and on farmland. Historically, Pennsylvania is the origin of the U.S. oil industry, with the first well in Titusville in 1859, and New York is the origin of the natural gas industry, with the first well in Fredonia in 1821. Tens of thousands of gas wells have been drilled throughout Pennsylvania and New York over the last 150 years, with little protest. The advent of high-volume hydraulic fracturing of horizontal wells has been perceived as a qualitatively and quantitatively different process that has transformed the landscape and communities. Notably, this recent concern is not limited to the eastern United States; high-volume hydraulically fractured horizontal wells are proposed for shale plays throughout the world, and grassroots organizations have sprung up to question the wisdom of large-scale industrialized drilling. It was in this context that this special edition of *New Solutions* was conceived. A paper in a previous issue of *New Solutions* [4] explored the use of animals as sentinels for the health effects of large-scale drilling and outlined the reasons for the lack of strong evidence to prove or disprove the safety of the process. This issue casts a wider net and explores a range of topics associated with unconventional gas drilling. The intention was to describe important public health, economic, and socio-ecological issues, to present available data, and to define topics that need further study. In the call for papers, all points of view were welcomed. After extensive peer review, a range of topics was included in this issue.

Entitled *Scientific, Economic, Social, Environmental, and Health Policy Concerns Related to Shale Gas Extraction*, the issue opens with an editorial by Charles Levenstein and Craig Slatin discussing the broader need for sustainable production and consumption—in particular, the need to make sure that our energy policies and plans help us move to a greener economy that eliminates poverty, promotes public health, and establishes the primacy of renewable and non-toxic energy sources. Next, Katrina Korfmacher and collaborators provide a comprehensive discussion of exposure pathways and describe a resolution on the use of hydraulic fracturing in shale gas extraction that was approved by the American Public Health Association at its meeting in San Francisco in November of 2012. This resolution proposes a number of commonsense recommendations and a series of action steps to minimize the public health effects of this process.

In the Scientific Solutions section, Simona Perry describes an ethnographic approach to studying the community health implications of unconventional oil and gas development. The work concentrates on hard-to-monitor factors (e.g., psychological, sociocultural) that are associated with chronic stress. A great deal of emphasis has been placed on measuring environmental impacts using air and water testing, but little has been done to monitor scientifically the psychological and sociocultural changes transforming individuals and communities living and working near large-scale industrial gas drilling. Dr. Perry explores how ethnography, with its rigorous methods of fieldwork and analysis, is useful in not only evaluating and monitoring psychological and sociocultural changes within these communities, but also in describing and assessing the short- and long-term environmental health and social justice implications of these changes.

Also in the Solutions section, Nadia Steinzor, Wilma Subra, and Lisa Sumi report on a survey of perceived health effects coupled with water and air monitoring in the Marcellus Shale regions of Pennsylvania. They find that perceived health effects were greater for individuals living within 1,500 feet of a well pad relative to those living beyond that distance. Their findings demonstrate the utility of community-based research designs, especially when industrial and commercial interests inhibit public health and environmental impact studies that could jeopardize profitable gas and oil drilling.

The Features section begins with an economic analysis by Janette Barth. Dr. Barth considers the conventional wisdom that hydrocarbon gas extraction will bring economic prosperity to state and local governments and critically reviews the literature on the subject. Her analysis includes both the positive and negative drivers and looks at both the long- and short-term effects. She concludes that, despite many uncertainties, the long-term economic impacts from shale gas extraction may not be positive for most communities.

Ronald Bishop then addresses the important public health and safety, ecological protection, and greenhouse gas emission concerns related to abandoned oil and gas wells. Using the example of New York State, he shows that the majority of abandoned wells in New York have not been plugged, that the number of unplugged wells has increased since 1992 due to inadequate enforcement, and that no program exists to monitor the integrity of those that have been plugged. Because of the potential for abandoned wells to disintegrate and leak, stronger regulations and additional resources are required not only to complete plugging of the current inventory of abandoned wells but also to provide adequate regulation for the expected increase in the number of new wells within the next few years.

The shale layers containing oil and gas also harbor naturally occurring radioactive material that can be brought to the surface along with the hydrocarbons. Alisa Rich and Earnest Crosby analyzed the radioactive materials found in two reserve sludge pits and found radioactive elements of the thallium and radium decay series. The health effects of the individual radionuclides, along with the regulation (or exemption from regulation) of technologically enhanced naturally occurring radioactive materials (referred to as TENORMs) in federal and state regulations, are discussed.

To understand the impacts of gas drilling on water resources, extensive predrilling testing should be performed. The nonprofit Community Science Institute, headed by Stephen Penningroth, has developed an innovative program that partners with community volunteers to sample streams in 50 locations across the Marcellus and Utica Shale regions in New York State. This is combined with more detailed testing of individual water wells by the Institute's certified water quality testing laboratory. This unique approach to water sampling is a small step toward understanding changes in water quality from a variety of sources and will be useful in understanding impacts from both agriculture and industrial drilling in New York State.

In the next piece, Madeleine Scammell and collaborators review the regulations surrounding the disclosure of the chemical additives in hydraulic fracturing fluid. Since disclosure is not mandated by the federal government except on federal lands (and then only after well completion), it is regulated by laws that vary from state to state. The shortcomings cited in this paper include permitted nondisclosure of proprietary chemicals and mixtures, insufficient penalties for inaccurate or incomplete information, and timelines that allow disclosure after well completion. The authors suggest that lax and varying regulations on disclosure leave lawmakers, public health officials, and regulators uninformed of the potential hazards and ill-prepared to take steps to protect public health. Exemptions from federal regulations and efforts to mandate chemical disclosure are discussed.

The question of whether industrialized gas drilling has affected our food supply is an important unresolved issue. One of the reasons for our lack of information about this issue is that farming is by definition a decentralized process without detailed public recordkeeping. Madelon Finkel and collaborators have used what data are available to study the changes in the dairy industry in Pennsylvania, comparing those counties with extensive gas drilling to those with little or none. Using data from the United States Department of Agriculture's National Agricultural Statistics Service and the Pennsylvania Department of Environmental Protection, the authors showed that both milk production and numbers of dairy cows began decreasing in 1996, but that larger decreases were seen between 2007 and 2011 in those counties with intensive gas drilling compared to those with little drilling. Although causal relationships are difficult to establish in studies such as this, the paper emphasizes the importance of considering the effects on the dairy industry when hydrocarbon extraction impacts large portions of a particular region of the country (e.g., the Marcellus and Utica Shales in the northeast United States).

The next section of the issue, Voices, includes an interview of Anthony Ingraffea by Adam Law. Both are founding members of Physicians, Scientists & Engineers for Healthy Energy. Dr. Law is a practicing endocrinologist in Ithaca, New York, and approaches the subject from a medical perspective. Dr. Ingraffea, an engineering professor at Cornell University, is one of the world's foremost experts in fracture mechanics; his simulations have provided important insights into hydraulic fracturing. Ingraffea and Law discuss the importance of studying the process of gas drilling and hydraulic fracturing from a variety of perspectives, including geological engineering, hydrology, and medicine. This interview was originally done as a part of a project funded by the Heinz Endowment, and the transcript is included here with permission of the Endowment. The original interview can be viewed at: http://www.heinz.org/grants_spotlight_entry.aspx?entry=982.

Health practitioners in communities that may suffer health effects of large-scale gas drilling need to obtain accurate medical histories from individuals with potential exposures. In the Movement Solutions section, Pouné Saberi, a practicing physician, describes the process of taking an environmental exposure history in areas that are being intensively drilled, and the issues surrounding detection of possible environmental exposure clusters.

This special issue of *New Solutions* cannot establish firm conclusions, largely because the data are not available to make firm conclusions. Rather, our goal is to add to and review current knowledge and to point out areas where data are lacking and where regulations are lax or nonexistent. In the United States, gas drilling with high-volume hydraulic fracturing is regulated by a patchwork of state laws, varying from comparatively little regulation in Pennsylvania to an outright ban in Vermont. Regulations are largely based on political considerations rather than on sound scientific evidence. However, what passes for "sound scientific evidence" is sometimes in the eye of the beholder. On one hand, an oft-stated refrain is that in the 60-odd years since the introduction of hydraulic fracturing to extract hydrocarbons, no drinking water has been proven to be contaminated. This statement parses the issue into a small part of the process (hydraulic fracturing) and ignores the complete life cycle from drilling to production to consumption. It perpetuates misplacement of the burden of proof, with disdain for the precautionary principle. Ample evidence exists from more than a century and a half of a fossil-fueled industrial economy that it is wrong to assume that the technological processes related to extracting, processing, and using these substances are safe unless proven otherwise by those impacted. In the case of high-volume hydraulic fracturing we are all best served, in the short and long terms, by demanding proof of safety prior to expanding the practice to new areas. The uncertainties and existing evidence make a strong argument for caution and for strong, well crafted, and strictly enforced regulations.

AUTHORS' BIOGRAPHIES

MICHELLE BAMBERGER is a practicing veterinarian and a member of the Ulysses Gas Drilling Advisory Board, which is a committee to advise local government on issues surrounding shale gas drilling. Contact her at mjb57@cornell.edu

ROBERT E. OSWALD is Professor of Molecular Medicine at Cornell University and faculty fellow of the Atkinson Center for a Sustainable Future, also at Cornell. His research interests include central nervous system pharmacology and toxicology. E-mail him at reol@cornell.edu

NOTES

1. Tara Meixsell, *Collateral Damage: A Chronicle of Lives Devastated by Gas and Oil Development and the Valiant Grassroots Fight to Effect Political and Legislative Change over the Impacts of the Gas and Oil Industry in the United States* (CreateSpace Independent Publishing Platform, 2010).
2. Andrew Nikiforuk, *Saboteurs* (Toronto: Macfarlane Walter & Ross, 2001).
3. T. Engelder and G. G. Lash, "Marcellus Shale Play's Vast Resource Potential Creating Stir in Appalachia," *American Oil and Gas Reporter* 51(6) (2008): 76-87.
4. M. Bamberger and R. E. Oswald, "Impacts of Gas Drilling on Human and Animal Health," *New Solutions: A Journal of Environmental and Occupational Health Policy* 22(1) (2012): 55-77, 10.2190/NS.22.1.e.

Direct reprint requests to:

Robert E. Oswald
Department of Molecular Medicine
Cornell University
Ithaca, NY 14853
e-mail: reo1@cornell.edu

NEW SOLUTIONS, Vol. 23(1) 13-31, 2013

Comment and Controversy

PUBLIC HEALTH AND HIGH VOLUME HYDRAULIC FRACTURING

KATRINA SMITH KORFMACHER
WALTER A. JONES
SAMANTHA L. MALONE
LEON F. VINCI

ABSTRACT

High-volume horizontal hydraulic fracturing (HVHF) in unconventional gas reserves has vastly increased the potential for domestic natural gas production. HVHF has been promoted as a way to decrease dependence on foreign energy sources, replace dirtier energy sources like coal, and generate economic development. At the same time, activities related to expanded HVHF pose potential risks including ground- and surface water contamination, climate change, air pollution, and effects on worker health. HVHF has been largely approached as an issue of energy economics and environmental regulation, but it also has significant implications for public health. We argue that public health provides an important perspective on policy-making in this arena. The American Public Health Association (APHA) recently adopted a policy position for involvement of public health professionals in this issue. Building on that foundation, this commentary lays out a series of five principles to guide how public health can contribute to this conversation.

Keywords: environmental health, hydrofracking, public health

doi: http://dx.doi.org/10.2190/NS.23.1.c
http://baywood.com

The recent growth of high-volume horizontal hydraulic fracturing (HVHF) to extract natural gas from unconventional gas reserves has been framed largely as an issue of economics and environment. Proponents emphasize the potential to bring prosperity to economically depressed communities and to vastly increase domestic natural gas production, decrease dependence on foreign energy sources, and replace dirtier energy sources, such as coal. At the same time, concerns have been raised that HVHF could result in ground- and surface water contamination, contributions to climate change, and increased air pollution. These concerns have focused attention on the inadequacy of existing regulations to protect the environment in the face of dynamic energy extraction technologies and practices.

Until recently, the public health perspective on this issue has received relatively little attention. Goldstein et al. [1] analyzed state and federal advisory committees related to HVHF in the Marcellus Shale region of the United States and concluded that public health was "missing from the table." But what would it mean to have public health voices "at the table," and what would they say? The American Public Health Association took an important first step by adopting a policy position on HFVH in October 2012, and has finalized a resolution as this article goes to press in January 2013 (http://www.apha.org/advocacy/policy/policysearch/default.htm?id=1439). Other public health organizations such as Physicians, Scientists, and Engineers for Healthy Energy (http://www.psehealthyenergy.org) are currently working on similar actions. In this commentary, we lay out a framework for the role of public health in decisions related to HVHF in the United States.

The public health framework for addressing issues that affect people's health is holistic, multidisciplinary, and oriented toward prevention. Bringing this perspective to the issue of HVHF may help identify areas of concern that are not encompassed by existing environmental regulations. In contrast to the lack of public health expertise among the membership of HVHF advisory committees, Goldstein et al. note that in one public hearing, nearly two-thirds of speakers mentioned health [1]. Thus, framing HVHF as an issue of public health may also help decision-makers address the public's concerns. Perhaps most importantly, the public health perspective has the potential to guide policy and management despite the persistent uncertainties about impacts of HVHF. Principles of public health emphasize the need for transparency in research and policy, a precautionary approach in the face of uncertainty, baseline and continued monitoring, and adapting management as understanding of risks increases.

This commentary considers the entire life cycle of, and processes involved in, the expansion of HVHF, including site preparation, drilling and casing, well completion, production, processing, transportation, storage and disposal of wastewater and chemicals, sand mining, and site remediation. The rapid socioeconomic changes, scale of development, and pace of extraction made possible by HVHF could affect health directly or indirectly through changes in vehicular traffic, community dynamics, unequal distribution of economic benefits, demands on public services, health care system effects, impacts on agriculture, and increased housing costs. At the same time, economic growth resulting from HVHF may contribute to improvements in individual health status, health care systems, and local public health resources. The public health perspective also requires assessing the long-term and cumulative impacts of this dispersed-site extractive industry, as well as the distribution of these impacts, particularly within low-income rural populations.

HEALTH AND HVHF: OVERVIEW OF THE POTENTIAL IMPACTS

As discussed in this special issue of *New Solutions*, high-volume horizontal hydraulic fracturing in unconventional gas reserves (often referred to as "fracing" or "fracking") has expanded rapidly since 2007 [2]. HVHF is a technology that injects water, solids, and fluids into wells drilled into the earth's crust as a means to enhance the extraction of natural gas from deep geologic formations, primarily shale, tight sands, and coal seam gas that underlie many regions of the United States [3]. Important unconventional natural gas reserves in the United States include: Barnett (Texas), Fayetteville (Arkansas), Haynesville (Louisiana and Texas), Antrim (Minnesota, Indiana, and Ohio), Marcellus (New York, Pennsylvania, and West Virginia), Bakken (North Dakota), Woodford (Oklahoma), and Eagle Ford (Texas). The basic technology of hydraulic fracturing has existed since the 1860s. However, its recent expansion arose from technological innovations that allowed for horizontal drilling, facilitating greater access to gas in certain shale formations than do conventional vertical wells. HVHF also uses vastly greater quantities of water and chemicals than conventional operations. These horizontal wells are often hydraulically fractured in a number of stages, greatly expanding the potential duration and scale of impacts at each individual site [4, 5].

The rapid expansion of HVHF, both in communities with a long history of natural gas development and in those with limited natural gas industry experience, has the potential to impact public health in numerous ways [1, 6]. These impacts range from direct health impacts for workers or residents who are exposed to harmful chemicals in air, surface water, or groundwater, to indirect effects such as those resulting from rapid community change (e.g., increased traffic and demand for housing), as well as off-site impacts, such as mining the sand required for the HVHF process. Some of these impacts may be positive—for example, from economic growth resulting in better nutrition and health care—while others may be negative.

The distribution of these health impacts varies by proximity to drilling operations, involvement in the industry (worker, property owner, neighboring community member), individual characteristics (children versus adults, asthmatics, etc.), and income (e.g., low income people may be more adversely affected by inflation of housing rental rates). Unequal distribution of benefits may contribute to community conflict and stress, thus indirectly affecting health [7]. Below, we summarize some of the potential health impacts of HVHF in greater detail to set the stage for considering the role of public health in anticipating and managing risks.

Surface and Ground Water Quality

Impacts on water quality and quantity are some of the most highly publicized environmental effects of HVHF with potential human health consequences [8, 9]. HVHF increases the amount of fresh water used by each natural gas well by as much as 100 times the quantity used in conventional drilling [10]. Additionally, wells can be hydraulically fractured more than once, each time using up to 5 million gallons of water [11, 12]. Between 25 and 100 percent of the fluids used in drilling may return to the surface; these "flowback" or "produced" fluids may contain hydraulic fracturing chemicals, as well as heavy metals, salts, and naturally occurring radioactive material (NORM), from below ground [13]. Therefore, this water must be treated, recycled, or disposed of safely [14].

The chemicals and proppants that are added to the water used in HVHF have raised public health concerns related to surface water and groundwater quality [2, 15]. Chemical additives used in fracturing fluids typically make up less than 2 percent by weight of the total fluid [16]. Over the life of a well this may amount to 100,000 gallons of chemical additives. These additives include proppants, biocides, surfactants, viscosity modifiers, and emulsifiers. The chemicals vary in toxicity. Some are known to be safe. However, others are known or suspected carcinogens, endocrine disruptors, or are otherwise toxic to humans—including silica, benzene, lead, ethylene glycol, methanol, boric acid, and gamma-emitting isotopes [16]. Manufacturers of hydraulic fracturing fluids are allowed to protect the precise identity and mixture of the fluids under "proprietary" or "trade secret" designations. From a public health perspective, this prevents effective baseline monitoring prior to hydraulic fracturing, as well as documenting of changes over time. In addition, without this information, it is difficult to apprise workers and the public of potential health hazards.

The manner in which wastewater from HVHF is handled and treated is another water quality concern. The disposal methods used for the "produced water" and brine extracted from the shale have the potential to affect the water quality of lakes, rivers, and streams, damage public water supplies, and overwhelm public wastewater treatment plants [17]. Surface water may be contaminated by leaking on-site storage ponds, surface runoff, spills, or flood events. Even if contaminated surface water does not directly impact drinking water supplies, it can affect human health through consumption of contaminated wildlife, livestock, or agricultural products [18].

Disposal through class II injection wells has traditionally been the primary option for oil- and gas-produced water [19]. Several recent earthquakes near Youngstown, Ohio, were linked to deep injection of HVHF wastewater, raising concerns about this practice under certain geologic conditions [20]. Produced water has also been treated in self-contained wastewater treatment systems at well sites, through local municipal wastewater treatment plants, and by commercial treatment facilities [14]. Because most municipal wastewater treatment plants cannot adequately treat wastewater from HVHF, some states (such as Pennsylvania) require treatment at industrial waste treatment plants [21]. However, the quantity of wastewater needing treatment and the capacity of existing plants to properly treat these wastes may be an issue in some areas [17]. For example, brine in Pennsylvania is permitted to be sprayed for road maintenance purposes, raising concerns about contamination of surface waters [21].

The potential for HVHF to cause methane to seep into drinking water supplies has received considerable media attention [10, 22]. While many of the assertions regarding flammability of drinking and surface water have yet to be substantiated, a study published in the *Proceedings of the National Academies of the Sciences* indicates that drinking-water wells within a one-kilometer radius of a drilling site have methane concentrations 17 times higher than wells outside of a one-kilometer radius [23]. The potential for health impacts from human exposure to methane released into household air from domestic water use is not well understood [23, 24].

Finally, on a local basis, using large volumes of fresh water for HVHF may consume a scarce commodity needed for agriculture, recreation, wildlife, environmental recharge, and drinking water supplies. Disrupting or displacing these pre-existing uses could have additional indirect public health impacts. Drilling fluids that do not return to the surface and remain below ground are effectively removed from the surface water cycle. Especially in areas with limited water resources, the impact of HVHF on the quantity of surface water available for other uses related to public health is a concern. Technological developments, such as gel-based fracking or closed-loop systems, could reduce water use in the future; however, the current practice of HVHF is water-intensive [25].

Air Quality

Globally, replacing coal with natural gas may result in reduced air pollution. However, combustion connected with extraction processes and fugitive emissions may increase air-quality–related health problems in HVHF production areas. Levels of ozone (including wintertime ozone) and concentrations of particulate matter (PM_{10} and $PM_{2.5}$) have been found to be elevated near gas activity [26]. Wintertime ozone caused by the release of volatile organic compounds (VOCs) mixed with the conditions of sunlight and snow cover has been noted in Utah, New Mexico, and Wyoming. Hydrocarbon emissions from gas drilling activity have also been found to be high in Colorado, where researchers found that twice as much methane was being leaked into the atmosphere from oil and gas activity as was originally estimated [27]. Researchers in Colorado have documented a wide range of air pollutants near an HVHF operation [28]. One study has found that residents living near well pads have a higher risk of health impacts from air emissions than those living farther away [29]. Domestic animals may also be affected [18].

Quality of Life

Noise and light have been cited as health concerns for residents and animals living near drilling operations [30, 31]. Excessive and/or continuous noise, such as that typically experienced near drilling sites, has documented health impacts [32]. According to community reports near these sites, some residents may experience deafening noise; light pollution that affects sleeping patterns; noxious odors from venting, gases, and standing wastewater; and livestock impacts [33]. Both noise and light can contribute to stress among residents.

Expansion of HVHF in rural communities may result in significant rapid population changes. These changes may create health care needs that overwhelm the capacity of existing public health systems to care for existing populations. Similarly, both the number and nature of emergency response resources needed in local communities may increase due to accidents, blowouts, or spills at drilling sites, as well as accidents during the transportation of supplies and waste through rural communities. Some areas have reported inadequate emergency medical services (EMS) training and insufficient communication between drilling operators and emergency responders. Pipeline construction and maintenance may also pose security and safety issues [34].

In addition to these environmental health threats, the rapid socioeconomic changes, scale of development, and pace of extraction made possible by HVHF may impact health. HVHF has the potential to significantly change the nature of communities, particularly in rural areas [34]. There have been reports of increased crime associated with the influx of natural gas workers [35, 36]. A study by the County Commissioners Association of Pennsylvania found that Pennsylvania was experiencing deficits in emergency management and hazardous materials response planning in drilling areas; courts and corrections impacts; human services burdens in areas such as drugs and alcohol, domestic relations, and children and youth; and effects on affordable housing, among others [37]. The stresses of social change, uncertainty, isolation, inadequate housing and infrastructure, and substandard services may combine in ways that significantly affect communities' quality of life [33]. Chronic psychological stress has been linked to respiratory health, both independently and in combination with air pollution exposures [38]. Therefore, social stressors, such as those seen with the changes that natural gas drilling brings to an area, may have a cumulative impact on public health.

Worker Health

Historically, natural gas extraction has been a dangerous occupation [39]. Many of the safety issues involved are well understood and regulated. According to the Bureau of Labor Statistics (BLS), transportation incidents are consistently the leading cause of fatalities, followed closely by contact with equipment [40]. However, the rapid pace and geographic scope of expansion into remote locations inhibits monitoring of worker protection at drill sites [41]. This environment creates significant challenges for protecting oil and gas extraction workers.

The industry is characterized by a high rate of fatal injury when compared to all U.S. industries. Worker safety in this industry is highly variable, both over time and across individual companies. The risk of fatality is higher among workers employed by contractors and small companies [42]. During times of high demand, the number of small companies and inexperienced workers entering the industry increase. The annual rate of fatalities is also associated with the number of drill rigs in operation [42]. This pattern of risk suggests particular attention should be paid to small operations during periods of rapid industry expansion, especially in rural areas with roadways unsuited to industrial traffic.

In addition to risks typical of the oil and gas industry, there may also be unique worker health concerns associated with HVHF, such as the potential for exposure to chemical constituents of hydraulic fracturing fluids, diesel exhaust, BTEX (benzene, toluene, ethylbenzene, and xylenes), particulate matter (PM), glutaraldehyde, and the sand used as a proppant that have not been fully characterized and are still poorly understood [43].

Sand Mining and Transport

HVHF operations typically involve hundreds of thousands of pounds of "frac sand," the sand used as proppant during the hydraulic fracturing process. Transporting, moving, and filling thousands of pounds of sand onto and through sand movers, along transfer belts, and into blenders generates dust containing respirable crystalline silica. Inhalation of fine dusts of respirable crystalline silica can cause silicosis [35]. Crystalline silica has also been determined to be an occupational lung carcinogen [44]. This exposure is of concern for workers and also for other individuals near the mining operations and well pads.

The National Institute for Occupational Safety and Health (NIOSH) recently collected air samples at 11 different HVHF sites in five different states (AR, CO, ND, PA and TX) to evaluate worker risks, including exposure to crystalline silica [43]. At each of the 11 sites, NIOSH consistently found levels that exceeded relevant occupational health criteria (e.g., the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) and the NIOSH Recommended Exposure Limit (REL)). At these sites, 47 percent of the samples collected exceeded the calculated OSHA PELs; 79 percent of samples exceeded the NIOSH RELs. The magnitude of the exposures is particularly important: 31 percent of samples exceeded the NIOSH REL by a factor of 10 or more. This study indicates that hydraulic fracturing workers are potentially exposed to inhalation health hazards from dust containing silica when open air mixing of sand is done on site.

There may also be impacts on workers and communities affected by the vastly increased production and transport of sand for HVHF in other areas of the country. NIOSH concluded that there continues to be a need to evaluate and characterize exposures to these and other chemical hazards in hydraulic fracturing fluids, which include hydrocarbons, lead, naturally occurring radioactive materials (NORM), and diesel particulate matter [26, 43].

Climate Change

Uncertainty remains over the potential for HVFH to affect climate change. Climate change is predicted to significantly affect health in numerous direct and indirect ways [45]. Natural gas is more efficient and cleaner-burning than coal. When burned, natural gas releases 58 percent less carbon dioxide (CO_2) than coal and 33 percent less CO_2 than oil [46]. Because of that, natural gas has been promoted as a transitional fuel to begin a conversion to greener energy such as wind and solar [11, 47]. However, some projections suggest that obtaining natural gas through HVHF actually produces more greenhouse gas emissions than does coal production and burning [48]. The impacts of HVHF on overall greenhouse gas emissions depend on actual fugitive emissions, the quantity of fossil fuels combusted during production processes (by compressors, trucks, machinery, etc.), and whether natural gas produced by HVHF reduces the use of other more greenhouse-gas–intensive fuels. Burning natural gas obtained through HVHF will result in a net increase of greenhouse gas emissions over time if it simply delays the burning of coal reserves.

The list of potential public health impacts outlined above is not comprehensive. However, it provides an overview of the diversity, extent, and nature of the issues that might be addressed by taking a public health perspective on HVHF. It is clear that while natural gas extraction is a long-standing and important part of our nation’s energy portfolio, the rapid implementation of large-scale HVHF in many parts of the country has presented a new industrial, environmental, and land use development pattern with significant potential for public health effects.

PUBLIC HEALTH RESPONSE

In 2008, Howard Frumkin and colleagues set forth a framework for public health responses to the challenge of climate change [45]. Both climate change and HVHF are usually considered issues characterized by tradeoffs between economic growth and environmental protection. As a policy problem, climate change is similar to the rapid expansion of HVHF in several key ways, including wide-ranging uncertainties, the potential for impacts in diverse sectors, and the need to address the issue through multidisciplinary investigation and at local, state, and federal levels (as well as internationally). For both issues, public health brings an important perspective, and public health professionals have an important role to play. Here, we adapt Frumkin's framework for climate change to the issue of HVHF to provide guidance for a constructive role for public health in future practice and policy.

Frumkin et al. describe five public health perspectives that inform responses to the challenges of climate change [45]:

- prevention;
- risk management;
- co-benefits;
- economic impacts; and
- ethical issues.

These perspectives are also salient for the many challenges facing public health professionals in addressing HVHF. Below, we discuss each perspective in turn as a source of guidance for what public health voices can add to the ongoing public dialogue about managing HVHF to promote the public good.

Central to each of these perspectives is the uncertainty surrounding the potential impacts of HVHF. Uncertainty is frequently cited as one of the primary barriers to determining whether—and if so how—HVHF can be managed in a manner that promotes public health. While instances of health problems have been reported in various communities where HVHF has occurred across the country, to date there has been little peer-reviewed literature on the nature or extent of these impacts [18]. This dearth of research is due to the limited number of years HVHF has been practiced, as well as to fundamental challenges in studying its health impacts. These include the lack of identified unique health indicators, latency of effects, limited baseline and monitoring data, cumulative impacts, low population densities, and, in some cases, industry practices and non-disclosure agreements that limit access to relevant information. Understanding of health effects is further complicated by the variations in HVHF operations geographically and over time. Many of these significant uncertainties are unlikely to be overcome in the foreseeable future. However, the public health community has extensive experience in situations that are rife with unknowns. The precautionary principle is often invoked to guide decision-making, so as to prevent suspected environmental or health risks when there is significant uncertainty. The theme of taking action despite remaining uncertainties carries through each of the principles discussed below.

Prevention

As Frumkin et al. [45] point out, public health professionals distinguish between primary prevention (taking action to avoid a harm) and secondary prevention (anticipating and taking action to reduce existing impacts). Principles of prevention suggest that public health professionals should urge federal, state, and local environment, health, and development agencies to adopt a precautionary approach in the face of uncertainty regarding the long-term environmental health impacts of HVHF. Such an approach might include:

- discouraging the use of chemicals or chemical mixtures with unknown health effects, particularly those with the potential for long-term or endocrine-disrupting potential, and favoring safer substitutes;
- requiring gas development companies to disclose and receive approval of the chemicals proposed in each HVHF operation, before drilling and completion;
- conducting baseline monitoring of air quality, water quantity and quality, land resources, and human health before drilling begins, throughout the extraction process, and after active operations cease;
- modeling and predicting cumulative environmental health impacts under various extraction scenarios;
- conducting health impact assessments that address multiple health effects at a local and regional scale prior to expansion of HVHF;
- insisting on the use of commonly accepted industry best practices to lower worker exposures, for example, dust controls, traffic control plans, closed chemical delivery systems, reduced worker exposure to produced water, and employer provision of personal protective equipment (PPE), training and monitoring;
- proceeding at a scale and pace that allow for effective monitoring, surveillance, and adaptation of regulation to anticipate/prevent negative health effects; and
- should negative health or environmental effects be observed, ceasing extraction until further evidence indicates that operations may resume safely.

Geological, geographic, climatological, technological, economic, social, and political differences between communities in which HVHF occurs result in widely varied potential for health impacts. The public health community should advocate for planning and policy approaches that take into account this variability.

Risk Management

The framework of risk management guides the systematic identification, assessment, and reduction of risks. Public health professionals should advocate for and participate in efforts to manage the risks of HVHF. These efforts should examine the full life cycle of the process at local, regional, and global levels.

This implies explicitly modeling the cumulative impacts of HVHF over time. For example, individual drilling operations are unlikely to produce enough pollution to trigger regulation under existing environmental laws. However, the cumulative impacts of emissions from drilling-associated activities at multiple sites may create significant public health threats for local communities or regions. Therefore, projections of aggregate emissions under expected extraction scenarios should be the basis for regulation of individual sources. Overall density and projected development over time should be considered.

Air pollution is just one type of impact to which the risk management approach should be applied. Health impact assessment (HIA) provides a framework for identifying and prioritizing multiple impacts. Only one HIA of HVHF has been conducted to date, and public health professionals and others have advocated for additional HIAs to be conducted in other areas [30].

Co-Benefits

Frumkin et al. invoke the principle of co-benefits to guide a public health response to climate change [45]. Co-benefits result when actions yield benefits in multiple arenas. Focusing on actions with co-benefits is particularly appropriate when resources are limited and uncertainties are high.

Public health professionals can look to the list of 10 essential services of public health, developed by the Public Health Functions Steering Committee in 1994 (see Figure 1) to help identify actions within their purview that may both reduce risks from HVHF and benefit health in other ways [49]. For example, monitoring private drinking water wells for baseline data prior to the onset of HVHF may identify pre-existing drinking water quality problems that would otherwise have gone undetected. Community partnerships forged to address the issues raised by HVHF may also be able to confront other local environmental public health problems. Training public health professionals, health care providers, and emergency responders to deal with potential spills, explosions, or accidents related to HVHF may improve local capacity to respond to other types of public health emergencies.

Economic Impacts

Public health planning aims to protect the public at the lowest possible cost. In the case of HVHF, this suggests the following:

- Both long- and short-term costs and benefits should be considered. The history of environmental health includes many examples long-term remediation costing more than prevention.
- The timing of HVHF has major implications for the economics of shale gas extraction because of expected changes in the price of natural gas. Policies regarding HVHF should explicitly compare tradeoffs between the economic, strategic, public health, and global climatological implications of energy alternatives under different extraction scenarios over the long term.
- The distribution of costs and benefits from HVHF is highly variable. While HVHF undoubtedly brings economic growth, the benefits do not accrue

1. Monitor health status to identify and solve community health problems.
2. Diagnose and investigate health problems and health hazards in the community.
3. Inform, educate, and empower people about health issues.
4. Mobilize community partnerships and action to identify and solve health problems.
5. Develop policies and plans that support individual and community health efforts.
6. Enforce laws and regulations that protect health and ensure safety.
7. Link people to needed personal health services and assure the provision of health care when otherwise unavailable.
8. Assure competent public and personal health care workforce.
9. Evaluate effectiveness, accessibility, and quality of personal and population-based health services.
10. Research for new insights and innovative solutions to health problems.

Figure 1. Ten essential services of public health.
Source: U.S. Centers for Disease Control and Prevention,
National Public Health Performance Standards Program (NPHPSP),
“10 Essential Public Health Services,”
http://www.cdc.gov/nphpsp/essentialservices.html

equally within communities, nor do the burdens. Because of public health’s focus on eliminating health disparities and the close association between economic and health status, the distribution of economic impacts has public health implications.

- The impacts of the boom-and-bust cycle of economics associated with extraction of nonrenewable resources like shale gas has significant implications for community health over the long-term.
- Many economic costs are not included in simple calculations of jobs and economic growth generated by new industry. These externalities may include losses to existing businesses (tourism, agriculture, etc.), damage to roads and increased costs of road maintenance, and days of work or school missed by asthmatics who suffer more when air pollution increases.

For these reasons, public health professionals should advocate for economic analyses that account for long-term costs, identify externalities, and clarify the distribution of costs and benefits. Such analyses may provide a basis for designing fee structures, prioritizing research needs, creating monitoring systems, and developing public health programs that reflect the true costs and benefits of HVHF.

Ethical Issues

The ethics of public health have been codified into 12 "principles for practice." In addition, Frumkin et al. [45] point to several ethical foundations that may inform public health responses in a given situation. Building on these principles, ethical considerations relevant to the public health perspective on HVHF include:

- *Future generations:* As noted above, the potential long-term costs of environmental and health damage should be considered. Given the long latency of diseases like cancer, intergenerational impacts of endocrine disruptors, and slow migration of groundwater, it is appropriate to advocate for a long-term perspective on health effects of HVHF.
- *Vulnerable populations:* Some individuals or populations may be more vulnerable to environmental health impacts of HVHF. Children, the elderly, and those with existing disease (for example, asthma) may be more susceptible to impacts such as air pollution. Workers (both on-site and in related industries) are another population that may be particularly affected due to their proximity to operations.
- *Environmental justice:* Public health ethics point to protection of those who have fewer resources to avoid or mitigate impacts, already bear disproportionate environmental risks, or have historically lacked a voice in policy decisions. By this definition, isolated and economically disadvantaged rural communities are of concern as a whole, and lower-income members of these communities may need particular consideration.
- *Public participation:* Informed, ongoing, and meaningful participation by affected communities is often advocated as a strategy to promote ethical decision processes and outcomes. Public health professionals have the tools and experience to communicate information, develop partnerships, and process the public's input in a meaningful way. The extent of public concern about health in discussions of HVHF points to the importance of public participation in decisions on this issue.

Public health professionals have a role to play in making sure that these ethical principles are considered in decision-making related to HVHF.

CONCLUSIONS

Natural gas development is regulated under local, state, and federal land use and environmental laws. However, implementing new natural gas extraction technologies on a large scale poses potential public health threats that existing regulatory systems may not adequately anticipate, monitor, or protect against. Therefore, it is essential that public health professionals be included in deliberation of administrative, programmatic, and policy approaches to natural gas extraction at all levels of government. Federal, state, and local commissions and agencies charged with regulating the natural gas industry should include strong representation by professionals with training and experience in public health. In addition, the role of local and state public health professionals in responding to public health concerns arising from HVHF should be recognized and supported accordingly.

Training of local health departments, health care providers, and occupational health centers, as well as open ongoing communication between health professionals and the gas extraction industry, are essential to protecting worker and public health. The implementation of new natural gas extraction technologies, continual changes in the gas development industry, rapid growth of drilling operations in new areas, and variations in operations between companies pose significant challenges for occupational health. Public health professionals should support training for workers and local health care providers to anticipate these challenges and the provision of resources to subsidize these additional needs.

There are clearly many uncertainties surrounding the nature, distribution, and extent of health effects from HVHF. However, as Frumkin et al. [45] note, "Preparedness often occurs in the face of scientific uncertainty." Based on past experiences with emergency response, offshore oil and gas production, nonpoint sources of air and water pollution, and occupational health, public health professionals have a wealth of experience relevant to many aspects of HVHF. Policies that anticipate potential public health threats, use a precautionary approach in the face of uncertainty, provide for monitoring, and promote adaptation as understanding increases may significantly reduce the negative public health impacts of this approach to natural gas extraction.

To help accomplish this goal, the public health workforce should become better educated about natural gas development and its potential for public health impacts. In particular, local public health agencies in areas of active natural gas development should receive adequate resources to support education, outreach, surveillance and monitoring, needs assessment, and prevention activities related to natural gas extraction. Federal and state legislatures should provide funding for the training and staffing of local public health agencies in areas of active natural gas development. Public health professionals should also reach out to health care providers and community partners to increase their capacity and involvement in this area.

Such awareness, education, and support may help public health professionals more actively engage in protecting public health from the potential impacts of HVHF. Policy position statements such as that recently adopted by the APHA provide a platform from which public health professionals can continue to engage in decision-making processes related to HVHF. This special issue of *New Solutions* offers additional information and inspiration for next steps.

AUTHORS' BIOGRAPHIES

WALTER A. JONES is the Associate Director of the Occupational Safety and Health Division for the Laborers' Health and Safety Fund of North America, in Washington, DC. Mr. Jones is a Certified Industrial Hygienist and helps contractors establish and maintain OHS best practices that create healthy work-sites and positive safety cultures. Mr. Jones is a member of NIOSH's Prevention through Design Council and sits on the OSHA Advisory Committee on Construction Safety and Health (ACCSH) and the American National Standards Institute (ANSI) A10 Construction and Demolition Standards Committee. Contact him at wjones@lhsfna.org

KATRINA SMITH KORFMACHER is Associate Professor in the Department of Environmental Medicine at the University of Rochester Medical Center and directs the Community Outreach and Engagement Core of the Environmental Health Sciences Center. Dr. Korfmacher's current research focuses on the use of science in community-based environmental health policy in the areas of healthy homes, hydrofracking, and health impacts assessments. Her email address is katrina_korfmacher@urmc.rochester.edu

SAMANTHA MALONE is the Manager of Science and Communications at the FracTracker Alliance. She provides user and partner support, coordinates organization-wide communications, and conducts and translates environmental health research for the blog. Sam has an MPH degree from the University of Pittsburgh Graduate School of Public Health (GSPH) and is currently a doctoral student in the school's Environmental and Occupational Health department. Contact her at slm75@pitt.edu

LEON F. VINCI, DHA, MPH, BA, RS. His thirty-year public health career has involved him in a variety of aspects of the environmental health profession. He has received national stature in such areas as school health issues, hazardous materials management, Health Reform, Public Health Preparedness, continuing education, institutional sanitation, Bioterrorism/Emergency Preparedness, Environmental Health, and infectious diseases. He is the founder and CEO of Health Promotion Consultants (HPC), a health consulting firm.

NOTES

1. B. D. Goldstein , J. Kriesky, and B. Pavliakova, "Missing from the Table: Role of the Environmental Public Health Community in Governmental Advisory Commissions Related to Marcellus Shale Drilling," *Environmental Health Perspectives* 120 (4) (2012): 483-486, doi: 10.1289/ehp.1104594.
2. R. J. Davies et al., "Hydraulic Fractures: How Far Can They Go?" *Marine and Petroleum Geology* 37 (1) (2012): 1-6, doi: 10.1016/j.marpetgeo.2012.04.001.
3. C. G. Groat and T. W. Grimshaw, *Fact-Based Regulation for Environmental Protection in Shale Gas Development,* 2012, http://energy.utexas.edu/images/ (accessed November 5, 2012).

4. R. Seale, "Open-Hole Completion Ion System Enables Multi-Stage Fracturing and Stimulation Along Horizontal Wellbores," *Drilling Contractor* (July/August, 2007): 112-114.
5. C. Mooney, "The Truth about Fracking," *Scientific American* 305 (2011): 80-85. doi: 10.1038/scientificamerican1111-80.
6. M. L. Finkel and A. Law, The Rush to Drill for Natural Gas: A Public Health Cautionary Tale, *American Journal of Public Health* 101 (5) (2011): 784-785, doi: 10.2105/AJPH.2010.300089.
7. E. N. Radow, "Homeowners and Gas Drilling Leases: Boon Or Bust?" *New York State Bar Association Journal* November/December (2011) 11-21.
8. T. Colborn et al., "Natural Gas Operations from a Public Health Perspective," *Human and Ecological Risk Assessment: An International Journal* 17 (5) (2011): 1039-1056, http://dx.doi.org/10.1080%2F10807039.2011.605662.
9. D. J. Rozell and S. J. Reaven, "Water Pollution Risk Associated with Natural Gas Extraction from the Marcellus Shale," *Risk Analysis* 32 (8) (2011): 1382-1393, http://dx.doi.org/10.1111%2Fj.1539-6924.2011.01757.x.
10. United States Environmental Protection Agency, *Investigation of Ground Water Contamination near Pavillion, Wyoming* [draft], 2011, www.epa.gov/region8/superfund/wy/pavillion/ (accessed November 12, 2012).
11. Ground Water Protection Council, ALL Consulting, *Modern Shale Gas Development in the United States: A Primer,* 2009, http://www.eogresources.com/responsibility/doeModernShaleGasDevelopment.pdf. (accessed May 29, 2012).
12. Chesapeake Energy, *Hydraulic Fracturing Facts*, 2012, http://www.hydraulicfracturing.com/Water-Usage/Pages/Information.aspx (accessed May 31, 2012).
13. S. McSurdy and R. Vidic, *Oil & Natural Gas Projects Exploration and Production Technologies: Sustainable Management of Flowback Water during Hydraulic Fracturing of Marcellus Shale for Natural Gas Production,* 2012, http://www.netl.doe.gov/technologies/oil-gas/Petroleum/projects/Environmental/Produced_Water/00975_ MarcellusFlowback.html (accessed December 11, 2012).
14. J. Arthur, A. J. Daniel, B. Langhus, and D. Alleman, *An Overview of Modern Shale Gas Development in the United States,* 2008, http://www.aogc.state.ar.us/ALL%20FayettevilleFrac%20FINAL.pdf (accessed May 17, 2012).
15. T. Myers, "Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers," *Ground Water* (2012): 50(6) 2012: 872-882, doi: 10.1111/j.1745-6584.2012.00933.x.
16. U.S. House of Representatives, Committee on Energy and Commerce, *Chemicals Used in Hydraulic Fracturing,* 2011, http://democrats.energycommerce.house.gov/ (accessed May 29, 2012).
17. R. Hammer and J. VanBriesen, *In Fracking's Wake,* 2012, http://www.aogc.state.ar.us/ALL%20FayettevilleFrac%20FINAL.pdf (accessed November 7, 2012).
18. M. Bamberger and R. E. Oswald, "Impacts of Gas Drilling on Human and Animal Health," *New Solutions: A Journal of Environmental and Occupational Health Policy* 22 (1) (2012): 51-77, doi: 10.2190/NS.22.1.e.
19. U.S. Environmental Protection Agency, *Class I Underground Injection Control Program: Study of the Risks Associated with Class I Underground Injection Wells* (EPA 816-R-01-007), 2001.

20. Ohio Department of Natural Resources, *Preliminary Report on the Northstar 1 Class II Injection Well and the Seismic Events in the Youngstown, Ohio, Area,* 2012, http://media.cleveland.com/business_impact/other/UICReport.pdf (accessed December 11, 2012).
21. Pennsylvania Department of Environmental Protection, *Road Spreading of Brine for Dust Control and Road Stabilization*, 2011, http://www.portal.state.pa.us/portal/server.pt/community/public_resources/20303 (accessed December 10, 2012).
22. S. Detrow, "State Impact/Pennsylvania/DEP Issues Statement On Bradford County Methane Migration Investigation," 2012, http://stateimpact.npr.org/pennsylvania/2012/05/24/dep-issues-statement-on-bradford-county-methane-migration-invest/ (accessed 05/31, 2012).
23. S. G. Osborn, A. Vengosh, N. R. Warner, and R. B. Jackson, "Methane Contamination of Drinking Water Accompanying Gas-Well Drilling and Hydraulic Fracturing," *Proceedings of the National Academy of Sciences* Early Edition 108 (20): 8172-8176 (2011), doi: 10.1073/pnas.1100682108.
24. United States Environmental Protection Agency, *Draft Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* (EPA/600/D-11/001), 2011.
25. United States Environmental Protection Agency, "Key Documents About Mid-Atlantic Oil and Gas Extraction: Clean Water Act Section 308 Information Requests/Clean Water Act Section 309 Administrative Orders/Administrative Orders and Information Requests to Wastewater Treatment Facilities Accepting Wastewater From Marcellus Shale Drilling Operations," 2012, http://www.epa.gov/region3/marcellus_shale/#309 (accessed December 11, 2012).
26. Utah Department of Environmental Quality (Deq), "Uintah Basin: Air Quality and Energy Development," http://www.deq.utah.gov/locations/uintahbasin/index.htm (accessed December 17, 2012).
27. G. Petron et al., "Hydrocarbon Emissions Characterization in the Colorado Front Range: A Pilot Study," *Journal of Geophysical Research* 117 (D4) (2012), http://dx.doi.org/10.1029%2F2011JD016360.
28. T. Colborn et al., "An Exploratory Study of Air Quality Near Natural Gas Operations," *Human and Ecological Risk Assessment* (in press), doi: 10.1080/10807039.2012.749447.
29. L. M. McKenzie et al., "Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources," *The Science of the Total Environment* 424 (2012): 79-87, doi: 10.1016/j.scitotenv.2012.02.018.
30. R. Witter et al., *Health Impact Assessment for Battlement Mesa, Garfield County, Colorado,* Draft 2, 2011, http://www.garfield-county.com/public-health/battlement-mesa-health-impact-assessment-draft2.aspx (accessed November 7, 2012).
31. S. Adair et al., "Considering Shale Gas Extraction in North Carolina: Lessons from Other States," *Duke Environmental Law and Policy Forum* 22 (2012): 257-301.
32. T. C. Morata, D. C. Byrne, and P. M. Rabinowitz, eds., *Occupational and Environmental Health: Recognizing and Preventing Disease and Injury,* 6th ed. (Oxford: Oxford University Press, 2011).
33. S. L. Perry, *Energy Consequences and Conflicts across the Global Countryside: North American Agricultural Perspectives,* 2011, http://forumonpublicpolicy.com/vol2011.no2/archivevol2011.no2/perry.pdf (accessed November 2, 2012).

34. K. J. Brasier et al., "Residents' Perceptions of Community and Environmental Impacts from Development of Natural Gas in the Marcellus Shale: A Comparison of Pennsylvania and New York Cases," *Journal of Rural Social Sciences* 26 (1) (2011): 92-106.
35. Associated Press, "Gas-Drilling Boom Brings More Crime, Carousing to some Towns," October 26, 2011, http://www.pennlive.com/midstate/index.ssf/2011/10/gas-drilling_boom_brings_more.html (accessed May 29, 2012).
36. R. Swift, "PA State Police Reassigned to Gas Drilling Region as Crime Rises," February 8, 2012, http://www.poconorecord.com/apps/pbcs.dll/article?AID=%2F20120218%2FNEWS90%2F202180308%2F-1%2FNEWS01 (accessed May 31, 2012).
37. County Commissioners Association of Pennsylvania, *Marcellus Shale Emergency Preparedness.* Senate Veterans Affairs & Emergency Preparedness Committee. Presented by Douglas E. Hill. 2010; Available at: http://www.pacounties.org/Lists/Whats%20New/Attachments/77/Marcellus_Emergency_Mgmt_Testimony_06-10[1].pdf (accessed January 4, 2013).
38. J. E. Clougherty and L. D. Kubzansky, "A Framework for Examining Social Stress and Susceptibility to Air Pollution in Respiratory Health," *Environmental Health Perspectives* 117 (9) (2009): 1351-1358, doi: 10.1289/ehp.0900612.
39. U.S. Centers for Disease Control and Prevention, "Fatalities among Oil and Gas Extraction Workers–United States, 2003-2006," *MMWR–Morbidity & Mortality Weekly Report* 57 (16) (2008): 429-431.
40. U.S. Department of Labor, Bureau of Labor Statistics (BLS), "Fatal Occupational Injuries by Selected Worker Characteristics and NAICS 2111X Selected Industry, All U.S., All Ownerships, 2005-2010," 2012, http://data.bls.gov/ (accessed December 13, 2012).
41. M. Elk, "Fracking Fatalities: Organized Labor Implores Federal Agencies to Stop the Killings," *In These Times,* May 31, 2012, http://inthesetimes.com/working/entry/13286/fracking/ (accessed June 1, 2012).
42. R. Hill, *Improving Safety & Health in the Oil and & Gas Extraction Industry though Research and Partnerships*, 2012, http://www.ucdenver.edu/academics/colleges/PublicHealth/research/centers/maperc/training/energysummit/Documents/2012%20MAP%20ERC%20Energy%20Summit_Improvements%20and%20Health%20in%20Oil%20and%20Gas%20Industry.pdf (accessed 12/13, 2012).
43. E. Esswein, "Worker Exposure to Crystalline Silica During Hydraulic Fracturing," *NIOSH Science Blog,* 2012, http://blogs.cdc.gov/niosh-science-blog/2012/05/silica-fracking/ (accessed January 4, 2013).
44. National Toxicology Program, *Report on Carcinogens, 12th ed.*, 2012, http://ntp.niehs.nih.gov/?objectid=03C9AF75-E1BF-FF40-DBA9EC0928DF8B15 (accessed November 7, 2012).
45. H. Frumkin et al., "Climate Change: The Public Health Response," *American Journal of Public Health* 98 (3) (2008): 435-445, doi: 10.2105/AJPH.2007.119362.
46. G. Tyler Miller, *Living in the Environment,* 14th ed. (Stamford, CT: Cengage Learning, 2004).
47. L. Barreto, A. Makihira, and K. Riahi, "The Hydrogen Economy in the 21st Century: A Sustainable Development Scenario," IIASA Research Reprint; reprinted from *International Journal of Hydrogen Energy* 28 (3) (2003): 267.

48. R. Howarth, R. Santoro, and A. Ingraffea, "Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations," *Climate Change* 106 (4) (2011): 679-69, doi: 10.1007/10.1007/s10584-011-0061-5.
49. U.S. Centers for Disease Control and Prevention (CDC), "National Public Health Performance Standards Program (NPHPSP)," 2010, http://www.cdc.gov/nphpsp/essentialservices.html (accessed December 10, 2012).
50. J. C. Thomas et al., "A Code of Ethics for Public Health," *American Journal of Public Health* 92 (7) (2002): 1057-1059, doi: 10.2105/AJPH.92.7.1057.

Direct reprint requests to:

Katrina Smith Korfmacher, Ph.D.
601 Elmwood Avenue, Box EHSC
Rochester, NY 14642
e-mail: katrina_korfmacher@urmc.rochester.edu

NEW SOLUTIONS, Vol. 23(1) 33-53, 2013

Scientific Solutions

USING ETHNOGRAPHY TO MONITOR THE COMMUNITY HEALTH IMPLICATIONS OF ONSHORE UNCONVENTIONAL OIL AND GAS DEVELOPMENTS: EXAMPLES FROM PENNSYLVANIA'S MARCELLUS SHALE

SIMONA L. PERRY

ABSTRACT

The ethnographer's toolbox has within it a variety of methods for describing and analyzing the everyday lives of human beings that can be useful to public health practitioners and policymakers. These methods can be employed to uncover information on some of the harder-to-monitor psychological, sociocultural, and environmental factors that may lead to chronic stress in individuals and communities. In addition, because most ethnographic research studies involve deep and long-term engagement with local communities, the information collected by ethnographic researchers can be useful in tracking long- and short-term changes in overall well-being and health. Set within an environmental justice framework, this article uses examples from ongoing ethnographic fieldwork in the Marcellus Shale gas fields of Pennsylvania to describe and justify using an ethnographic approach to monitor the psychological and sociocultural determinants of community health as they relate to unconventional oil and gas development projects in the United States.

Keywords: environmental justice, unconventional oil and gas, Marcellus Shale, community health, chronic stress, ethnography, fracking

doi: http://dx.doi.org/10.2190/NS.23.1.d
http://baywood.com

The term *onshore unconventional oil and gas developments* refers broadly to the activities and technologies used for extracting hydrocarbon resources from oil and gas shale, tight gas and tar sands, heavy oil reservoirs, and coal beds [1]. As the pace of exploration, drilling, extraction, and processing of shale oil and gas across North America has increased, medical doctors, research scientists, and federal agencies have raised concerns about the public health implications of the environmental and social changes that result from these developments [2-8]. Many of these public health concerns relate to air and water pollution from industrial facilities and accidents related to these developments. However, perhaps just as significant is the risk that such changes may lead to psychological and social (psychosocial) stress that can make individuals more susceptible to disease and chronic health problems [9-11].

Ethnography, the process of observing, interpreting, describing, and writing about local cultures [12], is an important social science method for systematically documenting and describing environmental and sociocultural factors and changes that may impact community health. Ethnographic methods can also be used to inform local public health research agendas, including carrying out health impact assessments and planning for or responding to emergencies, and making culturally appropriate health policy recommendations. Ethnographic methods as part of community health studies can also be used within an environmental justice framework. A hallmark of these environmental justice studies using ethnography is their grounded, systematic description of the persistent environmental inequalities within communities of color and the poor who are exposed to greater environmental hazards at the same time as they experience higher rates of poverty, malnutrition, social isolation, political powerlessness, and discrimination [13-15]. This article expands on this application and describes how ethnography can be used as an important community health monitoring tool in rural, urban, and suburban areas where unconventional oil and gas developments are taking place.

Concrete examples are drawn from an ongoing ethnographic study in Bradford County, Pennsylvania, where Marcellus Shale gas exploration and development is taking place. Data collected from interviews, focus groups, and participant observations in 2009, 2010, and 2011 confirm that rapid environmental and social changes were happening in the county as a result of Marcellus Shale developments. A total of 31 landowners and 68 other residents of the county were interviewed during this time period, and most spoke about experiencing what was later classified during data analysis as psychosocial stress. The majority of this stress was articulated by landowners or observed in the field as resulting from the environmental and social changes taking place over such a short period of time. These psychosocial stress factors were then analytically sorted into three themes with direct relevance to understanding the psychological and sociocultural determinants of community health outcomes: anticipated or perceived changes to quality of life; economic inequalities; and acts of violence.

These themes raise new questions about the risks posed by unconventional oil and gas development and lead to new avenues for investigation of the links among such developments, environmental and social changes, chronic stress, and community health outcomes.

AN ENVIRONMENTAL JUSTICE FRAMEWORK FOR ASSESSING COMMUNITY HEALTH IMPLICATIONS OF UNCONVENTIONAL OIL AND GAS DEVELOPMENTS

The rapid rise in onshore unconventional oil and gas developments has new and serious implications for local communities, particularly in poorer rural areas, making this an emerging environmental justice issue. Compared to the offshore oil and gas developments of the 1970s and 1980s in the Gulf of Mexico [16], these onshore developments, particularly in the Marcellus Shale in Pennsylvania and Ohio, occur in closer proximity to people's water wells, homes, schools, places of work and worship, playgrounds, and historic locations. There is increased competition and direct conflict with existing and future private and public land uses, particularly where new natural gas pipelines are being constructed. Adding to these tensions are unknown risks regarding the use of chemical compounds and other materials labeled "trade secrets" by the industry and used in the drilling, extraction, and production processes. The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 created environmental and right-to-know regulatory exemptions for hydraulic fracturing and added tax breaks and government subsidies to encourage domestic exploration of unconventional oil and gas resources. In addition, the U.S. Environmental Protection Agency is investigating concerns about the amount and type of waste materials that are generated from drilling and production and their appropriate disposal [17].

This article applies an environmental justice framework that incorporates the public health model of prevention and the precautionary principle [18] to the assessment of the community health implications of onshore unconventional oil and gas developments. The public health model of prevention focuses on eliminating a threat before harm can occur. This approach shifts the focus from treatment to prevention and demands that affected communities not have to wait for conclusive proof of causation before preventive action is taken [18, pp. 19, 20, 26]. The precautionary principle says that if there is scientific uncertainty about the harms posed by an activity, then those proposing that activity have the duty to prevent harm. The burden of proof lies on those who propose to use risky technologies, not those who may be harmed by such technologies [18, pp. 19, 28].

In the United States, the use of ethnography to study environmental pollution as it relates to public health has its roots in the environmental justice movement, looking at the social, geographic, and procedural burdens disproportionately placed on communities of color and the poor, particularly in urban areas [18, pp. 30-31]. The bottom-up, grounded approach that ethnographic fieldwork takes provides information on the cultural context: where people live, work, play, and attend school and how they interact with the physical and natural world on a daily and lifetime basis. Ethnographic analysis, and use of the iterative process of returning to the fieldwork location to verify and check analytical themes, also provides a means to track environmental and social changes and their impact on the psychological, social, and physical health of individuals and communities over time.

THE ROLE OF PSYCHOLOGICAL AND SOCIAL STRESS IN DETERMINING COMMUNITY HEALTH OUTCOMES

Since at least the mid-1950s public health scientists, psychologists, and sociologists have studied how psychological, social, and environmental stressors impact individual and community susceptibility to disease or changes in overall health. In this previous work, a stress or stressor is defined as "any environmental, social, or internal demand which requires the individual to readjust his/her usual behavior patterns" [11, p. 54], having a negative influence on a person's overall well-being and quality of life, and in some cases triggering physiological mechanisms that in turn may determine an individual's or a community's susceptibility to disease, environmental pollution, or toxic substances [11, 18, 21].

In their study of abandoned coal mine communities Liu et al. [22] found that economic deprivation was significantly associated with a greater number of abandoned mines in rural Pennsylvania. And, while they do not draw definitive conclusions regarding the community health implications of their results, they do identify important interactions between sociocultural characteristics and available material and institutional resources that may result in poor overall health outcomes. Namely, they point to problems of industrial and social abandonment and landscape changes in addition to poverty and economic inequality that can limit access to health care, healthy food choices, and recreational spaces [22, p. 7]. Previous studies of the social determinants of health have also identified poverty and economic inequality as significant contributing factors to chronic stress that may lead to adverse health outcomes [23-28]. These economic metrics may sometimes be an inaccurate and culturally inappropriate way to identify and measure overall well-being and quality of life [29]; however, at least in studies conducted in the United States, personal and community economic status does seem to play a key role in determining levels of chronic stress, the overall health of individuals and groups, and susceptibility to disease.

Anecdotal reports by individuals in communities where onshore unconventional oil and gas developments are occurring describe rapid environmental changes related to well pad and pipeline construction, road damage, physical health problems, and deteriorating air and water quality [30]. In more rural areas, there are also anecdotal reports of rapid social changes related to an increase in population numbers and density (especially of transient young men working in the oil and gas industry), an influx of new personal income from lease-signing bonuses and royalty income, a shortage of affordable housing, and increased crime [31, 32]. While anecdotal reports such as these may indicate that communities are experiencing increased psychological and social stress as a result of environmental and social changes, they do not provide systematic evidence that individuals and entire communities are experiencing the type of chronic stress that may lead to an increased susceptibility to disease or changes in overall health. To rigorously and systematically collect this type of information on chronic stress, we need a way to document both individual and collective experiences before, during, and after environmental and social changes take place. The practice of ethnography and its grounded data collection and iterative analysis methods offer a comprehensive way of doing just that.

ETHNOGRAPHIC METHODS

Ethnographic research methods seek to describe everyday lives and practices through cultural interpretation. An ethnographer's goal is to explain how these descriptions represent what can be called "webs of meaning" [12, pp. 5, 33] in which we all live. To do this, ethnographers have developed a variety of methods for studying the everyday lives of humans and the systems and patterns (language, artifacts, visual symbols, etc.) connecting humans to each other, as well as to natural and built environments, institutional structures, and other constructs of traditional and contemporary society [34]. In contrast to other social science methods and approaches, ethnography takes what is known as an inductive and grounded perspective, meaning that categories and meanings of analysis emerge from data collection rather than being imposed from existing models or hypotheses. Done correctly, this grounded perspective ensures that the data emerging from ethnographic fieldwork can be used to develop further research questions and hypotheses that have local salience. A closer look at the methods used in the Bradford County study illustrates these points.

The objective of the ethnographic study conducted in Bradford County was to describe the cultural world views and personal and social interactions of rural landowners, specifically related to their land, water resources, and the rapid industrial developments taking place as a result of the potential boom in Marcellus Shale gas production [35]. The study utilized mixed-methods data collection and analysis, including a community-integrated geographic information system (GIS) process [36, 37], focus group meetings [38, 39], questionnaires, photo-voice (described below) [40, 41], oral history interviews, ethnographic interviews, participant observations, and archival document analysis.

To develop a plan for recruiting landowners and other interviewees, conversations and informal interviews were held with individuals at the County

Conservation District and the Planning and Grants Office, County Commissioners, township supervisors, and several Bradford County residents who had lived 10 or more years along the Susquehanna River. Observations were also conducted at various meetings of landowners and concerned citizens in the county and north-central and northeastern Pennsylvania to understand the diverse types of landowners and other residents. Based on this early fieldwork, a decision was made to focus on landowners owning close to 100 acres, or more, and who were actively using their land for farming, timber, and other forest uses. Specific names of possible participants in the focus groups were drawn from word-of-mouth referrals from county staff and other farmers and forest landowners. The successful recruitment of focus group participants took four months longer than anticipated. Two things caused this delay: difficulties in gaining the trust of a diversity of rural landowners in the county and the inability to guarantee complete anonymity to potential focus group participants who had signed previous legal agreements (non-disclosure agreements) or were in legal proceedings with a shale gas company. These difficulties required the scaling back of the number and size of focus groups. It was a trade-off that favored the collection of deeper, richer data from a smaller group of participants instead of broader, more representative data from a larger group of participants. To capture some of the diversity of landowners that was lost in the smaller focus groups, individual interviews were conducted with the landowners who could not participate because of anonymity concerns (but who still wanted to participate), and with those landowners who were unable to make the meetings, felt uncomfortable in a group setting, or who no longer actively used their land for farming or forest uses. These individual landowner interviews, plus additional interviews with county residents who were recruited by word of mouth referrals and identified during participant observations, were used both on their own and as a supplement to the analysis of the focus group data.

Seven landowners participated in two focus groups, each of which met four times. The two separate groups were based on their primary land use, one group of four crop and livestock (primarily corn, hay, dairy, horse) farmers and the other group of three woodland (timber, hunting, wildlife watching) landowners. The focus group participants were involved in the community-integrated GIS process during which they selected geographic places of special importance to them in the county, mapped their land, and identified their neighbors, all the while discussing their relationship to place and community. Focus group participants were also involved in a photo-voice process that involved taking photographs of things and places that exemplified their relationship with their land, the county, and the changes they were experiencing, and then writing about those photographs and sharing them with others in the group. To supplement this group work, individual oral histories were conducted with each of these seven landowners.

Twenty-four landowners and 68 other local residents, including a county commissioner, agricultural extension specialist, town residents, small business owners, township supervisors, oil and gas contractors, and school teachers, participated in individual ethnographic interviews. Participant observations were conducted at community events such as local fairs and church dinners, at public meetings such as monthly township meetings and weekly county commissioner meetings, at public hearings related to Pennsylvania Department of Environmental Protection Marcellus Shale regulations, and at private meetings such as gas industry community advisory panels.

The ethnographic data from the Bradford County study includes audio and video of focus groups and interviews, photographs and writings from the photovoice process, spatial data and maps from the GIS process, informational brochures and handouts from meetings, field notes of participant observations and interviews, as well as historic photographs and documents from archival research. Even though all the data were collected in the same county, the data cannot be analyzed for generalizations about the entire county, a township, a specific type of landowner, the region, or the state. Instead, data was analyzed to differentiate and describe particular aspects of the relationships humans have to their local environments and to each other; in other words, the data were used to discern the various cultural worldviews and "webs of meaning" held by those who participated as interviewees or under observation as part of the study [42].

ETHNOGRAPHIC ANALYSIS: THEMES OF CHANGE AND STRESS

The interpretation of ethnographic data and its analysis is an iterative process. It involves coding of interviews and observational notes, re-entering the field and asking new questions where necessary to refine themes emerging from the coding, and finally developing a set of themes that can be used to convey a detailed cultural description of local places and local people who were the focus of the study. The iterative nature of the analysis process ensures that an ethnographic study remains grounded in the local cultural context over time. This refining of themes and descriptions over time is critical to documenting and describing real-time environmental and social changes and the impact of those changes on local individuals and communities.

In the Bradford County study, cultural analysis revealed three themes directly related to environmental and social changes and what were articulated by local participants as increased levels of psychological and social stress: anticipated or perceived changes to quality of life, economic inequalities, and acts of violence. These themes are being used in continued ethnographic fieldwork in the county to ask new questions and form hypotheses. But these themes can also serve in planning future ethnographic studies on community health in other rural, suburban, and urban locations where unconventional oil and gas developments are located or are being planned and to inform preventive public health policies. How each theme emerged from the ethnographic data, and each theme's significance to understanding the community health implications of unconventional oil and gas development, are described below.

Changes in Quality of Life

The seven rural landowners who participated in focus groups in Bradford County identified six components to what quality of life meant to them: clean water, fresh air, fertile soil, rural way of life, economic security, and family and personal histories with the land in the present time and for their grandchildren. This local meaning of quality of life was probed for relevance in ethnographic interviews with the 24 individual landowners and it was found to resonate with them as well. When focus group discussions, or individual interviews, turned to how these qualities of life were either currently being changed or anticipated to change as a result of the Marcellus Shale gas developments, landowners spoke of many changes, including these: destruction of their dirt and gravel roadways (which were described as "arteries of rural community life" and the boundaries of family lands); a noticeable increase in "dust" in the air that gets on laundry hung out to dry, porches, and even inside their houses; an increase in loud noises from trucks applying their brakes and from drilling rigs at all hours of the day and night; bright lights in the night sky from construction activities and drilling rigs; visual and odor changes in the appearance or odor of their drinking water (all landowners who participated have private water wells); the number of strange new faces and non–English-speakers at local stores and gas stations; chemical spills into landowners' ponds and crop fields; and expectations of greater economic security as a result of signing a lease to allow a gas well, compressor station, or pipeline on their property.

When matching emotions to these changes, one landowner in a focus group described a feeling of "dread in the pit of my stomach," and all the landowners interviewed said they felt that as a result of the development of the Marcellus Shale in the county they were losing certain aspects of their quality of life, especially the fresh air and rural feel. Most landowners also expressed great uncertainty about whether these changes in quality of life would be temporary or permanent. This uncertainty turned to fear, anxiety, and depression in some landowners, particularly regarding what the changes would mean for their future well-being and the well-being of their children and grandchildren.

Uncovering and naming what quality of life meant to them allowed landowners to name and describe some of the psychological, social, and environmental factors that they felt may be leading to improvements or declines in their quality of life and overall well-being as a result of both external and internal forces, including state or national farming policies, environmental regulations, the shale gas industry, local politics, family and social relationships, and many others. Landowners said this helped them name, sometimes for the first time, what their quality of life meant to them. They reported feeling more aware of what was important to them, and this gave them a greater will to fight to keep their quality of life and help their neighbors do the same; however, they also reported that this greater awareness left them at times with a greater sense of loss and sadness. Ethnographic methods, with the focus on asking questions that directly relate to accessing local culture through understanding the language and behaviors of locals, put interviewees' cultural viewpoints above the researchers' and thereby allow for this sort of awareness-raising in ways that other social science methods cannot.

The concept of quality of life is closely associated with what people report as a sense of well-being. Behavioral economists and political scientists have found that among individuals, families, and communities, this sense of well-being can lead to overall improvements in quality of life and society [43-46]. During a speech at the University of Kansas in 1968, Robert F. Kennedy famously said,

> ". . . the gross national product does not allow for the health of our children, the quality of their education, or the joy of their play. It does not include the beauty of our poetry or the strength of our marriages; the intelligence of our public debate or the integrity of our public officials. It measures neither our wit nor our courage; neither our wisdom nor our learning; neither our compassion nor our devotion to our country; it measures everything, in short, except that which makes life worthwhile" [47].

Today international development agencies and national governments are developing indicators that seek to measure the sense of well-being that Kennedy spoke of in his speech. Measurements such as the United Nation's Human Development Index [29, 48] look not just at income or financial indicators but also levels of health, education, political freedom, and inequality. These types of quality-of-life measures have also been used in epidemiologic studies to assess the impact of industrial development, specifically fossil fuel developments, on local communities [22]. Ethnography offers a set of methodological and analytical tools that allow for the rigorous documentation, description, and analysis of what quality of life means to local communities faced with periods of rapid change.

Economic Inequality

All participants interviewed or observed as part of the ethnographic study in Bradford County expressed the belief that crop/livestock landowners tend to have less money than landowners who own only woodlands. But would a crop/livestock landowner who needs annual or semi-annual supplemental income to meet expenses be more eager to sign a lease for locating a shale gas well pad, water impoundment pond, compressor station, or pipeline on his or her property than a woodland landowner or other type of landowner who does not rely on supplemental income to meet his or her financial obligations?

In focus group meetings of the crop/livestock landowners, all four landowners said that they would allow Marcellus Shale gas development on their properties if the "price was right." At the time of the focus groups (January 2010–August 2010) all four of the crop/livestock landowners had active gas leases on their properties. In individual interviews these same landowners expressed more specific concerns regarding how the property would be treated during the developments (e.g., spills of hazardous wastes, accidents, destruction of prime pasture, etc.), but as in guided conversations in the focus group meetings, they individually conceded that if enough money was offered they would consider agreeing to development.

In contrast, the three landowners in the woodland focus group said that what was most important to them was not the price they would be offered or paid by the gas company to develop their land, but instead how the land would be developed and if the gas company would allow them to negotiate protection of their water, timber, wildlife, and access. In individual interviews with these landowners, one of these landowners admitted that price was an important consideration although certainly not the only thing to be considered in signing an agreement to allow shale gas development on his land. The other two woodland owners had no interest in the money, but only in the preservation of their land and water resources. At the time of the focus groups (February 2010–August 2010), none of the three woodland owners had a gas lease on his/her property.

Responses to a socioeconomic questionnaire given to the focus group participants indicated that income, not land use, was the main factor separating the four crop/livestock landowners from the three woodland owners. All landowners in the crop/livestock group reported annual household incomes (minus the salaries of minors and dependents) of less than $40,000, with two reporting less than $20,000. All woodland landowners reported annual household incomes of greater than $40,000. These responses are within the same range of estimates for mean household income in the entire county as reported in federal census statistics from 2006-2010. The 2006-2010 mean household income for the county was $51,372, with 30.2 percent of all total households in the county reporting less than $24,999, 29.9 percent reporting between $25,000 and $49,999, and 40.3 percent reporting over $50,000 [49]. In addition, the crop/livestock group participants responded that an average of 67 percent of their annual household income is derived from agricultural activities, while in the woodland group the percentage from agriculture was reported as only 2 percent.

Differences in household income revealed in such a small sample cannot lead to conclusive evidence regarding the impact that economic differences or inequalities may have on the psychological, sociocultural, and environmental indicators of community health. However, data confirming these income disparities was also collected during open-ended ethnographic interviews with individual landowners and in participant observations at a 2011 meeting of the

Bradford-Sullivan Forest Landowners' Association. Specifically, the point was made in these open-ended interviews and observations that supplemental income from both harvest of timber resources and off-the-farm jobs may be more important for crop/livestock landowners than for woodland owners. In addition to this income disparity between different types of rural landowners in Bradford County, the differences in occupation and employment status between landowners raises questions about differential access to affordable and timely health services. For example, all of the crop/livestock landowners in the focus groups and the majority of crop/livestock landowners and active farmers who were interviewed individually reported having no health insurance coverage. Current evidence or lack of evidence for the health effects of employment status are reviewed in detail by Catalano et al. [50], with a recommendation that more research is needed to understand how job and income loss in families and individuals may impact well-being, anxiety, and overall health outcomes [50, p. 445]. Clearly, given what the data collected during this ethnographic research say about economic inequalities and rural landowner types in Bradford County, more research needs to be done to understand how rural landowners' economic status influences their well-being, anxiety, and overall health and what this may mean in light of new shale gas developments.

This ethnographic data on economic inequalities between different types of landowners raises important questions with regard to the geographic locations of shale gas facilities and what this may mean with regard to the uneven psychological, social, and environmental stressors faced by different landowners, or even an entire region and the nation. For example, could income differences between landowners have implications for where unconventional oil and gas facilities are located in the first place given different landowners' willingness to either accept "the right price" or preserve their land and water resources regardless of the price? If certain types of landowners, such as crop and livestock farmers, are more willing or eager to have development on their land, does this put them and their families and other farm workers at a greater risk of exposure to industrial accidents and hazardous materials related to shale gas development? If landowners who own cropland or livestock and are actively farming are more willing to have shale gas developments, does this mean the products that come from those farms also run a greater risk of being contaminated by hazardous materials? Do shale gas developments on farmland pose a threat to the nation's food supply? And, if there is a threat, what does this mean to the livelihoods, incomes, and overall sense of well-being of farmers in Bradford County? To answer some of these questions environmental health and toxicology studies must be done. However, in drawing conclusions, and more importantly in offering management and policy recommendations, these environmental health studies must also rely on the psychological and sociocultural information that is being collected from the on-going ethnographic research described here and elsewhere [34].

Acts of Violence

Violence is defined as “the intentional use of physical force or power, threatened or actual, against oneself, another person, or against a group or community that either results in or has a high likelihood of resulting in injury, death, psychological harm, mal-development or deprivation” [51]. Political scientists, psychologists, and social workers who research violence document how different types of violent acts (physical, sexual, psychological, deprivation or neglect, and environmental) can have long-term implications for individual, family, and community stress levels, leading to widespread abuses of power, racism, continuous cycles of abuse, and in the worst cases murder, civil war, and genocide [52-54].

During the first months of fieldwork among Bradford County landowners, local officials and residents of the county talked in open-ended ethnographic interviews about prior cases of beatings, rape, incest, murder, bullying, and intimidation that they had knowledge of or had been directly involved in. Analysis of these early interviews and field notes bears evidence that violence and violent behavior are a part of everyday life in the county. Sometimes particular stories of violence were brought up by interviewees when they wanted to illustrate their concerns about society or politics, such as a belief that lack of education and low-income conditions lead to social turpitudes. Other times, though, these violent stories told by Bradford County residents were very personal and conveyed individual feelings of fear, anxiety, disassociation, loss, and powerlessness, all found in other studies [55-58] to be feelings symptomatic of stress and psychological trauma.

In interviews with landowners and other residents of the county, and most notably in the focus group meetings with the seven rural landowners, these feelings surrounding personal experiences of violent behavior were spoken of as analogous to the way some participants felt they and their families were experiencing changes related to Marcellus Shale gas developments. For example, interviewees described being bullied or intimidated by gas industry employees and their agents, by their neighbors when there were disagreements about the pros and cons of gas development in the local community, and by local politicians when they denied or did not listen to residents’ experiences with the shale gas industry and the severity of pollution events at particular locations. An article published in the anthropology journal *Culture, Food, Agriculture, and Environment* provides a more comprehensive discussion of these findings [35]. Confirming this, participant observation and interview data also contain descriptions of bullying and intimidation of landowners by gas company employees, local politicians, and other landowners related to leasing, siting, construction, and operation of shale gas facilities throughout the county [35]. The recall of past violent acts and the creation of new anxieties and feelings of powerlessness around the Marcellus Shale developments could increase the development of chronic stress patterns [56].

With regards to acts of physical violence in the county since unconventional gas developments began, there is preliminary evidence of an increase in overall physical violence, or threats of violence, from filings of Protection from Abuse (PFA) orders and arrests [59, 60]. However, the current ethnographic data from Bradford County does not allow for an analysis of the relationship between different levels of physical violence and unconventional oil and gas developments or other factors.

Anthropologists, geographers, and political scientists working in Africa, the United States, and other fossil-fuel–rich nations have documented the different acts of violence—physical, psychological, economic, political, environmental, and social—that exist in the context of large-scale oil and gas developments [61-63]. However, none of this research makes the explicit connection between such acts of violence, increased chronic stress, and community health outcomes. In urban settings, the relationship between environmental health and violence has been investigated by social epidemiologists. Epidemiological research in Boston showed that in neighborhoods where childhood asthma rates are higher, children tend to also be exposed to greater violence [64, 65]. While this urban epidemiological research shows that the two issues—asthma and violence—are spatially and temporally correlated, it does not answer the question of whether they are causally linked and, if so, what factors may link them. Using ethnography to describe and monitor the levels of violence in communities where unconventional oil and gas developments are taking place gives community health researchers and epidemiologists a way to track the spatial and temporal interactions between psychosocial stress factors, such as violence and violent behavior, and community health outcomes.

CONCLUSION

Ethnography and ethnographic approaches for monitoring the community health implications of onshore unconventional oil and gas developments are not without their limitations. Several of the most important limitations are faced by all ethnographic researchers regardless of the topic. These involve lack of funding for qualitative, grounded, exploratory, or descriptive social science research, the enormous volumes of data produced from interviews and fieldwork and the amount of time and organizational skill required for analysis of the data, and the difficulty in recruiting and maintaining trust with a diversity of informants and interviewees for the duration of a project. An additional limitation is a lack of understanding of what ethnography is (and is not) and how it can be employed to understand environmental justice concerns, inform further research agendas, and make concrete policy recommendations. For example, ethnography uses qualitative and sometimes anecdotal information as part of a systematic approach to documenting and describing culture based on prescribed methodological and analytical practices. However, the results of this research methodology are not anecdotal stories and information, but are defensible descriptions and analyses of the cultural worldviews and context within which specific people or places exist, which are documented and verified through intense immersion in those people's ways of life or a place. In spite of these limitations, ethnographic approaches to community health have much to offer other researchers, community health practitioners, policy makers, and communities.

To enhance understanding and communication about the potentially important role ethnography can play in gathering environmental health data in communities where unconventional oil and gas developments are taking place, ethnographic researchers must build a solid case for the usefulness and importance of both fieldwork methods and analytical tools by detailing what exactly ethnographic approaches look like on the ground, providing more information about the history of the method in addressing environmental health concerns where necessary, and justifying what sets ethnography apart from other social science approaches. The examples from Pennsylvania's Marcellus Shale described in this article are just one attempt to begin communication and build the case for more ethnographic and other community health research in shale gas areas. Clearly much more needs to be done in this regard.

In many of the rural and urban communities across North America where onshore unconventional oil and gas developments are being considered or already taking place there is a lack of scientific and clinical information on the local psychological and sociocultural factors that may directly influence community health outcomes [9]. Without such baseline information on the determinants of community health with particular emphasis on psychosocial stress factors, practitioners and policy makers have a difficult time determining the potential for harm to public health associated with these relatively new development projects and then enacting appropriate preventive measures. Thus, serious problems are raised regarding application of the precautionary principle and social, geographic, and procedural equity [18, pp. 30-31].

Ethnographic approaches can serve as one way to evaluate community health outcomes related to unconventional oil and gas developments, a growing need identified by health care practitioners, researchers, and government agencies [2, 3, 5, 7, 17]. As illustrated by the examples from ongoing ethnographic fieldwork in communities living near Marcellus Shale gas wells, compressor stations, and pipeline routes in northeastern Pennsylvania, these approaches show potential usefulness in systematically documenting the psychological, sociocultural, and environmental determinants of health.

While the exact causal mechanisms that link stress to disease may vary from case to case, there are some physiological mechanisms that do seem to be consistent in similar cases and offer models of how psychological, social, and environmental factors influence individual and community health outcomes. One of these mechanisms is known as allostatic load, or "the cumulative physiological burden that results as the body adapts to environmental and psychosocial stressors" [66, p. 30]. Allostatic load has been implicated in poor health outcomes when social and environmental factors create chronic stress that elevates cortisol levels, which then work to biologically impact the body [67, 68]. There are physiologic indicators of this chronic stress that can be monitored, including high blood pressure, elevated blood sugar, and hormonal changes [69-72]. However, the psychological and behavioral indicators of chronic stress—such as higher rates of smoking, alcohol consumption, sleeping problems, accidents, and eating disorders—may be more difficult to track [10]. Ethnographic approaches, such as the ones described here, could be used to monitor some of these more difficult-to-track indicators and compare them over time in communities where unconventional oil and gas developments are occurring.

Ethnography also offers a way to collect data on the cumulative impacts of industrialization and chemical pollution on local communities. The assessment of cumulative risks and impacts to already overburdened local communities in the United States is the subject of scientific study and debate, and is also one of the top research priorities of environmental justice advocates [8, 73]. The close bonds and sometimes long-term engagements that ethnographic researchers have with the communities where they conduct fieldwork makes this approach to documenting localized changes in psychological, sociocultural, and environmental stress levels through time a valuable contribution to cumulative impact assessments.

The emergent themes described in this paper offer a possible starting point for further community health research by social epidemiologists and others into the impacts of onshore unconventional oil and gas developments. Studies can be designed to identify and describe some of the contributing factors to chronic stress by eliciting culturally and locally relevant meanings of quality of life and well-being and the factors that contribute to or detract from it. More research in rural communities can be conducted that provides data on the relationship between economic inequality and psychological, sociocultural, and environmental stress factors, including the impact on local livelihoods and incomes from public perceptions of food safety on farms near shale gas developments. And, psychological and anthropological studies could be undertaken that document and describe the ways that societal and individual forms of violence interact with psychological, social, and environmental factors that may contribute to chronic stress near unconventional oil and gas projects.

National and state decision-makers need to examine the solid scientific evidence on the psychological, social, and environmental determinants of community health. In collaboration with medical practitioners, researchers, and the communities they serve, strategies need to be developed that can address the large gaps still existing in our knowledge about the linkages between human health, ecosystem health, large-scale industrialization, and chemical pollution. The ethnographic approach introduced here, alongside an environmental justice framework that includes the public health model of prevention and the precautionary principle, offers an opening to such collaboration, and the outline of a strategy to fill in some of those gaps. As others have suggested [3, 73], public-policy–makers and decision-makers in the United States must step beyond the political rhetoric over the community and environmental health impacts of energy policies and decisions to develop informed policies that prevent harm, embolden the precautionary principle, and ensure that environmental protection is a right, not a privilege.

ACKNOWLEDGMENTS

This work was funded in part by a Post-Doctoral Fellowship from the Mellon Foundation and Dickinson College. I am grateful for the two anonymous reviewers and Dr. Craig Slatin who offered thoughtful critique and recommendations that greatly improved the article.

AUTHOR'S BIOGRAPHY

SIMONA PERRY is a social and environmental scientist actively working to document, analyze, and develop alternative dispute mechanisms addressing social and environmental conflicts emerging from economic development projects across North America. She uses multiple data collection methods to conduct case study research on these conflicts. Her theoretical and practical focus is on understanding the everyday lives of individuals and communities in a rapidly changing world, sense of place phenomena in the face of globalized markets and identities, and conducting interpretive policy analyses. She is a member of c.a.s.e. "Community Awareness and Solutions for Empowerment," a cooperative roots-based consultancy. Send her email at communitypower.slp@gmail.com

NOTES

1. Energy Information Administration, *Annual Energy Outlook 2011 with Projections to 2035* (DOE/EIA0383), 2011, http://www.eia.gov/oiaf/archive/aeo10/index.html (accessed November 12, 2012).
2. M. L. Finkel and A. Law, "The Rush to Drill of Natural Gas: A Public Health Cautionary Tale," *American Journal of Public Health* 101(5) (2011): 784-785, doi: 10.2105/AJPH.2010.300089.
3. B. D. Goldstein, J. Kriesky, and B. Pavliakova, "Missing from the Table: Role of the Environmental Public Health Community in Governmental Advisory Commissions Related to Marcellus Shale Drilling," *Environmental Health Perspectives* 120 (2012): 483-486, doi: http://dx.doi.org/10.1289/ehp.1104594.

4. L. M. McKenzie et al., "Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources," *Science of the Total Environment* 424 (2012): 79-87, doi: 10.1016/j.scitotenv.2012.02.018.
5. T. Colborn et al., "Natural Gas Operations from a Public Health Perspective," *Human & Ecological Risk Assessment* 17 (5) (2011): 1039-1056, doi: 10.1080/10807039.2011.605662.
6. M. Bamberger and R. E. Oswald, "Impacts of Gas Drilling on Human and Animal Health," *New Solutions* 22 (1) (2012): 51-77, doi: http://dx.doi.org/10.2190/NS.22.1.e.
7. W. N. Rom, J. S. Lee, and B. F. Craft, "Occupational and Environmental Health Problems of the Developing Oil Shale Industry: A Review," *American Journal of Industrial Medicine* 2 (3) (1981): 247-260, doi: 10.1002/ajim.4700020306.
8. A. Wernham, "Inupiat Health and Proposed Alaskan Oil Development: Results of the First Integrated Health Impact Assessment/Environmental Impact Statement for Proposed Oil Development on Alaska's North Slope," *EcoHealth* 4 (2007): 500-513, doi: 10.1007/s10393-007-0132-2.
9. R. Witter et al., Potential Exposure-Related Human Health Effects of Oil and Gas Development: A Literature Review (2003-2008), 2008, http://docs.nrdc.org/health/files/hea_08091702b.pdf (assessed July 31, 2012).
10. N. Schneiderman, G. Ironson, and S. D. Siegel, "Stress and Health: Psychological, Behavioral, and Biological Determinants," *Annual Review of Clinical Psychology* 1 (2005): 607-628, doi: 10.1146/annurev.clinpsy.1.102803.144141.
11. P. A. Thoits, "Stress, Coping, and Social Support Processes: Where are We? What Next?," *Journal of Health and Social Behavior* 35, Extra Issue (1995): 53-79. doi: 10.2307/2626957.
12. Clifford Geertz, *The Interpretation of Cultures* (New York: Basic Books, 1973).
13. Phil Brown, "Qualitative Methods in Environmental Health Research," *Environmental Health Perspectives* 111 (14) (2003): 1789-1798, doi: 10.1289/ehp.6196.
14. R. Morello-Frosch and E. D. Shenassa, "The Environmental 'Riskscape' and Social Inequality: Implications for Explaining Maternal and Child Health Disparities," *Environmental Health Perspectives* 114 (8) (2006): 1150-1153, doi: 10.1289/ ehp.8930.
15. S. E. Bell, "'There Ain't No Bond in Town Like There Used to Be': The Destruction of Social Capital in the West Virginia Coalfields," *Sociological Forum* 24 (3) (2009): 631-657, doi: 10.1111/j.1573-7861.2009.01123.x.
16. B. Gramling and S. Brabant, "Boomtowns and Offshore Energy Impact Assessment: The Development of a Comprehensive Model," *Sociological Perspectives* 29 (2) (1986): 177-201, doi: 10.2307/1388958.
17. U.S. Environmental Protection Agency, Office of Research and Development, *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*, 2011, http://www.epa.gov/hfstudy/HF_Study__Plan_110211_FINAL_508.pdf (accessed May 14, 2012).
18. Robert D. Bullard, "Environmental Justice in the Twenty-First Century," in *The Quest for Environmental Justice: Human Rights and the Politics of Pollution,* ed. Robert D. Bullard (San Francisco: Sierra Club Books, 2005).
19. D. Kriebel and J. Tickner, "Reenergizing Public Health through Precaution," *American Journal of Public Health* 91 (9) (2001): 1351-1355, doi: 10.2105/AJPH.91.9.1351.
20. J. A. Tickner, "Precaution and Preventive Public Health Policy," *Public Health Reports* 117 (2002): 493-497. doi: 10.1093/phr/117.6.493.

21. Sheldon Cohen, Ronald C. Kessler, and Lynn Underwood Gordon, *Measuring Stress: A Guide for Health and Social Scientists* (New York: Oxford University Press, 1995).
22. Liu et al., “Associations of the Burden of Coal Abandoned Mine Lands with Three Dimensions of Community Context in Pennsylvania,” *International Scholarly Research Network Public Health* Article ID 251201 (2012): 11 pages. doi: 10.5402/2012/251201.
23. J. D. Morenoff et al., “Understanding Social Disparities in Hypertension Prevalence, Awareness, Treatment, and Control: The Role of Neighborhood Context,” *Social Science and Medicine* 65 (9) (2007): 1853-1866, doi: 10.1016/j.socscimed.2007.05.038.
24. D. A. Shoham et al., “Kidney Disease in Life-Course Socioeconomic Context: The Atherosclerosis Risk in Communities (ARIC) Study,” *American Journal of Kidney Diseases* 49 (2) (2007): 217-226, doi: 10.1053/j.ajkd.2006.11.031.
25. T. Leventhal and J. Brooks-Gunn, “Moving to Opportunity: An Experimental Study of Neighborhood Effects on Mental Health,” *American Journal of Public Health* 93 (9) (2003): 1576-1582, doi: 10.2105/AJPH.93.9.1576.
26. T. Augustin et al., “Neighborhood Psycho-social Hazards and Cardiovascular Disease: The Baltimore Memory Study,” *American Journal of Public Health* 98 (9) (2008): 1664-1670, doi: 10.2105/AJPH.2007.125138.
27. N. E. Adler and K. Newman, “Socioeconomic Disparities in Health: Pathways and Policies,” *Health Affairs* 21 (2) (2002): 60-76, doi: 10.1377/hlthaff.21.2.60.
28. E. Brunner, “Socioeconomic Determinants of Health: Stress and the Biology of Inequality,” *British Medical Journal* 314 (1997): 1472-1476, doi: 10.1136/bmj.314.7092.1472.
29. United Nations Development Programme, Human Development Report 1990: Concept and Measurement of Human Development (New York: Oxford University Press, 1990), http://hdr.undp.org/en/reports/global/hdr1990/ (accessed on July 31, 2012).
30. Pennsylvania Alliance for Clean Water and Air, “List of the Harmed: People and Animals Harmed by Fracking,” (May 2012), http://www.damascuscitizensforsustainability.org/2012/05/list-of-the-harmed/ (accessed December 13, 2012).
31. Amanda Paulson, “Fury on the Frontier of Energy Drilling,” *The Christian Science Monitor* March 8, 2004, http://www.csmonitor.com/2004/0308/p01s01-ussc.html (accessed December 13, 2012).
32. James Loewenstein, “Over 200 Attend WVIA Program on 'Boomtown Towanda’ at Keystone Theatre,” December 10, 2010, http://thedailyreview.com/news/over-200-attend-wvia-program-on-boomtown-towanda-at-keystone-theater-1.1075401 (accessed December 13, 2012).
33. Margaret D. LeCompte and Jean J. Schensul, *Designing and Conducting Ethnographic Research: An Introduction* [Ethnographer's Toolkit, Book 1 (2nd edition)] (Walnut Creek, California: AltaMira Press, 2010).
34. Stephen L. Schensul, Jean J. Schensul, and Margaret D. LeCompte, *Essential Ethnographic Methods: Observations, Interviews, and Questionnaires* (Walnut Creek, California: AltaMira Press, 1999).
35. S. L. Perry, “Development, Land Use, and Collective Trauma: The Marcellus Shale Gas Boom in Rural Pennsylvania,” *Culture, Agriculture, Food, and Environment* 34 (1) (2012): 81-92, doi: 10.1111/j.2153-9561.2012.01066.x.

36. T. Harris and D. Weiner, "Empowerment, Marginalization and 'Community-Integrated' GIS," *Cartography and Geographic Information Systems* 25 (1998): 67-76, doi: http://dx.doi.org/10.1559/152304098782594580.
37. R. Pain, "Social Geography: Participatory Research," *Progress in Human Geography* 28 (5) (2004): 652-663, doi: 10.1191/0309132504ph511pr.
38. B. Pini, "Focus Groups, Feminist Research and Farm Women: Opportunities for Empowerment in Rural Social Research," *Journal of Rural Studies* 18 (3) (2002): 339-351, doi: http://dx.doi.org/10.1016/S0743-0167(02)00007-4.
39. David L. Morgan, *Focus Groups as Qualitative Research* (Thousand Oaks, California: SAGE Publications, 1997).
40. J. Pierce, "On Community Capitals as We See Them through Photovoice: Cowell Oyster Industry in South Australia," *Australasian Journal of Environmental Management* 15 (3) (2008): 159-168, doi: 10.1080/14486563.2008.9725198.
41. C. C. Wang et al., "Flint Photovoice: Community Building among Youths, Adults, and Policy Makers," *American Journal of Public Health* 94 (6) (2004): 911-913, doi: 10.2105/AJPH.94.6.911.
42. Michel De Certeau, *The Practice of Everyday Life* (University of California Press, 1998).
43. Runt Veenhoven, "World Database of Happiness: Continuous Register of Research on Subjective Appreciation of Life," in *Challenges for Quality of Life in the Contemporary World: Advances in Quality-of-Life Studies, Theory and Research*, eds. W. Glatzer, S. VonBelow, and M. Stoffregen, Vol. 24, Social Indicators Research Series (Dordrecht, The Netherlands: Kluwer Academic Publishers, 2004).
44. L. Osberg and A. Sharpe, "An Index of Economic Well-Being for Selected OECD Countries," *Review of Income and Wealth* 48 (3) (2002): 291-316, doi: 10.1111/1475-4991.00056.
45. J. F. Helliwell and R. D. Putnam, "The Social Context of Well-Being," *Philosophical Transactions of the Royal Society of London* 359 (2004): 1435-1446, doi: 10.1098/rstb.2004.1522.
46. U.S. Environmental Protection Agency, Office of Research and Monitoring, Environmental Studies Division, *The Quality of Life Concept: A Potential New Tool for Decision-Makers,* 1973, http://nepis.epa.gov/ (accessed July 31, 2012).
47. Robert F. Kennedy, remarks at the University of Kansas, Lawrence, KS, March 18, 1968, http://www.jfklibrary.org/Research/Ready-Reference/RFK-Speeches/Remarks-of-Robert-F-Kennedy-at-the-University-of-Kansas-March-18.aspx (accessed July 31, 2012).
48. United Nations Development Programme, *Human Development Report 2011: Sustainability and Equity: A Better Future for All*, http://hdr.undp.org/en/reports/global/hdr2011/ (accessed on July 31, 2012)
49. U.S. Census Bureau, 2006-2010 American Community Survey, Selected Economic Characteristics (Employment Status, Occupation, Industry, Income and Benefits) for Bradford County, Pennsylvania, http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ACS_10_SF4_DP03&prodType=tab (accessed July 31, 2012).
50. R. Catalano et al., "The Health Effects of Economic Decline," *Annual Review of Public Health* 32 (2011): 431-450, doi: 10.1146/annurev-publhealth-031210-101146.

51. World Health Organization Global Consultation on Violence and Health, *Violence: A Public Health Priority,* WHO/EHA/SPI.POA.2 (Geneva, Switzerland: World Health Organization, 1996).
52. E. G. Krug, "The World Report on Violence and Health," *The Lancet* 360 (2002): 1083-1088, doi: http://dx.doi.org/10.1016/S0140-6736(02)11133-0.
53. V. J. Felitti et al., "Relationship of Childhood Abuse and Household Dysfunction to Many of the Leading Causes of Death in Adults: The Adverse Childhood Experiences (ACE) study," *American Journal of Preventive Medicine* 14 (4) (1998): 245-58. doi:10.1016/S0749-3797(98)00017-8.
54. N. Sambanis, "What Is a Civil War? Conceptual and Empirical Complexities of an Operational Definition," *Journal of Conflict Resolution* 48 (6) (2004): 814-858, doi: 10.1177/0022002704269355.
55. D. Durst, "Conjugal Violence: Changing Attitudes in Two Northern Native Communities," *Community Mental Health Journal* 27 (5) (1991): 359-373, doi: 10.1007/BF00752386.
56. J. R. T. Davidson et al., "Post-Traumatic Stress Disorder in the Community: An Epidemiological Study," *Psychological Medicine* 21 (1991): 713-721, doi: http://dx.doi.org/10.1017/S0033291700022352.
57. S. S. L. Mol et al., "Symptoms of Post-Traumatic Stress Disorder after Non-Traumatic Events: Evidence from an Open Population Study," *The British Journal of Psychiatry* 186 (2005): 494-499, doi: 10.1192/bjp.186.6.494.
58. M. R. Harvey, "An Ecological View of Psychological Trauma and Trauma Recovery," *Journal of Traumatic Stress* 9 (1) (1996): 3-22, doi: 10.1002/jts.2490090103.
59. Sally Vaughn (Prothonotary, Bradford County), personal communication, February 16, 2012.
60. Amanda Renko, "Crime Rising in Bradford County," *Towanda Daily Review,* July 27, 2011, http://thedailyreview.com/news/crime-rising-in-bradford-county-1.1180649 (accessed July 31, 2012).
61. T. L. Weaver and G. A. Clum, "Psychological Distress Associated with Interpersonal Violence: A Meta-Analysis," *Clinical Psychology Review* 15 (2) (1995): 115-140, doi: http://dx.doi.org/10.1016/0272-7358(95)00004-9.
62. R. Boele, H. Fabig, and D. Wheeler, "Shell, Nigeria and the Ogoni. A Study in Unsustainable Development: I. The Story of Shell, Nigeria and the Ogoni People—Environment, Economy, Relationships: Conflict and Prospects for Resolution," *Sustainable Development* 9 (2001): 74-86, doi: 10.1002/sd.161.
63. R. Seydlitz et al., "Development and Social Problems: The Impact of the Offshore Oil Industry on Suicide and Homicide Rates," *Rural Sociology* 58 (1) (1993): 93-110, doi: 10.1111/j.1549-0831.1993.tb00484.x.
64. J. Clougherty et al., "Synergistic Effects of Traffic-Related Air Pollution and Exposure to Violence on Urban Asthma Etiology," *Environmental Health Perspectives* 115 (8) (2007): 1140-1146, doi: 10.1289/ehp.9863.
65. R. J. Wright et al., "Community Violence and Asthma Morbidity: The Inner-City Asthma Study," *American Journal of Public Health* 94 (4) (2004): 625-632, doi: 10.2105/AJPH.94.4.625.
66. B. S. McEwen and T. E. Seeman, "Protective and Damaging Effects of Mediators of Stress: Elaborating and Testing the Concepts of Allostasis and Allostatic Load,"

Annals of the New York Academy of Science 896 (1999): 30-47, doi: 10.1111/j.1749-6632.1999.tb08103.x.

67. Arlene S. Bierman et al., "Social Determinants of Health and Populations at Risk," in *Project for an Ontario Women's Health-Based Report: Volume 2,* ed. Arlene S. Bierman (Toronto: St. Michael's Hospital and the Institute for Clinical Evaluative Sciences, 2012).
68. T. E. Seeman et al., "Allostatic Load as a Marker of Cumulative Biological Risk: MacArthur Studies of Successful Aging," *Proceedings of the National Academy of Science USA* 98 (8) (2001): 4770-4775, doi: 10.1073/pnas.081072698.
69. T. E. Seeman et al., "Cumulative Biological Risk and Socio-Economic Differences in Mortality: MacArthur Studies of Successful Aging," *Social Science & Medicine* 58 (10) (2004):1985-1997, doi: 10.1016/S0277-9536(03)00402-7.
70. M. Kivimaki et al., "Work Stress and Risk of Cardiovascular Mortality: Prospective Cohort Study of Industrial Employees," *British Medical Journal* 325 (7369) (2002): 1-5 doi: http://dx.doi.org/10.1136/bmj.325.7369.857.
71. E. J. Brunner et al., "Adrenocortical, Autonomic, and Inflammatory Causes of the Metabolic Syndrome: Nested Case-Control Study," *Circulation* 106 (21) (2002): 2659-2665, doi: 10.1161/01.CIR.0000038364.26310.BD.
72. J. P. Shonkoff and D. A. Phillips, eds., *From Neurons to Neighborhoods: The Science of Early Childhood Development* (Washington, D.C.: National Academy Press, 2000).
73. Public Meeting of National Environmental Justice Advisory Council, Crystal City, VA, July 25-26, 2012.

Direct reprint requests to:

Simona L. Perry
c.a.s.e. Consulting Services
9810 Dairyton Court
Montgomery Village, MD 20886
e-mail: communitypower.slp@gmail.com

NEW SOLUTIONS, Vol. 23(1) 55-83, 2013

Scientific Solutions

INVESTIGATING LINKS BETWEEN SHALE GAS DEVELOPMENT AND HEALTH IMPACTS THROUGH A COMMUNITY SURVEY PROJECT IN PENNSYLVANIA

NADIA STEINZOR
WILMA SUBRA
LISA SUMI

ABSTRACT

Across the United States, the race for new energy sources is picking up speed and reaching more places, with natural gas in the lead. While the toxic and polluting qualities of substances used and produced in shale gas development and the general health effects of exposure are well established, scientific evidence of causal links has been limited, creating an urgent need to understand health impacts. Self-reported survey research documenting the symptoms experienced by people living in proximity to gas facilities, coupled with environmental testing, can elucidate plausible links that warrant both response and further investigation. This method, recently applied to the gas development areas of Pennsylvania, indicates the need for a range of policy and research efforts to safeguard public health.

Keywords: health surveys, shale gas, toxic exposure, hydraulic fracturing, fracking

> Public health was not brought into discussions about shale gas extraction at earlier stages; in consequence, the health system finds itself lacking critical information about environmental and public health impacts of the technologies and unable to address concerns by regulators at the federal and state levels, communities, and workers. . . .
>
> —Institute of Medicine at the National Academies of Science [1]

doi: http://dx.doi.org/10.2190/NS.23.1.e
http://baywood.com

For many years, extracting natural gas from deep shale formations across the United States (such as the Marcellus Shale in the East or the Barnett Shale in Texas) was considered economically and technologically infeasible. More recently, changes in hydraulic fracturing technology and its combination with horizontal drilling have made it possible to drill much deeper and further. Bolstered by declining global oil resources and a strong political push to expand domestic energy production, this has resulted in a boom in shale gas production nationwide and projections of tens or even hundreds of thousands of wells being drilled in the coming decades.

By mid-2012, there were nearly 490,000 producing natural gas wells in the United States, 60,000 more than in 2005 [2]. In Pennsylvania alone, more than 5,900 unconventional oil and gas wells had been drilled, and more than 11,700 had been permitted, between 2005 and September 2012; the pace of expansion has been rapid, with 75 percent of all unconventional wells drilled just in the last two years [3]. The rapid pace of industry expansion is increasingly divergent from the slower pace of scientific understanding of its impacts, as well as policy and regulatory measures to prevent them—in turn raising many questions that have yet to be answered [4]. Further, the limited availability of information has both contributed to public perception and supported industry assertions that health impacts related to oil and gas development are isolated and rare.

Modern-day industrial gas and oil development has many stages, uses a complex of chemicals, and produces large volumes of both wastewater and solid waste, which create the potential for numerous pathways of exposure to substances harmful to health, in particular to air and water pollution [5]. Many reports of negative health impacts by people living in proximity to wells and oil and gas facilities have been documented in the media and through research by organizations [6-8]. In addition, several self-reporting health survey and environmental testing projects have been conducted in response to complaints following pollution events or the establishment of facilities [9-12].

Such short-term projects have been initiated in a research context in which longer-term investigations—particularly ones that seek to establish causal links between health problems and oil and gas development—have historically been narrow and inconsistent [13]. Reflecting growing concern over the need to deepen knowledge among scientists, public agency representatives, and environmental and health professionals, four conferences on the links between shale gas development and human health were convened in just a one-year period (November 2011–November 2012), including those convened by the Graduate School of Public Health at the University of Pittsburgh; by Physicians, Scientists, and Engineers for Healthy Energy; and by the Institute of Medicine of the National Academy of Sciences.

In-depth research on the health impacts of oil and gas development has also begun to appear in the literature. In 2011, a review of more than 600 known chemicals used in natural gas operations concluded that many could cause cancer and mutations and have long-term health impacts (including on the skin, eyes, and kidneys and on the respiratory, gastrointestinal, brain/nervous, immune, endocrine, and cardiovascular systems) [14]. In early 2012, a study by researchers at the University of Colorado concluded that the toxicity of air emissions near natural gas sites puts residents living close by at greater risk of health-related impacts than those living further away [15]. Also in 2012, a paper (published in this journal) documented numerous cases in which livestock and pets exposed to toxic substances from natural gas operations suffered negative health impacts and even death [16].

Public health has not been a priority for decision-makers confronting the expansion of natural gas development and consumption. Commissions to study the impacts of shale gas development have been established by Maryland and Pennsylvania and by the U.S. Secretary of Energy, but of the more than 50 members on these official bodies, none had health expertise [17]. In addition, state and federal agencies in charge of reviewing energy proposals and issuing permits do not require companies to provide information on potential health impacts, while only a few comprehensive health impact assessments (HIAs) on oil and gas development have ever been conducted in the United States [18]. Data on air and water quality near oil and gas facilities are also lacking because federal environmental testing and monitoring has long focused on a limited number of air contaminants and areas of high population density [19], while testing at oil and gas facilities in states like Pennsylvania began only recently [20]. Finally, only a few states (including Pennsylvania, Ohio, and Colorado) have any requirements for baseline air and water quality testing before drilling begins, making it difficult for researchers and regulators—as well as individuals who are directly impacted—to establish a clear connection afterwards.

SUMMARY OF THE RELEVANCE OF SELF-REPORTING HEALTH SURVEYS

For many individuals and communities living amidst oil and gas development and experiencing rapid change in their environments, too much can be at stake to rely solely on the results of long-term studies, especially those that are just now being developed. Recent examples include a new study by Guthrie Health and the Geisinger Health System in Pennsylvania, set to take from 5 to 15 years [21], and research proposals solicited in April 2012 by the National Institute of Environmental Health Sciences [22].

In contrast, self-reporting health survey research facilitates the collection and analysis of data on current exposures and medical symptoms—thereby helping to bridge the prevailing knowledge gap and pointing the way toward possible policy changes needed to protect public health. Another premise throughout the various phases of this project (location selection, survey distribution and completion, environmental testing, report development and distribution, and outreach to decision-makers) was the value of public participation in science and the engagement of a variety of actors and networks to both conduct the research and ensure its beneficial application [23].

With this in mind, this health and testing project reflects some of the core principles of community-based participatory research (CBPR), including an emphasis on community engagement, use of strengths and resources within communities, application of findings to help bring about change, and belief in the research relevance and validity of community knowledge [24]. For example, the current project selected areas for investigation based in part on the observations of change in environmental conditions by long-time residents, and upon completion, participants received resources on testing and reporting of drilling problems for use in their communities.

In addition, CBPR is often used by public agencies and academic researchers to gather information on health conditions that may be related to social or environmental factors manifested on the community as well as individual level [25]. Relevant examples include identification of linkages between environmental health and socioeconomic status [26], adverse health impacts associated with coal mining [27], and the perception of health problems from industrial wind turbines [28].

Community survey and environmental testing projects such as the current one are also valuable in identifying linkages and considerations that can be used to develop protocols for additional research and policy measures. For example, community survey projects similar to the current one have revealed the presence of toxic chemicals in water and air that were known to be associated with health symptoms reported by residents, resulting in the strengthening of state standards for the control of drilling-related odors in Texas [9], expansion of a groundwater contamination investigation by the U.S. Environmental Protection Agency in Wyoming [10], and relocation of residential communities away from nearby oil refineries and contaminated waste storage areas in Louisiana) [29].

METHODS

Between August 2011 and July 2012, a self-reporting health survey and environmental testing project was undertaken in order to:

- investigate the extent and types of health symptoms experienced by people living in the "gas patches" (that is, gas development areas) of Pennsylvania;
- provide air and water quality testing to some of the participating households in need of such information;
- identify possible connections between health symptoms and proximity to gas extraction and production facilities;
- provide information to researchers, officials, regulators, and residents concerned about the impact of gas development on health and air and water quality; and

- make recommendations for both further research and the development of policy measures to prevent negative health and environmental impacts.

This project did not involve certain research elements, such as structured control groups in non-impacted areas and in-depth comparative health history research, that aim to show a direct cause-and-effect relationship or to rule out additional exposures and risks. Such work, while important, was beyond the scope of the project.

The primary routes of exposure to chemicals and other harmful substances used and generated by oil and gas facilities are inhalation, ingestion, and dermal absorption—of substances in air, drinking water, or surface water—which can lead to a range of symptoms. The health survey instrument explored such variations in exposure through checklists of health symptoms grouped into categories (skin, sinus/respiratory, digestive/stomach, vision/eyes, ear/nose/mouth, neurological, urinary/urological, muscles/joints, cardiac/circulatory, reproductive, behavioral/mood/energy, lymphatic/thyroid, and immunological). A similar structure was followed for different categories of problems in participants' disease history (kidney/urological, liver, bones/joints, ulcers, thyroid/lymphatic, heart/lungs, blood disorders, brain/neurological, skin/eyes/mouth, diabetes, and cancer). Questions were also asked about occupational background and related toxic exposure history. In addition, the survey included questions on proximity to three types of facilities (compressor and pipeline stations, gas-producing wells, and impoundment or waste pits) to explore possible sources of exposure. It also asked participants to describe the type and frequency of odors they observe, since odors can both indicate the presence of a pollutant and serve as warning signs of associated health risks [30].

As indicated in Table 1, the survey was completed by 108 individuals (in 55 households) in 14 counties across Pennsylvania, with the majority (85 percent) collected in Washington, Fayette, Bedford, Bradford, and Butler counties. Taken together, the counties represent a geographical range across the state and have active wells and other facilities that have increased in number in the past few years, allowing reports of health impacts and air and water quality concerns by residents to surface [31, 32]. The survey and testing locations were all in rural and suburban residential communities.

All survey participants were assured that their names, addresses, and other identifying information on both the surveys and environmental testing results would be kept confidential and used only for purposes related to this project, such as following up with clarifying questions, responding to requests for assistance, or providing resources. Due to expressed concerns about confidentiality, participants had the option of completing the surveys anonymously, which some chose to do. Most participants answered questions on their own. In some cases, spouses, parents, or neighbors completed surveys for participants, and a few provided answers to the project coordinator in person or over the phone.

Table 1. Survey Locations

County surveyed	Number of surveys collected and percent of all surveys
Washington	24 (22%)
Fayette	20 (18%)
Bedford	20 (18%)
Bradford	17 (16%)
Butler	12 (11%)
Jefferson	3 (3%)
Sullivan	2 (2%)
Greene	2 (2%)
Warren	2 (2%)
Elk	2 (2%)
Clearfield	1 (1%)
Erie	1 (1%)
Susquehanna	1 (1%)
Westmoreland	1 (1%)
Total	108

While less formal and structured, the approach taken to identifying project participants has similarities to established non-random research methods that are respondent-driven and rely on word-of-mouth and a chain of referrals to reach more participants, such as "snowball" and "network" sampling [33]. As in studies in which these methods are used, the current project had a specific purpose in mind, focused on a group of people that can be hard to identify or reach, and had limited resources available for recruitment [34].

The survey was distributed in print form either by hand or through the mail and was initiated through existing contacts in the target counties. These individuals then chose to participate in the project themselves and/or recommended prospective participants, who in turn provided additional contacts. The survey was also distributed to individuals who expressed interest in participating directly to the project coordinator at public events or through neighbors, family members, and friends who had already completed surveys.

A second phase of the project involved environmental testing conducted at the homes (i.e., in the yards, on porches, or at other locations close to houses) of a subset of the survey participants (70 in total) in order to identify the presence of pollutants that may be coming from gas development facilities. In all, 34 air tests and nine water tests were conducted at 35 households. Test locations were selected based on household interest, the severity of symptoms reported, and proximity to gas facilities; results were made available to the households where the testing took place. The air tests were conducted with Summa Canisters put out for 24 hours by trained individuals and the results analyzed with TO-14 and TO-15 methods, which are used and approved by the U.S. Environmental Protection Agency to test for volatile organic compounds (VOCs) such as benzene, toluene, ethylbenzene, and xylene (known as BTEX chemicals). The water tests were based on samples drawn directly from household sinks or water wells by technicians employed by certified laboratories and covered the standard Tier 1, Tier 2, and Tier 3 (including VOCs/BTEX) and in one case, gross alpha/beta radiation, radon, and radium.

FINDINGS

Health Surveys

Among participants, 45 percent were male, ranging from 18 months to 79 years of age, and 55 percent were female, ranging from 7 to 77 years of age. The closest a participant lived to gas facilities was 350 feet and the farthest away was 5 miles.

Participants had a wide range of occupational backgrounds, including animal breeding and training, beautician, child care, construction, domestic work, farming, management, mechanic, medical professional, office work, painter, retail, teaching, and welding. About 20 percent of participants reported an occupation-related chemical exposure (for example, to cleaning products, fertilizers, pesticides, or solvents). At the time of survey completion, 80 percent of participants did not smoke and 20 percent did. More than 60 percent of the current nonsmokers had never smoked, although 20 percent of nonsmokers lived with smokers.

Almost half of the survey participants answered the question on whether they had any health problems prior to shale gas development. A little less than half of those responses indicated no health conditions before the development began and a little more than half reported having had one or just a few—in particular allergies, asthma, arthritis, cancer, high blood pressure, and heart, kidney, pulmonary, and thyroid conditions were named by respondents.

While not asked specifically in the survey, some participants volunteered (verbally or in writing) additional information that points to health-related concerns warranting further investigation. For example, five reported that their existing health symptoms became worse after shale gas development started and 15 that their symptoms lessened or disappeared when they were away from home. Participants in 22 households reported that pets and/or livestock had unexplained symptoms (such as seizures or losing hair) or suddenly fell ill and died after gas development began nearby.

Some variation was noted with regard to the specific symptoms reported for each category surveyed, and some symptoms were reported to a notable degree in only one or a few locations. However, as seen in Table 2, the same overall categories of problems reported by survey participants garnered high response rates among survey participants regardless of region or county. For example, sinus/respiratory problems garnered the highest percentage of responses by participants overall, as well as in four of the five focus counties; the second top complaint category, behavioral/mood/energy, was the first in one county, second in three, and fourth in one. The total number of symptoms reported by individual participants ranged from 2 to 111; more than half reported having more than 20 symptoms and nearly one-quarter reported more than 50 symptoms. The highest numbers were reported by a 26-year-old female in Fayette County (90), a 51-year-old female in Bradford County (94), and a 59-year-old female in Warren County (111).

The 25 most prevalent individual symptoms among all participants were increased fatigue (62%), nasal irritation (61%), throat irritation (60%), sinus problems (58%), eyes burning (53%), shortness of breath (52%), joint pain (52%), feeling weak and tired (52%), severe headaches (51%), sleep disturbance (51%), lumbar pain (49%), forgetfulness (48%), muscle aches and pains (44%), difficulty breathing (41%), sleep disorders (41%), frequent irritation (39%), weakness (39%), frequent nausea (39%), skin irritation (38%), skin rashes (37%), depression (37%), memory problems (36%), severe anxiety (35%), tension (35%), and dizziness (34%).

Many symptoms were commonly reported regardless of the distance from the facility (in particular sinus problems, nasal irritation, increased fatigue, feeling weak and tired, joint pain, and shortness of breath). In addition, there was some variability in the percentage of respondents experiencing certain symptoms in relation to distance from facility, including higher rates at longer distances in a few instances. Possible influencing factors could include topography, weather conditions, participant reporting, the use of emission control technologies at facilities, or type of production (e.g., wet gas contains higher levels of liquid hydrocarbons than dry gas).

However, many symptoms showed a clearly identifiable pattern: as the distance from facilities increases, the percentage of respondents reporting the symptoms generally decreases [35]. For example, when a gas well, compressor station, and/or impoundment pit were 1500-4000 feet away, 27 percent of participants reported throat irritation; this increased to 63 percent at 501-1500 feet and to 74 percent at less than 500 feet. At the farther distance, 37 percent reported sinus problems; this increased to 53 percent at the middle distance and 70 percent at the shortest distance. Severe headaches were reported by 30 percent of respondents at the farther distance, but by about 60 percent at the middle and short distances.

Table 2. Percent of Participants Reporting Symptoms in the Most Prevalent Categories of Symptoms, by County

		Percent of individuals reporting symptoms in category					
Symptom category	All counties	Bedford	Bradford	Butler	Fayette	Washington	Others[a]
Sinus/respiratory	88	80	82	75	85	95	87
Behavioral/mood/energy	80	60	88	67	85	74	67
Neurological	74	45	71	50	70	79	60
Muscles/joints	70	55	82	67	70	74	47
Digestive/stomach	64	55	65	58	75	63	33
Ear/nose/mouth	66	40	59	50	75	68	47
Skin reactions	64	45	70	67	75	63	27
Vision/eyes	63	40	65	50	70	79	53

[a]Includes Clearfield, Elk, Erie, Jefferson, Greene, Sullivan, Susquehanna, Warren, and Westmoreland counties. The surveys from these counties (15) were analyzed together to create a group comparable in number to each of the counties where more surveys were collected.

Figure 1 shows, for the top 20 symptoms, the percentage of residents living within 1500 feet of a natural gas facility (well, compressor, or impoundment) who reported the symptom, compared to the percentage among residents living more than 1500 feet from the facility. For 18 of the 20 symptoms, a higher percentage of those living within 1500 feet of a facility experienced the symptom than of those living farther away.

The difference in percentages reporting the symptom in the two groups (i.e., 1500 feet or closer vs. more than 1500 feet from a facility) was statistically significant for 10 of the 20 symptoms. Notably, this finding reinforces the value of data attained through self-reporting health surveys. It shows that, regardless of how symptom data were acquired, they suggest that increased proximity to gas facilities has a strong association with higher rates of symptoms reported.

When the most prevalent symptoms are broken out by age and distance from facility, some patterns stand out [35]. Within each age group, the subset living within 1500 feet of any oil and gas facility had a higher percentage of most symptoms than the age group as a whole.

Among the youngest respondents (1.5-16 years of age), for example, those within 1,500 feet experienced higher rates of throat irritation (57% vs. 69%) and severe headaches (52% vs. 69%). It is also notable that youngest group had the highest occurrence of frequent nosebleeds (perhaps reflective of the more sensitive mucosal membranes in the young), as well as experiencing conditions not typically associated with children, such as severe headaches, joint and lumbar pain, and forgetfulness.

Among 20- to 40-year-olds, those living within 1500 feet of a facility reported higher rates of nearly all symptoms; for example, 44 percent complained of frequent nosebleeds, compared to 29 percent of the entire age group. The same pattern existed among 41- to 55-year-olds with regard to several symptoms (e.g., throat and nasal irritation and increased fatigue), although with smaller differences and greater variability than in the other age groups.

The subset of participants in the oldest group (56- to 79-year-olds) living within 1,500 feet of facilities had much higher rates of several symptoms, including throat irritation (67% vs. 47 %), sinus problems (72% vs. 56%), eye burning (83% vs. 56%), shortness of breath (78% vs. 64%), and skin rashes (50% vs. 33%).

In sum, while these data do not prove that living closer to oil and gas facilities causes health problems, they do suggest a strong association since symptoms are more prevalent in those living closer to facilities than those living further away. Symptoms such as headaches, nausea, and pounding of the heart are known to be the first indications of excessive exposure to air pollutants such as VOCs [36], while the higher level of nosebleeds in the youngest age group is also consistent with patterns identified in health survey projects in other states [9, 10].

The survey also asked respondents to indicate whether they were smokers. While the average number of symptoms for smokers was higher for smokers than nonsmokers (30 vs. 22), the most frequently reported symptoms were very

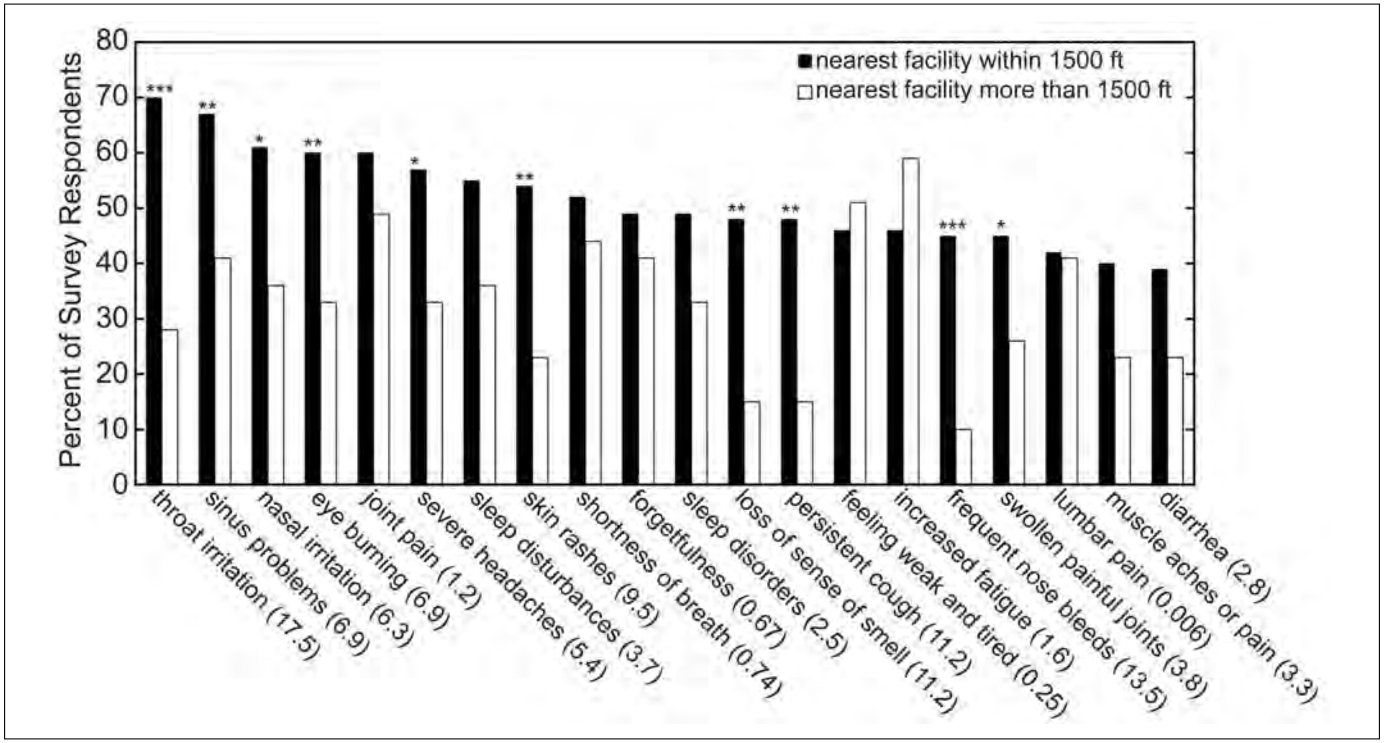


Figure 1. Association of symptoms and distance from facilities

Note: The significance of the effect was tested using a two-way contingency table analysis, and the chi-square value is given in parenthesis after each symptom. Effects significant at $p < 0.001$ are indicated by ***, those significant at $p < 0.01$ by **, and those significant at $p < 0.05$ by *.

similar (including forgetfulness, increased fatigue, lumbar pain, joint pain, eye burning, nasal irritation, sinus problems, sleep disturbances, severe headaches, throat irritation, shortness of breath, frequent nausea, muscle aches or pains, and weakness). The fact that the nonsmokers experienced symptoms that are commonly considered to be side effects of smoking (e.g., persistent hoarseness, throat irritation, sinus problems, nasal irritation, shortness of breath, and sleep disturbances) suggests that factors other than smoking were at play.

In addition, while the smoking subpopulation generally reported a larger number of symptoms, the symptoms most frequently reported by smokers and nonsmokers were remarkably similar within each age group [35]. For example, for 20- to 40-year-olds, increased fatigue, sinus problems, throat irritation, frequent nausea, and sleep problems were among the top symptoms for both smokers and nonsmokers. In the 41- to 55-year-old group, increased fatigue, throat irritation, eye burning, severe headaches, and nasal irritation were among the top symptoms for both smokers and nonsmokers, and in the over-55 age group, eye burning, sinus problems, increased fatigue, joint pain, and forgetfulness were among the top symptoms of both smokers and nonsmokers.

Participants were asked if they had noticed any odors and were asked whether they knew the source of the odors. In all but a few cases, survey participants mentioned only gas-related sources. Responses focused on locations, facilities, and processes, including drilling, gas wells, well pads, fracturing, compressor stations, condensate tanks, flaring, impoundments and pits, retention ponds, diesel engines, truck traffic, pipelines and pipeline stations, spills and leaks, subsurface ground events or migrations from underground, seismic testing, blue-colored particles in the air (possibly catalytic compounds or particulate matter), and water and stock wells. Odors were among the most common of complaints, with 81 percent of participants experiencing them sometimes or constantly. The frequency ranged from one to seven days per week and from several times per day to all day long; 18 percent said they could smell odors every day.

Participants were also asked to describe odors and whether they noticed any health symptoms when odor events occurred. The most prevalent links between odors and symptoms reported were:

- *nausea:* ammonia, chlorine, gas, propane, ozone, rotten gas;
- *dizziness:* chemical burning, chlorine, diesel, ozone, petrochemical smell, rotten/sour gas, sulfur;
- *headache:* chemical smell, chlorine, diesel, gasoline, ozone, petrochemical smell, propane, rotten/sour gas, sweet smell;
- *eye/vision problems:* chemical burning, chlorine, exhaust;
- *respiratory problems*: ammonia, chemical burning, chlorine, diesel, perfume smell, rotten gas, sulfur;
- *nose/throat problems:* chemical smell, chlorine, exhaust, gas, ozone, petrochemical smell, rotten gas, sulfur, sweet smell;

- *nosebleeds:* kerosene, petrochemical smell, propane, sour gas;
- *skin irritation:* chemical smell, chlorine, ozone, sulfur;
- *decreased energy/alertness:* chemical gas, ozone, rotten/sour gas, sweet smell; and
- *metallic/bad taste in mouth:* chemical burning, chlorine, turpentine.

Environmental Testing

As detailed in Table 3, the air tests detected a total of 19 VOCs in ambient air sampled outside of homes.

The number of compounds detected in a single sample ranged from one to 25; there was some consistency with regard to the chemicals present in most of the samples, although the concentrations of VOCs detected varied across counties [35]. The highest numbers of VOCs were detected in air samples from Washington County (15), Butler County (15), Bradford County (12), and Fayette County (9). Washington County also had the highest measured concentration of five VOCs and the second highest concentration of 12 chemicals. Samples from Butler and Bradford Counties had the highest concentrations of five and three VOCs, respectively. Five chemicals were detected in all nine of the samples from Washington County and in the six samples from Butler County: 1,1,2-trichloro-1,2,2-trifluoroethane, carbon tetrachloride, chloromethane, toluene, and trichlorofluoromethane.

It is also possible that in some places, sampling did not occur at the precise times when facilities were emitting high concentrations of chemicals or when the wind was blowing contaminants toward canisters. Some of the additional variation in number of chemicals and concentrations could be due to differences in topography, the total number of active oil and gas wells, the types of wells (conventional versus unconventional), the use of emission control technologies, and the number of active drilling sites, compressor stations, and oil and gas waste impoundments located within a certain radius of the sampling locations.

In 2010, the Pennsylvania Department of Environmental Protection (DEP) conducted air testing around natural gas wells and facilities in three regions across the state, in part using the same canister sampling methods as in this project [37]. When compared to DEP's results, our results showed some striking similarities in both the chemicals detected and concentrations. In particular, BTEX chemicals that we measured in Butler and Washington counties were consistently higher than concentrations found at DEP control sites (ethylbenzene and *m*- and *p*-xylenes were not detected at any of the control sites). When compared to the sampling done by DEP around oil and gas facilities, the concentrations in Butler and Washington counties were in the same range for benzene, but were considerably higher for toluene, ethylbenzene and *m*- and *p*-xylenes. It is also striking that some of the concentrations of ethylbenzene and

Table 3. Volatile Organic Compounds (VOCs) in Ambient Air, Sorted by Percent Detection[a]

Compound	Total number of samples	Number of samples detecting VOCs	Percent of samples detecting VOCs	Minimum concentration	Maximum concentration	Chemical reporting limits for the three labs		
						Columbia	Con-Test	Pace[b]
2-Butanone	17	16	94	0.95	2.9	0.85-1.3	NA	NA
Acetone	17	15	88	8.0	19	6.5-10	NA	NA
Chloromethane	34	27	79	1.0	1.66	0.59-0.90	0.1	1.39-1.53
1,1,2-Trichloro-1,2,2-trifluoroethane	34	26	76	0.54	0.73	0.22-0.34	0.38	5.13-5.67
Carbon tetrachloride	34	26	76	0.4	0.76	0.091-0.14	0.31	4.21-4.65
Trichlorofluoromethane	34	26	76	0.6	1.8	0.81-1.2	0.28	3.32-3.66
Toluene	34	22	65	0.68	7.9	0.53-0.82	0.19	2.52-2.79
Dichlorodifluoromethane	17	9	63	1.9	2.8	NA	0.25	3.32-3.66
n-Hexane	8	3	38	3.03	7.04	NA	NA	2.37-2.61
Benzene	34	11	32	0.31	1.5	0.46-0.67	0.16	2.14-2.36

Methylene chloride	34	10	29	1.9	32.62	0.49-0.76	1.7	2.33-2.57
Total hydrocarbons (gas)[c]	8	2	25	49.8	146	NA	NA	46.9-52.2
Tetrachloroethylene	34	8	24	0.12	10.85	0.10-0.16	0.34	4.54-5.02
1,2,4-Trimethylbenzene	17	4	24	0.38	0.61	NA	0.25	3.30-3.64
Ethylbenzene	34	6	1	0.27	1.5	1.4-1.9	0.22	2.91-3.21
Trichloroethylene	34	6	18	0.17	5.37	0.08-0.12	0.27	3.60-3.98
Xylene (*m*- and *p*-)	34	5	15	0.92	5.2	2.5-3.8	0.43	2.82-3.12
Xylene (*o*)	34	5	15	0.39	1.9	1.2-1.9	0.22	2.91-3.21
1,2-Dichloroethane	34	1	3	0.64	0.64	0.59-0.90	0.2	2.71-2.99

[a]Concentrations are in micrograms per cubic meter, μg/m^3 (n = total number of canister samples that were analyzed for a particular chemical).

[b]Pace Lab's reporting limits were in parts per billion volume (ppbv). We converted to micrograms per cubic meters (μg/m^3) using equations in the Air Unit Conversion Table (Torrent Labs, www.torrentlab.com/torrent/Home/ResourceCenter.html).

[c]Total hydrocarbons reported as parts per billion volume (ppbv).

xylene measured at rural and suburban residential homes in Butler and Washington counties were higher than any concentration detected by the DEP at the Marcus Hook industrial site in 2010.

As stated above, several factors can influence air results. However, it is also highly possible that the poorer air quality in the areas where we tested—which were rural and residential, with little or no other industry nearby—can be attributed to gas facilities. While the DEP reports on the agency's air testing indicated that some of the VOCs we found in our study may not be due to oil and gas development since they persist in the atmosphere and have been widely used (for example, as refrigerants), the agency also indicates that acetone and the BTEX chemicals can be attributed to gas development [37].

With regard to the water tests conducted, Table 4 shows the 26 parameters that were detected in at least one sample. More than half of the project water samples contained methane; although some groundwater contains low concentrations of methane under normal conditions, this finding could also indicate natural gas migration from casing failure or other structural integrity problems [38]. Four of the substances detected in water well samples in Bradford and Butler Counties—manganese, iron, arsenic, and lead—were found at levels that exceed the Maximum Contaminant Levels (MCLs) set by Pennsylvania DEP's Division of Drinking Water Management [39]. Two of the water samples, both from Butler County, were more acidic than the recommended pH for drinking water.

Some metals, such as manganese and iron, are elevated in Pennsylvania surface waters and soils, either naturally or due to past industrial activities, and levels can vary regionally [40]. In 2012, Pennsylvania State University (PSU) researchers found that some drinking water wells in the state contained somewhat elevated concentrations of certain contaminants prior to any drilling in the area [41]. However, seven out of the nine water supplies sampled in our study (78%) had manganese levels above the state MCL—a much higher percentage than what was found in the pre-drilling samples in the PSU study (27%). Even where metals are naturally occurring or predate gas development, drilling and hydraulic fracturing can contribute to elevated concentrations of these contaminants [42] and have the potential to mobilize substances in formations such as Marcellus Shale, which is enriched with barium, uranium, chromium, zinc, and other metals [43].

LINKAGES BETWEEN SURVEYS AND ENVIRONMENTAL TESTING

More research would be required to identify cause-and-effect connections between the chemicals present in air and water in Pennsylvania's gas patches and symptoms reported by residents in specific locations. Nonetheless, such links are plausible since many of the chemicals detected in the testing are known to be related both to oil and gas operations and to the health symptoms reported by individuals living at the sites where air and water testing was conducted [13-15].

The air tests together detected 19 chemicals that are known to cause sinus, skin, ear/nose/mouth, and neurological symptoms, 17 that may affect vision/eyes, and 16 that may induce behavioral effects; as well as 11 that have been associated with liver damage, nine with kidney damage, and eight with digestive/stomach problems. In addition, the brain and nervous system may be affected by five of the VOCs detected, the cardiac system by five, muscle by two, and blood cells by two [44, 45].

Using these sources [44, 45], we compared lists of the established health effects of the chemicals detected at households where testing occurred with lists of the symptoms reported in surveys by participants at those testing locations in order to identify associations. We then calculated the rate of association, in which the denominator is the total number of health impacts reported by an individual and the numerator is the total number of health impacts reported by that individual that are consistent with the known health impacts of the chemicals detected through air or water testing where they live.

Benzene, toluene, ethylbenzene, xylene, chloromethane, carbon disulfide, trichloroethylene (TCE), and acetone were detected through testing at the same households where survey participants reported symptoms established in the literature [13-15, 44, 45] as associated with these chemicals, including symptoms in the categories of sinus/respiratory, skin, vision/eyes, ear/nose/mouth, and neurological. Some of these chemicals, as well as others (such as carbon tetrachloride and tetrachloroethylene) were found at sites where survey participants reported known associated symptoms in the categories of digestion, kidney and liver damage, and muscle problems. Specific examples of chemicals and symptoms that are linked in the research literature, and were found together at households where testing and surveys were conducted, are: benzene and dizziness and nasal, eye, and throat irritation; carbon tetrachloride and nausea, headaches, and liver and kidney disease; and tetrachloroethylene and skin rashes, persistent cough, and nerve damage.

As shown in Table 5, health symptoms reported by the individuals living in a home where testing occurred matched the known health effects of chemicals detected in that home at an overall rate of 68 percent. Fayette and Washington counties had the highest match, followed by Greene, Bedford, and Butler counties.

In addition, the percent of individuals reporting symptoms that have been associated with chemicals detected in air testing at households participating in this study showed some consistency across counties with regard to the most significant categories of problems reported, as shown in Table 6—indicating that patterns in both chemicals detected and symptoms exist despite different geographic locations.

Table 4. Water Quality Results from Nine Private Water Wells in Bradford and Butler Counties, Pennsylvania

Parameter[a]	Units	Number of sample	Number above detection limit	Minimum[b]	Maximum	Mean[c]	PA DEP MCL[d]	Number of samples above MCL[e]
Barium	mg/L	9	9	0.029	0.5	0.25	2	0
Calcium	mg/L	9	9	33	66.2	43.7	None	
Magnesium	mg/L	9	9	4.5	16.8	9.1	None	
Sodium	mg/L	9	9	9.2	64.1	20.9	None	
Strontium	mg/L	9	9	0.126	1.7	0.5	None	
Hardness (total as $CaCO_3$)	mg/L	9	9	120	234	147	None	
pH	Std Units	9	9	6	7.9	6.5	6.5-8.5	[f]
Alkalinity (total as $CaCO_3$)	mg/L	9	9	38	285	130	None	
Total dissolved solids	mg/L	9	9	138	392	218	500	0
Sulfate	mg/L	9	9	6.7	231	33	250	0
Manganese	mg/L	9	7	< 0.005	6.44	1.04	0.05	7
Chloride	mg/L	9	7	< 5.0	84.3	24.1	250	0
Iron	mg/L	9	6	< 0.04	153	19.5	0.3	5
Potassium	mg/L	6	6	1.14	1.57	1.1	None	

Specific conductance	μmhos/cm	6	6	287	552	326	None	
Methane	μg/L	9	5	1.06	57.4	10	0.3	
Arsenic	mg/L	9	4	< 0.001	0.0282	0.005	0.010	1
Lead	mg/L	9	4	< 0.001	0.113	0.113	0.01	3
Total coliform	per 100 mL	9	4	Absent	Present		None	
Total suspended solids	mg/L	6	4	< 5	448	118	None	
Temperature, water	Degree/Celsis	3	3	25	29	28	None	
Turbidity	NTU	3	3	0.22	5.7	2.3	None	
Nitrate	mg/L	3	3	0.076	0.71	0.46	10	0
E. coli	per 100 mL	9	2	Absent	Present		None	
Sulfur	μg/L	1	1	< 1,000	7,550	2,850	None	
Bromide	mg/L	1	1	0.26	0.26	0.26	None	

[a]Note: not all parameters were analyzed in every sample.

[b]Minimum values: If reports included non-detects of a particular chemical, the minimum value in the table was shown as being less than (<) the lowest laboratory detection limit.

[c]Mean values: Non-detected chemicals were assigned a concentration equal to half of the detection limit *only if* there were other samples that detected the chemical.

[d]MCL: Maximum Contaminant Levels published by the Pennsylvania Department of Environmental Protection Division of Drinking Water Management.

[e]No values are provided if MCLs for substances do not exist.

[f]Two samples had higher acidity (lower pH) than the value recommended by the PA DEP.

Table 5. Match between Health Symptoms Reported by Individuals at Air Testing Sites and Known Effects of Chemicals Detected

County	Number of individuals surveyed at homes where testing was conducted	Match between known health effects of chemicals detected and symptoms reported (percent)[a]	
		Average	Range
Overall	59	68	33-100
Fayette	16	73	33-100
Washington	15	73	33-100
Bradford	8	58	16-100
Butler	8	63	56-68
Bedford	6	69	63-100
Elk	2	64	53-74
Clearfield	1	none	none
Greene	1	70	70
Susquehanna	1	50	50

[a]When a health symptom was associated in the literature with more than one of the chemicals detected, only one match was counted for that symptom.

As mentioned above, levels of iron, manganese, arsenic, and lead were detected in our water well samples in Bradford and Butler Counties at levels that exceeded drinking water standards set by the Pennsylvania DEP. These substances are known to be associated with numerous symptoms reported by individuals living in the homes where these particular exceedances occurred, including symptoms in the categories of sinus/respiratory, skin reactions, digestive/stomach, vision/eyes, ear/nose/mouth, neurological, muscle/joint, behavioral/mood/energy, and liver and kidney damage. Survey participants in the homes where water samples contained methane reported health symptoms known to be associated with methane, including symptoms in the categories of sinus/respiratory, digestive/stomach, neurological, and behavioral/mood/energy. While the water samples taken for this project did not show detectable exceedances of safety standards for other substances, it is notable that no drinking water standards have been set for methane, bromide, sodium, strontium, or Total Suspended Solids (TSS)—and thus no exceedances would be indicated in laboratory reports.

Table 6. Percent of Individuals at Air Testing Sites Reporting Symptoms Associated in the Literature with Chemicals Detected at Those Sites, by Symptom Category and Primary Air

		Testing counties					
Symptom category	All	Bedford	Bradford	Butler	Fayette	Washington	Others[a]
Sinus/respiratory	83	100	88	100	81	73	80
Vision/eyes	73	—	100	63	69	67	60
Digestive/stomach	69	50	63	88	75	80	—
Skin reactions	63	50	63	88	69	53	40
Neurological	60	50	88	75	44	53	60
Behavioral/mood/energy	54	67	50	63	63	47	40
Ear/nose/mouth	33	50	—	38	44	33	20
Muscle problems	—	—	—	—	—	40	—

[a]This includes air samples from Clearfield, Elk, Greene, and Susquehanna counties.

DISCUSSION

> Complete evidence regarding health impacts of gas drilling cannot be obtained due to incomplete testing and disclosure of chemicals, and non-disclosure agreements. Without rigorous scientific studies, the gas drilling boom sweeping the world will remain an uncontrolled health experiment on an enormous scale.
>
> —Michelle Bamberger and Robert Oswald [16]

While the survey and testing results, and their related findings, do not constitute definitive proof of cause and effect, we believe they do indicate the strong likelihood that the health of people living in proximity to gas facilities is being affected by exposure to pollutants from those facilities. Most participants report a high number of health symptoms; similar patterns of symptoms were identified across project locations and distances from facilities; and consistency in symptoms reported exists regardless of age group or smoking history. In addition, contaminants that result from oil and gas development were detected in air and water samples in areas where residents are experiencing health symptoms that are established in the literature as consistent with such exposures.

Because of the short-term nature of the air-canister testing (24 hours) and the single water tests conducted at households, our results were contingent on conditions at particular "moments in time." Thus additional chemicals, or the same chemicals at different concentrations, might be captured through expanded testing; and residents could be experiencing exposures that were not detected but would be detectable through such testing. In addition, some of the variation in the air test results may have been due to the different reporting protocols used by the laboratories used in this project. Although all the labs test for the same core suite of chemicals, both their reporting limits and the additional chemicals for which they test vary; these will be key considerations for future testing work.

Another consideration that warrants further exploration involves the established standards on both the state and federal levels for "safe" concentrations, which are set only for exposure to single contaminants. This prevailing regulatory approach can not adequately address the potential risks posed by chronic, long-term exposure to lower levels of multiple contaminants simultaneously—in other words, the experience of people living in oil and gas areas day in and day out, and of workers at job sites where toxic substances are continuously used. In addition, for many substances in the environment (including those that come from gas operations and were detected in our air and water sampling), data on health risks or safe exposure levels simply do not exist.

More research is also needed that focuses on the sources of odors and odor events experienced by residents living near gas facilities. In some cases, participants reported different health impacts associated with specific sources and odor events than those they reported in the overall health survey. Since odors are a clear sign of the presence of airborne substances (such as fuel and chemicals), this aspect warrants tracking and analysis.

Although we did not investigate additional factors that can influence health conditions (e.g., through ordered control groups, in-depth health history research, or identification of other potential sources of contaminants), such factors may affect an individual's health independent of gas operations. The relationship between symptoms and distance from gas facilities also warrants more research.

At the same time, we strongly suggest that for individuals with a history of other health concerns (e.g., asthma or heart conditions) and who are already living with other exposures (e.g., traffic fumes or workplace chemicals), the presence of gas facilities and related pollution could have a strong "trigger effect" that can make existing problems worse and put individuals at higher risk of developing new ones.

RECOMMENDATIONS

As discussed earlier, scientific knowledge about the health and environmental impacts of shale gas development—and also the adoption of policy and regulatory measures to prevent them—are proceeding at a far slower pace than the development itself. This timing mismatch creates situations (already being experienced by residents of Pennsylvania and other states) in which problems are widely reported but left unaddressed. Several measures can be taken to ensure that public health impacts are fully understood and given greater priority in decision-making about shale gas development.

1) *Elevate the role of public health considerations in gas development decisions.* A key measure would be to conduct health impact assessments before permitting begins. HIAs aim to minimize negative impacts and to improve health outcomes associated with land use decisions by analyzing problems that could arise over time as well as existing health and environmental risks that could be exacerbated by new activities [46]. HIAs can also have a strong preventive effect by identifying mitigation measures related to aspects such as toxic exposures, air and water pollution, and emergency response [47]. In addition, regulatory agencies could comprehensively plan the scope and pace of permits for wells and other facilities in order to reduce impacts on air and water quality, rather than continuing the permit-by-permit process currently being followed in Pennsylvania and other states. Information on where wells and facilities would be built in relation to places where health could be at risk (e.g., homes, schools, and hospitals) could also be required in permit applications.

2) *Increase the involvement of state departments of health in assessing the impacts of gas development.* Efforts should be increased to track and respond to health concerns, and a database should be established to document these problems and the agency response. Health departments could provide training for health and medical professionals on exposure pathways and health symptoms

related to gas operations, so that residents receive more informed advice and appropriate testing and care referrals. Financial aid mechanisms should be established to enable low-income residents to have blood and urine tests for chemical exposure.

3) *Conduct baseline water testing and continuous long-term monitoring of air quality.* Such testing would apply to private wells and public drinking water supplies prior to drilling and to the air at or near facilities during all phases of operations. Testing and monitoring should cover a full suite of chemicals, and contaminants and results should be reported regularly and made available to the public. Air quality testing in particular should be conducted at a range of facilities (e.g., compressor stations, impoundment pits, dehydrators) that cause emissions. These efforts could be carried out by the state regulatory agencies that issue permits or through an agreement between those agencies and health departments. Inter-agency agreements could also be developed to track potential health impacts that could result following spills of chemicals and waste, the underground migration of fracturing fluids, leaks, and other problems.

4) *Strengthen regulations for facilities to minimize air and water pollution risks.* These could include significantly increased setback distances; the installation of advanced technologies on all equipment to reduce emissions, odors, and noise; the use of closed-loop storage systems for waste and drilling fluids (rather than open pits); and the practice of "green completions" to reduce or eliminate flaring and venting of methane gas and other pollutants.

5) *Advance changes in testing parameters that determine "safe" exposure in order to account for low-level, chronic exposure and multiple chemical exposure in testing and monitoring.* Such changes are necessary to reflect impacts on people living in oil and gas development areas day in and day out, as well as workers at facilities. Under current testing parameters (which are based largely on acute episodes involving single contaminants), results may show below-threshold levels even though residents are negatively affected. For example, a recent paper showed that endocrine-disrupting chemicals can have different but still harmful effects at lower doses than at higher ones and concluded that fundamental changes in chemical testing and safety protocols are needed to protect human health [48]. Additionally, current health guidelines should be updated to capture more of the chemicals currently in use and to assess complex or indirect sources of contamination, such as oil and gas operations that rely on a variety of substances, equipment, and facilities at numerous stages of development.

CONCLUSION

> While we realize that human activities may involve hazards, people must proceed more carefully than has been the case in recent history. Corporations, government entities, organizations, communities, scientists, and other individuals must adopt a precautionary approach to all human endeavors. . . . When an activity raises threats of harm to human health or the environment,

> precautionary measures should be taken even if some cause and effect relationships are not fully established scientifically.
>
> —Wingspread Consensus Statement on the Precautionary Principle [49]

Across the gas patches of the United States, people experiencing health problems voice the simple wish to be believed. Many say that their health has worsened since gas development began in their communities and that they feel better when they are away from home. Often these conversations turn to what it will take for regulators and policymakers to view their stories not just as "anecdotes," but as valid concerns worthy of an effective response.

There is no doubt that more research on the environmental and health impacts of shale gas development is needed and can play a critical role in making sound decisions about a complex and controversial issue. Yet an equally important consideration is how to respond to the presence of unanswered questions. For many proponents of unfettered gas development, the absence of definitive causal links between gas facilities and specific health impacts indicates the absence of a problem. But for impacted communities and others who believe health and the environment deserve protection and that water and air quality should be maintained, what we don't yet know makes the need for caution even greater.

We believe that the findings of this survey and testing project in Pennsylvania, coupled with similar projects elsewhere and an emerging body of research, provide sufficient evidence for decision-makers to take action to slow the rush to drill, at least until the wide gaps in scientific knowledge, policies, and regulations are bridged. Much is already known about the chemicals used and pollution caused by oil and gas activities, which alone create the real potential for negative health effects in any area where development occurs [50]. The precautionary principle should be applied to decisions about shale gas development (both in existing gas patches and in areas slated for new development), and this should include shifting the burden of proof that harm does or does not occur to those proposing the action.

The status quo—in which science and policy changes proceed slowly while gas development accelerates rapidly—is likely to worsen air and water quality, resulting in negative health impacts and possibly a public health crisis. Greater understanding of the experiences reported by individuals living near gas facilities can play an important role in pointing the way forward to preventing these problems, both in Pennsylvania and nationwide.

ACKNOWLEDGMENTS

This project would not have been possible without the caring, concern, and openness of project participants, who shared their time and personal experiences and trusted us to write about them. Much gratitude is also owed to the community members and organizational partners who provided the contacts and guidance that made it possible to engage project participants. Many thanks to the Colcom Foundation for its generous support of this project and commitment to protecting the environment and public health.

AUTHORS' BIOGRAPHIES

NADIA STEINZOR is the Eastern Program Coordinator of Earthworks' Oil & Gas Accountability Project. She works with landowners, concerned citizens, and environmental organizations to educate and support impacted communities, advance state oil and gas regulations, and promote Earthworks' federal reform agenda. Nadia has worked for nearly two decades in research, communications, writing, and editing to promote action and policies on environmental protection and land conservation. She holds an M.S. in Environmental Policy from Bard College and an M.A. in Peace and Development Studies from the University of Gothenburg, Sweden, Send email to her at nsteinzor@earthworksaction.org

WILMA SUBRA is President of Subra Company, Inc., a chemistry lab and environmental consulting firm in New Iberia, Louisiana, which provides technical assistance to citizens and victims of environmental issues. She serves on local, state, and federal committees dealing with oilfield waste, oil refineries, and toxic release inventory. Wilma holds an M.S. in Microbiology and Chemistry from the University of Southwestern Louisiana. She is a recipient of the MacArthur Fellowship Genius Award for helping ordinary citizens understand, cope with, and combat environmental problems in their communities. Send email to her at subracom@aol.com

LISA SUMI is a consultant who works on the environmental, community, and health impacts of extractive industries such as coal and hard rock mining, tar sands, and oil and gas. She conducts work that integrates science, technology, policy, and corporate research and analysis with community education and outreach. She has served as Research Director for the Oil and Gas Accountability Project and the Environmental Mining Council of British Columbia, and has worked for clients such as As You Sow, Council of Canadians, Earthworks, ForestEthics, Initiative for Responsible Mining Assurance, Massachusetts Institute of Technology Center for Future Civic Media, MiningWatch Canada, and Natural Resources Defense Council. Lisa holds a M.S. in Physican Geography from the University of Toronto. Isumi@earthworksaction.org

NOTES

1. Institute of Medicine, "The Health Impact Assessment of New Energy Sources: Shale Gas Extraction," www.iom.edu/Activities/Environment/EnvironmentalHealthRT/2012-APR-30.aspx (accessed June 27, 2012).

2. U.S. Energy Information Administration, "Number of Producing Gas Wells," [data table], http://205.254.135.7/dnav/ng/ng_prod_wells_s1_a.htm (accessed July 8, 2012).
3. Pennsylvania Department of Environmental Protection, "Oil and Gas Reports," www.portal.state.pa.us/portal/server.pt/community/oil_and_gas_reports/20297#InteractiveReports (accessed September 10, 2012).
4. C. W. Schmidt, "Blind Rush? Shale Gas Boom Proceeds amid Human Health Questions," *Environmental Health Perspectives* 119 (2011): A348-353, doi: 10.1289/ehp.119-a348.
5. Earthworks Oil and Gas Accountability Project, "Oil and Gas Pollution," www.earthworksaction.org/issues/detail/oil_and_gas_pollution (accessed September 20, 2012).
6. Pennsylvania Alliance for Clean Water and Air, "List of the Harmed," http://pennsylvaniaallianceforcleanwaterandair.wordpress.com/the-list/ (accessed July 8, 2012).
7. Edward Humes, "Fractured Lives: Detritus of Pennsylvania's Shale Gas Boom," *Sierra Magazine,* July/August 2012, 52-59.
8. Earthworks' Oil & Gas Accountability Project, *Natural Gas Flowback: How the Texas Gas Boom Affects Community Health and Safety,* 2011.
9. Earthworks' Oil & Gas Accountability Project, *Health Survey Results of Current and Former Residents of DISH/Clark, Texas Residents*, 2009.
10. Earthworks' Oil & Gas Accountability Project, *Community Health Survey Results: Pavillion, Wyoming,* 2010.
11. Subra Company, *Health Report on Mossville, Calcasieu Parish, Louisiana*, 2009.
12. Louisiana Environmental Action Network, "Survey of the Human Health Impacts Due to the BP Deepwater Horizon Disaster," 2012, http://leanweb.org/our-work/water/bp-oil-spill/results-of-the-louisiana-environmental-action-network-lean-survey-of-the-human-health-impacts-due-to-the-bp-deepwater-horizon-disaster (accessed July 15, 2012).
13. R. Witter et al., *Potential Exposure-Related Human Health Effects of Oil and Gas Development: A Literature Review (2003-2008),* 2008.
14. T. Colborn et al., "Natural Gas Operations from a Public Health Perspective," *Human & Ecological Risk Assessment* 17 (5) (2011): 1039-1056, doi: 10.1080/10807039.2011.605662.
15. L. M. McKenzie et al., "Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources," *Science of the Total Environment* 1 (424) (2012): 79-87, doi: 10.1016/j.scitotenv.2012.02.018.
16. M. Bamberger and R. E. Oswald, "Impacts of Gas Drilling on Human and Animal Health," *New Solutions: A Journal of Environmental and Occupational Health Policy* 22 (1) (2012): 51-77, doi: 10.2190/NS.22.1.e.
17. B. Goldstein, J. Kriesky, and B. Pavliakova, "Missing from the Table: Role of the Environmental Public Health Community in Governmental Advisory Commissions Related to Marcellus Shale Drilling," *Environmental Health Perspectives* 120 (4) (2012): 483-486, doi: 10.1289/ehp.1104594.
18. The Health Impact Project, "HIA in the United States," www.healthimpactproject.org/hia/us (accessed June 27, 2012).
19. U.S. Environmental Protection Agency, "Ambient Air Monitoring Program," http://www.epa.gov/airquality/qa/monprog.html (accessed September 20, 2012).

20. Clean Air Council, "PA DEP Launches Long-term Air Sampling," http://cleanair.org/program/outdoor_air_pollution/marcellus_shale/pa_dep_launches_long_term_air_sampling (accessed September 20, 2012).
21. Geisinger Health System, "Guthrie Health and Geisinger Collaborate on Marcellus Shale Work," https://webapps.geisinger.org/ghsnews/articles/GuthrieHealthandGeisingerc8464.html (accessed September 22, 2012).
22. National Institutes of Environmental Health Sciences, "Shale Gas Workshop Explores Needed Research on Fracking," *Environmental Factor,* June 2012, www.niehs.nih.gov/news/newsletter/2012/6/spotlight-shalegas/index.htm (accessed September 22, 2012).
23. B. L. Allen, "Shifting Boundary Work: Issues and Tensions in Environmental and Health Science in the Case of Grand Bois, Louisiana," *Science as Culture* 13 (12) (2004): 429-448, doi: 10.1080/0950543042000311805.
24. Minkler, M. et al., *Community-Based Participatory Research: A Strategy for Building Health Communities and Promoting Health through Policy Change,* PolicyLink, School of Public Health, University of California Berkeley, 2012.
25. B. A. Israel et al., "Review of Community-Based Research: Assessing Partnership Approaches to Improve Public Health," *Annual Review of Public Health* 19 (1998): 173-202, doi: 10.1146/annurev.publhealth.19.1.173.
26. National Institute of Environmental Health Sciences, "Community-Based Participatory Research in Environmental Health," Request for Applications ES-01-003, January 2001.
27. M. Hendryx et al., "Self-Reported Cancer Rates in Two Rural Areas of West Virginia With and Without Mountaintop Coal Mining," *Journal of Community Health* 37 (4) (2012): 32-327, doi: 10.1007/s10900-011-9448-5.
28. C. M. E. Krogh et al., "WindVOiCe, A Self-Reporting Survey: Adverse Health Effects, Industrial Wind Turbines, and the Need for Vigilance Monitoring," *Bulletin of Science Technology Society* 31 (4) (2011): 334-345, doi: 10.1177/0270467611412551.
29. Mossville Environmental Action Now, Subra, W., and Advocates for Environmental Human Rights, *Industrial Sources of Dioxin Poisoning in Mossville, Louisiana: A Report Based on the Government's Own Data,* 2007.
30. S. Schiffman, "Science of Odors as a Potential Health Issue," *Journal of Environmental Quality* 34 (2005): 129-138, doi: 10.2134/jeq2005.0129.
31. Pennsylvania Department of Environmental Protection, eFacts database, www.ahs2.dep.state.pa.us/eFACTSWeb/criteria_sitesbymuni.aspx (accessed October 3, 2012).
32. FracTracker, Data-Generated Map of the Distribution of Gas Wells across Pennsylvania, www.fractracker.org/maps (accessed October 3, 2012).
33. D. D. Heckathorn, "Respondent-Driven Sampling: A New Approach to the Study of Hidden Populations," *Social Problems* 44 (2c) (1997): 174-199.
34. Department of Psychology, University of California at Davis, "Types of samples," http://psychology.ucdavis.edu/sommerb/sommerdemo/sampling/types.htm (accessed June 25, 2012).
35. Earthworks' Oil & Gas Accountability Project, *Gas Patch Roulette: How Shale Gas Development Risks Public Health in Pennsylvania,* 2012.
36. Swiss Agency for the Environment, Forests, and Landscapes, "National Air Pollutions Monitoring Network," 2001.

37. Pennsylvania Department of Environmental Protection, *Northeastern Pennsylvania Marcellus Shale Short-Term Ambient Air Sampling Report; Northcentral Pennsylvania Marcellus Shale Short-Term Ambient Air Sampling Report,* 2011; and *Southwestern Pennsylvania Marcellus Shale Short-Term Ambient Air Sampling Report*, 2010.
38. A. E. Ingraffea, *Fluid Migration Mechanisms Due to Faulty Well Design and/or Construction: An Overview and Recent Experiences in the Pennsylvania Marcellus Play*, 2012.
39. Pennsylvania Department of Environmental Protection, Division of Drinking Water Management, "Maximum Contaminant Levels," www.portal.state.pa.us/portal/server.pt?open=18&objID=437830&mode=2 (accessed July 20, 2012).
40. National Science Foundation, "Can Marcellus Shale Development and Healthy Waterways Co-exist?," www.nsf.gov/discoveries/disc_summ.jsp?cntn_id=122543 (accessed October 2, 2012).
41. Pennsylvania State University Extension. "Iron and Manganese in Private Water Systems," http://extension.psu.edu/water/converted-publications/iron-and-manganese-in-private-water-systems (accessed October 2, 2012).
42. E. Boyer et al., The Center for Rural Pennsylvania, Pennsylvania State University, *The Impact of Marcellus Gas Drilling on Rural Drinking Water Supplies,* 2011.
43. T. Banks, "Fluid Rock Interactions Associated with Hydraulic Fracturing and Natural Gas Development," *Global Water Program Magazine,* January 2011, http://globalwater.jhu.edu/index.php/magazine/article/fluid_rock_interactions_associated_with_hydraulic_fracturing_and_natural_ga/ (accessed October 2, 2012).
44. Agency for Toxic Substances and Disease Registry (ATSDR), "Toxicological Profiles," http://www.atsdr.cdc.gov/toxprofiles/index.asp (accessed July 30, 2012).
45. New Jersey Department of Health, "Right to Know Hazardous Substance Fact Sheets," http://web.doh.state.nj.us/rtkhsfs/indexfs.aspx (accessed July 30, 2012).
46. A. Wernham, "Health Impact Assessment for Shale Gas Extraction," www.healthimpactproject.org/resources/health-impact-assessment-for-shale-gas-extraction (accessed July 10, 2012).
47. Garfield County, Colorado, "Battlement Mesa Health Impact Assessment," www.garfield-county.com/environmental-health/battlement-mesa-health-impact-assessment-ehms.aspx (accessed July 10, 2012).
48. L. N. Vandenberg et al., "Hormones and Endocrine-Disrupting Chemicals: Low-Dose Effects and Nonmonotonic Dose Responses," *Endocrine Reviews* 33 (3) (2012): 1-78, doi: 10.1210/er.2011-1050.
49. Science and Environmental Health Network, "Wingspread Consensus Statement on the Precautionary Principle," 1998, www.sehn.org/wing.html (accessed July 18, 2012).
50. R. Witter et al., *Potential Exposure-Related Human Health Effects of Oil and Gas Development: A White Paper,* 2008.

Direct reprint requests to:

Nadia Steinzor
Earthworks' Oil & Gas Accountability Project
P.O. Box 149
Willow, NY 12495
e-mail: nsteinzor@earthworksaction.org

NEW SOLUTIONS, Vol. 23(1) 85-101, 2013

Features

THE ECONOMIC IMPACT OF SHALE GAS DEVELOPMENT ON STATE AND LOCAL ECONOMIES: BENEFITS, COSTS, AND UNCERTAINTIES

JANNETTE M. BARTH

ABSTRACT

It is often assumed that natural gas exploration and development in the Marcellus Shale will bring great economic prosperity to state and local economies. Policymakers need accurate economic information on which to base decisions regarding permitting and regulation of shale gas extraction. This paper provides a summary review of research findings on the economic impacts of extractive industries, with an emphasis on peer-reviewed studies. The conclusions from the studies are varied and imply that further research, on a case-by-case basis, is necessary before definitive conclusions can be made regarding both short- and long-term implications for state and local economies.

Keywords: economic impact; shale gas development; extractive industries; hydraulic fracturing, fracking

The combined technologies of horizontal drilling and hydraulic fracturing have made it possible to extract large amounts of natural gas from the Marcellus Shale, which underlies portions of five states in the Northeast. Many commentators have assumed that shale gas exploration and development in these states will be enormously beneficial to the state and local economies. While externalities, both positive and negative, are commonly experienced along with the direct

doi: http://dx.doi.org/10.2190/NS.23.1.f
http://baywood.com

activities of extractive industries, the negative externalities and the overall net benefits are often overlooked in economic impact studies. Examples of negative externalities in connection with shale gas development include water, air and land contamination; related public health impacts; wear and tear on roads and other infrastructure; and costs to communities due to increased demand for services such as police, fire, first responders, and hospitals.

An understanding of economic impacts in the Marcellus Shale region can be enhanced by a wider knowledge of boom-bust cycles, the resource curse, and extractive industries generally. In an effort to investigate both the potential net benefits to state and local economies and how policymakers may evaluate them, this article offers a summary review of research findings and makes suggestions for further research that would be necessary to adequately analyze the net economic impact of shale gas development. It also offers a preliminary look at some economic measurements in the Barnett Shale play in Texas that are not often mentioned in relation to shale gas development. The first section provides a brief critique of some of the industry-sponsored, non-peer-reviewed studies, and it is followed by a summary of peer-reviewed literature and non-industry-funded studies that are relevant to extractive industries such as shale gas development. The final section discusses some of the costs and uncertainties inherent in any economic assessment of shale gas development.

STUDIES FUNDED BY INDUSTRY

Numerous studies have been prepared by and/or funded by the gas industry [1-6]. They generally conclude that there will be large, positive economic impacts to both states and local communities. These studies primarily highlight benefits such as employment, income, and tax revenue growth. Kinnaman [7] has reviewed several of these industry-sponsored studies and observed that they are not peer-reviewed. He has raised a number of concerns about the industry-sponsored studies, and concluded that due to unrealistic assumptions regarding windfall gains to households, location of suppliers and property owners, and the methodology used, the estimates of economic benefits in the industry-sponsored studies are very likely overstated. Any economic activity, including shale gas development, will generate some level of state and local economic revenues and provide some number of state and local employment opportunities, but policymakers should recognize that the estimated gains in revenues and employment are probably exaggerated in the industry-funded studies and the long-term economic impact may be far different than expected. In addition to the points made by Kinnaman [7], the estimates in these studies may be further overstated if overly optimistic gas reserve and production assumptions were used. There have been widely differing estimates of Marcellus Shale gas reserves from various sources, including academicians and federal government agencies [8]. For all these reasons, it is possible that the net benefits cited by industry-sponsored studies are overstated even before any adjustments are made for negative externalities.

Input-output analysis is frequently used by industry in their efforts to show direct, indirect, and induced economic impacts of shale gas development [1-3]. Using this technique, the industry-funded studies have captured some of the likely benefits of shale gas development, including the growth of ancillary and other industries. Input-output analysis relies on tables of coefficients that link each industry in a region to all other industries. An input-output matrix shows how much output from each industry is used as input into other industries. In a region where shale gas drilling has not existed in the past, it is impossible to know with certainty what the inter-industry coefficients will be, and "borrowing" them from other regions or industries may result in inaccurate impact conclusions [9].

An important fact to bear in mind when viewing the shale gas experience in Texas and trying to extrapolate it to other states, such as New York, is that Texas is likely to experience greater economic benefits from shale gas development than is New York. Texas has had a well-established oil and gas industry for many years and a labor force with the requisite skill sets. Oil and gas headquarters and main offices are more often in Texas than in New York. Many of the industries that are ancillary to gas exploration and development are also located in Texas, not in New York. New York will have to import skilled labor as well as materials and equipment, much of which is manufactured, managed, contracted for, and maintained in Texas. Economists at the Federal Reserve Bank of Dallas (Dallas Fed) have pointed out that due to the extensive oilfield machinery and energy services located in Texas, the state greatly benefits from oil and gas production throughout the world [10]. In addition, the Barnett Shale is in the Dallas–Fort Worth metroplex, a region that is much more urban than the Marcellus Shale region. The literature indicates that the impact of extractive industries in nonmetropolitan areas may be much different than in metropolitan areas [11]. Economic multipliers tend to be larger in metropolitan areas, such as the Dallas-Fort Worth metroplex, where there are larger populations and greater industrial diversity than in nonmetropolitan areas, such as the Marcellus Shale region of upstate New York [12].

Kinnaman has pointed out that "economic resources necessary to fuel a growing industry would either relocate from other regions of the country or shift from local industries within the region. . . . The IMPLAN model used . . . largely ignores the possibilities of direct spending crowding out other users of the resource" [7]. An additional weakness is the fact that environmental impacts are ignored. Wassily Leontief, who received the Nobel Prize in Economic Science for his model of input-output economics, had himself stressed as early as the 1970s that environmental repercussions and externalities should be incorporated into input-output analysis [13-15]. Leontief recommended that a pollution abatement industry be entered into the input-output matrix, and that the abatement industry be in the business of eliminating pollutants generated by the productive sectors, consumers, and the abatement industry itself. And Wiedmann, Lenzen, Turner, and Barrett stated, "in the last few years models have emerged that use a more sophisticated multi-region, multi-sector input-output framework . . . in order to calculate environmental impacts. . . . Results demonstrate that it is important to explicitly consider the production recipe, land and energy use as well as emissions in a multi-region, multi-sector and multi-directional trade model with detailed sector disaggregation" [16]. The industry-sponsored studies have not addressed environmental repercussions, such as water and air contamination, or externalities such as damage to roads and costs to communities. Unless appropriate adjustments are made, input-output analysis tends to use unrealistic assumptions. Bess and Ambargis [17] and Lazarus, Platas, and Morse [18] discuss some of the limitations of input-output analysis. For example, Bess and Ambargis state, "Regional input-output models can be useful tools for estimating the total effects that an initial change in economic activity will have on a local economy. However, these models are not appropriate for all applications and care should be given to their use. . . . Key assumptions of these models typically include fixed production patterns and no supply constraints. Assumptions about the amount of inputs that are supplied from the local region are also important in these models. Ignoring these assumptions can lead to inaccurate estimates" [17]. There are several additional problems of particular relevance to the application of input-output analysis to the study of shale gas development. For example, while spending patterns in communities with an established drilling industry would probably be different than spending patterns in communities without an established drilling industry, this difference is not reflected. Input-output analysis implicitly assumes that all populations have identical spending patterns. This assumption exaggerates the estimated economic impact if new workers are transient. The gas industry frequently brings in transient workers and houses them in man-camps or rental housing on a short-term basis [19]. Such workers often send their wages to their families living elsewhere, improving the economies in those distant locations, not in the shale region, and thereby exaggerating the estimated economic impact. In addition, input-output analysis assumes "constant returns to scale." This means that the gas industry would get no volume discounts on supplies. This is an unrealistic assumption, and it inflates estimates of industry spending and thus estimates of economic impacts from the industry's activity in the community. Input-output models used in the industry-sponsored studies tend to be static in time, implying that there are no changes in coefficients over time and no allowance for price changes in factors of production such as supplies and labor. The production function is also assumed to be constant. This does not allow for input substitution or changes in the proportions of inputs as technology and/or prices change over time. Input-output models tend to be aspatial, implying that transportation costs are not fully reflected. Transportation costs in gas drilling areas may differ due to differences in availability of and proximity to fresh water supplies and wastewater disposal wells.

In order to produce even somewhat accurate results using an input-output approach, inter-industry relationships must be known. There are several frequently used sources of input-output coefficients that indicate how the input and output of each industry in a given region are related [20, 21]. One cannot know what the true coefficient values are in a case where the industry being studied does not already exist in a region, as is the case for horizontal drilling and hydraulic fracturing in New York State. Even if the input-output coefficients could be known, the technique is of limited use. Input-output methodology estimates the positive impacts on variables such as employment, value added, and tax revenue, but as shown in the above discussion of assumptions, the estimates are often exaggerated; and the methodology does not capture the impacts of environmental degradation or the full costs to communities and society.

STUDIES NOT FUNDED BY INDUSTRY

While studies not funded by the gas industry on the economic impact of shale gas drilling are in short supply, there is substantial peer-reviewed literature on the economic impact of extractive industries generally. There are also some studies that are not peer-reviewed but are not funded by the gas industry. Conclusions from peer-reviewed literature and from studies not funded by the gas industry should be considered in the analysis of shale gas development. The research summary below is categorized into three areas: the resource curse, boom and bust cycles, and socio economics.

The Resource Curse

Research by Sachs and Warner [22, 23] concluded that there is a “natural resource curse,” meaning that countries with great natural resource wealth tend to grow more slowly than resource-poor countries The so-called “resource curse” has been the subject of several literature surveys and the peer-reviewed research indicates that the resource curse holds within the United States, particularly in regions where there was once a strong extractive industry. After reviewing much of the literature, Stevens [24] pointed out that while there has been some disagreement, the evidence appears to support a negative relationship between abundance of natural resources and economic growth. He concluded that there is no simple single explanation of what creates a “blessing” rather than a “curse,” and he argued for a case-by-case approach to analysis. His findings indicate that to decrease the likelihood of a “curse,” the resource should be developed at a slow pace, thereby improving the chances that the economy and society can adjust and the crowding-out effect may be reduced. Increased diversification is suggested as another way to decrease the “curse” effect. Key dimensions of the resource curse that have been studied include negative impacts on economic growth, prevalence of poverty, and creation of greater conflicts in society. Regional and national impacts may be quite different. Stevens stated, “A final dimension of ‘resource curse’ is the regional impact of the projects. Thus while the effect at a national level might be debated, because of the heavy local impact of the projects, clear damage is done especially in terms of both the environment and human rights. Meanwhile, the benefits appear to flow to central rather than regional authority. However, this aspect of the ‘curse’ tends to be neglected in the economics literature” [24].

This dichotomy between benefits to a nation and damage to localities should be studied further in the case of shale gas development in the United States. Industry-funded studies [25, 26] have concluded that there will be large positive impacts on tax revenues and national employment levels, but they have ignored many negative impacts that would be incurred at the local and state levels. In the case of shale gas development, it is likely that policymakers at the state and local levels will have different interests than policymakers at the national level. One question that policymakers at all levels should consider is whether shale gas development, including its exploration, production, and exportation, is worth the costs to the states, communities, and individuals that are directly impacted.

Initial research on the natural resource curse was focused on how it impacts developing nations [22-24]. Such research includes extensive empirical analysis and speculation on what causes the resource curse. While there has been less research on the natural resource curse specific to the United States, Papyrakis and Gerlagh [27] focused on the United States. They concluded that even in the United States, natural resource abundance is a significant negative determinant of economic growth. James and Aadland [28] extended the research to a disaggregated level within the United States, by focusing on counties. Their results show “clear evidence that resource-dependent counties exhibit more anemic growth, even after controlling for state specific effects, socio-demographic differences, initial income, and spatial correlation” [28].

Headwaters Economics studied county-level impacts and concluded, “counties that were not focused on fossil fuel extraction as an economic development strategy experienced higher growth rates, more diverse economies, better educated populations, a smaller gap between high and low income households and more retirement and investment income” [29]. Peach and Starbuck [30] studied oil and gas extraction in New Mexico and found a small but positive effect on income, employment, and population.

It may be difficult to determine if extraction of a natural resource caused poorer economic performance in an affected region or if the region was already relatively poor or on the path to poverty prior to exploitation of the resource. In two cases that are specific to counties in the United States, and were cited above, James and Aadland [28] and Headwaters [30], attempts were made to control for initial income and other differing characteristics of the areas under study.

Boom and Bust

Extractive industries are known for their boom-and-bust cycles [31], and the bust must be analyzed as well as the boom. Weber [32] focused on the short-term impact of a natural gas boom in Colorado, Texas, and Wyoming and found modest increases in employment, wage and salary income, and median household income. The negative economic consequences during the bust may exceed the positive direct economic impact during the boom. Black, McKinnish, and Sanders [33] studied the coal boom in the 1970s and the bust in the 1980s on local economies in the four-state region of Kentucky, Ohio, Pennsylvania, and West Virginia. They concluded, "for each 10 jobs produced in the coal sector during the boom, we estimate that fewer than 2 jobs were produced in the local-good sectors of construction, retail and services. The spillovers from the coal bust were larger. During the coal bust, we estimate that for each 10 jobs lost in the coal sector, 3.5 were lost in the construction, retail and services sector" [33]. Seydlitz and Laska studied boom-and-bust cycles of the petroleum industry in Louisiana and concluded that improved community economic health is transitory in areas with petroleum extraction, and "improvements can be lost as early as the second or third year after an increase in petroleum activity and will be lost during the bust if not sooner" [34]. They suggest that a diversified economy may help to prevent some of the loss in benefits. Christopherson and Rightor [35] have written about the boom and bust phenomenon as it impacts shale gas extraction, and they suggest that the boom and bust cycle can be controlled by slowing the pace and scale of shale gas development.

Socioeconomics

Peer-reviewed sociology journals have published articles on the socioeconomic impact of extractive industries in the United States, and the results of this research should be considered by policymakers in their assessment of the economic impact of shale gas development. For example, Freudenburg and Wilson [11] analyzed 301 research findings regarding the impact of mining in the United States, and they concluded that adverse conditions are significantly more likely than positive outcomes. They also stated, "the areas of the United States having the highest levels of long-term poverty, outside of those having a history of racial inequalities, tend to be found in the very places that were once the site of thriving extractive industries" [11].

Wilson [36] studied the socioeconomic well-being of mining communities by comparing two communities in the Midwest and concluded that local well-being as a result of mining in a community is influenced by local circumstances such as "levels of economic dependence on mining, the geographic distribution of the workforce, and the options available to the companies to confront changes in minerals price." Wilson's research indicates that different mining communities within the same region of the Untied States can have different long-term employment impacts, and case-by-case research is required.

SOME COSTS AND UNCERTAINTIES SPECIFIC TO SHALE GAS

The relevant peer-reviewed research, as described above, indicates that each extractive industry and its impacts on specific states and locations must be studied on a case-by-case basis. There are many uncertainties regarding the long-term impacts on local and regional economies. Long-term impacts on the number of jobs created, unemployment rates, and income and poverty levels should each be considered. There are likely to be significant local costs, and these must also be considered. As horizontal, high-volume slick-water hydraulic fracturing for natural gas is still in its early stages, it is premature to analyze and attempt to make definitive conclusions regarding the long-term economic impacts of shale gas development in the United States. However, since the Barnett Shale play in Texas has been active for about a decade, some early indications of economic health are emerging. According to the Texas Railroad Commission [37], there are four core gas-drilling counties in the Barnett Shale: Denton, Johnson, Tarrant, and Wise counties. While there are many reasons why economic data and trends in certain counties differ from state-level data, it is interesting to examine unemployment rates, growth in median household income, and the number of people in poverty in these core gas-drilling counties as compared to statewide data. The data indicate that the residents of these counties are not experiencing great economic prosperity relative to the rest of Texas. Data were obtained from the U.S. Census Bureau, Small Area Estimates Branch, and the Bureau of Labor Statistics [38, 39]. For the period from 2003 to 2010, median household income increased by 21.2 percent in the state of Texas, but in the four core counties, median household income increased between 10 percent and 16 percent. And for the same period, the increase in the unemployment rates for the four counties ranged from 1.8 to 2.4 percentage points, a little higher than the increase in the state-level unemployment rate, which was 1.5 percentage points. Finally, the number of people in poverty in the four-county areas increased, in percentage terms, just as much as statewide.

Significant costs that are associated with shale gas development and other extractive industries should be considered in any study of the economic impact of shale gas development. Such costs are often omitted in both peer-reviewed literature and in the industry-funded studies. Kinnaman [7] briefly discusses the implications of social costs and implementation of a tax on negative externalities, which is intended as an incentive to reduce the negative externality and may be used as a source of funds to help mitigate negative impacts. A few of the costs that have not been adequately addressed in the literature are summarized here.

Shale gas development may transform a previously pristine and quiet natural region, bringing increased industrialization to the region in the form of industrial contaminants, heavy truck traffic, and excessive noise. Due to concerns regarding potential water, air, and land contamination, industries that have been vital to some of the communities in the shale region may decline. Industries that are incompatible with high levels of industrialization and potential environmental degradation include agriculture, tourism, organic farming, hunting, fishing, outdoor recreation, and wine and beer making. Each of these industries that rely on clean air, land, water, and/or a tranquil environment is currently important to the shale counties in upstate New York. Kauffman [40] has calculated that the net present value, using a discount rate of 3 percent over 100 years, of natural goods and services from ecosystems in the New York State portion of the Delaware River Basin is $113.6 billion.

Tourism is an industry that been encouraged in many of the communities on the Marcellus Shale, and Rumbach [41] reported that in 2008, visitors spent more than $239 million in three counties of New York State's Southern Tier, and the tourism and travel sector accounted for 3,335 direct jobs and nearly $66 million in labor income. The Outdoor Industry Association [42] reports that 6.1 million American jobs are directly supported by the outdoor industry and that Americans spend $646 billion each year on activities like camping, hunting, fishing, and snow sports, all of which are popular in the Marcellus Shale region.

Deller et al. [43] analyze economic growth due to tourism in areas with natural amenities that encourage outdoor recreation and conclude that rural areas that can take advantage of such amenities are in a position to expand their local economies. Public fears of water, air, and land contamination due to shale gas development, whether those fears are realistic or not, may forever negatively impact the public perception of the rural areas that currently enjoy tourism dollars. Another related sector of the economy in the shale region of New York centers around retirees and owners of second homes, both of whom may become less enamored of a region when it becomes industrialized. Such potential losses to communities should be reflected in an economic assessment.

Estimating the ignored costs is not a simple task, but there are ways to at least roughly estimate many of the costs that have been ignored to date. Rumbach [41] analyzed the potential impact of shale gas drilling on the New York tourism industry, and his work may assist in attempting to estimate impacts. He points out that tourism brings many non-monetary benefits to the region and its communities, and its amenities improve the quality of life for residents. He states, "Restaurants, shops, parks and outdoor recreation areas, campgrounds, wineries, festivals, museums and other related amenities are beneficial to local residents as well as visitors. These amenities also make a region more attractive for economic investment; they are some of the crucial resources that allow an area to attract economically mobile populations." He questions whether drilling will permanently damage the "brand" of the region as a pristine and picturesque destination. Brand image may also be affected for agricultural products from shale areas. In an open letter on the subject of shale gas development, the president of the Park Slope Food Coop, a very large food coop in Brooklyn, NY, stated, “I guarantee that our members will not want the fruits and veggies that come from farms in an industrial area” [44]. The use of surveys and focus groups may help to estimate the extent of the impact of “brand” image on customers and the overall impact on some of the impacted industries. Probability or risk models, based on the likelihood of contamination, may also be employed. In the case of the impact on hunting and fishing, volume decreases can be estimated using surveys of businesses and customers together with official state data on game animal harvests and creel surveys in areas already experiencing shale gas development. The impact on outdoor recreation and related facilities can be estimated through surveys, attendance records at major facilities, and the loss to businesses that cater to such customers.

Additional costs that should be estimated are the costs to communities associated with increased demand for community social services, such as police and fire departments, first responders, and local hospitals. Such cost increases resulting from gas drilling have taken place in the Rocky Mountains [45, 46], and research from Pennsylvania shows that many municipalities have experienced increased costs [47]. As the shale gas industry imports labor from other states, transient workers will exert additional demand on community services and further upward pressure on costs.

There will be costs associated with traffic congestion and road damage. The heavy truck traffic required for shale gas development is known to cause air quality issues and significant road damage. It was recently reported that the Texas Department of Transportation told industry representatives and elected officials that “repairing roads damaged by drilling activity to bring them up to standard would ‘conservatively’ cost $1 billion for farm-to-market roads and another $1 billion for local roads. And that doesn’t include the costs of maintaining interstate and state highways” [48]. The New York State Department of Transportation made a preliminary statement that “the impacts of Marcellus Shale gas development on State transportation financing needs is likely to be profound. . . . The incremental costs to mitigate Marcellus impacts for the State range from $90 million to $156 million per year. The estimate for costs for local roads and bridges range from $121 million to $222 million per year, some of which may well flow from the State Transportation Budget” [49].

The impact on property values is uncertain and has been inadequately addressed in the literature. On the one hand, increased property valuations of large tracts may be expected due to potential income from gas drilling, and an influx of transient workers will probably increase the demand for and value of rental properties. The net impact on property values, however, is uncertain. Shale gas drilling is taking place in homeowners’ backyards, and such industrial activity and the presence of hazardous materials are in many cases in violation of residential mortgage conditions [50]. Boxall, Chan, and McMillan [51] studied the impact of oil and gas drilling on residential property values in

Alberta, Canada, and found a negative relationship. The authors note that three industry-funded studies did not find a negative relationship between gas drilling and residential property values [52-54]. Again, while the impact on property values is difficult to estimate, there is relevant literature. For example, Taylor, Phaneuf, and Liu [55] used an empirical model to identify the direct impact of environmental contamination on residential housing prices separate from land use externalities. Muehlenbachs, Spiller, and Timmins [56] demonstrated that the risk of groundwater contamination from natural gas extraction leads to "a large and significant reduction in house prices." They further found that "these reductions offset any gains to the owners of groundwater-dependent properties from lease payments or improved local economic conditions, and may even lead to a net drop in prices. . . . To the extent that the net effect of drilling on groundwater-dependent houses might even be negative, we could see an increase in the likelihood of foreclosure in areas experiencing rapid growth of hydraulic fracturing."

Recent reports indicate that obtaining insurance is likely to become increasingly difficult, if not impossible, for properties that may be impacted by shale gas drilling [57]. This will negatively impact property values, as residential mortgages require the property owner to carry homeowner's insurance. A representative of Nationwide Insurance recently stated in email correspondence, "From an underwriting standpoint, we do not have a comfort level with the unique risks associated with the fracking process to provide coverage at a reasonable price" [58]. If available in the future, the cost of obtaining such insurance to protect against the substantial risks inherent in shale gas drilling using hydraulic fracturing techniques may become prohibitively high. This is another example of a cost that is omitted in the research to date. Data on trends in housing sales and prices in existing shale regions should be analyzed in detail to help identify the impact on property values.

Potential public health costs should be reflected in a thorough economic assessment. Multiple researchers have discussed potential negative health impacts that may result from water and air contamination. Various chemicals used in hydraulic fracturing include carcinogens and endocrine disruptors, which are related to serious diseases and birth defects, both involving significant costs. Bamberger and Oswald [59], Schmidt [60], Weinhold [61], and McKenzie, Witter, Newman, and Adgate [62] have investigated health impacts. In the case of humans, such costs can be estimated by measuring health services costs related to specific diseases and the loss of life and decreases in life expectancy. In the case of domestic and farm animals, values may be assigned based on market prices. All these health costs should be estimated using probabilities based on the likelihood of contamination by the various pathways.

An opportunity cost that should be factored into the analysis is the foregone economic development in areas where networks of gas pipelines are constructed.

As buildings cannot be placed on or adjacent to pipelines, shale gas development may cause future construction and economic development to be significantly curtailed [63]. This foregone regional development and the possibility of earthquake damage caused by disposing wastewater into deep injection wells [64] are uncertain costs that may be impossible to measure, but they may become enormous costs to communities in the long-run. Dutzik, Ridlington, and Rumpler [65] have outlined many of the economic costs, made a few suggestions regarding estimation of some of the costs, and shown that communities and states will bear many of the costs.

All potential benefits and costs of shale gas development should be considered during the decision-making process. Some questions that policymakers should ponder, in addition to the basic question of whether there will be net economic benefits to states and communities, are the following: (1) Are the potential benefits to the nation in the form of balance of payments gains from shale gas exports worth the risks to the environment, public health, and local economies? (2) Is the continued development of fossil fuels and their impact on climate change sensible in light of the uncertainty regarding the impacts on public health and state and local economies? One cannot answer such questions until a comprehensive analysis of net economic impacts has been completed. One way to view the net impacts and the many tradeoffs is to think of the benefits and costs to a region or a state as assets and liabilities in the form of a balance sheet for the region. As an example, Figure 1 presents such a balance sheet for New York State.

In conclusion, there are many uncertainties regarding the net benefits of shale gas development on state and local economies. There are sufficient independent research findings on extractive industry impacts to question the claims commonly propounded by the industry, and repeated by the press, that shale gas extraction will bring prosperity to local communities. The preponderance of independent research indicates that long-term prosperity for local communities is unlikely, but far more research is required in order to make a definitive conclusion. Policymakers should insist on unbiased, comprehensive economic assessments of shale gas development for each state and community that may be impacted.

AUTHOR'S BIOGRAPHY

JANNETTE M. BARTH, Ph.D., is founder and managing director of Pepacton Institute LLC, a research organization, and president of JM Barth & Associates, Inc., an economic consulting firm. She has been conducting economic analyses and developing economic models for more than 35 years. Much of her work has involved local and regional economic impacts. In recent years, her research has focused on economic impacts of shale gas development. Write her at this address: jm.barth@mac.com

A Balance Sheet for New York State: What is New York State's Net Equity from Shale Gas Development?

➤ Assets*

Tax Revenue:
- Direct from the gas industry based on future legislation
- Increased income tax based on
  - Royalty income to leaseholders
  - Lease income to landowners

Stimulation of industries based on byproducts of natural gas

Climate benefits from decreases in green house gases from burning shale gas

Indirect benefit to NYS from improved Balance of Payments assuming substantial shale gas exports

Short-term job gains in the gas industry and related industries

Increased spending by leaseholders in New York State

Lower cost of energy as long as it lasts

TOTAL ASSETS ???

*These are not necessarily comprehensive lists of assets and liabilities. They serve only as examples. Note that where an asset or liability is a future stream of income or expense, discounted present value should be used.

➤ Liabilities*

Tax Revenue Loss:
- Income tax losses by leaseholders who vacate properties and relocate out-of-state
- Income tax losses caused by decreases in tourism and other industries negatively affected by drilling
- Property tax losses caused by negative impact of drilling on property values and financing

Decreased spending by leaseholders if they move out of state, or buy second homes out of state

Human health costs associated with:
- Water contamination from frack fluids and wastewater
- Air pollution from compressors, leaks, gas released at well-sites

Costs due to impacts on animals (domestic, agricultural and game) of water, land and air contamination

Climate costs associated with increases in greenhouse gases from methane leaks and venting

Costs associated with declining quality of life due to the creation of an industrial landscape

Costs associated with declines in tourism industry

Costs associated with declines in organic farming and other agriculture and food manufacturing

Costs associated with declines in outdoor recreation

Costs associated with increased air pollution from increased truck traffic

Costs associated with declines in fisheries and trout fishing industry

Infrastructure costs due to use of and damage to roads and bridges from increased truck traffic

Costs due to declines in numbers of retirees and retirement housing market

Costs due to declines in numbers of second home owners and second home market

Costs due to crowding out (loss of jobs to existing businesses and governments)

Costs to communities due to increased demand for police, fire and first responder services

Social costs associated with the gas drilling industry

Costs to the mortgage industry and housing market, and related declines in property values and property tax revenue

Costs associated with increased homelessness

Costs associated with the postponement of investment in renewables

Opportunity costs due to the prevention of future building and economic development

Costs associated with a long-term bust, characteristic of extractive industries

TOTAL LIABILITIES ???

NET EQUITY ???

Is the **Discounted Present Value of Total Assets** minus the **Discounted Present Value of Total Liabilities** a positive value?

This question cannot be answered until a comprehensive risk assessment and economic analysis has been conducted.

Figure 1. A snapshot of one state's net impacts and tradeoffs, formatted as a balance sheet.

NOTES

QA: Please supply authors' initial

1. T. Considine et al., *An Emerging Giant: Prospects and Economic Impacts of Developing the Marcellus Shale Natural Gas Play,* 2009, study commissioned by the Marcellus Shale Coalition, http://alleghenyconference.org/PDFs/PELMisc/PSUStudyMarcellusShale072409.PDF (accessed June 2, 2012).
2. A. R. Thomas et al., *An Analysis of the Economic Potential for Shale Formations in Ohio* (study commissioned by the Ohio Shale Coalition), http://ohshalecoalition.com/study/study.pdf (accessed July 30, 2012).
3. ?? Higginbotham et al., "The Economic Impact of the Natural Gas Industry and the Marcellus Shale Development in West Virginia in 2009" (study funded by the West Virginia Oil and Natural Gas Association), December 2010, http://ohshalecoalition.com/study/study.pdf (accessed July 30, 2012).
4. T. Considine et al., *The Pennsylvania Marcellus Natural Gas Industry: Status, Economic Impacts and Future Potential* (study commissioned by the Marcellus Shale Coalition), 2011.
5. The Public Policy Institute of New York State, Inc., *Drilling for Jobs: What the Marcellus Shale Could Mean for New York*, July 2011.
6. T. Considine et al. (2011), "The Economic Opportunities of Shale Energy Development," Center for Energy Policy and the Environment, The Manhattan Institute, May 2011.
7. T. Kinnaman, "The Economic Impact of Shale Gas Extraction: A Review of Existing Studies," *Ecological Economics* 70 (2011): 1243-1249, doi: 10.1016/j.2011.02.005.
8. Mason Inman, "Estimates Clash for How Much Natural Gas in the United States," *National Geographic Daily News,* February 29, 2012, http://news.nationalgeographic.com/news/energy/2012/03/120301-natural-gas-reserves-united-states (accessed July 30, 2012).
9. U.S. Department of Commerce, "Regional Multipliers, A User Handbook for the Regional Input-Output Modeling System (RIMS!!)," March 1997.
10. M. K. Yucel and J. Thies, "Oil and Gas Rises Again in a Diversified Texas," *Southwest Economy* (a publication of Dallas Fed), First Quarter 2011, http://dallasfed.org/research/swe/2011/swe1101g.cfm (accessed August 28, 2012).
11. W. R. Freudenburg and L. J. Wilson, "Mining the Data: Analyzing the Economic Implications of Mining for Nonmetropolitan Regions," *Sociological Inquiry* 72 (4) (2002): 549-575.
12. R. J. Hustedde, R. Shaffer, and G. Pulver, "Community Economic Analysis: A How to Manual," December 1993, http://www.epa.gov/greenkit/pdfs/howto.pdf (accessed June 7, 2012).
13. Wassily Leontief, *Input-Output Economics* (New York: Oxford University Press, 1986).
14. Wassily Leontief, "Structure of the World Economy—Outline of a Simple Input-Output Formulation," Nobel Memorial Lecture, December 11, 1973.
15. W. Leontief, "Environmental Repercussions and the Economic Structure: An Input-Output Approach," *The Review of Economics and Statistics* 52 (3) (1970): 262-271.
16. T. Wiedmann et al., "Examining the Global Environmental Impact of Regional Consumption Activities – Part 2: Review of Input-Output Models for the Assessment of Environmental Impacts Embodied in Trade," *Ecological Economics* 61 (2007): 15-26, doi: 10.1016/j.ecolecon.2006.12.003.

17. R. Bess and Z. O. Ambargis, "Input-Output Models for Impact Analysis: Suggestions for Practitioners Using RIMS II Multipliers," 50th Southern Regional Science Association Conference, New Orleans, Louisiana, March 23-27, 2011.
18. W. F. Lazarus, D. E. Platas, and G. W. Morse, "IMPLAN's Weakest Link: Production Functions or Regional Purchase Coefficients?" *The Journal of Regional Analysis & Policy* 32 (1) (2002): 33-48.
19. M. Lloyd, *Natural Gas Drilling: Questions Residents and Local Leaders Should be Asking* (The Ohio State University, 2012), http://ohioline.osu.edu/cd-fact/pdf/1282.pdf (accessed August 28, 2012).
20. MIG, Inc. (Hudson, Wisconsin), The IMPLAN System.
21. U.S. Department of Commerce, Bureau of Economic Analysis, RIMS II.
22. J. D. Sachs and A. M. Warner, "The Curse of Natural Resources," *European Economic Review* 45 (2001): 827:838, doi: 10.1016/S0014-292(01)00125-8.
23. J. D. Sachs and A. M. Warner, "Natural Resource Abundance and Economic Growth," National Bureau of Economic Research Working Paper 5398 (1995).
24. P. Stevens, "Resource Impact – Curse or Blessing? A Literature Survey," University of Dundee, 2003.
25. IHS Global Insight, "The Economic and Employment Contributions of Shale Gas in the United States," December 2011.
26. IHS Global Insight, "America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy," October 2012.
27. E. Papyrakis and R. Gerlagh, "Resource Abundance and Economic Growth in the U.S.," *European Economic Review* 51 (4) (2007): 1011-1039, doi: 10.1016/j.euroecorev.2006.04.001.
28. A. James and D. Aadland, "The Curse of Natural Resources: An Empirical Investigation of U.S. Counties," *Resource and Energy Economics* 33 (2) (2011): 440-453, doi: 10.1016/j.reseneeco.2010.05.006.
29. Headwaters Economics, "Fossil Fuel Extraction as a County Economic Development Strategy: Are Energy-Focusing Counties Benefiting?" *Energy and the West Series,* Bozeman, MT (Sept 2008 – revised 7/11/09), http://www.headwaterseconomics.org/energy (accessed March 10, 2010).
30. J. Peach and C. M. Starbuck, "Oil and Gas Production and Economic Growth in New Mexico," *Journal of Economic Issues* 45 (2) (2011): 511-526, doi: 10.2753/JEI0021-3624450228.

QA: Please supply authors' initial

31. ?? Putz, A. Finken, and G. S. Goreham, *Sustainability in Natural Resource-Dependent Regions that Experienced Boom-Bust Recovery Cycles: Lessons Learned from a Review of the Literature*, North Dakota State University, July 2011, http://www.ag.ndsu.edu/ccv/documents/sustainability-report (accessed August 28, 2012).
32. J. G. Weber, "The Effects of a Natural Gas Boom on Employment and Income in Colorado, Texas, and Wyoming," *Energy Economics* 34 (2012): 1580-1588, doi: 10.1016/j.eneco.2011.11.013.
33. D. Black, T. McKinnish, and S. Sanders, "The Economic Impact of the Coal Boom and Bust," *The Economic Journal* 115 (503) (2005): 449-476, doi: 10.1111/j.1468-0297.2005.00996.x.
34. R. Seydlitz and S. Laska, U.S. Department of Interior, *Social and Economic Impacts of Petroleum 'Boom and Bust' Cycles* (OCS Study MMS 93-0007), 1994.

35. S. Christopherson and N. Rightor, *How Should We Think about the Economic Consequences of Shale Gas Drilling?* Working Paper Series, A Comprehensive Economic Impact Analysis of Natural Gas Extraction in the Marcellus Shale, May 2011.
36. L. J. Wilson, “Riding the Resource Roller Coaster,” *Rural Sociology* 69 (2) (2004): 261-281.
37. Railroad Commission of Texas, *Barnett Shale Information*, http://www.rrc.state.tx.us/barnettshale/index.php (accessed April 30, 2012).
38. U.S. Census Bureau, Small Area Estimates Branch, “Table 1: 2010 Poverty and Median Income Estimates – Counties,” Release date November 2011; and “Table 1: 2003 Poverty and Median Income Estimates – Counties,” Release date October 2006.
39. U.S. Department of Labor, Bureau of Labor Statistics, *Labor Force Data by County (not seasonally adjusted),* www.bls.gov/lau (accessed April 30, 2012).
40. G. J. Kauffman, *Socioeconomic Value of the Delaware River Basin in Delaware, New Jersey, New York and Pennsylvania: The Delaware River Basin, an Economic Engine for Over 400 Years*, University of Delaware, Water Resources Agency, May 25, 2011.
41. A. Rumbach, *Natural Gas Drilling in the Marcellus Shale: Potential Impacts on the Tourism Economy of the Southern Tier*, Prepared for Southern Tier Central Regional Planning and Development Board, 2011.
42. Outdoor Industry Association, *The Outdoor Recreation Economy*, 2012.
43. S. C. Deller et al., “The Role of Amenities and Quality of Life in Rural Economic Growth,” *American Journal of Agricultural Economics* 83 (2) (2001): 352-365, doi: 10.1111/0002-9092.00161.
44. J. Holtz, “Open Letter to Members of the New York State Senate, Members of the New York State Assembly, Governor Patterson and Governor-Elect Cuomo,” December 2010.
45. J. Morrison, Presentation by Powder River Basin Resource Council, November 2010, http://www.earthworksaction.org/2010summit/Panel2_JillMorrison_PowderRiverBasinResourceCouncil.pdf (accessed March 3, 2012).
46. M. Haefele and P. Morton, “The Influence of the Pace and Scale of Energy Development on Communities: Lessons from the Natural Gas Drilling Boom in the Rocky Mountains,” Western Economics Forum, Fall 2009.
47. T. W. Kelsey and M. W. Ward, *Natural Gas Drilling Effects on Municipal Governments Throughout Pennsylvania’s Marcellus Shale Region, 2010*, Penn State Cooperative Extension, 2011.
48. Barry Schlachter, “Drilling Trucks have Caused an Estimated $2 Billion in Damage to Texas Roads,” *Star-Telegram*, July 2, 2012. http://www.star-telegram.com/2012/07/02/4075195/drilling-trucks-have-caused-an.html#storylink=cpy (accessed July 2, 2012).
49. New York State Department of Transportation, “Transportation Impacts of Potential Marcellus Shale Gas Development,” Draft Discussion Paper, June 2011.
50. E. N. Radow, “Homeowners and Gas Drilling Leases: Boon or Bust?” *New York State Bar Association Journal* 83 (9) (2011): 10-21.
51. P. C. Boxall, W. H. Chan, and M. L. McMillan, “The Impact of Oil and Natural Gas Facilities on Rural Residential Property Values: A Spatial Hedonic Analysis,” *Resource and Energy Economics* 27 (3) (2005): 248-269, doi: 10.1016/j.reseneeco.2004.11.003.

52. Deloitte Haskins & Sells, *The Effect of Sour Gas Facilities on Property Values in the Crossfield, Okotoks and Pincher Creek Regions of Alberta*, Report prepared for Shell Canada, 1988.
53. J. Lore and Associates, Ltd., *The Effect of Sour Gas Facilities on Land Values in West Central Alberta*, Report prepared for Shell Canada, 1988.
54. Serecon Valuation and Agricultural Consulting, Inc., *Impact of Sour Oil/Gas Facilities on Property Values*, Report prepared for Shell Canada, 1997.
55. L. O. Taylor, D. J. Phaneuf, and X. Liu, *Disentangling the Impacts of Environmental Contamination from Locally Undesirable Land Uses*, January 2012, http://www.ncsu.edu/cenrep/research/documents/Tayloretal.pdf (accessed September 12, 2012).
56. L. Muehlenbachs, E. Spiller, and C. Timmins, *Shale Gas Development and Property Values: Differences across Drinking Water Sources*, Discussion Paper, Resources for the Future, July 2012.
57. "Nationwide Insurance: No Fracking Way," *The River Reporter*, July 11, 2012, http://www.riverreporteronline.com/news/14/2012/07/11/nationwide-insurance-no-fracking-way (accessed July 12, 2012).
58. Nancy Smelter (Communication Consultant, Nationwide Insurance), personal communication, July 2012.
59. M. Bamberger and R. E. Oswald, "Impacts of Gas Drilling on Human and Animal Health," *New Solutions* 22 (1) (2012): 51-77, doi: http://dx.doi.org/10.2190/NS.22.1.e.
60. C. W. Schmidt, "Blind Rush? Shale Gas Boom Proceeds Amid Human Health Questions," *Environmental Health Perspectives* 119 (8) (2011): 348-353.
61. B. Weinhold, "The Future of Fracking," *Environmental Health Perspectives* 120 (7) (2012): 272-279.
62. L. M. McKenzie et al., "Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources," *Science of the Total Environment* 424 (2012): 77-87.
63. U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, *Building Safe Communities: Pipeline Risk and its Application to Local Development Decisions*, October 2010.
64. C. Nicholson and R. L. Wesson, *Earthquake Hazard Associated With Deep Well Injection – A Report to the U.S. Environmental Protection Agency*, U.S. Geological Survey Bulletin 1951 (1990).
65. T. Dutzik, E. Ridlington, and J. Rumpler, *The Costs of Fracking: The Price Tag of Dirty Drilling's Environmental Damage*, Penn Environment Research & Policy Center, Fall 2012.

Direct reprint requests to:

Jannette M. Barth, Ph.D.
Pepacton Institute LLC
P.O. Box 127
Croton on Hudson, NY 10520
e-mail: jm.barth@mac.com

NEW SOLUTIONS, Vol. 23(1) 103-116, 2013

Features

HISTORICAL ANALYSIS OF OIL AND GAS WELL PLUGGING IN NEW YORK: IS THE REGLATORY SYSTEM WORKING?

RONALD E. BISHOP

ABSTRACT

The aim of this work was to evaluate New York State's regulatory program for plugging inactive oil and gas wells. Analysis of reports from the Division of Mineral Resources, Department of Environmental Conservation, reveals that three-fourths of the state's abandoned oil and gas wells were never plugged. Inadequate enforcement efforts have resulted in steady increases of unplugged oil and gas wells abandoned since 1992. Further, no program exists or is proposed to monitor abandoned wells which were plugged. These results strongly suggest that comprehensive reform and increased agency resources would be required to effectively regulate conventional oil and gas development in New York. Industrial expansion into shale oil and gas development should be postponed to avoid adding stress to an already compromised regulatory system.

Keywords: oil, gas, plugging, regulatory, New York, fracking

New York's oil and gas industry is just nine years from its bicentennial, since the pilot project, a natural gas well near Fredonia, was drilled in 1821. Now, there is a dedicated and sophisticated Bureau of Oil and Gas Permitting and Management (BOGPM), established as a unit of the Division of Mineral

doi: http://dx.doi.org/10.2190/NS.23.1.g
http://baywood.com

Resources (DMN) within the state Department of Environmental Conservation (DEC) in 1970. State guidance documents and regulations have undergone multiple updates, including those newly proposed in 2011 to accommodate concerns peculiar to the extraction of oil and gas from unconventional reservoirs such as shale. But before state regulators adopt new rules to permit expansion of the industry into shale oil and gas development, we should evaluate how the regulatory system has managed petroleum development so far. Few aspects of the regulatory system are as cogently diagnostic as New York's record on plugging abandoned oil and gas wells.

BACKGROUND

Abandoned Wells Issue

With great attention paid these days to proper oil and gas well construction, appropriate control of chemicals and wastes, and other production issues, post-production plugging and cleanup has received relatively little notice. But as production from the first oil and gas wells declined, this was recognized as an important issue. New York became the first state to require the plugging of abandoned wells in 1879 [1]. No particular state entity existed to monitor compliance or enforce the plugging law, but an 1882 amendment to it offered half of any fines collected to informants who reported violations [1]. From that time forward, regulating this aspect of the petroleum industry has posed a unique challenge.

Scope of the Problem

The number of abandoned oil and gas wells in New York State is not definitely known. The Historic Well Survey of 1988, included in that year's DMN annual report, established a baseline of 42,322 oil and gas wells of unknown status [2], while the Plugged Wells Estimate of 1993, included in that year's annual report, identified 13,070 wells which were known to have been plugged [3]. For their external review in 1994 by the Interstate Oil and Gas Compact Commission, BOGPM staff estimated that 61,000 wells had been developed historically, but the agency had no records on 30,000 of them [4]. Of the wells on record, 12,857 were active and about 18,000 were known to not be plugged. Therefore, of 48,000 abandoned oil and gas wells total, 13,000 were plugged and approximately 35,000 were not plugged as of 1994 [4]. It should be noted that this report represented an improvement in the BOGPM's accounting for oil and gas wells since the Historic Wells Survey of 1988, reducing the approximate number of "unknown status" wells from 42,000 to 35,000 over that six-year period.

Well Accounting Issues

Accounting for abandoned oil and gas wells is complicated by the fact that New York's BOGPM maintains more than one system for recording them. For example, the 2005 DMN annual report reported on (a) inactive oil and gas wells, (b) known, unreported wells and (c) "other, known orphan wells" [5], which summed to fewer than 9,000 wells, far short of the 35,000 unplugged, abandoned wells noted above. Annual reports from 2002 onward suggest that the locations of fully half of the state's orphan abandoned oil and gas wells are unknown, and from the 2009 annual report, "Most of the [abandoned] wells date from before New York established a regulatory program" [6]. Thus it appears that state regulators have given up on old wells for which location or operational data are missing; for clarity, I will call them "forgotten." Abandoned oil and gas wells in known locations, but for which the BOGPM lacks current ownership data, dominate the Priority Plugging List [7]. Although some of these wells have been plugged with the use of agency or external funds, most have not. Therefore, I refer to this group as "generally ignored." The primary focus of the BOGPM, then, is on those inactive wells for which all information is actionable; I call them "standing inventory." The boundaries that delimit these groups are not always clear, but the fresh discovery of a "forgotten" well typically results in its transfer to the "generally ignored" category, and the loss of ownership information may move a well from "standing inventory" to "generally ignored." Plugging oil or gas wells results in their removal from the state's accounting, although they are still abandoned structures; one might call them "forsaken."

Practical Significance

Why would abandoned wells matter to anyone? As if to answer this question, DMN annual reports from 2002 and 2003 presented case studies with photographs of individual abandoned oil and gas wells [8, 9]. One case involved an old gas well that discharged brine at a rate of five gallons per minute into a wetland near Rome, killing over an acre of vegetation [8]. Another involved the entire village of Rush, on the border between Ontario and Schuyler Counties, where two dozen unplugged abandoned wells were responsible for widespread emanation of gas from the soil, so that methane accumulated to explosive levels in some structures [8]. Plugging or excavation of abandoned wells on school properties in Allegany and Wyoming Counties cost those school districts thousands of dollars [8]. Further, abandoned wells have been found leaking oil into creeks and wetlands in Steuben and Allegany Counties, and into residential ponds and lawns in Allegany and Cattaraugus Counties [9]. These case studies provide evidence that many abandoned petroleum wells across New York leak fluids to the ground surface.

This issue is by no means limited to New York. In a 1987 report, the U.S. Environmental Protection Agency (EPA) estimated that, of about 1.2 million abandoned oil and gas wells nationwide, approximately 200,000 (17%) were portals for pollution to reach the surface [10], and in 1989 the U.S. General Accounting Office reported that the number of improperly abandoned wells was increasing [11].

Long-Term Instability

Abandoned wells leak because well casings deteriorate over time, and once-depleted rock formations repressurize with oil, gas, and brines [12–14]. Dusseault and coworkers showed that because temperature, pressure, and salt concentrations all tend to increase with depth, steel pipe and concrete degradation occurs most rapidly in the deepest segments of abandoned wells, where the damage is most difficult to detect. They estimated that essentially all unmaintained well bores lose integrity over a 50-year time frame, and further, that deep rock structures frequently repressurize [12]. One industry study of offshore oil and gas wells determined that half of the well casings studied began to leak in just 15 years [13]. A more recent industry study of oil and gas projects in Alberta, Canada, found leaks in just over 4 percent of the wellbores, including some which were plugged before abandonment [14]. A possible explanation for the lower percentage of leaks found in the onshore wells might be that they were more actively maintained. That is, the Canadian projects were more consistently monitored for sustained casing vent flow and external gas migration, and were more aggressively re-grouted when these problems were discovered [14]. Ongoing maintenance, then, is required to keep old wellbores stable. Therefore, to be effective, the state's oil and gas regulatory program must not only ensure that abandoned wells are properly plugged, but must also periodically inspect and, when necessary, repair the plugged wells.

Economic Impact

The cost of plugging abandoned oil and gas wells varies for different situations, but two contract awards cited in DMN's 2008 annual report provide some context [15]. One contract was for $190,000 to plug 45 wells in Allegany County, an average cost of $4,222 per well, and the other was for $150,000 to plug 25 wells in Cattaraugus County, or $6,000 per well. At about $5,000 per abandoned well, plugging the 4,722 wells on the BOGPM's current priority plugging list [7] would cost $23.6 million. And on this basis, finding and plugging the 35,000 unplugged, abandoned wells which were estimated in 1994 would cost at least $175 million.

In the agency's defense, the DMN began to amass an "Oil and Gas Fund" in 1981 to pay for the plugging of priority oil and gas wells, but in 1993 the Legislature appropriated $1 million of that fund for general expenditures, and changed state law to prevent the use of collected fines for plugging activities [4]. The DMN never accumulated that much money again; the plugging fund balance at the end of 2009 was $209,000 [6].

Difficulty of Enforcement

What is involved in enforcing compliance with the state's oil and gas plugging laws? This question is nuanced, according to Louis W. Allstadt, a former senior oil and gas company executive [16]:

> Very little attention is paid to the end of the life of an oil or gas well. I think you will find that it is rare for the larger companies to plug and abandon their older wells. Rather, at some point, a smaller company with lower overheads and less expensive operating costs will offer to buy the old wells at a price that gives the original company a better return than continued operations. The original company uses the cash to finance new investments. The buying company operates with lower costs because they spend less on maintenance and safety items and they have fewer well-qualified people to pay. The chain may end there or continue through smaller and ever lower cost operators who do no preventive maintenance at all, do the bare minimum of repairs to keep the well going and eventually walk away, maybe after plugging the hole as cheaply as possible and maybe not plugging at all.
>
> In conventional fields these selling/buying cycles might start when the field is 20-30 years old and run for another 20–30 years. By the time these wells are abandoned, the casings have been subjected to corrosive fluids for many years. When it costs too much to repair versus what might be produced, the well is abandoned. Whether it is plugged before it is abandoned depends on the final operator. In tight shale this could all take place over a much shorter time period and the abandoned wells could increase quickly [16].

Hence, inspecting low-production oil and gas projects and tracking well ownership through multiple transfers pose particular challenges to state regulators, and may help to explain how many owners have avoided plugging their abandoned wells. This problem would be exacerbated by shorter-lived projects, and indeed, industry analysts have presented evidence that tight shale gas wells decline much more quickly than oil and gas wells in conventional deposits, with shale gas projects exhibiting half-lives of about eight years [17, 18].

Therefore, with state regulators proposing to permit dramatic expansion of the oil and gas industry into extraction from shale, the principal aim of this study is to answer the question: "How successful has New York's oil and gas regulatory program been, especially since the 1994 review, with respect to post-production plugging?"

METHODS

Data Sources

Most data for this investigation came from annual reports by the DEC's Division of Mineral Resources. Reports that were accessible from the DEC's web site included those from 1994 through 2009 [19]. Reports from 1985 through 1993 were obtained by Freedom of Information Law (FOIL) request from the DEC. Other data came from the 1994 New York State Review (STRONGER review) [4] and the New York State priority plugging list [7]. These documents constitute the entire body of publicly available records on this topic in the State of New York.

Categories of Inactive Wells

As stated in the introduction, the primary focus of the BOGPM appears to be the "standing inventory" of oil and gas wells declining to zero commercial production, for which complete location and owner information is currently available. That subset of inactive wells represents all that are detailed in the DMN annual reports, and forms the main substance of the Results section, below.

Influence of Shut-in Wells

The results below are expressed in terms of oil and gas wells that had been reported as "inactive," defined as having zero commercial production. An oil or gas well may be considered inactive either because it is depleted or because it is shut in. From 1966 to 1990, no distinction was made in DMN annual reports between depleted and shut-in wells. Since 1991, shut-in wells have been consistently identified as those that may be capable of producing oil or gas, but are not connected to pipelines or for some other reason are temporarily sealed to prevent product loss. Shut-in wells are not required to be plugged, even though they are inactive. Therefore, a summary of shut-in application approvals by year was requested from the BOGPM. The agency claimed to have no responsive records, but informed me that "269 shut-in applications are currently approved" [20]. Hence, the number of inactive oil and gas wells in each year's standing inventory may include some which were not required to be plugged at the time, but no data are available to resolve that question for individual years.

Influence of "Other" Plugged Wells

In DMN annual reports, data for well plugging included oil, gas, and "other regulated wells." The other regulated wells included salt solution and stratigraphic geothermal wells, and their numbers were expressly stated in only seven of the reports, from 2003 through 2009. These "other" plugged wells ranged from 15 to 55 per year, with mean and median averages of 28.3 and 24, respectively. To maintain consistency of data handling across the entire 39 years reported, the more conservative median average of 24 wells was subtracted from the raw "plugged" data for each year from 1971 through 1992, and the actual number of "other" plugged wells was subtracted from the raw "plugged" data prior to plotting and analysis. This modest correction is supported by data from the salt solution mining section of the DMN 1995 annual report, which indicated that 167 wells were plugged in the seven-year period from 1988 through 1994 (average of 24 wells per year) for a single salt solution project (Tully Valley) [21].

RESULTS

The yearly data for inactive and plugged wells are summarized in Table 1, and a plot of inactive oil and gas wells and corrected plugged wells by year shows the results of Table 1 graphically (Figure 1).

Trend Analysis

The results shown in Figure 1 indicate that New York has maintained a significant standing inventory of inactive oil and gas wells, a fraction of which have been plugged each year. Over time, this standing inventory tended to increase, except for the period 1990-1992. That period, when the inventory decreased, coincided with Pennzoil's closing out of its Chipmunk Field operations in Cattaraugus County; it unilaterally plugged 629 wells in 1990, contributing to a record 937 wells plugged that year [22]. The inventory then increased steadily from 1992 through 2009, approximately doubling over that 17-year period. Hence, for most of their recorded history, New York regulators' efforts to enforce plugging laws have not kept pace with the number of oil and gas wells that needed to be plugged.

To evaluate what would be required for the BOGPM to prevent an increase in unplugged wells, we need to know how many oil and gas wells become newly inactive each year. When I requested this information, the agency responded that its records are not structured to provide it: one would have to simultaneously monitor every well in the database and observe when each one was first reported to have zero production [20]. Nevertheless, the annual decline of oil and gas wells to zero production can be deduced from the trends shown in Figure 1.

A stable standing inventory would indicate that plugging rates matched the entry of inactive wells into the DMN database. Plugging rates would have to be lower than the entry of inactive wells into the database for the inventory to increase, and conversely, plugging rates would have to exceed the entry of inactive wells into the database for the inventory of unplugged wells to decrease. Average annual values derived from these trend parameters are shown in Table 2.

Table 1. Annual Plugging Data for Abandoned Oil and Gas Wells in New York

Year	Inactive[a]	Number plugged (raw)	Correction	Number plugged (corrected)
1996[b]	4500	N.A.	N.A.	N.A.
1967	4600	N.A.	N.A.	N.A.
1968	4450	N.A.	N.A.	N.A.
1969	1009	N.A.	N.A.	N.A.
1970	1350	N.A.	N.A.	N.A.
1971[c]	1567	418	–24	394
1972	1619	573	–24	549
1973	1484	544	–24	520
1974	1862	622	–24	598
1975	1883	553	–24	529
1976[d]	1825	442	–24	418
1977	1820	455	–24	431
1978	1864	352	–24	328
1979	2020	117	–24	93
1980	1900	119	–24	95
1981	2128	184	–24	160
1982	2304	262	–24	238
1983	2431	90	–24	66
1984	2296	182	–24	158
1985	2519	269	–24	245
1986	2468	471	–24	447
1987	2543	417	–24	393
1988[e]	2348	322	–24	298
1989	2620	260	–24	236
1990[f]	2707	961	–24	937
1991[g]	2069	376	–24	352
1992	1502	244	–24	220
1993[h]	1642	263	–24	239
1994[i]	1887	248	–24	224

Table 1. (Cont'd.)

Year	Inactive[a]	Number plugged (raw)	Correction	Number plugged (corrected)
1995	1784	219	–24	195
1996[j]	2215	233	–24	209
1997[k]	1974	187	–24	163
1998	2169	169	–24	145
1999[l]	1748	138	–24	114
2000[m]	2190	131	–24	107
2001[n]	2259	79	–24	55
2002[o]	2272	146	–24	122
2003[p]	2379	142	–15	127
2004	2526	145	–39	106
2005[q]	2658	150	–55	95
2006[r]	2871	213	–22	191
2007[s]	2460	192	–31	161
2008	3071	221	–12	209
2009[t]	3043	240	–24	216

[a] Oil and gas wells reported to have zero commercial production.
[b] Earliest official records.
[c] Earliest plugging records.
[d] Earliest reporting of "shut-in" gas wells.
[e] Estimated 42,32 wells of unknown status.
[f] Record high number of wells plugged.
[g] "Shut-in" wells first referred to as "inactive."
[h] Total plugged wells reported as 13,070.
[i] Total unplugged wells estimated at 35,000 [4].
[j] 96 newly discovered abandoned wells.
[k] 200 newly discovered abandoned wells.
[l] 270 newly discovered abandoned wells.
[m] 220 newly discovered abandoned wells.
[n] 150 newly discovered abandoned wells.
[o] First mention of priority plugging list.
[p] First explicit reporting of "other" plugged wells.
[q] 2117 Known wells unreported.
[r] 1103 Known wells unreported.
[s] 822 Known wells unreported.
[t] Last available annual report.

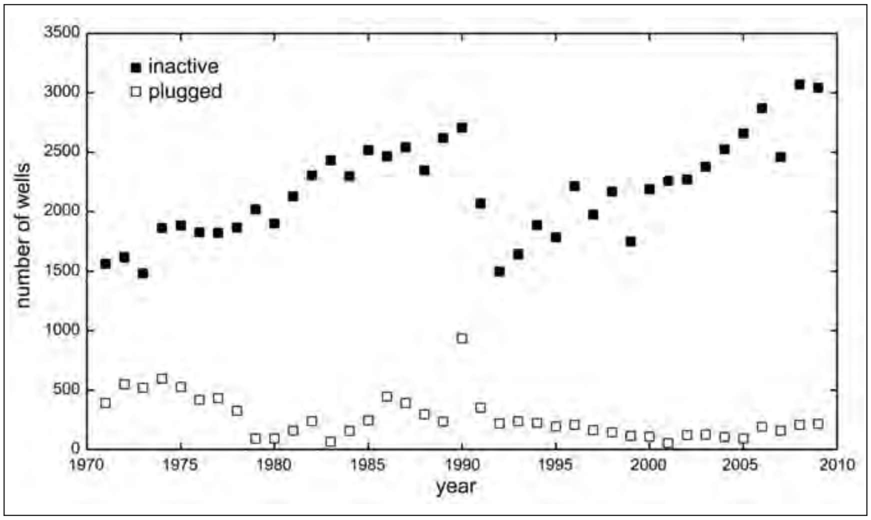


Figure 1. Annual reports of standing inventory of inactive wells (filled squares) and plugged inactive wells (open squares) by year reported, 1971-2009. Data taken from Table 1.

Table 2. Annual Newly Inactive Oil and Gas Wells

Period	Plug rate[a]	Inventory trend	Change[b]	Newly inactive[c]
1973-1978	499/yr	Stable	0	499/yr
1979-1987	151/yr	Increasing	+92/yr	243/yr
1987-1992	444/yr	Decreasing	–208/yr	236/yr
1992-2009	161/yr	Increasing	+91/yr	252/yr

[a]Total oil and gas wells plugged/number of years in period.
[b]Increase or decrease in inventory/number of years in period.
[c]Plug rate column value ± Add/subtract column value.

The results of Table 2 indicate that since 1980, approximately 250 oil and gas wells have become newly inactive annually. Therefore, for plugging to keep pace with ongoing demand, the BOGPM would have to enforce the plugging of at least 250 wells each year. The data in Table 1 show that such an enforcement level has not been achieved since 1991.

Current Status of Abandoned Oil and Gas Wells

Summary statistics from the DMN annual reports from 2008 and 2009 indicate that 75,000 total oil and gas projects are believed to have been developed in New York, of which about 11,000 remain active [6, 15]. Using these values in conjunction with the results shown in Table 1, it is possible to estimate how many oil and gas wells have been abandoned in the state, both plugged and unplugged. The data for 1994 and 2009 are presented for comparison in Table 3.

The results shown in Table 3 indicate that, while the number of plugged oil and gas wells has grown considerably since 1994, the number of unplugged abandoned oil and gas wells has increased even more. The percentage of plugged wells, out of all the abandoned wells, has slipped from 27 percent in 1994 to 25 percent currently, leaving the state with an estimated 48,000 wells that need to be plugged. At an estimated cost of $5,000 per well, about a quarter of a billion dollars would be needed to plug all these wells, if they could be found.

CONCLUSIONS AND RECOMMENDATIONS

Since 1970, New York's Bureau of Oil and Gas Permitting and Management has failed to adequately enforce state laws that require industry operators to plug inactive oil and gas wells. As a result, three-fourths of inactive oil and gas wells remain unplugged, and the number of unplugged abandoned wells in New York continues to increase. In the last year reported, only 216 of an estimated 250 newly inactive oil and gas wells (86%) were plugged. Further, no program to monitor and maintain plugged abandoned wells exists or is proposed, in spite of evidence that plugged wells can disintegrate and leak.

Table 3. Summary of Plugged and Unplugged Abandoned Oil and Gas Wells

Year	1994[a]	2009[b]
Total projects	61,000	75,000
Active wells	12,857	10,982
Abandoned wells, plugged	13,070	15,748
Abandoned wells, unplugged	35,000	48,000
Total abandoned wells	48,000	64,000
Percentage plugged	27	25

[a]Data from STRONGER review [4] and Plugged Wells Survey [3].
[b]Data from 2009 DMN annual report [6], Plugged Wells Survey [3], and Table 1.

Therefore, the following actions are recommended:

1. Approval of permits for conventional oil and gas development projects in New York should be reduced by 15 percent immediately until industry compliance with inactive well-plugging requirements can be demonstrated for a minimum of three consecutive years.
2. Oil and gas well transfer requests should be suspended immediately, until the DMN can re-evaluate financial security and bonding levels which will ensure that all declining oil and gas wells are plugged when they reach zero commercial production.
3. The state legislature should appropriate funding for the specific purpose of inspecting and plugging every well in the BOGPM standing inventory and priority plugging list.
4. New York should establish a program to register, inspect, and maintain abandoned oil and gas wells that have been plugged.
5. The New York State Bureau of Oil and Gas Regulation, Division of Mineral Resources, Department of Environmental Conservation should invite the Interstate Oil and Gas Compact Commission to conduct an updated state review.
6. Expansion of the state's petroleum industry into extraction of oil and gas from shale should be postponed until the above actions have been carried out.

Overall, the goal should be to establish a comprehensive plan for regulatory improvement, including progress on the issue of oil and gas well plugging and abandonment in New York.

ACKNOWLEDGMENTS

The author wishes to thank Sustainable Otsego members Lou Allstadt, Anne Bishop, Nicole Dillingham, James Herman, Harry Levine, Adrian Kuzminski, and James Northrup for extremely valuable discussions.

AUTHOR'S BIOGRAPHY

RONALD E. BISHOP has a B.A. in Chemistry from Youngstown State University and a Ph.D. in Biochemistry from The West Virginia University School of Medicine. Currently a lecturer in the Department of Chemistry and Biochemistry at the State University of New York at Oneonta, he is a Chemical Hygiene Officer listed with the National Registry of Certified Chemists. A member of the New York Academy of Sciences, the Union of Concerned Scientists, and Physicians, Scientists and Engineers for Healthy Energy, he actively maintains interests in chronic diseases, environmental challenges and national security. Ron can be reached at Ron.Bishop@oneonta.edu

NOTES

1. Division of Mineral Resources, New York State Department of Environmental Conservation, *Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (GEIS)*, Chapter 4: "History of Oil, Gas and Solution Salt Production in New York State," 1992, http://www.dec.ny.gov/docs/materials_minerals_pdf/dgeisv1ch4.pdf (accessed December 3, 2012).
2. New York State Department of Environmental Resources Division of Mineral Resources, *New York State Oil, Gas and Mineral Resources, 1988*, July 1991, p. 12, http://www.dec.ny.gov/docs/materials_minerals_pdf/1988rpt.pdf (accessed December 3, 2012).
3. New York State Department of Environmental Resources, Division of Mineral Resources, *New York State Oil, Gas and Mineral Resources, 1993*, July 1996, p. 6, http://www.dec.ny.gov/docs/materials_minerals_pdf/1993rpt.pdf (accessed December 3, 2012).
4. P. Beaver et al., *New York State Review: IOGCC/EPA State Review of Oil and Gas Exploration, Production and Waste Management Regulatory Programs*, September 1994, http://67.20.79.30/sites/all/themes/stronger02/downloads/New%20York%20Initial%20Review%209-1994.pdf (accessed December 3, 2012).
5. New York State Department of Environmental Resources, Division of Mineral Resources, *New York State Oil, Gas and Mineral Resources, 2005*, July 2007, p. 19. http://www.dec.ny.gov/docs/materials_minerals_pdf/05anrpt1.pdf (accessed December 3, 2012).
6. New York State Department of Environmental Resources, Division of Mineral Resources, *New York State Oil, Gas and Mineral Resources, 2009*, July 2011, pp. 22-23, http://www.dec.ny.gov/docs/materials_minerals_pdf/09anrpt1.pdf (accessed December 3, 2012).
7. New York State Department of Environmental Conservation, "2011 Priority Plugging List," August 2011, obtained through FOIL request.
8. New York State Department of Environmental Resources, Division of Mineral Resources, *New York State Oil, Gas and Mineral Resources, 2002*, July 2004, pp. 22-24, http://www.dec.ny.gov/docs/materials_minerals_pdf/prod023.pdf (accessed December 3, 2012).
9. New York State Department of Environmental Resources, Division of Mineral Resources, *New York State Oil, Gas and Mineral Resources, 2003*, July 2005, pp. 24-26, http://www.dec.ny.gov/docs/materials_minerals_pdf/03anrpt2.pdf (accessed December 3, 2012).
10. United States Environmental Protection Agency, Office of Solid Waste and Emergency Response, *Management of Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy*, December 1987, pp. 204-205, http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=20012D4P.txt (accessed December 3, 2012).
11. United States General Accounting Office, Resources, Community and Economic Development Division, *Drinking Water Safeguards Are Not Preventing Contamination from Injected Oil and Gas Wastes*, July 1989, p. 4, http://www.gao.gov/assets/150/147952.pdf (accessed December 3, 2012).
12. M. B. Dusseault, M. N. Gray, and P. Nawrocki, "Why Oilwells Leak: Cement Behavior and Long-Term Consequences" (SPE Paper 64733), Society of Petroleum

Engineers International Oil and Gas Conference and Exhibition, Beijing, China, November 7-10, 2000; *OnePetro* (2001), www.onepetro.org.
13. C. Brufatto et al., "From Mud to Cement—Building Gas Wells," *Oilfield Review* (Schlumberger), August 2003, 62-76.
14. T. L. Watson and S. Bachu, "Evaluation of the Potential for Gas and CO_2 Leakage along Wellbores," Exploration and Production Environmental and Safety Conference, Galveston, Texas, March 5-7, 2007; *SPE Drilling & Completion* 24 (1) (March 2009): 115-126, http://dx.doi.org/10.2118/106817-PA.
15. New York State Department of Environmental Resources, Division of Mineral Resources, *New York State Oil, Gas and Mineral Resources, 2008*, July 2010, pp. 22-23, http://www.dec.ny.gov/docs/materials_minerals_pdf/08anrpt1.pdf (accessed December 3, 2012).
16. Louis W. Allstadt (Executive Vice President, Mobil Oil Corporation (retired)), personal communication, January 2012.
17. A. E. Berman and L. F. Pittinger, "U.S. Shale Gas: Lower Abundance, Higher Cost," The Oil Drum [blog], August 5, 2011, http://www.theoildrum.com/node/8212 (accessed January 4, 2012).
18. T. Cook and R. R. Charpentier, *Assembling Probabilistic Performance Parameters of Shale-Gas Wells*, U.S. Geological Survey Open File Report 2010-1138, 2010, http://pubs.usgs.gov/of/2010/1138/pdf/OF10-1138.pdf (accessed December 3, 2012).
19. New York State Department of Environmental Conservation, "New York Oil, Gas and Mineral Resources Annual Reports," http://www.dec.ny.gov/pubs/36033.html (accessed January 4, 2012).
20. Donald J. Drazan, "Re: Freedom of Information Law (FOIL) Request 12-2362," Technical Assistance Section, Bureau of Oil & Gas Permitting and Management, New York Department of Environmental Conservation, September 11, 2012.
21. New York State Department of Environmental Resources, Division of Mineral Resources, *New York State Oil, Gas and Mineral Resources, 1995*, July 1997, p. 11, http://www.dec.ny.gov/docs/materials_minerals_pdf/prod95.pdf (accessed December 3, 2012).
22. New York State Department of Environmental Resources, Division of Mineral Resources, *New York State Oil, Gas and Mineral Resources, 1990*, July 1992, p. 17, http://www.dec.ny.gov/docs/materials_minerals_pdf/1990rpt.pdf (accessed December 3, 2012).

Direct reprint requests to:

Ronald E. Bishop
Department of Chemistry and Biochemistry
State University of New York, College at Oneonta
108 Ravine Parkway
Oneonta, NY 13820
e-mail: ron.bishop@oneonta.edu

NEW SOLUTIONS, Vol. 23(1) 117-135, 2013

Features

ANALYSIS OF RESERVE PIT SLUDGE FROM UNCONVENTIONAL NATURAL GAS HYDRAULIC FRACTURING AND DRILLING OPERATIONS FOR THE PRESENCE OF TECHNOLOGICALLY ENCHANCED NATURALLY OCCURRING RADIOACTIVE MATERIAL (TENORM)

ALISA L. RICH
ERNEST C. CROSBY

ABSTRACT

Soil and water (sludge) obtained from reserve pits used in unconventional natural gas mining was analyzed for the presence of technologically enhanced naturally occurring radioactive material (TENORM). Samples were analyzed for total gamma, alpha, and beta radiation, and specific radionuclides: beryllium, potassium, scandium, cobalt, cesium, thallium, lead-210 and -214, bismuth-212 and -214, radium-226 and -228, thorium, uranium, and strontium-89 and -90. Laboratory analysis confirmed elevated beta readings recorded at 1329 ± 311 pCi/g. Specific radionuclides present in an active reserve pit and the soil of a leveled, vacated reserve pit included ^{232}Thorium decay series (^{228}Ra, ^{228}Th, ^{208}Tl), and ^{226}Radium decay series (^{214}Pb, ^{214}Bi, ^{210}Pb) radionuclides. The potential for impact of TENORM to the environment, occupational workers, and the general public is presented with potential health effects of individual radionuclides. Current oversight, exemption of TENORM in federal and state regulations, and complexity in reporting are discussed.

Keywords: reserve pit, radiation, Technologically-Enhanced Naturally Occurring Radioactive Materials (TENORM), Naturally Occurring Radioactive Materials (NORM), Barnett Shale, natural gas mining, fracking

doi: http://dx.doi.org/10.2190/NS.23.1.h
http://baywood.com

Reserve pits are commonly seen throughout areas of unconventional natural gas extraction. The purpose of the reserve pits (commonly referred to as pits, ponds, cellars, tanks, impoundments, etc.) is to hold the large quantities of water and drilling mud required for hydraulic fracturing ("fracking") operations. These pits also provide a depository for brine water that occurs naturally in natural gas deposits, drilling mud, drilling cuttings and hydraulic fracturing fluids. Hydraulic fracturing fluids can contain chemical additives (acids, bactericides, breakers, corrosion inhibitors, cross-linkers, emulsifiers, flocculants, foaming agents, proppants, scale inhibitors, surfactants) and cuttings (rock, soil and metal shavings excavated by the drill bit) which can contain technologically enhanced naturally occurring radioactive material (TENORM) [1, 2]. Previous research has identified ^{226}radium (^{226}Ra), ^{228}radium (^{228}Ra), and radon gas (^{222}Rn) as the predominant radionuclides in natural gas wastes from oil and gas drilling. The focus of existing regulation guidelines has been related to ^{226}Ra and ^{228}Ra, which have the potential to release radon gas into the atmosphere when these radioactive nuclides are brought to the surface through the oil and gas extraction processes [3]. The long half-lives of these two radium isotopes (^{226}Ra, 1,600 years; ^{228}Ra, 5.8 years) are particularly concerning given that they have been identified as abundant in saline and chloride-rich produced waters [4]. To date, few other radionuclides have been identified as associated with natural gas extraction, and fewer still have had regulatory guidelines developed for occupational or public health exposures.

Naturally occurring radioactive material (NORM) is terrestrial radiation distributed by nature throughout natural geologic formations. It is undisturbed radioactive material that exists in nature as background material, or at its in-situ location, whether at the earth's surface or subsurface. TENORMs are when naturally occurring radionuclides are transported by anthropogenic activity to where humans are present, thereby increasing exposure potential, which may result in concentrations enhanced above natural background levels [5]. As such, NORM transported or concentrated during exploration and mining of oil and gas is thereby reclassified, according to regulatory definition, as TENORM.

Both NORM and TENORM are clearly defined and distinct from radionuclides that are produced through nuclear reactions, nuclear explosions or nuclear accelerators (commonly referred to as "man-made, artificial, or anthropogenic"). The term NORM is often misused when applied to radioactive material introduced into the human environment by oil and gas exploration and mining processes.

Estimates of water needed for unconventional natural gas extraction are reported to range from one to five million gallons per well for initial well completion [6]. The use of up to 12 million gallons per well completion (one million gallons per stage) has been documented for the 12-stage open-hole completion systems [7]. Disposal of large quantities of chemical- and radionuclide-laden materials in wastewater is a known problem [8]. Reserve pits are commonly found in agricultural areas where the potential for crop and animal contamination is high. Animals drinking pit water, dust particles blowing onto soil and crops, and berms breaching (thus contaminating adjacent croplands) are all potential exposure pathways. If reserve pits are built with an aerator, aerosolized radioactive material can be further dispersed onto soil, crops, livestock, and humans. Deposition of reserve pit contents in county landfills and municipal water treatment facilities has elicited a public outcry of concern for environmental contamination and potential human exposure to harmful radioisotopes often present in the drilling mud and cuttings, since these facilities do not have the capability to test for or remove radioactive material from the waste stream [9-11]. Incorporation of reserve pit material into the earth's surface either by draining and leveling the reserve pit where it exists, and/or land farming the material into the ground in place or at other locations, may increase the potential for surface and drinking water contamination from percolation or migration of radionuclides into water bodies. A better understanding is needed to assess the potential effects that radionuclides may have on the health of cattle, on cattle productivity, and on agricultural products. The potential exposure to humans is from reserve pit contents via wind, and by consumption of crops and animal products that have taken up radioactivity, has not been established [12-17].

The purpose of this article is to present laboratory analysis of water and soil (sludge) analyzed for the presence of TENORM, obtained from two unrelated reserve pits located on agricultural land in the Barnett Shale (located in Texas) and used as holding ponds for unconventional natural gas mining and extraction processes. This study originated as part of a field study conducted as a preliminary exploratory investigation (Phase II) during a property transaction to ascertain if, in fact, any regulatory impact existed (such as the presence of radioactive materials in the reserve pits). Comparison of study findings to state and federal guidelines for TENORM material identifies the complexity in regulatory reporting and guidelines, and current voids in regulatory oversight.

EXPERIMENTAL METHODS

Field Sampling

Soil and water matrices from reserve pits in the core area of the Barnett Shale East Newark Field were obtained and analyzed for the presence of radionuclides (TENORM). Soil and water was collected from two separate site locations: 1) farmland that was once a reserve pit, which had been drained and leveled to the surrounding elevation; and 2) a reserve pit that, at the time of sampling, held drilling mud, water for hydraulic fracturing, processed water and/or cuttings. For the purpose of this report the drained reserve pit has been identified as Reserve Pit #1 (RP1) and the pit with fluid has been identified as Reserve Pit #2 (RP2). In total, four separate samples of water and soil were obtained, two from each sampling location, and identified by the laboratory as sludge due to high water content. Water was collected in clear plastic 500-ml containers with no preservative. Two sample points were selected for each pit based on each pit's use and the most likely impact resulting from surrounding exploration and extraction activities.

Samples in RP1 were obtained at a soil depth of 6 inches from the soil surface, since the RP1 pit had been drained and appeared to have the greatest potential to be relatively homogeneous from initial field investigation. This reserve pit was originally constructed with above-ground berms without any surface discharge outlet. Water could be pumped into the pit from an adjacent water well and could flow out of the pit only via its natural down-gradient seepage. Two samples were obtained along a line following the direction of the pit's down-gradient groundwater flow, which ultimately intersected with a flowing creek located near to and down-gradient from the pit.

RP2 is a typical triangular ranch pond with the triangle base side perpendicular to the downgradient flow line of the pond. A surface flow outlet is located at the center of the downgradient side. The samples were taken inside of the pond. Since cuttings and drilling mud settle to the bottom of ponds, efforts were made to obtain sludge/sediment samples from the pit bottom of RP2 along with water. Impact to or from the pit appeared to occur at either end of this down-gradient side (i.e., at the corners). Flow gradients dictated exploration and production impact would occur at the corners and then would flow from these corners down-gradient to the outfall. A sample was taken at one corner and a second sample was taken at the upstream pond side of the outfall. RP2 samples were collected from the pond's floor on the down-gradient side of the pit.

Initial observations indicated that impact from well mining extraction and injection materials appeared to be located on the upgradient side of each pond's downhill side. This observed material in the pit was considered likely to be from the geologic formations mined and materials injected. All samples were shipped to a certified radiological laboratory (American Radiation Services, Inc., Port Allen, LA) for analysis of radioactive isotopes by EPA method 901.1M (ARS-007/EPA901.1M). Radioisotope concentrations were reported in picocuries/gram (pCi/g). Reserve pit contents were analyzed for the radionuclides beryllium (^{7}Be), potassium (^{40}K), scandium (^{46}Sc), cobalt (^{60}Co), cesium (^{137}Cs), thallium (^{208}Tl), lead (^{210}Pb and ^{214}Pb), bismuth (^{212}Bi and ^{214}Bi), radium (^{226}Ra and ^{228}Ra), thorium (^{228}Th), uranium (^{235}U), strontium (^{89}Sr and ^{90}Sr), and total gamma, total alpha, and total beta radiation.

This study was designed to be an initial investigative field study performed for an industrial land transaction decision. Samples were not randomized, but selected to represent the most likely worst-case down-gradient impact point. Analysis of a control sample was not performed or authorized. Soil sample results were compared to findings of previous studies and to regulatory limits. However, inconsistencies in collection and analysis of specific radioisotopes in previous studies made comparison difficult and it was not easy to ascertain in many cases whether the samples exceeded expected baseline concentrations.

Reserve Pit #1 (RP1)

The location identified as Reserve Pit #1 (RP1) had originally been part of a reserve pond, but at the time of sampling had been drained and leveled to the original ground surface grade. The original reserve pit was a manmade pond of approximately 2.9 acres, whose depth was increased with berms to a height of six to seven feet above ground level. Soil in the drained and leveled area sampled (RP1 location) appeared to have been undisturbed and the pond material allowed to drain and settle naturally, incorporating back into the existing soil rather than being removed and disposed of offsite. The RP1 sampling sites chosen were at one time the reserve pit bottom material. The remaining reserve pit was still present at the time of sampling and was still in use as a water reservoir for mining operations. Soil and water samples taken at this location were identified as RP1.1-West and RP1.2-East. The RP1.1-West sample was obtained approximately 15 feet from the edge of the existing pit berm, and the RP1.2-East sample was obtained approximately 75 feet from the edge of the existing pit berm. The purpose of obtaining soil from this location was to examine if any radioactivity in the soil existed after the reserve pit had been drained and the land left fallow. The adjacent land was used as agricultural land, which at the time of sampling was growing livestock feed. Field notes taken at RP1 locations identified the soil to be homogeneous black clay with very little organic matter and high water content, believed to be related to a precipitation event a few days prior to sampling. The U.S. Department of Agriculture Natural Resource Conservation Service defines black clay as having slow infiltration rates, high runoff potential when wet, and high shrink swell potential [18].

Reserve Pit #2 (RP2)

At the time of sampling, Reserve Pit #2 was being used as a water reservoir for natural gas extraction and mining operations and was believed to have been used to hold drilling mud, processed water, water for hydraulic fracturing operations, and drill cuttings. RP2 encompassed approximately 11.3 acres. This pit was originally a manmade pond at ground level. The water level was high due to recent precipitation events with an area overflowing the banks of the pit into a neighboring stream. The overflow area led to a creek and had been graded and cemented to provide a controlled exit for overflow water to minimize water breaching the pit berm at various locations. Two separate samples were obtained at RP2: one was obtained inside the pit along the east edge at the overflow location (identified as RP2.1-North), inside the pit along the northeast edge; the second sample was obtained on the south end of the pit closest to the well pad site inside the pit (identified as RP2.2-South). The samples taken in the reserve pit consisted of both water, obtained from approximately 6 inches below the surface, and soil, obtained approximately 3 feet from the berm edge at the bottom of the pit.

The soil matrix at RP2 location was varied, with the presence of dark grey sticky clay soil, commonly referred to as black clay soils on the exterior of the pit and a light yellowish brown clay soil mixed with high very fine sand (<1 mm diameter) interior to the pit [20].

Field notes taken at the RP2 location identified a noticeable lack of any insects, fish, turtles, snakes or birds present in the or around the pit. The pit contained water grasses and reeds which are optimum breeding and cover areas for fish, snake and bird activity but no activity or signs of any feeding, nesting, or breeding activity were apparent.

RESULTS

Results of laboratory analysis of the four samples are presented in Table 1. The level of radioactivity is presented as pCi/g, and the minimum detection concentration (MDC) is the lowest concentration reliably detected by the laboratory equipment. The Analysis of Error is a numerical factor that represents error in the laboratory detection technique. This error factor is specific to each radionuclide and specific to each test. A zero is entered in the table if the radioactivity detected is below the MDC.

In general, specific radioisotopes detected included ^{40}K, elements of the ^{228}Th decay series (^{228}Th, ^{228}Ra, and ^{208}Tl), elements of the ^{226}Ra decay series (^{226}Ra, ^{214}Bi, ^{214}Pb, ^{210}Pb), and ^{90}Sr. With the exception of total alpha radiation for RP2-North, varying levels of total alpha, beta, and gamma radiation were detected in all samples. Interestingly, different portions of the same pit showed some differences in the radioactivity present.

It is important to note that not all radioisotopes present in sample RP1.1-West were also present in sample RP1.2-East, despite their close proximity and presumed homogeneous material. At the time of sampling, both locations had a high water content in the soil due to a recent precipitation event that may have been a contributing factor to variability in radioisotope concentrations. Sample RP1.2-East had a greater variety of isotopes recorded above laboratory minimum detection. Some of the isotopes present in this study are known to have very short half-lives (^{214}Bi, 20 minutes; ^{214}Pb, 27 minutes), and their presence is not easily captured. Their presence is likely to be due to the fact that they are part of a decay series and are continuously being generated. Other isotopes have longer half-lives and are more easily identified. In comparing results of the two RP1 locations, similar concentrations were noted for ^{40}K, ^{208}Ti, ^{214}Pb, ^{228}Ra, ^{228}Th. Notably, ^{210}Pb and ^{90}Sr were found in the RP1.1-West sample but not in the RP1.2-East sample, while ^{226}Ra was detected in the RP1.2-East sample but not the RP1.1-West sample. The gross gamma radiation (22.8 and 21.4 pCi/g),

Table 1. TENORMs Found in Reserve Pits

Isotope	RP1.1-west	RP1.2-east	RP2.1-north	RP2.2-soth
Beryllium (^{7}Be)	0 (0.45)	0 (0.48)	0 (0.45)	0 (0.53)
Potassium (^{40}K)	5.3 ± 1.3 (0.82)	5.5 ± 1.0 (0.41)	4.9 ± 1.1 (0.68)	3.6 ± 1.0 (0.67)
Scandium (^{46}Sc)	0 (0.076)	0 (0.078)	0 (0.064)	0 (0.58)
Cobalt (^{60}Co)	0 (0.090)	0 (0.064)	0 (0.10)	0 (0.69)
Cesium (^{137}Cs)	0 (0.086)	0 (0.062)	0 (0.72)	0 (0.62)
Thallium (^{208}Tl)	0.20 ± 0.07 (0.060)	0.27 ± 0.06 (0.041)	0.18 ± 0.06 (0.076)	0.19 ± 0.05 (0.04)
Lead (^{210}Pb)	1.7 ± 1.2 (1.4)	0 (0.94)	0 (1.1)	0.99 ± 0.65 (0.94)
Bismuth (^{212}Bi)	0 (0.56)	0 (0.46)	0 (0.56)	0 (0.54)
Bismuth (^{214}Bi)	0.45 ± 0.15 (0.17)	0.35 ± 0.30 (0.15)	0.36 ± 0.12 (0.15)	0.25 ± 0.12 (0.18)
Lead (^{214}Pb)	0.68 ± 0.63 (0.14)	0.70 ± 0.15 (0.14)	0.44 ± 0.12 (0.15)	0.40 ± 0.11 (0.13)
Radium (^{226}Ra)	0 (1.3)	2.4 ± 1.0 (1.2)	0 (1.5)	0 (1.1)
Radium (^{228}Ra)	0.66 ± 0.21 (0.26)	0.71 ± 0.13 (0.19)	0.51 ± 0.15 (0.25)	0 (0.24)
Thorium (^{228}Th)	0.72 ± 0.11 (0.087)	0.67 ± 0.11 (0.093)	0.64 ± 0.13 (0.12)	0.36 ± 0.10 (0.10)
Uranium (^{89}Sr)	0 (0.34)	0 (0.27)	0 (0.42)	0 (0.32)
Strontium (^{89}Sr)	0 (0.24)	0 (0.24)	0 (0.36)	0 (0.26)
Strontium (^{90}Sr)	0.30 ± 0.17 (0.24)	0 (0.24)	0.59 ± 0.26 (0.36)	0.29 ± 0.18 (0.26)
Total gamma	22.8	21.4	10.8	8.22
Total alpha	10.8 ± 3.3 (2.6)	16.4 ± 4.6 (3.1)	0 (3.6)	9.1 ± 3.4 (3.9)
Total beta	9.1 ±2.5 (1.8)	5.7 ± 2.0 (2.3)	1329 ± 311 (5.0)	5.8 ± 1.8 (1.7)

[a]The level of radioactivity is given in pCi/g and is shown with the analysis error. The numbers in parentheses are the Minimum Detection Concentrations (MDCs). In cases where the radioactivity measured was less than the MDC, a value of 0 is entered.

gross alpha radiation (10.8 ± 3.3 and 16.4 ± 4.6), and gross beta radiation (9.1 ± 2.5 and 5.7 ± 2.0) were not significantly different in the two RP1 samples.

Similar results were seen in individual radioisotopes in the second reserve pit RP2.1-North and RP2.2-South samples. ^{228}Ra was detected in RP2.1-North but not RP2.2-South, whereas ^{210}Pb was observed in RP2.2-South but not RP2.1-North. Total gamma radiation was similar in the two samples, but gross alpha radiation was observed only in RP2.2-South.

The most unexpected result of this study was the difference identified in gross beta radiation within the same pond. Gross beta radiation in the RP2.1-North sample was considerably higher than in the South sample (1329 ± 310 vs. 5.8 ± 1.8 pCi/g). The highest beta radiation levels were recorded near the spillway in pond RP2. Radionuclides are unstable isotopes of elements that undergo radioactive decay continually. Accumulation of sediment near the spillway may have accounted for the variability in beta radiation levels. Despite the close proximity of the soil samples within the pond, it is difficult to determine if the variability in concentrations reflects initial concentration in the soil, amount of material deposited in the pond, or lack of uniformity of soil chemistry. The fact that such variability can exist provides a complexity to single sample testing and may indicate that numerous samples within a single reserve pond are needed for accurate identification and quantification of TENORM, and proper representation of potential exposure to radioactive material.

DISCUSSION

Routine field study analysis of reserve pit contents from unconventional natural gas mining confirmed the presence of alpha, beta, and gamma radiation in the soil and water in reserve pits located on agricultural land. The specific gamma-emitting radionuclides identified included ^{40}K, ^{208}Tl, ^{210}Pb and ^{214}Pb, ^{214}Bi, ^{226}Ra and ^{228}Ra, ^{228}Th, and ^{90}Sr. Total beta radiation of 1329 pCi/g found in this study exceeded regulatory guideline values by more than 800 percent. Data from this limited field study showed elevated levels of alpha, beta, and gamma radiation to be present in reserve pit water/sludge material and also in the soil of a vacated reserve pit after draining and grading to original topographic levels. Based on the use of the pit, the presence of radioactive materials was not anticipated. Agricultural land adjacent to the drained reserve pit may have an increased potential for radioactive material taken up in livestock feed crops growing on the land due to wind transport, runoff, and migration of soil onto adjacent land. Deposition of radioactive material on land has been shown to have the potential to raise the radiation levels in soils above natural background levels increasing the potential for contamination of groundwater, soil, animals (domestic and migratory), and humans (through occupational and residential exposures). Historically, background levels of naturally occurring radiation prior to land use have not been measured, and little information on true background radiation actually exists. Texas has a long history of oil and gas exploration, which has involved the practice of land farming and surface deposition of mining material. Further, for decades, unrefined oil has been deposited on roadways for dust control. Assessment of true background radiation levels may not be possible given this historical misuse of the land. Total radiation was found to be elevated above known background levels for radiation, but information is limited and exposure pathways poorly understood. Regulatory guidance documents currently do not address many of the radionuclides found in this study and provide few directives and little guidance in determining the potential synergistic or additive effects of exposure to several radionuclides simultaneously, or the potential for an increased incidence of disease in animals or humans due to simultaneous multiple exposures. Expansion of urban drilling and the practice of siting reserve pits within residential communities will increase the potential for radiation exposure to the general public. Health complaints related to low-level radiation sickness, common to occupational workers, may be overlooked by medical professionals who do not anticipate an industrial-type exposure to patients living within these communities. Stricter guidelines may be warranted in order to protect the general public from increased levels of radiation in soil, water, and air.

Radionuclide Decay

Radioactive decay releases three types of radiation: alpha (α), beta (β) and gamma (γ) emissions. All three types of radiation are known to present health hazards. The radionuclides in TENORM that present the most concern in the human environment due to potential health impacts are isotopes of radium, thorium, and uranium and their decay products. ^{238}U decays by alpha emission into ^{234}Th, and ^{234}Th decays by beta emission to protactinium and then ^{234}U. ^{226}Ra, ^{214} Bi, and ^{210}Pb are all daughter isotopes of ^{238}U. ^{234}U decays by alpha emission into ^{230}Th, which decays by alpha emission into ^{226}Ra, ultimately decaying by beta emission into products seen in this study: ^{214}Pb, ^{214}Bi, and ^{210}Pb.

Environmental and Health Impact of Exposure to TENORM

There are numerous potential pathways of exposure to radioactive material from wastes extracted by natural gas exploration and mining. This study attempts to investigate only one form of waste, reserve pit contents. However, there are several potential pathways of exposure from this one waste form alone. The potential exposures to humans directly, whether occupational or residential, include: ground-water contamination, soil contamination, windborne particulates and aerosolized material, and fugitive air emissions from industrial processes. Another secondary potential exposure pathway exists in the ingestion of agricultural products (vegetables, dairy, and meat products) that may contain these radionuclides. This is an area that has received little attention or investigation.

The complexity in examining potential exposure is in quantifying how much radiation one has been exposed to, and the dose absorbed due to the exposure, and in accurately assessing the potential health impacts from multiple pathways. In order to properly assess exposure, exposures to all forms of radiation (alpha, beta, gamma) as well as to specific radioisotopes must be quantified and a thorough human health risk assessment performed. This is rarely done unless concentrations of a single radionuclide, for which regulatory guidelines have been established, greatly exceed those guideline levels; and for many radionuclides, no regulatory guideline levels have been established. Since many radionuclides have not been identified to be present in reserve pit wastes until recently, regulatory guidelines have not been established for non-occupational exposure limits.

The radionuclides discussed below were found in the samples taken in this study. Evaluating the potential health impacts of each radionuclide individually is important, in addition to evaluating the total decay (alpha, beta, and gamma) radiation, as the target organs and sites of damage can differ.

Health Effects of Potassium (^{40}K)

Potassium can be taken into the body through ingestion (food or water) or inhalation. ^{40}K is a naturally occurring radioisotope of potassium and widely distributed in nature (although normally at very low levels—0.015% in soil). It has a very long half-life of 1.3 billion years and decays primarily to ^{40}Ca by beta emission. External exposure to ^{40}K is generally to gamma radiation as ^{40}K decays to ^{40}Ar. Internal exposure to ^{40}K can pose a health hazard from ionizing beta and gamma emissions as it decays, with the potential to cause cell damage [19].

Health Effects of Radium (^{226}Ra, ^{228}Ra)

According to a U.S. Geological Survey (USGS) study (2009), little data exists on natural background concentrations of radium in the environment. Levels have been documented to increase as a result of human activity [20]. Radium levels in drinking water can become elevated in areas of mining. Exposure to radium may result in a variety of health effects such as tooth fractures, anemia, and cataracts. Chronic exposure to radium is known to increase the incidence of cancer in humans [21, 22]. Gamma radiation from radium is able to travel long distances through air before expending its energy, thus increasing exposure to the general population [23]. Radium is the radionuclide on which most of the drinking water and air regulations are set. It is the primary radionuclide identified in the past as a potential source of exposure to radon, a decay product of radium and a known lung carcinogen.

Health Effects of Strontium (^{90}Sr)

^{90}Strontium is a manmade isotope of strontium. ^{90}Sr is used as a subsurface radioactive tracer in mining processes and has a half-life of 29.1 years [24]. It is also present at low levels in surface soil due to fallout from previous atmospheric nuclear tests. It is hydrophilic, easily moving into and through the environment, adding to its ability to contaminate aquifers and drinking water sources [25]. It is known to be dangerous to the health of animals and humans. Exposure to ^{90}Sr can occur by inhalation of dust, eating food, or drinking water contaminated with the radionuclide. Grains, leafy vegetables, and dairy products can contain significantly high levels of ^{90}Sr [26]. The primary target organ for ^{90}Sr is bone. Strontium competes with calcium taken up in bone and can damage bone marrow, causing anemia. It can also cause cancer as a result of damage to cellular genetic material [27].

Health Effects of Thallium (^{208}Ti)

Thallium is absorbed by the human body through inhalation of dust particles and through ingestion of food and water. The nervous system is the primary target organ for thallium, which is known to cause trembling, nerve pains, paralysis, and behavioral impacts. Tiredness, depression, lack of appetite, and hair loss are all symptoms of chronic low-level Ti exposure. Thallium exposure to the fetus has been known to cause congenital disorders [28].

Health Effects of Thorium (^{228}Th)

Inhalation of thorium can adversely impact the respiratory system, causing damage that can eventually culminate as lung cancer. Exposure to thorium is known to cause pancreatic cancer, and thorium can be stored in bone, leading to bone cancer years after the initial exposure. People living in industrial areas near hazardous waste sites and near waste materials may be exposed to higher concentrations of thorium from wind-blown dust and consumption of food contaminated by the radionuclide [29].

Potential for Plant and Animal Exposure to TENORM

Contamination of soil and water from TENORM can expose workers and the general public to increased levels of radiation above normal background levels. Other important aspects of environmental contamination are through radiation taken up by the soil-plant system and exposure to animals through feedstock. Radionuclides in the soil can be directly intercepted by crops, which are then used as livestock feed, further increasing the potential for human exposure to increased levels of radiation through ingestion of milk and meat products.

In 2009, the U.S. Fish and Wildlife Service identified the importance of protecting migratory birds from exposure to reserve pit contents which can contain diesel, glycols, and heavy metals, but failed to recognize the potential for bird populations to be exposed to radioactive material deposited in reserve pits [30]. Some states with oil and gas regulations recommend netting or screening of pits or open tanks to prevent contamination of birds and wildlife. For example, Texas Administrative Code, Title 16, Part 1, Chapter 3, Rule §3.22(b) Protection of Birds requires that an operator "screen, net, cover or otherwise render harmless to birds" specific tanks and pits with "frequent surface film or accumulation of oil," but does not address the potential exposure of birds or cattle to radioactive materials. Proper reserve pit management techniques include fencing cattle out of areas to prevent livestock from drinking reserve pit contents. Consumption of reserve pit fluids by livestock has been documented to cause poisoning, abortions, birth defects, weight loss, contaminated milk, and death [31, 32].

Proper public health protection may involve stringent quality controls upon agricultural and farm practices, to prevent exposure to reserve pit waste materials, and controls on harvest and food movement to prevent exposures to workers and the public. The presence of radioactive materials in agricultural soils and food products can create financial hardship and a significant psychological impact for communities whose economic base consists of agricultural and food products. Many of the radionuclides have long half-lives, which can result in contamination of the soil for decades. This ultimately could affect the marketability of both the land and any products produced from the land for decades.

Federal Regulatory Oversight

Neither the U.S. Environmental Protection Agency (EPA) nor the U.S. Nuclear Regulatory Commission (NRC) has established federal regulations that directly govern NORM waste from the oil and gas industry. In fact, wastes containing NORM are generally not regulated by federal agencies with one exception, transportation. NORM-containing wastes with a specific activity greater than 2,000 pCi/g (70 Bq/g) are subject to U.S. Department of Transportation (DOT) regulations governing transport of radioactive materials [33]. The Occupational Safety and Health Administration (OSHA) has promulgated rules specific to occupational exposure to ionizing radiation [34] , which may be applicable to petroleum industry NORM management activities.

By definition, oil and gas industry NORM that does not exceed 0.05 percent uranium or thorium by weight or any combination, is not subject to regulatory control under the Atomic Energy Act of 1954 due to the fact it is not a source material, special nuclear material, or by-product material [35].

The Low-Level Radioactive Waste Policy Act as amended in 1986 provides guidance to states on disposal of low-level radioactivity material, like the waste material generated from oil and gas activities, but does not include oil and gas NORM waste. NORM wastes generated during the exploration, development, and production of crude oil, natural gas, and geothermal energy have been categorized by the EPA as "special wastes" and are currently exempt from federal hazardous waste regulations under Subtitle C of the Resource Conservation and Recovery Act (RCRA) by the Bevill Amendment and are not considered a listed or characteristic waste. The Superfund Amendments and Reauthorization Act listed none of the constituents of NORM as "extremely hazardous substances." The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) lists radionuclides as hazardous substances because the CAA (Clean Air Act) lists them as hazardous air pollutants. Oil and gas waste streams that may contain NORM are exempt under RCRA and therefore considered not hazardous substances under CERCLA, although individual radioisotopes might be. Reportable Quantities (RQs) are one pound of radionuclides (cumulative), or concentrations expressed in curies for individual radionuclide, whichever is less (40 CFR 302.4).

In 1989 EPA issued a final regulation covering RQs for radionuclides. EPA used 1, 10, 100, 1000, and 5000 pounds as RQs for non-radionuclides and 0.001, 0.01, 0.1, 1, 10, 100, and 1,000 Curies (Ci) as RQs for radionuclides. Release values for approximately 760 radionuclides were calculated for each of four human health intake pathways. The lowest pathway release value for each radionuclide was selected and then rounded down to the nearest decade to set the RQ for each radionuclide. Radionuclides not having published intake limits were assigned an RQ of 1 Ci, based on the observation that 91 percent of the radionuclides being studied were below the 1 Ci level [36]. These RQ are not applicable to oil and gas exploration as a result of the RCRA Bevill Amendment and its relationship to CERCLA.

The EPA under the CAA developed National Emission Standards for Hazardous Air Pollutants (NESHAPs) specific to radionuclide emissions for several sources, but not for industrial activities that include NORM generated by the oil and gas industry.

The EPA under the provisions of the Safe Drinking Water Act (SDWA) regulates the following radionuclides in drinking water: (adjusted) gross alpha emitters, beta particle and photon (gamma) radioactivity, ^{226}Ra and ^{228}Ra (combined), and uranium. The EPA established drinking water standards for several types of radioactive contaminants: $^{226/228}Ra$ (5 pCi/L); beta emitters (4 mrems); gross alpha standard (15 pCi/L); and uranium (30 μg/L).

State Regulatory Oversight

NORM is subject primarily to individual state radiation control measures and varies across the nation. "Section 651(e) of the Energy Policy Act of 2005 gives NRC jurisdiction over discrete sources of NORM by redefining the definition of source material" [37]. For example, the State of Texas has three agencies are responsible for regulating different aspects of NORM. In Texas, NORM is regulated under the Texas Radiation Control Act (TRCA) as follows:

- The Texas Department of State Health Services (TDSHS), Radiation Control, has jurisdiction over the receipt, possession, use, treatment and storage of NORM (TDSHS NORM Licensing).
- "The Railroad Commission of Texas (RRC) has jurisdiction of handling and disposal of NORM wastes produced during the exploration and production of oil and gas (RRC rules for NORM)" [37], and disposal by the owner through on-site land farming and/or injection well. "The Texas Commission on Environmental Quality (TCEQ) has jurisdiction over the disposal of other NORM wastes" [37].

Under such a system, the Texas Administrative Code (TAC) defines exemptions for persons (parties/agencies) who receive, possess, use, process, transfer, transport, store, and commercially distribute NORM; that is, an exemption does not need to be licensed or is not regulated since NORMs are not hazardous waste streams. Often these exemptions are based on the NORM concentration of the waste stream being below a certain activity level (pCi/g) or radiation level (microRoentgens per hour μR/hr). Radium radionuclides are generally the measured standard for multiple radionuclide waste streams, while a higher exemption threshold is used for an individual radionuclide. This system requires the determination of nuclide concentration or emission only when a disposal permit is sought. Ponds used to store and receive waters from drilling, well rework, and hydraulic fracturing operations can be filled without determining radionuclide release or impact since they are not technically considered hazardous waste and no disposal permit is required.

The environmental management of lands contaminated with naturally occurring radioactive materials will require threshold guidance levels to be established to indicate when action is required. Successful management will need federal and state authority to enforce such threshold guidance levels. Unless regulatory loopholes are closed, testing, monitoring, and reporting of radionuclide release to the environment above existing background will continue, resulting in more human and environmental exposure. Guidelines for NORM/TENORM should correspond to levels of naturally occurring radionuclides in the environment at which it is practical to distinguish the radionuclides resulting from human activities from those in the undisturbed natural background. In 2008, the National Council on Radiation Protection and Measurements summarized the issue of radiation exposure and public health in the following statement: "There is a need to address public health concerns and to provide guidance on the cleanup and potential reuse of lands contaminated with NORM or technologically-enhanced NORM (TENORM). Although there are environmental cleanup standards in place for manmade radioactive contamination, there are no consistent federal or state regulatory controls or environmental management policies for NORM or TENORM contamination resulting from industrial practices associated with processing natural metal and mineral resources" [35].

Recommendations

Historically, ^{226}Ra and ^{228}Ra have been tested for in water and guidance levels set with the intention of protecting people from exposure to radon gas. The findings of this study raise the question of whether radium, a single radionuclide, is the proper indicator for assessing radiation exposure levels to the general public, given the potential for the vast amount of radioactive waste, and number of radionuclides, produced from oil and natural gas exploration and mining that may be present in reserve pits. Current regulations require that ^{226}Ra and ^{228}Ra combined exposure levels not exceed 5 pCi/g, averaged over 100 m^2, identifying radon as the primary emission of concern [39]. The Texas RRC Commission can issue a permit for the burial of oil and gas NORM waste "if, prior to burial, the oil and gas NORM waste has been treated or processed so that the radioactivity concentration does not exceed 30 pCi/g ^{226}Ra and ^{228}Ra or 150 pCi/g of any other NORM nuclide" [40]. These limits were not established with the support of public health/medical professionals nor based on potential human health impacts of cumulative exposures to multiple radionuclides. The total beta radiation found in one sample (RP2.1-North) of this study of 1329 pCi/g exceeds regulatory guideline values by more than 800 percent. However, individual radionuclides did not exceed existing regulatory guidelines. Data from this limited field study showed that elevated levels of alpha, beta, and gamma radiation were present in reserve pit water/sludge material and also in the soil of a decommissioned reserve pit. Evaluating the single radionuclide radium as regulatory exposure guidelines indicate, rather than considering all radionuclides, may indeed underestimate the potential for radiation exposure to workers, the general public, and the environment.

Limitations to this study include the small sample size and limited analysis of reserve pit contents. The study does not make the assumption that all reserve pits contain radioactive materials. The study does not imply that all reserve pit contents are disposed of by land farming (either onsite or offsite) or postulate the extent to which contaminated material is incorporated back into the earth. Comparison of radionuclide levels found in this study to existing regulatory levels was difficult since regulatory guidelines have been established for only a few radionuclides. Furthermore, TENORM waste has been excluded from many regulatory guidelines and from regulatory oversight. Future studies are needed to evaluate what percentage of reserve pits are actually used for deposition of radioactive materials. Further studies are needed to understand how radioactive materials transfer to vegetation and animal products and the uptake mechanisms of those materials through the food chain. The long half-lives that are intrinsic to many radionuclides are a major concern for future generations. Further research needs to be done to understand what exposure levels can be anticipated given the complex interactions within the physical and chemical components of soil and the lack of uniformity of soil chemistry.

As the United States goes forward with the expansion of drilling natural gas reservoirs (especially drilling in shale, which requires hydraulic fracturing with millions of gallons of water and producing nearly equal amounts of flowback), it is imperative that we obtain better knowledge of the quantity of radioactive material and the specific radioisotopes being brought to the earth's surface from these mining processes. Proper regulation of surface deposits and disposal of wastes can prevent elevation of natural levels of radiation and increased exposure of animals and humans to potentially harmful levels of radioactivity. It is essential that the public health community be consulted when establishing future regulatory guidelines. Materials classified as exempt under current regulations should be reviewed given the potential for adverse health effects from radiation exposure to the general public and with continued growth of urban drilling.

AUTHORS' BIOGRAPHIES

ERNEST CROSBY was a Professor of Civil and Environmental Engineering with the University of Texas at Arlington for 28 years. He has 43 years consulting experience with the U.S. Army Corps of Engineering, Federal Highway Administration (FHWA), Department of Transportation (DOT), and Urban Mass Transportation Administration (UMTA). Send him email at eccrosby@transystems.com

ALISA RICH is an Adjunct Assistant Professor at the University of North Texas Health Science Center, School of Public Health, Department of Environmental and Occupational Health where she teaches graduate level Toxicology and Human Health Risk Assessment. Send her email at rich@wolfeagleenvironmental.com

NOTES

1. Chesapeake Energy, "Barnett Shale Hydraulic Fracturing: Fact sheet, Revision 8," http://www.chk.com/Media/Educational-Library/Fact-Sheets/Pages/default.aspx (accessed September 19, 2009).
2. Ohio Environmental Protection Agency, *Fact Sheet: Drill Cuttings from Oil and Gas Exploration in the Marcellus and Utica Shale Regions of Ohio*, February 2012, http://www.ohioshaleinfo.com (accessed May 12, 2012).
3. U.S. Environmental Protection Agency, "Radioactive Wastes from Oil and Gas Drilling," http://www.epa.gov/radtown/drilling-waste.html (accessed August 14, 2012).
4. U.S. Geological Survey, *Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment—An Issue for the Energy Industry* (USGS

Fact Sheet FS-142-00), September 1999, http://www.pubs.usgs.gov/fs/fs-0142-99/fs-0142-99.pdf (accessed November 2, 2011).
5. Anselmo S. Paschoa and Friedrich Steinhausler, eds., *Technologically Enhanced Natural Radiation* (Oxford, Great Britain: Elsevier Publications, 2010).
6. "Hydraulic Fracturing and Potential Risks to Groundwater," *The Woodshed: The Virginia Cooperative Extension Northwest District Natural Resources Newsletter*, http://www.anr.ext.vt.edu/enviroandnatres/newsletters/woodshedvol2issue22007.pdf (accessed August 14, 2012).
7. V. A. Kuuskraa, "The Start of Gas Shale Revolution. Case Study #1, Barnett Shale," Gas Shale Development Workshop, Beijing China, April 2, 2010.
8. D. J. Soeder and W. M. Kappel, *Water Resources and Natural Gas Production from the Marcellus Shale*, U.S. Geological Society Fact Sheet 2009-3032 (May 2009).
9. "Hydraulic Fracturing Poses Substantial Water Pollution Risk, Analysts Say," *Science Daily*, August 2012, http://www.sciencedaily.com/releases/2012/08/120806093929.htm (accessed October 29, 2012).
10. Mary Perham, "Gas Drilling Committee Mulls Taking Drill Cuttings," *Steuben Courier*, January 11, 2011, http://www.steubencourier.com/news/x250684855/Gas-drilling-committee-mulls-taking-drill-cuttings (accessed November 1, 2012).
11. K. P. Smith et al., "Assessment of the Disposal of Radioactive Petroleum Industry Waste in Nonhazardous Landfill Using Risk-Based Modeling," *Environmental Science & Technology* 37 (10) (2003): 2060-2066, doi: 10.1021/es0261729.
12. M. Bamberger and R. E. Oswald, "Impacts of Gas Drilling on Human and Animal Health," *Scientific Solutions* 22 (1) (2012): 51-77, doi: 10.2190/NS.22.1.e.
13. W. C. Edwards and D. G. Gregory, "Livestock Poisoning from Oil Field Drilling Fluids, Muds and Additives," *Veterinarian Human Toxicology* 35 (5) (1991): 502-504.
14. R. W. Coppock, E. L. Stair, and S. S. Semalulu, "Toxic Pathology of Oilfield Poison in Cattle: A Review," *Veterinarian Human Toxicology* 38 (1) (1996): 36-43.
15. W. C. Edwards, "Toxicology of Oil Field Wastes: Hazards to Livestock Associated with the Petroleum Industry," *Veterinary Clinics of North America: Food Animal Practice* 5 (2) (1989): 363-374.
16. Byard Duncan, "Fracking with Food: How the Natural Gas Industry Poisons Cows and Crops," http://www.alternet.org/print/story/147634/fracking_with_food%3A_how_the_natural_gas_industry_poisons_cows_and_crops (accessed August 16, 2012).
17. Anonymous, "19 Head of Cattle Die Near North LA Gas Well," *Shreveport Times*, April 29, 2009, http://www.shreveporttimes.com/article/20090429/NEWS01/904290368/1060 (accessed July 25, 2010).
18. United States Department of Agriculture, Natural Resource Conservation Service, Web Soil Survey Soil Survey (WSS), http://websoilsurvey.nrcs.usda.gov/app/WebSoilSurvey.aspx (accessed October 2, 2012).
19. Argonne National Laboratory, *Human Health Fact Sheet Potassium-40*, www.ead.anl.gov/pub/doc/potassium.pdf (accessed August 1, 2012).
20. U.S. Geological Survey, *Naturally Occurring Radioactive Material (NORM) in Produced Water and Oil-Field Equipment—An Issue for the Energy Industry* (USGS Fact Sheet FS-142-99), 2009, http://pubs.usgs.gov/fs/fs-0142-99/fs-0142-99.pdf (accessed November 2, 2012).

21. U.S. Department of Health and Human Services, Agency for Toxic Substances and Disease Registry, *Radium*, July 1999, http://www.atsdr.cdc.gov/toxfaqs/tfacts144.pdf (accessed August 1, 2012).
22. E. A. Martell, "Tobacco Radioactivity and Cancer in Smokers: Alpha Interactions with Chromosomes of Cells Surrounding Insoluble Radioactive Smoke Particles May Cause Cancer and Contribute to Early Atherosclerosis Development in Cigarette Smokers," *American Scientist* 63 (4) (1975): 404-412, http://jstor.org/stable 27845575 (accessed February 12, 2012).
23. U.S. Environmental Protection Agency, "Gamma Rays/What are the properties of gamma radiation?" http://www.epa.gov/radiation/understand/gamma.html#properties (accessed October 12, 2012.
24. U.S. Environmental Protection Agency, *EPA Facts About Strontium-90*, 2002, http://www.epa.gov/superfund/health/contaminants/radiation/pdfs/strontium.pdf (accessed November 1, 2012).
25. Argonne National Laboratory, *Human Health Fact Sheet: Strontium*, November 2006, http://www.evs.anl.gov/pub/doc/strontium.pdf (accessed October 2012).
26. Forbes, "Radioactive Strontium Found in Hilo, Hawaii Milk," April 27, 2011, http://www.forbes.com/sites/jeffmcmahon/2011/04/27/radioactive-strontium-found-in-hilo-hawaii-milk (accessed August 15, 2012).
27. U.S. Department of Health and Human Services, Agency for Toxic Substances and Disease Registry, *ToxFAQs: Strontium*, http://www.atsdr.cdc.gov/toxfaqs/tfacts159.pdf (accessed August 16, 2012).
28. U.S. Department of Health and Human Services, Agency for Toxic Substances and Disease Registry, *Toxicological Profile for Thallium*, 1992, http://www.atsdr.cdc.gov/toxprofiles/tp.asp?id=309&tid=49 (accessed August 17, 2012).
29. U.S. Environmental Protection Agency, Office of Solid Waste, *Human Health and Environmental Damages from Mining and Mineral Processing Wastes*, 1995, http://www.epa.gov/wastes/nonhaz/industrial/special/mining/minedock/damage/damage.pdf (accessed August 11, 2012).
30. U.S. Fish and Wildlife Service, *Reserve Pit Management: Risk to Migratory Birds,* September 2009, http://www.fws.gov/mountain-prairie/contaminants/documents/ReservePits.pdf (accessed August 1, 2012).
31. U.S. Department of the Interior and U.S. Department of Agriculture, *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development: The Gold Book,* 4th ed. (BLM/WO/ST-06/021+3071), 2007, http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices/gold_book.htm (accessed November 11, 2012).
32. U.S. Environmental Protection Agency, *Solid Waste Report to Congress: Management of Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy, Oil and Gas Damage Cases*, 1988, http://nepis.epa.gov (accessed August 11, 2012).
33. U.S. Code of Federal Regulations, Title 49, Chapter 1, Part 173, Subpart I, "Class 7 (Radioactive) Materials," §173.401-173.476, http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=612482550203e9738c0e34f2f2d19d04&rgn=div6&view=text&node=49:2.1.1.3.9.9&idno=49 (accessed November 9, 2012).

34. U.S. Code of Federal Regulations, Title 29, Part 1910.1096, "Ionizing Radiation," July 10, 2010, http://cfr.vlex.com/vid/1910-ionizing-radiation-19686808 (accessed November 20, 2012)
35. United States Code, Title 42, Chapter 23, "Development and Control of Atomic Energy," § 2011-2259 (October 1, 2000), http://grants.nih.gov/grants/compliance/42_CFR_50_Subpart_F.htm (accessed November 21, 2012).
36. U.S. Environmental Protection Agency, *Superfund Reportable Quantities*, http://www.epa.gov/superfund/policy/release/rq May 24, 1989 (accessed August 6, 2012).
37. Texas Commission on Environmental Quality, *Disposal of Exempt Waste that Contains Radioactive Material RG-486*, http://m.tceq.texas.gov/permitting/radmat/uranium/norm.html#normdef November 2010, 1989 (accessed August 6, 2012).
38. National Council on Radiation Protection and Measurements, *Strategic Program Plan 2008-2010* [no date], http://www.ncrponline.org/PDFs/2008/NCRP_2008-10_Strat_Plan-3-19.pdf (accessed August 3, 2012).
39. Texas Administrative Code, Title 25, Part 1, Chapter 289, Subchapter F, Rule §289.259(d)(1)(B)(ii), April 11, 1999.
40. Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, Rule §4.614 20(d), March 3, 2003.

Direct reprint requests to:

Dr. Alisa Rich
Assistant Professor
Dept. of Environmental and Occupational Health
UNT Health Science Center School of Public Health
3500 Camp Bowie Blvd.
Fort Worth, TX 76107
e-mail: Alisa.Rich@unthsc.edu

NEW SOLUTIONS, Vol. 23(1) 137-166, 2013

Features

COMMUNITY-BASED RISK ASSESSMENT OF WATER CONTAMINATION FROM HIGH-VOLUME HORIZONTAL HYDRAULIC FRACTURING

STEPHEN M. PENNINGROTH
MATTHEW M. YARROW
ABNER X. FIGUEROA
REBECCA J. BOWEN
SORAYA DELGADO

ABSTRACT

The risk of contaminating surface and groundwater as a result of shale gas extraction using high-volume horizontal hydraulic fracturing (fracking) has not been assessed using conventional risk assessment methodologies. Baseline (pre-fracking) data on relevant water quality indicators, needed for meaningful risk assessment, are largely lacking. To fill this gap, the nonprofit Community Science Institute (CSI) partners with community volunteers who perform regular sampling of more than 50 streams in the Marcellus and Utica Shale regions of upstate New York; samples are analyzed for parameters associated with HVHHF. Similar baseline data on regional groundwater comes from CSI's testing of private drinking water wells. Analytic results for groundwater (with permission) and surface water are made publicly available in an interactive, searchable database. Baseline concentrations of potential contaminants from shale gas operations are found to be low, suggesting that early community-based monitoring is an effective foundation for assessing later contamination due to fracking.

Keywords: high-volume horizontal hydraulic fracturing, groundwater contamination, certified baseline testing, volunteer stream monitoring partnerships, fracking

doi: http://dx.doi.org/10.2190/NS.23.1.i
http://baywood.com

The risk of contaminating surface water and groundwater as a result of shale gas extraction activities utilizing high-volume horizontal hydraulic fracturing (HVHHF) technology has not yet been assessed [1]. An abundance of evidence suggests that contamination can and does occur, including academic studies [2, 3], agency reports [4], accidents [5,6], regulatory violations [7, 8], interviews with sick homeowners near gas well pads [9, 10], and out-of-court settlements with confidentiality agreements between homeowners and gas companies [11]. There is also evidence to suggest that contamination may occur along natural subsurface pathways and not necessarily as a consequence of HVHHF [12]; however, probability bounds analysis points to disposal of HVHHF waste as the greatest risk to water [13]. Despite abundant indications of adverse effects on human health and the environment, conventional risk assessment methodologies have not yet been applied to the shale gas industry, and this has resulted in a void in public health protection on the part of the state and federal governments [14]. Here we explore one possible reason for this void: a lack of government data on water quality. We describe how rural homeowners and communities in New York's Southern Tier region are attempting to fill data gaps and create baselines for risk assessment purposes before HVHHF is approved in New York.

The nonprofit Community Science Institute (CSI) was founded in 2000 and has operated a state-certified water quality testing laboratory in Ithaca, New York, since 2003 (New York State Department of Health–Environmental Laboratory Approval Program (NYSDOH-ELAP) ID# 11790). With financial support from local governments in Tompkins County, CSI partners with seven groups of volunteers who perform synoptic sampling of Cayuga Lake tributary streams— that is, volunteers collect samples at specified locations within a few hours of one another, allowing comparison of water quality values throughout the area sampled. These volunteers collect approximately 350 samples a year and transport them to the CSI lab, where they are analyzed for bacteria, phosphorus and nitrogen nutrients, suspended sediment, minerals, and other parameters. Results are made publicly available in an interactive, searchable data archive at www.communityscience.org/database, which currently contains over 30,000 certified water quality data items. We have been recruiting, training, and providing technical support for community groups to conduct long-term baseline stream monitoring in New York's gas-rich Southern Tier region since 2010. Further, with the prospect of HVHHF in New York, CSI began offering pre-drilling baseline testing of private drinking water wells in 2009. The existence of pre-drilling data should make it possible to detect whether groundwater and surface water are impacted by HVHHF and to begin the essential task of conducting formal risk assessments using methodologies that are widely accepted in the public and private sectors [15-17].

METHODS

For the Cayuga Lake watershed, surface water samples (from Six Mile Creek and its tributaries) were analyzed for parameters including a set of gas well "signature chemicals." For the Upper Susquehanna River Basin, samples from Catatonk Creek and Cayuta Creek were analyzed for "red flag" indicators of water quality. Finally, samples of untreated groundwater, collected by CSI from private wells across the Utica and Marcellus Shale regions within New York, were analyzed for gas well "signature chemicals."

Streams in Cayuga Lake Watershed

Trained groups of volunteers perform synoptic sampling of Cayuga Lake tributary streams independently of each other up to five times per year under base-flow and stormwater conditions (Figure 1). Data collection began between 2002 and 2009, depending on when a monitoring group was established for a tributary of Cayuga Lake. Each group collects grab samples at four to 23 fixed locations, depending on the size of the watershed. Volunteer teams deliver samples to the CSI lab in Ithaca with chain-of-custody documentation. Certified analyses are performed within prescribed holding times and using methods approved by NYSDOH-ELAP. Certified results are posted in CSI's online searchable data archive at www.communityscience.org/database. While focused primarily on impacts from agriculture and residential development, such as nutrients and pathogenic bacteria, Cayuga Lake watershed monitoring also includes a number of parameters that overlap with gas well "signature chemicals": pH, alkalinity, total hardness, turbidity, total suspended solids, chloride, and specific conductance. Monitoring of Cayuga Lake tributaries is guided by a Quality Assurance Project Plan (approved by the New York State Department of Environmental Conservation (NYSDEC).

Expanded monitoring of gas well "signature chemicals" in the Cayuga Lake watershed began in 2012, with financial support from the Tompkins County Legislature. Volunteer teams collect additional samples once a year at a subset of their regular synoptic monitoring locations for certified laboratory analyses of barium, strontium, gross alpha and gross beta radioactivity, total dissolved solids, chemical oxygen demand, sulfate, and methylene blue active substances (MBAS) (anionic surfactants). The list of "signature chemicals" recommended by CSI to screen for gas well impacts on surface water quality is similar to that for groundwater quality (as listed in Table 7 below) and is based on general knowledge of HVHHF technology and on analyses reported in the NYSDEC's 2011 draft Supplemental Generic Environmental Impact Statement of the frequencies and concentrations of chemicals in flowback from gas wells in Pennsylvania and West Virginia [18]. A moderate degree of redundancy is included, such that screening for several of the major characteristics of flowback

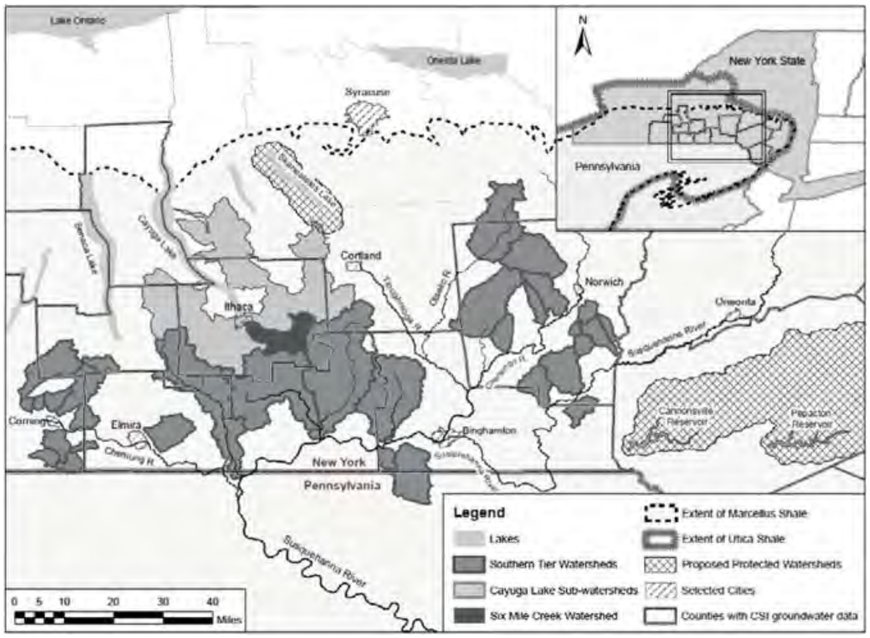


Figure 1. Map showing CSI-volunteer baseline water quality monitoring activities in the Marcellus and Utica Shale regions. Shaded areas are watersheds where volunteers monitor streams in the Finger Lakes and Upper Susquehanna River regions. The 13 counties where CSI has collected groundwater data from private drinking water wells and where clients have given permission to incorporate their results into CSI's regional groundwater baseline are shown in outline. The crosshatched areas—so-called Proposed Protected Watersheds—are areas feeding unfiltered drinking water systems in Syracuse and New York City where the New York State Department of Environmental Conservation proposes to exclude high-volume hydraulic fracturing per Section 6.1.5.4 in its 2011 draft Supplemental Generic Environmental Impact Statement, which states that "high volume hydraulic fracturing operations within the NYC and Syracuse watersheds pose the risk of causing significant adverse impacts to water resources" [18].

is based on two or more related tests. Streams are not tested for methane and volatile organic compounds (VOCs) as concentrations are expected to be low and difficult to detect due to volatilization.

Streams in Upper Susquehanna River Basin

CSI initiated a "red flag" volunteer stream monitoring program in 2010, training and partnering with groups of volunteers in several Southern Tier counties where HVHHF is most likely to take place if approved in New York

(Figure 1). Groups of 15 to 30 of these volunteers monitor local streams that together drain 250 to 400 square miles. Each group is organized in teams of two to six, and each team takes responsibility for monitoring a specific set of stream locations once a month for five red-flag indicators of water quality: temperature, pH, dissolved oxygen, specific conductance, and total hardness. Teams are required to calibrate their portable test kits and meters prior to each monitoring event, using standards provided by the CSI lab, and to perform at least one set of duplicate tests for each red-flag indicator. Teams submit original field data sheets to CSI in hard copy. Results that meet data quality criteria for accuracy and precision (Table 1) are entered in the open searchable data archive on the CSI website. For added quality control, red-flag groups are asked to split all samples with CSI's certified lab during the first two months of their monitoring program, and one sample per team per quarter thereafter. Groups are encouraged to seek funding from local sources and to contract with CSI or a local certified lab to conduct expanded baseline testing of gas well "signature chemicals" at as many stream locations as possible at least once a year, similar to the expanded baseline testing in the Cayuga Lake watershed made possible by the Tompkins County Legislature.

Stream water quality data presented for comparison with CSI data (see Tables 2, 3, and 4) were extracted from the U.S. Geological Survey's (USGS's) National Water Information System (NWIS) and the U.S. Environmental Protection Agency's (EPA's) STORET (STOrage and RETrieval) Data Warehouse. All data were filtered to extract only base flow sampling events. The NWIS data available for Six Mile Creek were from three sites on the main stem and two sites on tributaries. STORET data were for four sites in the Catatonk Creek watershed and five sites in the Cayuta Creek watershed.

Groundwater in the Marcellus and Utica Shale Regions

CSI's certified lab offers fee-for-service baseline testing of private residential wells for gas well "signature chemicals" in groundwater. Baseline testing provides a form of insurance for homeowners in the event their water supply is contaminated and the contamination can reasonably be traced to nearby shale gas extraction activities. Clients are advised that the recommended baseline is designed as a broad screen that attempts to balance cost against the probability of identifying a "chemical signature" of gas well contamination, and that more extensive testing for specific carcinogenic, neurotoxic, terratogenic, endocrine-disrupting, and radioactive chemicals is indicated if post-drilling changes in results for some, but not necessarily all, "signature chemicals" provide reasonable evidence that contamination has occurred. Residential groundwater well samples are collected by CSI staff onsite, at a point that precedes any treatment system, such as a filter or a water softener, with chain-of-custody documentation to the CSI lab and subcontract labs.

Table 1. CSI Acceptance Criteria[a] for "Red-Flag" Stream Monitoring Results Reported by Volunteer Teams on Hard-Copy Field Data Sheets

	Temperature (°C)	pH[b]	Dissolved oxygen[c] (mg/L)	Specific conductance[d] (μS/cm)	Total hardness[e] (mg $CaCO_3$/L)
Precision—acceptance of reported duplicates	± 1°C	± 0.5 pH Units	Greater of ± 20% or 0.4 mg/L[c]	± 10%	Greater of ± 20% or 8 mg/L[e]
Accuracy—acceptance of reported standards	Calibration[f]	± 0.5 pH Units	No calibration necessary[c]	± 1%	± 20%[e]
Splits—comparison with certified lab	N/A	N/A[b]	N/A[c]	± 20%[d]	± 20%[e]

[a]Red-flag teams of two to five volunteers typically monitor five or fewer stream locations once a month. For quality control, teams are required to perform one standard and/or one duplicate, depending on the analyte. Quality controls are performed once per monitoring event. Red-flag teams are required to split samples with CSI at the rate of one location per quarter, or four splits per year, for certified analyses of specific conductance and total hardness. In the first months of a new red-flag monitoring program, volunteer teams are required to split one sample from every location in order to establish baselines for specific conductance and total hardness and to facilitate trouble-shooting by CSI staff if the team is having difficulty performing the tests.

[b]pH is measured streamside using a wide range pH test kit accurate to 0.5 pH units over the pH range 3.0 to 10.5, LaMotte code 5858, or a hand-held meter, Hanna Instruments model HI98103. The CSI lab provides volunteer teams with an unlimited supply of pH 7.0 standard. Split samples are analyzed if requested by volunteers and if split is received by lab for analysis within 48 hours of sample collection as the frequency of spontaneous changes in pH is observed to increase after 48 hours.

[c]Dissolved oxygen is measured using test kit, LaMotte code 5860-01, based on the modified Winkler method approved by EPA. Test is accurate if performed correctly. Measurement range for titrator is 0.2-10.0 mg/L and is readily extended to higher concentrations by continuing to add titrant until the endpoint is reached. Limit of quantitation (sensitivity) is 0.4 mg/L or two times the smallest unit of measurement on the titrator. Results are considered reportable to the limit of quantitation, assuming quality control criteria are met, consistent with certified lab protocol. At low concentrations, precision is acceptable if duplicates agree within the limit of quantitation, 0.4 mg/L. Split samples are analyzed if requested by volunteers and if split is fixed streamside and received by lab within 8 hours of sample collection, as per EPA protocol.

[d]Specific conductance is measured using Hanna Instruments hand-held meter model HI 98303, range 1 to1,999 μS/cm. CSI lab provides volunteer teams with an unlimited supply of 353 NTU specific conductance standard. Volunteer teams may hold stream samples at 4°C and perform the specific conductance test up to 28 days after sample collection, as per certified lab holding time.

[e]Total Hardness is measured using LaMotte kit 4482-DR-LT-01. Measurement range for titrator is 4 to 200 mg/L as calcium carbonate equivalents (CCE) and is readily extended to higher concentrations by continuing to add titrant until the endpoint is reached. Limit of quantitation (sensitivity) is taken to be 8 mg/L CCE, or two times the smallest unit of measurement on the titrator. Results are reportable to the limit of quantitation, assuming quality control criteria are met, consistent with certified lab protocol. At low concentrations, precision is acceptable if duplicates agree within the limit of quantitation, or 8 mg/L CCE. The CSI lab provides teams with an unlimited supply of 100 mg/L CCE or 20 mg/L CCE total hardness standard, depending on sampling sites. Teams may hold samples at 4°C and perform the total hardness test up to 14 days after sample collection, as per certified lab holding time.

[f]Volunteers are instructed to calibrate their thermometers based on the temperature of boiling water equal to 100°C.

While onsite, CSI staff ask clients for voluntary written permission to incorporate their test results in CSI's data pool on groundwater quality in the Marcellus and Utica Shale regions in upstate New York. Approximately 85 percent of clients have granted permission to date. Groundwater data will be incorporated into CSI's online interactive data archive by 2013. Data will be pooled in one-mile grid squares to protect homeowners' privacy. Each grid square will link to 20 separate graphs, one for each "signature chemical" (Figure 2). The grid squares will allow chemical concentrations to be mapped, providing enough information to spot spatial trends in "signature chemicals" relative to nearby gas wells or other potential sources of contamination, while protecting homeowners' privacy. As the map in Figure 2 shows, sample wells tend to occur in loose clusters, probably because private clients often find out about CSI through word of mouth, and because CSI splits travel costs among clients whose wells we sample in the same area on the same day. Other than splitting travel costs, CSI does not offer financial incentives. Clients pay 100 percent of the cost of baseline tests themselves. Therefore, pooled groundwater results comprise a near-random sample of groundwater quality in the Marcellus and Utica Shale regions in rural Southern and Central New York.

Groundwater quality data for New York State were downloaded from NWIS from 1990 to September 2012. ArcGIS [19] was used to select groundwater sampling sites in the area of New York State underlain by the Utica and Marcellus shale gas formations. Within the shale gas formations, a subset of sites was selected that corresponds more closely with the 13 counties in upstate New York where CSI has performed baseline testing on private wells: Otsego, Tompkins, Chenango, Delaware, Steuben, Tioga, Schuyler, Broome, Chemung, Yates, Schoharie, Seneca, and Sullivan. Results were averaged if a well was sampled more than once. A geographic information system (GIS) layer representing urban centers, residential areas, and industrial zones was created as a way to evaluate the distribution of the USGS's groundwater monitoring sites.

The CSI Database: A Tool for Community-Based Risk Assessment

Placing water quality data in the public domain and facilitating its analysis and use by stakeholders is central to the Community Science Institute's nonprofit mission of empowering communities to understand local water resources and manage them sustainably. The CSI data archive at www.communityscience.org/database is an integral feature of community-based risk assessment because it makes it possible for any member of the public, free of charge, to view, search, download, and analyze surface water data developed in collaboration with our volunteer stream monitoring groups as well as groundwater data belonging to our private clients who voluntarily agree to include their test results in CSI's anonymous groundwater data pool. CSI's database structure has evolved from a

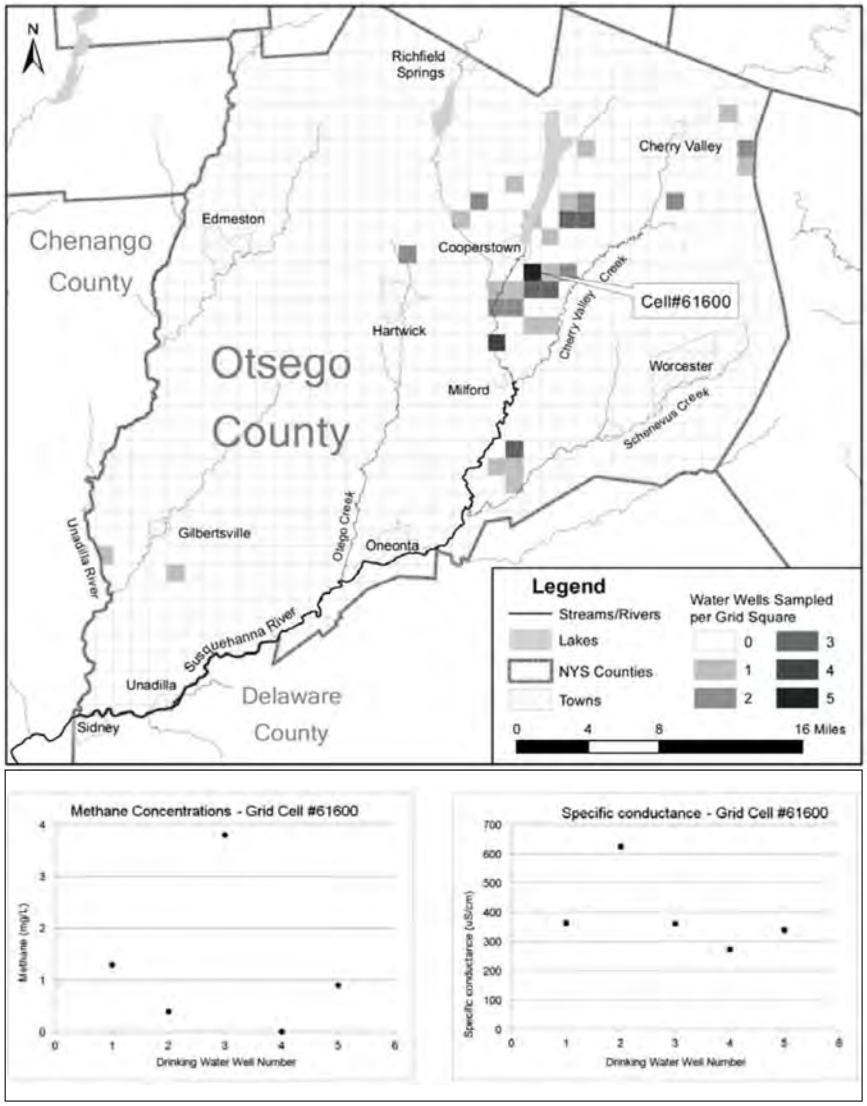


Figure 2. Example map and graphs illustrating presentation of regional groundwater baseline data planned for CSI website in 2013. The drinking water wells sampled by CSI in Otsego County are aggregated by one-mile grid square (total wells = 65). Methane and specific conductance data are grappled for one-mile grid square #61600.

Microsoft Excel-based approach, to a web-based architecture using the PHP scripting language and an SQL database back-end, and finally since 2011 to a Ruby on Rails® platform, chosen for its efficiency in building web applications. Visitors are provided with interactive tools to access over 30,000 data items linked to maps and graphs and to use a powerful querying mechanism to search the archive and export raw data. As a scalable archive, the CSI database is capable of organizing and presenting surface water and groundwater data from geographic areas of any size, including individual monitoring locations, watersheds, regions, countries, and continents. One hundred percent of the raw data produced by volunteer-CSI stream monitoring partnerships is made available to the public on the CSI website. Surface water data is searchable by region, stream, location, date, "signature chemical," and flow conditions. Pooled groundwater data shared by private clients will be incorporated into the database by 2013. Groundwater data will be searchable by region, county, one-mile grid square and "signature chemical" (see Figure 2).

RESULTS AND CONCLUSIONS

Surface Water Monitoring in Partnership with Groups of Trained Volunteers

Streams in Cayuga Lake Watershed

Baseline stream monitoring for an expanded list of gas well "signature chemicals" is in progress at this writing (October 2012). As noted above, although CSI's volunteer monitoring partnerships in this watershed since 2002 have focused on impacts from agriculture and residential development, there is some overlap between CSI's traditional sampling parameters and gas well "signature chemicals." Beginning in 2012, additional gas well "signature chemicals" are being tested once a year at a subset of Cayuga Lake watershed monitoring locations (see Methods). As a representative dataset for streams in the Cayuga Lake watershed, selected certified test results for Six Mile Creek and tributaries, downloaded through the data query interface for the CSI database at http://www.communityscience.org/database/entries, are summarized in Table 2 and compared to available data from the NWIS database. Median values are in good agreement considering CSI volunteers and agency staff sampled different locations on Six Mile Creek. As a preliminary estimate of variability in the CSI data set, the coefficient of variation was calculated for specific conductance under base-flow conditions for each of the 14 monitoring locations on Six Mile Creek, as follows. The data query interface in the CSI database was used to select the time period (2004-2012), monitoring region (Cayuga Lake watershed), monitoring set (Six Mile Creek), analyte (specific conductance), flow conditions (base flow), and test location (lab). The filtered data were

Table 2. Comparison of Selected "Signature Chemical" Indicators of Water Quality Under Base Flow Conditions[a] in Six Mile Creek and Tributary Streams as Measured by CSI's Certified Lab in Stream Samples Collected Synoptically by Volunteers[b] and by the U.S. Geological Survey (USGS)

	Data from certified CSI lab analyses of samples collected by Six Mile Creek volunteer group in 23 synoptic sampling events at 15 stream locations[c]			USGS data[d]
Parameters	Min	Max	Median (n)	Median (n)
Alkalinity (mg $CaCO_3$/L)	10.3	165	92.3 (299)	79 (14)
Barium (mg/L)[e]	0.017	0.056	0.0435 (8)	no data
Calcium hardness (mg $CaCO_3$/L)	19	89	71 (13)	no data
Chloride (mg/L)	3.54	57.8	18.6 (312)	19.7 (18)
Gross alpha radioactivity (pCi/L)[e]	0.22	1.55	0.595 (8)	no data
Gross beta radioactivity (pCi/L)[e]	0.97	3.83	1.69 (8)	no data
Total hardness (mg $CaCO_3$/L)	10.3	183	108 (312)	120.5 (18)
pH	6.75	8.85	7.5 (312)	8 (17)
Total nitrogen (mg/L)[f]	non-detect (< 0.11)	1.754	0.4 (291)	0.545 (15)
Total suspended solids (mg/L)	non-detect (< 0.625)	85	2.05 (311)	no data
Specific conductance (μS/cm)	58	450	254.5 (312)	297.5 (20)
Strontium (mg/L)[e]	0.045	0.108	0.085 (8)	no data
Sulfate (mg/L)	4.4	17.4	10.25 (139)	11.7 (18)
Total dissolved solids (mg/L)[e]	100	180	161.5 (8)	173 (17)
Turbidity (NTU)	0.38	81.2	4.48 (312)	no data

[a]Base flow is defined as a flow equal to or less than two times the historic median as recorded by the U.S.GS gauging station on Six Mile Creek at Bethel Grove for the day of a synoptic sampling event. The Six Mile Creek volunteer group performs on average three base flow and two stormwater sampling events per year.

[b]A "synoptic sampling event" or "synoptic monitoring event" is defined as one in which a group of volunteers collect samples at specific locations on the same day within a few hours of each other in order to facilitate comparison of water quality values throughout the sampled drainage area. In the CSI database (www.communityscience.org/database), "synoptic monitoring location" refers to a stream location that is always included in synoptic monitoring events for a particular monitoring set (e.g., the Six Mile Creek watershed) year after year. An "investigative monitoring location" is one which is sampled occasionally to track pollution that may be detected at synoptic locations.

[c]Certified lab data from 23 base flow sampling events at 14 synoptic sampling sites plus one investigative site on the Six Mile Creek mainstem and tributary streams from 2004-2012. Results may be viewed at www.communityscience.org/database/monitoringsets/5. Raw data may be selected and downloaded at http://www.communityscience.org/database/entries.

[d]U.S. Geologic Survey data from 16 sampling events at three sites on the Six Mile Creek main stem and six sites on Six Mile Creek tributaries from 2003-2005 (waterdata.usgs.gov/).

[e]Expanded gas well baseline parameters measured one time at seven synoptic sampling sites and one investigative site as part of a base flow synoptic sampling event in 2012.

[f]CSI Total Nitrogen equal to sum of total Kjeldahl nitrogen (TKN) and nitrate- + nitrite-nitrogen. According to Table 5.10 in the 2011 draft Supplemental Generic Environmental Impact Statement (dSGEIS) by the New York State Department of Environmental Conservation (NYSDEC), TKN is elevated approximately 300-fold in flowback compared to typical values in Six Mile Creek, making it a potential contributor to a "chemical signature" of gas well impacts.

downloaded to MS Excel, the mean and standard deviation were calculated, and the coefficient of variation (COV) was calculated as the ratio of the standard deviation to the mean multiplied by 100. The COV was calculated for each of the 14 synoptic sampling locations on Six Mile Creek. COVs for specific conductance at the 14 locations ranged from 13.6 percent to 31.5 percent, the mean COV was 21.4 percent, and the median COV was 20.7 percent. It is noted that the data query interface in the CSI database can be used to select and export other data sets for Six Mile Creek and analyze their variability. For example, COVs for total hardness were calculated for each of the 14 locations, and the mean COV for total hardness was found to be 22 percent. This low variability strengthens the baseline from which to assess possible impacts on specific streams and stream reaches if HVHHF activities take place in the Cayuga Lake watershed.

Streams in Upper Susquehanna River Basin

Unlike the Cayuga Lake watershed, where volunteer groups collect grab samples two to five times a year for certified analyses by the CSI lab, volunteers in the Upper Susquehanna River Basin perform monthly measurements of five red-flag parameters in the field and report their results to CSI. At this writing (October 2012), 77 red-flag volunteers are monitoring 125 locations draining 1,233 square miles in sub-watersheds of the Upper Susquehanna River basin (Figure 1). Volunteers are added continuously as word spreads and citizens contact CSI for training and technical support. Volunteer results that meet data acceptance criteria (provided in Table 1) are entered in the CSI database by CSI staff and may be searched and downloaded via the data query interface at http://www.communityscience.org/database/entries. Results obtained by CSI's first red-flag group, the Cayuta-Catatonk Water Watch, in the first year of their monthly monitoring program from February 2011 to February 2012, are summarized in Tables 3 and 4 and compared to data reported by state and federal agencies. Median values for pH, specific conductance and total hardness are lower than values reported by the NYSDEC and the Susquehanna River Basin Commission (SRBC). A possible explanation is that most of the agency data are collected from a single monitoring site located near the mouths of Catatonk Creek (Table 3) and Cayuta Creek (Table 4), while volunteers collected red-flag data throughout both watersheds including headwater streams. Coefficients of variation for specific conductance at 26 red-flag monitoring locations under base-flow conditions in Catatonk and Cayuta Creeks ranged from 9.8 percent to 74.6 percent with a mean COV for all locations of 33 percent and a median COV of 32.9 percent. The generally higher COVs at red-flag monitoring locations compared to Six Mile Creek locations may be due to the smaller data set, the lower accuracy of field measurements (Tables 3 and 4) compared to certified lab results (Table 2), greater temporal variation in specific conductance in Cayuta and Catatonk Creeks compared to Six Mile Creek, or a combination of these and other factors. Nevertheless, field measurements at fixed stream locations by volunteers (Tables 3 and 4) are sufficiently consistent over time to serve as effective baselines for detecting possible HVHHF impacts on streams. Baselines established by volunteers are important in view of the paucity of agency data on streams in recent years. A search of the federal STORET database indicated that stream data had been collected at 270 agency monitoring sites between 1990 and October of 2012 in the 13 counties in upstate New York where CSI is focusing its baseline monitoring programs (Figure 1). At least three of four red-flag parameters (pH, dissolved oxygen, specific conductance, total hardness) were measured at 85 percent of STORET sites. However, the median number of sampling events per site over the 22-year period from 1990-2012 was only four. Of the 270 STORET sites in the 13-county region, only 39 have been sampled since January 1, 2010.

Groundwater in the Marcellus and Utica Shale Regions

The NWIS database was searched for gas well "signature chemicals" that might be used in a regional baseline to assess HVHHF impacts on groundwater quality. Search results indicated that only a small fraction of wells in New

Table 3. Comparison of "Red-Flag" Indicators of Water Quality Measured by Cayuta-Catatonk Water Watch (CCWW) Volunteers with Agency Data under Base Flow Conditions in Catatonk Creek

	Catatonk Creek—CCWW data[a]			Catatonk Creek—NYSDES data[b]		
"Red-flag" indicators	Median (*n*)	Min	Max	Median (*n*)	Min	Max
pH	7.25 (48)	6.39	8.14	7.76 (46)	6.49	8.42
Dissolved oxygen (mg/L)	9.25 (58)	5.8	13.4	10.25 (22)	7.85	13.48
Specific conductance (μS/cm)	154.5 (56)	36	431	211 (46)	49	395
Total hardness (mg/L)	68 (44)	16	160	98.5 (10)	70.4	160

[a]Data collected by 4 volunteer teams at 11 sites throughout the Catatonk Creek watershed from Feb. 2011-Feb. 2012 (http://www.communityscience.org/database/monitoringsets/13).

[b]Data are primarily from the New York State Department of Environmental Conservation (NYSDEC), Rotating Integrated Basin Studies (RIBS), site #06032102, Apr.-Nov. 2004 (http://www.epa.gov/storet/dw_home.html), with additional data from two Susquehanna River Basin Commission sites and one NYDEC site.

Table 4. Comparison of “Red-Flag” Indicators of Water Quality Measured by Cayuta-Catatonk Water Watch (CCWW) Volunteers and Agency Data under Base Flow Conditions in Cayuta Creek

	Catatonk Creek—CCWW data[a]			Catatonk Creek—SRBC data[b]		
“Red-flag” indicators	Median (*n*)	Min	Max	Median (*n*)	Min	Max
pH	7 (118)	6	8.71	7.8 (186)	6.1	9
Dissolved oxygen (mg/L)	9.4 (135)	5.8	13.9	9.8 (164)	4.95	15.2
Specific conductance (μS/cm)	118 (134)	22	351	282 (190)	71	1165
Total hardness (mg/L)	53 (128)	12	152	120 (3)	106	148

[a]Data collected by 4 volunteer teams at 15 sites throughout the Cayuta Creek watershed from Feb. 2011-Feb. 2012 (http://www.communityscience.org/database/monitoringsets/12).

[b]Data are primarily from the Data are primarily from the Susquehanna River Basin Commission (SRBC), Interstate Stream Water Quality Network, Apr.-1990)-Oct. 2010 (http://www.epa.gov/storet/dw_home.html). The station providing the majority of data is CAYT001.7-4176 near the mouth of Cayuta Creek. Additional data are from three SRB stations and one NYSDEC station within the Cayuta Creek watershed.

York have been characterized with respect to potential HVHHF contamination. A total of 1,995 wells in New York have been analyzed for at least one chemical in at least one of eleven “signature chemical” categories since 1990 (Table 5). However, only 208 wells have been analyzed for at least one chemical in each of eight “signature chemical” categories, and of these, only 16 are located in rural areas of the Southern Tier (Table 5). Thus, the geographic distribution of agency data on groundwater quality is skewed away from the rural areas that are most at risk of impacts from HVHHF in New York.

Available agency data were filtered and tabulated in Table 6 to facilitate comparison with CSI groundwater data on “signature chemicals” in Table 7. Median values in CSI’s regional groundwater database reported in Table 7 were generally similar to median values extracted from the USGS’s NWIS database and tabulated in Table 6. Chloride, total dissolved solids, total hardness and specific conductance values were somewhat higher in the USGS data set. These differences could be explained by random variability. Groundwater quality is known to change over short horizontal and vertical distances as a result of differences in aquifer characteristics, geochemical conditions, and residence time [20]. Indeed, we observed substantial variability among private drinking water wells, including wells in the same 1-mile grid square (Figure 2). Another possible

Table 5. Certified Measurements of CSI "Signature Chemicals" in Groundwater Wells in Urban and Rural Areas of New York State Performed by the Community Science Institute and the U.S. Geological Survey

	Number of groundwater wells where certified measurements of gas well "signature chemicals" (SC) have been performed in New York					
	CSI		USGS			
Geographic area	8[a] of 11 SC categories[b]	11[a] of 11 SC categories[b]	1[a] of 11 SC categories[b]	5[a] of 11 SC categories[b]	7[a] of 11 SC categories[b]	8[a] of 11 SC categories[b]
New York total	121	110	1,995	1,260	580	208
New York shale region	121	110	709	458	109	80
Shale region—rural[c]	121	110	415	274	62	46
Shale region—urban/ contaminated[c]	0	0	294	184	47	34
Outside of shale region	0	0	1,286	802	471	128
13-county area	121	110	245	162	48	27
13-county area[d]—rural[c]	121	110	178	110	28	16
13-county area[d]—urban/ contaminated[c]	0	0	67	52	20	11

[a]Number of “signature chemical” categories for which certified measurements were performed on groundwater wells.

[b]CSI’s recommended list of 19 gas well “signature chemicals” and 52 volatile organic compounds (VOCs) were organized into eleven (11) categories of chemical characteristics with the goal of searching the NWIS database of the U.S. Geological Survey for existing groundwater quality data related to “hydrofracking.” Each of the eleven “signature chemical” (“SC”) categories contains one or more certified tests recommended by CSI as part of a pre-HVHHF baseline designed for use in screening groundwater for possible contamination due to gas well waste. The eleven (11) CSI “signature chemical” categories used to search the NWIS database are: (1) Methane; (2) Chemical oxygen demand; (3) Methylene blue active substances (anionic surfactants); (4) Total hardness, calcium; (5) Barium, strontium; (6) Iron, manganese, arsenic; (7) Turbidity, total suspended solids; (8) Gross alpha radioactivity, gross beta radioactivity; (9) Benzene, ethylbenzene, toluene, xylene; (10) pH, alkalinity; and (11) Chloride, specific conductance, total dissolved solids. While these eleven (11) categories are considered to be broadly representative of the chemical characteristics most likely to change as a result of contamination from shale gas wells, it is recognized that they are not completely inclusive, and that there are other groundwater characteristics in the NWIS database that might be impacted by “fracking.”

[c]Urban/contaminated areas are defined as the union of four GIS layers: (1) U.S. Census Bureau 2010 populated places, (2) U.S. Census Bureau 2010 urban areas, (3) One-mile corridors around EPA facilities and sites subject to environmental regulation and (4) One-mile corridors around the NYDEC remediation sites. This final GIS layer represents a rough measure of areas that have intensive residential, commercial, and industrial land use and can be distinguished from areas that are primarily rural in character.

[d]The 13-county area in upstate New York is defined as those counties where CSI has performed baseline testing on private groundwater wells: Otsego, Tompkins, Chenango, Delaware, Steuben, Tioga, Schuyler, Broome, Chemung, Yates, Schoharie, Seneca, and Sullivan.

Table 6. Levels of Gas Well "Signature Chemicals" in USGS Groundwater Monitoring Wells, 1990-2012

	USGS results for Marcellus and Utica Shale regions			USGS results for 13-county area in rural Southern Tier[a]		
Gas well signature chemical (units)	Wells tested (wells with detects)[b]	Min-max values for all wells[c]	Median values for all wells[d]	Wells tested (wells with detects)[b]	Min-max values for all wells[c]	Median values for all wells[d]
Calcium (mg Ca/L)	16 (16)	11.13-309.2	85	0 (0)	—	—
Alkalinity (mg $CaCO_3$/L	0 (0)	—	—	0 (0)	—	—
Total hardness (mg $CaCO_3$/L)	590 (590)	0.28-87,600	219	119 (119)	1.47-1,700	137
Total dissolved solids (mg/L)	459 (459)	33-193,000	294	119 (119)	33-7,130	205
Total suspended solids (mg/L)	0 (0)	—	—	0 (0)	—	—
Turbidity (NTU)	17 (17)	0.2-230.06	15.9	0 (0)	—	—
pH (pH units)	566 (566)	5.8-12.4	7.6	114 (114)	5.9-9.1	8
Chloride (mg/L)	574 (574)	0.4-126,000	32.4	119 (119)	0.4-3,380	13
Specific conductance (μS.cm)	555 (555)	45-129,333	535	119 (119)	47-11,300	356
Chemical oxygen demand (mg/L)	4 (0)	non-detect (< 10)	non-detect (<10)	4 (0)	non-detect (< 10)	non-detect (< 10)
Gross alpha radioactivity (pCi/L)[e]	98 (90)	–4-10.7	0.7	24 (16)	–0.4-10.7	1.05
Gross beta radioactivity (pCi/L)[e]	98 (87)	–0.9-19.1	1.6	24 (13)	–0.5-19.1	1.05
Methane (mg/L)	172 (153)	non-detect (< 0.001)-45.4	0.003	37 (18)	non-detect (< 0.001)-38.3	non-detect (< 0.001)

Methylene blue active substances (MBAS) (mg/L)	0 (0)	—	—	0 (0)	—	—
Barium, unfiltered (mg/L)	276 (276)	0.00109-10.4	0.1155	73 (73)	0.00488-10.4	0.110
Iron, unfiltered (mg/L)	275 (272)	non-detect (< 0.0046)-29.171	0.138	69 (66)	non-detect (< 0.0046)-3.47	0.138
Manganese, unfiltered (mg/L)	273 (271)	non-detect (< 0.00016)-1.6	0.0351	70 (68)	non-detect (< 0.00016)-0.594	0.03265
Arsenic, unfiltered (mg/L)	219 (209)	non-detect (< 0.00006-0.148)	0.00084	50 (40)	non-detect (< 0.00006)-0.027	0.00079
Strontium, unfiltered (mg/L)	276 (276)	0.0104-53.8	0.227	73 (73)	0.0104-31.1	0.247
Benzene (mg/L)	338 (5)	non-detect (<0.00002)-0.0561)	non-detect (< 0.00002)	85 (1)	non-detect (< 0.00002)-0.0003)	non-detect (< 0.00002)
Ethylbenzene (mg/L)	335 (4)	non-detect (< 0.00003)-0.0076)	non-detect (< 0.00003)	85 (1)	non-detect (< 0.00003)-0.0001	non-detect (< 0.00003)
Toluene (mg/L)	340 (30)	non-detect (< 0.00002)-0.023	non-detect (< 0.00002)	85 (8)	non-detect (< 0.00002)-0.001	non-detect (< 0.00002)
Xylene (mg/L)	27 (2)	non-detect (< 0.0002)-0.00475)	non-detect (< 0.0002)	0 (0)	—	—

[a]Counties included in this analysis: Otsego, Tompkins, Chenango, Broome, Steuben, Sullivan, Delaware, Schuyler, Tioga, Chemung, Schoharie, Seneca, Yates. Rural areas are defined as not urban/industrial areas. Urban/industrial areas are defined as U.S. Census Bureau 2010 populated places and urban areas; these GIS layers were merged with a layer comprised of 1-mile corridors around EPA facilities and sites subject to environmental regulation as well as NYSDEC remediation sites.

[b]Number of wells with concentrations above the laboratory's limit of quantitation (similar to detection).

[c]Minimum values that are below the laboratory's limit of quantitation (LOQ) are reported as "non-detect" with the LOQ in parenthesis.

[d]If the laboratory reported a non-detect, the value is less than the laboratory's limit of quantitation (similar to detection). If a well was sampled more than once, the value is taken to equal the average of all samples collected from that well. The quantitation limit is indicated by "<"; for example, a chloride value of < 2 means that the measurement was less than a limit of quantitation of 2 mg/L.

[e]USGS non-detects defined as "Radiochemistry non-detect, result below sample specific critical level."

Table 7. Levels of Shale Gas Well "Signature Chemicals" in Private Groundwater Wells Measured by the Community Science Institute, 2009-2012

Gas well "signature chemical" (units)	USGS results for rural Southern Tier[a]			Drinking water regulations/guidelines	
	Number of wells tested (number of wells with detects)[b]	Min-max values for all wells[c]	Median values for all wells[d]	Federal MCL value[e] (number of CSI wells over)	NY State MCL value[f] (number of CSI wells over)
Calcium (mg Ca/L)	121 (120)	< 1.2-156	32.6	none	none
Alkalinity (mg $CaCO_3$/L	122 (122)	8.13-450	140.5	none	none
Total hardness (mg $CaCO_3$/L)	121 (121)	8.8-635	107	none	none
Total dissolved solids (mg/L)	120 (114)	< 50-1090	180	none	500g (3)
Total suspended solids (mg/L)	121 (5)	< 4.0-91.6	< 4.0	none	none
Turbidity (NTU)	121 (120)	< 0.01-91.8	0.83	5 (14)	5 (14)
pH (pH units)	122 (122)	5.9-8.65	7.535	none	6.5-8.5[g]
Chloride (mg/L)	121 (82)	0.46-281.5	4.18	none	250[g] (2)
Specific conductance (μS.cm)	122 (122)	40.4-1682	298.5	none	none
Chemical oxygen demand (mg/L)	121 (31)	non-detect (< 10)-26.9	non-detect (< 10)	none	none
Gross alpha radioactivity (pCi/L)	121 (121)	–0.45-4.97	0.655	15 (0)	15 (0)
Gross beta radioactivity (pCi/L)	121 (121)	–0.59-40.83	1.08	15-50[j] (0)	15-50[j] (0)
Methane (mg/L)	122 (51)	non-detect[h]-14	non-detect[h]	none	10[i] (2)

Methylene blue active substances (MBAS) (mg/L)	122 (13)	non-detect (< 0.04)-0.054	non-detect (< 0.04)	none	0.5[g] (0)
Barium, unfiltered (mg/L)	122 (122)	0.0019-0.895	0.0657	2 (0)	2 (0)
Iron, unfiltered (mg/L)	122 (110)	non-detect (< 0.005)-11.3	0.0885	none	0.3[g] (26)
Manganese, unfiltered (mg/L)	122 (101)	non-detect (< 0.002)-1.52	0.045	none	0.3[g] (2)
Arsenic, unfiltered (mg/L)	122 (44)	non-detect (< 0.0005)-0.0248	non-detect (< 0.0005)	0.01 (2)	0.01 (2)
Strontium, unfiltered (mg/L)	108 (108)	0.0006-2.07	0.217	none	none
Benzene (mg/L)[k]	114 (0)	non-detect (< 0.0005)	non-detect (< 0.0005)	0.005 (0)	POC[l]
Ethylbenzene (mg/L)[k]	114 (0)	non-detect (< 0.0005)	non-detect (< 0.0005)	0.7 (0)	POC[l]
Toluene (mg/L)[k]	114 (3)	non-detect (< 0.0005)-1.3	non-detect (< 0.0005)	1 (1)	PCO[l]
Xylene (mg/L)[k]	114 (0)	non-detect (< 0.0005)	non-detect (< 0.0005)	10 (0)	POC[l]

[a]Counties (number of wells included in baseline): Otsego (59), Tompkins (13), Chenango (13), Broome (10), Steuben (7), Sullivan (5), Delaware (4), Schuyler (4), Tioga (3), Chemung (2), Schoharie (1), Seneca (1), Yates (1). Private clients must give written permission for their results to be included in the regional baseline.

[b]Number of wells with concentrations above the laboratory's limit of quantitation (similar to detection).

[c]Minimum values that are below the laboratory's limit of quantitation (LOQ) are reported as "non-detect" with the LOQ in parenthesis.

[d]If the laboratory reported a non-detect, the value is less than the laboratory's limit of quantitation (similar to detection). The quantitation limit is indicated by "<"; for example, a chloride value of < 2 means that the measurement was less than a limit of quantitation of 2 mg/L. If a well was sampled more than once, the value is taken to equal the average of all samples collected from that well with one exception: Exceedances of federal and state standards are noted regardless of the number of times a well is sampled.

Table 7. (Cont'd.)

[e]The MCL refers to the Maximum Contaminant Level, a health-based, enforceable standard under the federal Safe Drinking Water Act (SDWA). MCLs are based on human health risk assessments and are listed on the EPA website at: http://water.epa.gov/drink/contaminants/index.cfm#List. MCLs are distinct from National Secondary Drinking Water Standards (NSDWS), which are not health-based and not enforceable by EPA.

[f]State standards refer to levels of chemicals in drinking water that are enforced by New York State under the federal Safe Drinking Water Act (SDWA) and are listed at http://www.health.ny.gov/regulations/nycrr/title_10/part_5/subpart_5-1_tables.htm. An enforceable state standard must be equally or more stringent than a federal standard. A state is not required to base its enforceable standards on human health risk assessments; however, a state may refer to its standards as MCLs. In general, state MCLs are a mixture of federal health-based MCLs and federal non-health-based National Secondary Drinking Water Standards (NSDWS). For example, New York bases several enforceable standards on NSDWS, available at http://water.epa.gov/drink/contaminants/index.cfm#SecondaryList. NSDWS are not enforceable at the federal level because they are directed at cosmetic properties of drinking water such as taste and odor, not at risks to human health.

[g]Based on a National Secondary Drinking Water Standard (NSDWS) that is not health-based and is not enforceable by the federal government (see http://water.epa.gov/drink/contaminants/index.cfm#SecondaryList).

[h]The limit of quantitation (LOQ) for methane depends on the subcontract lab used. The lab used from 8/2009 to 6/2010 had an LOQ of 0.01 mg/L; the lab used since 6/2010 has an LOQ of 0.001 mg/L.

[i]A guidance value, not a standard. The U.S. Department of the Interior recommends that wells containing greater than 10 mg/L of dissolved methane be vented to minimize the explosion hazard that could result from methane volatilizing (escaping) from water and building up inside a home.

[j]Standard is based on an exposure limit of 4 mrem/year. This level of exposure corresponds to a concentration of 15 pCi/L to 50 pCi/L, depending on various factors. It is possible that the one well that exceeded 15 pCi/L may have resulted in an exposure greater than the federal MCL of 4 mrem/year.

[k]Results for so-called BTEX chemicals are reported here. Additional 48 volatile organic compounds (VOCs) analyzed by EPA Method 524.2 are omitted from this table but will be included in CSI's online groundwater database.

[l]*POCs* (principal organic contaminants) have an automatic New York State MCL of 0.005 mg/L: http://www.health.ny.gov/regulations/nycrr/title_10/part_5/subpart_5-1_tables.htm

explanation is that more USGS samples may have been collected in areas or regions with higher mineral content than CSI samples. Minimum values were similar in the CSI and USGS data sets, while maximum values were significantly higher in the USGS data set (compare Tables 6 and 7). The most likely explanation for the maximum values for chloride (126,000 mg/L), total dissolved solids (193,000 mg/L) and specific conductance (129,333 μS/cm) is groundwater brine resulting from salt deposits in the Syracuse area [21].

CSI's growing database indicates that groundwater quality in rural areas of New York's Southern Tier region is generally excellent with respect to gas well "signature chemicals." Results from 122 private wells with an aggregate total of 8,224 certified test results including 2,296 tests for 19 parameters related to brine, acid, metals, suspended solids, surfactants, bulk organic compounds, radioactivity, and methane, and 5,928 tests for 52 VOCs included in EPA Method 524.2, are summarized in Table 7. Twelve wells exceeded the federal standard for turbidity, one well exceeded the federal standard for arsenic and one exceeded the federal standards for both turbidity and arsenic. A fifteenth well exceeded the federal standards for turbidity and toluene; however, this was a newly drilled well, and no exceedances were observed in follow-up sampling. The remaining 107 wells showed no exceedances of federal standards for any of the 19 "signature chemicals" and 52 VOCs. Stated as a fraction of the total number of "signature chemical" results summarized in Table 7, exceedances of federal standards comprised 17 of 8,224 test results or 0.2 percent. Methane was detected in 51 of 122 wells (detection limit 0.001 or 0.01 mg/L, depending on subcontract lab); two wells had levels greater than 10 mg/L, the federal guideline for explosion hazard (Table 7). Methane concentrations may have been underestimated because containers were open during the approximately 20 seconds required to collect a sample, providing an opportunity for methane, a gas, to volatilize. Ethane, which was routinely analyzed along with methane, was not detected in any wells (detection limit 0.019 mg/L, data not shown).

It is important to note that state drinking water standards differ substantially from federal standards. In particular, New York enforces several federal National Secondary Drinking Water Standards (NSDWS), which address cosmetic, smell, and taste characteristics as MCLs, including state MCLs for iron, manganese, total dissolved solids, and methylene blue active substances (MBAS) (anionic surfactants). While the state has valid reasons for these regulations, they result in MCLs that are not based strictly on human health risk assessments. For example, the Institute of Medicine of the National Academy of Sciences has set an upper intake level (UL) for iron for adults of 45 mg/day [22], and thus an adult would have to ingest 150 liters or about 37 gallons of water per day to incur adverse health effects when the iron concentration is 0.3 mg/L, the MCL for New York State. A number of VOCs are regulated by New York as Principal Organic Contaminants (POCs) with obligatory MCLs of 0.005 mg/L even though health-based toxicity thresholds may be higher or unknown (Table 7). For these reasons, the number of MCL exceedances under New York State regulations exceeded the number of MCL exceedances under federal regulations (Table 7).

DISCUSSION

High-volume horizontal hydraulic fracturing or HVHHF, commonly known as fracking, is a new technology that is widely believed to present substantial risks to human health and the environment. Weak regulation of fracking by federal and state governments has resulted in a dearth of data on exposure to the hazardous chemicals employed by the shale gas industry and the effects of exposure on humans and other species.

The Value of Risk Assessment

Many if not most large-scale industrial activities entail the use of hazardous chemicals and the generation of hazardous chemical waste. The role of government is to encourage entrepreneurship, innovation, and productivity while ensuring that public health and environmental resources required for diverse economic activities are protected [23]. Risk assessment, properly conducted, provides an effective tool with which to evaluate industrial activities and decide the extent to which benefits to society justify inherent risks to human health and environmental resources. Even rudimentary risk assessments offer effective decision-making tools by helping to situate risks and benefits within the broader context of economic activity and quality-of-life goals for a place or a region.

The principles of risk assessment are well known to policymakers in government agencies and, one presumes, to lawmakers and their staffs in state legislatures and Congress. Nevertheless, the authors are not aware of a single systematic risk assessment anywhere in the United States that follows protocols developed by the National Academy of Sciences and the U.S. Environmental Protection Agency [15-17, 24] and widely accepted throughout the risk assessment community to marshal available evidence and examine the risks and benefits of HVHHF-based shale gas extraction. To the contrary, the industry has been exempted from key provisions of federal environmental laws [25], and its hazardous byproducts have been arbitrarily classified as non-toxic "industrial wastewater" in New York [26], effectively privileging the industry's growth and deflecting attention from the risks its growth entails. Risk assessment is the only available tool to evaluate the industry's impacts within the broader context of the diverse human and environmental communities in which it operates. In the absence of action by government, it is up to citizens to gather evidence on risk. The goal of CSI-volunteer monitoring partnerships is to target data gaps at the local level where government agency data is scarce or non-existent.

Surface Water Monitoring by Citizen Volunteers

Through its partnerships with groups of volunteers from rural communities in Upstate New York, the Community Science Institute collects scientifically credible water quality data in an effort to evaluate risks to local streams and lakes from land uses such as agriculture, residential development and, most recently, from the burgeoning HVHHF-based shale gas industry. Results are disseminated to the general public through CSI's unique online data archive, providing factual information that can be accessed by citizens and municipal and county governments to help understand and manage water resources in their jurisdictions.

There is a growing scientific literature that seeks to understand the degree to which data collected by volunteers are valid, the purposes for which these data can or should be used, how volunteer data might be disseminated, and how to create a nexus between volunteers, planners, and regulators so that the data are put to use [27-31]. We report here on monitoring partnerships between trained groups of volunteers and CSI's certified lab that represent a workable compromise between a formal structured program with integrated quality control and a more autonomous organizational structure that promotes volunteer empowerment. Key elements of CSI-volunteer monitoring partnerships are:

- Recruitment of volunteers in groups of 15-30 people loosely defined by region.
- A series of three free training workshops spaced at least two weeks apart to give group members an opportunity to reflect on what they are learning and to foster group identity and commitment.
- Stream-side demonstrations of test kits and meters by CSI staff and hands-on practice with test kits by volunteers.
- Organization of each group into teams of two to five volunteers.
- A clear quality assurance protocol that volunteer teams can implement on their own.
- Selection of sampling sites by teams with guidance and mapping support from CSI.
- Management of the online data repository by CSI, with CSI staff entering only data that satisfy acceptance criteria (Table 1).
- Capacity for dynamic mapping and graphing of data in CSI's public database, including capacity for visitors to the CSI website to select and export raw data free of charge.

The results presented here provide evidence that surface water monitoring partnerships between groups of public-spirited citizens and CSI's certified lab are capable of generating and publicizing data for use in understanding, protecting, and managing water resources in New York State's shale gas region. Median values obtained by CSI-volunteer monitoring partnerships agreed well with available agency data on surface water quality in the same general region, taking into account CSI's intentional focus on sampling sites located upstream and on small tributary streams as opposed to agencies' greater reliance on sampling sites located near stream mouths and agencies' inclusion of areas where contamination is suspected. Generally low coefficients of variation of data collected by volunteers at individual monitoring locations suggest that potential contamination events as well as long-term trends can be detected. The quality of volunteer data reported here is consistent with reports by other authors [29, 31].

Regional Groundwater Initiative

Groundwater monitoring is structured differently from surface water monitoring. While surface water monitoring is structured around active partnerships between CSI and volunteer groups, groundwater monitoring is based on private clients who contract with CSI's certified lab to collect and test drinking water samples from their home, then grant permission to aggregate their test results for anonymous dissemination on the CSI website. CSI's groundwater database continues to grow as more private clients request baseline tests and grant permission to pool their results. The groundwater data in CSI's archive of aggregated private client results were found to be representative of New York's shale gas region as indicated by the similarity of median values for gas well "signature chemicals" (Table 7) to groundwater data in the NWIS database (Table 6). Higher median and maximum values in the NWIS data set (Table 6) were probably due to the inclusion of groundwater data from areas with salt deposits and industrial and contaminated sites. The quality of groundwater in rural households with respect to gas well "signature chemicals" can only be described as excellent (Table 7). The most prevalent water quality issue by far was turbidity, which exceeded the federal standard of 5 NTU in 14 out of 122 private groundwater wells tested and which accounted for 14 out of 17 documented exceedances of federal health-based standards (Table 7). Methane was present in nearly half of private wells, in line with agency data [32, Table 6]. Methane concentrations ranged from barely detectable up to 14 mg/L, and the median value was 0.005 mg/L. The principal hazard associated with methane is explosion when concentrations reach 5.5 percent by volume in air, or about 55,000 ppm, and similar concentrations of methane can cause asphyxiation [33]. The U.S. Department of the Interior recommends venting wells containing methane concentrations greater than 10 ppm by weight or 0.001 percent in water in order to avoid gradual methane accumulation in air in enclosed living spaces. Methane is classified as toxicologically inert as long as oxygen is available, and animals are not affected by concentrations up to 10,000 ppm by volume in air [33, 34]; however, at concentrations greater than 50 percent or about 500,000 ppm by volume in air, nonspecific toxic effects secondary to oxygen deprivation have been noted [33]. The prevalence of methane in groundwater does not negate the value of methane as a "signature chemical," because concentrations would be expected to increase dramatically in the event of contamination resulting from leaks in well casings or from methane migration through subsurface fractures [12]. Ethane was not detected in any groundwater wells.

Aggregated private client groundwater results are being incorporated into CSI's electronic database (www.communityscience.org/database) and will be made available to the general public online by 2013. Online groundwater data will be organized by region, county and 1-mile grid square (Figure 2) in contrast to surface water results, which are organized by region, "monitoring set" (e.g., the watershed of a stream such as Six Mile Creek or Catatonk Creek), and monitoring location. One-mile grid squares should provide sufficient spatial information to investigate increases in post-drilling concentrations of "signature chemicals" in private drinking water wells.

Documenting HVHHF Impacts on Water

A post-fracking increase in the concentration of one or more "signature chemicals" can, in principle, be interpreted as evidence that water has been contaminated by nearby shale gas operations. The greater the number of "signature chemicals" and the higher their concentrations compared to pre-fracking baseline levels, the stronger the evidence of contamination. This application of "signature chemical" baselines should be valid both for an individual groundwater well and for a specific stream reach where pre-fracking baseline data is available. While it should be easier to detect contamination of a groundwater well that has been characterized on the basis of over 70 certified lab tests than a stream location that has been characterized on the basis of five red-flag tests performed by volunteers in the field, the guiding principle is the same: A significant change in the "chemical signature" of water quality that can be reasonably attributed to waste from the shale gas industry. Clearly the terms "significant" and "reasonable" are subject to interpretation. We anticipate that regulatory agencies and the courts will make decisions on a case-by-case basis, and that they will use a weight-of-evidence approach and take into account other factors in addition to changes in water quality, for example, proximity to a drill pad and visual evidence of a spill. Nevertheless, an increase over pre-fracking levels of "signature chemicals" is likely to constitute a strong, if not the strongest, piece of evidence that HVHHF-related contamination has occurred.

Detecting contamination by extrapolating "signature chemical" levels to groundwater wells and stream locations that lack pre-fracking data is decidedly less robust conceptually than comparing pre- and post-fracking data for the same drinking water well or the same stream location. Nevertheless, regional baselines should prove useful to agencies as part of a weight-of-evidence approach to identifying HVHHF impacts. Agencies will have to decide whether post-fracking levels of "signature chemicals" exceed regional values for groundwater, in the case of a private well, or regional values for surface water, in the case of a stream or a stream reach, sufficiently to support a determination that the well or the stream has been degraded as a result of shale gas extraction activities.

It seems possible that despite the heterogeneity of groundwater sources in the regional baseline, some "signature chemicals" might be distributed in statistically recognizable patterns, the simplest example being a normal distribution, or bell curve. The regional baseline for a normally distributed "signature chemical" in groundwater might be used to estimate the probability that its post-fracking concentration in a private well is due to chance (that is to say, it falls within the normal distribution of the pre-fracking data set); a low probability would strengthen the case for contamination. Similarly, statistical patterns of "signature chemicals" in regional stream baselines, if present, might be used to estimate the probability that post-fracking concentrations signify contamination of a stream for which no baseline data exists. Regional surface water baselines also include a temporal component, because red-flag data are collected monthly. Temporal patterns such as seasonal variation, which can be readily analyzed by filtering and downloading red-flag data from the CSI database (http://www.communityscience.org/database/entries), might strengthen the case for or against HVHHF impacts.

ACKNOWLEDGMENTS

Expanded baseline testing of Cayuga Lake tributary streams was made possible by funding from the Tompkins County Legislature. Support from the Park Foundation was crucial to expanding CSI's red-flag stream monitoring initiative in New York's Southern Tier counties. The authors wish to acknowledge the excellent work of CSI's laboratory staff, present and past, in performing certified baseline tests: Michi Schulenberg, Dan Liu, Tiffany Williams, and Sarah Brower. CSI's dedicated volunteer stream monitors perform outstanding work, year in and year out, and are the backbone of our baseline monitoring efforts. Finally, we wish to thank CSI's private clients for agreeing to pool their test results in order to provide the public with a clearer understanding of the state of groundwater resources prior to a decision by New York State whether to allow HVHHF to go forward.

AUTHORS' BIOGRAPHIES

REBECCA J. BOWEN is an Outreach Coordinator at the Community Science Institute (CSI) in Ithaca, NY. She works on the development and implementation of CSI's "red flag" monitoring partnerships with volunteer groups in New York's Southern Tier region. Her responsibilities also include the collection of groundwater samples from private drinking water wells for comprehensive baseline testing of gas well "signature chemicals." A member of the Ithaca Carshare staff before coming to work at CSI, she serves on the Board of Directors of the Finger Lakes Permaculture Institute. Rebecca is interested in designing practical solutions to complex ecological problems and finding mutually beneficial ways for humans to interact with the earth. Write to becky@communityscience.org

SORAYA DELGADO, the Latin American Director of Great Wilderness, is a Conservation Biologist and Environmental Educator and a native of coastal Ecuador. She studied Biology in Ecuador and has a bachelor's degree in environmental sciences from Florida International University. She has worked on conservation of biodiversity and research projects in diverse regions of Ecuador and Venezuela, including the Galapagos Islands, the Andean region, Pacific rainforests, and the Amazonian region. Since 2004, she has helped develop a long-term study of wild parrot communication in Venezuela established by scientists from U.C. Berkeley. In 2010 and 2011, she worked as Field Coordinator at CSI, coordinating the collection of groundwater samples from private drinking water wells for baseline testing of gas well "signature chemicals." Great Wilderness is a small NGO that supports protection and preservation of tropical biodiversity in South America. You can reach her at soraya@greatwilderness.org

ABNER X. FIGUEROA is a Senior Web Developer at the Community Science Institute, Ithaca, N.Y. and Web Applications Engineer III, UT Southwestern Medical Center in Dallas, Texas. He contributes extensive experience with relational database technologies to the development and design of CSI's website and its database web application. He is a skilled web applications engineer with a love of clean code and strong fundamentals in object-oriented programming. His passion is to make beautiful products and to bring critical thinking to real challenges.

STEPHEN M. PENNINGROTH holds a Ph.D. in Biochemical Sciences from Princeton University. He is founder of the non-profit Community Science Institute (CSI) in 2000 and serves as its Executive Director as well as Lead Technical Director of its state-certified environmental testing lab. Previously, Steve served on the faculty of the University of Medicine and Dentistry of New Jersey's School of Osteopathic Medicine as assistant and associate professor from 1978-1993, pursuing research on the molecular basis of cell motility and teaching pharmacology and toxicology to medical students. From 1993 to 2000, he taught environmental toxicology at Cornell University in Ithaca and worked as a consultant for community groups impacted by Superfund sites in New York and New Jersey, with funding through EPA's Technical Assistance Grant (TAG) program. He is interested in ways that scientists at non-profit organizations can support sustainable development at the local level by fostering the production of data to inform communities about the state of their local resources. Write to him at spenningroth@communityscience.org

MATTHEW M. YARROW has a Ph.D. in Ecology and Evolutionary Biology from the Universidad de Chile. He is a GIS analyst at the Community Science Institute in Ithaca, NewYork and a member of the Centro Transdisciplinario de Estudios FES-Sistemicos in Santiago, Chile. At CSI, he works as a cartographer, GIS analyst and data analyst. His doctoral thesis addressed the spatial aspects of nutrient cycles, and as a member of the Ecological Modeling Lab at the Universidad de Chile, he participated in an international multidisciplinary project that created integrated management tools for stakeholders in the Aysen Basin of southern Chile. Matt seeks to understand how water, nutrients, and contaminants move in the landscape and how these processes interact with human activities. He thinks that furthering this knowledge is key to managing our water resources sustainably. His email address is myarrow@communityscience.org

NOTES

1. M. Mitka, "Rigorous Evidence Slim for Determining Health Risks From Natural Gas Fracking," *JAMA—Journal of the American Medical Association* 307 (20) (2012): 2135-2136, doi: 10.1001/jama.2012.3726.
2. S. Entrekin et al., "Rapid Expansion of Natural Gas Development Poses a Threat to Surface Waters," *Frontiers in Ecology and the Environment* 9 (9) (2011): 503-511, doi: 10.1890/110053.
3. S. G. Osborn et al., "Methane Contamination of Drinking Water Accompanying Gas-Well Drilling and Hydraulic Fracturing," *Proceedings of the National Academy of Sciences* 108 (20) (2011): 8172-8176, doi: 10.1073/pnas.1100682108.
4. U.S. Environmental Protection Agency, *EPA Releases Draft Findings of Pavillion, Wyoming Ground Water Investigation for Public Comment and Independent Scientific Review*, December 8, 2011, http://yosemite.epa.gov/opa/admpress.nsf/20ed1dfa1751192c8525735900400c30/ef35bd26a80d6ce3852579600065c94e!OpenDocument (accessed July 24, 2012).
5. Associated Press, "2 Killed in Gas Well Explosion in Western Pa." October 29, 2010, http://www.timesleader.com/news/hottopics/shale/2-killed-in-gas-well-explosion-in-western-Pa.html (accessed July 24, 2012).
6. Associated Press, "Pennsylvania Gas Well Spews Polluted Water," April 20, 2011, http://www.nytimes.com/2011/04/21/us/21frack.html (accessed July 24, 2012).
7. PA Department of Environmental Protection, "DEP Fines Catalyst Energy $185,000 for Water Contamination, Erosion Violations, Spills," February 22, 2012, http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=19275&typeid=1 (accessed July 24, 2012).
8. J. Blevins, U.S. Environmental Protection Agency, "Emergency Order to Range Resources Corporation," [Letter], December 7, 2010, http://www.epa.gov/region6/6xa/pdf/range_letter.pdf (accessed July 24, 2012).
9. E. Griswold, "The Fracturing of Pennsylvania," *The New York Times*, November 17, 2011, http://www.nytimes.com/2011/11/20/magazine/fracking-amwell-township.html?_r=1&pagewanted=all (accessed July 24, 2012).

10. A. Lustgarten and N. Kusnetz, “Science Lags as Health Problems Emerge Near Gas Fields,” *ProPublica*, http://www.propublica.org/article/science-lags-as-health-problems-emerge-near-gas-fields (accessed July 26, 2012).
11. M. Bamberger and R. E. Oswald, “Impacts of Gas Drilling on Human and Animal Health,” *New Solutions: A Journal of Environmental and Occupational Health Policy* 22 (1) (2012): 51-77, doi: 10.2190/NS.22.1.e.
12. N. R. Warner et al., “Geochemical Evidence for Possible Natural Migration of Marcellus Formation Brine to Shallow Aquifers in Pennsylvania,” *Proceedings of the National Academy of Sciences* (in press), doi: 10.1073/pnas.1121181109.
13. D. J. Rozell and S. J. Reaven, “Water Pollution Risk Associated with Natural Gas Extraction from the Marcellus Shale,” *Risk Analysis* 32 (8) (2012): 1382-1393, doi: 10.1111/j.1539-6924.2011.01757.x.
14. “Physician Sign-On Letter to Governor Cuomo 10/5/11,” [Letter], October 5, 2011, http://www.psehealthyenergy.org/data/lettertoGovCuomofinal.pdf (accessed July 20, 2012).
15. Committee on the Institutional Means for Assessment of Risks to Public Health, Commission on Life Sciences, National Research Council, *Risk Assessment in the Federal Government: Managing the Process* (Washington, DC: National Academy Press, 1983).
16. U.S. Environmental Protection Agency, Risk Assessment Forum, *Guidelines for Ecological Risk Assessment* (EPA/630/R095/002F), 1998.
17. Committee on Improving Risk Analysis Approaches Used by the U.S. EPA, Board on Environmental Studies and Toxicology, Division on Earth and Life Studies, National Research Council of the National Academies, *Science and Decisions: Advancing Risk Assessment* (Washington, DC: National Academy Press, 2009).
18. New York State Department of Environmental Conservation, *Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program*, 2011, http://www.dec.ny.gov/energy/75370.html (accessed October 1, 2012).
19. ArcGIS Desktop: Release 10, Environmental Systems Research Institute, Redlands, CA, 2011.
20. L. DeSimone, P. Hamilton, and R. Gilliom, U.S. Geologic Survey, *Quality of Water from Domestic Wells in Principal Aquifers of the United States, 1991-2004: Overview of Major Findings* (Circular 1332), 2009.
21. R. M. Yager, W. M. Kappel, and L. N. Plummer, *Halite Brine in the Onondaga Trough Near Syracuse, New York: Characterization and Simulation of Variable-Density Flow* (Scientific Investigations Report 2007-5058), 2007, http://pubs.usgs.gov/sir/2007/5058/pdf/SIR2007-5058.pdf (accessed October 15, 2012).
22. Panel on Micronutrients, Subcommittees on Upper Reference Levels of Nutrients and of Interpretation and Use of Dietary Reference Intakes, and the Standing Committee on the Scientific Evaluation of Dietary Reference Intakes, Food and Nutrition Board, Institute of Medicine, *Dietary Reference Intakes for Vitamin A, Vitamin K, Arsenic, Boron, Chromium, Copper, Iodine, Iron, Manganese, Molybdenum, Nickel, Silicon, Vanadium and Zinc* (Washington, DC: National Academy Press, 2001).
23. Stephen Penningroth, *Essentials of Toxic Chemical Risk: Science and Society* (Boca Raton: CRC Press, 2010).

24. U.S. Environmental Protection Agency, “Risk Assessment Portal.” http://www.epa.gov/riskassessment (accessed July 26, 2012).
25. Energy Policy Act of 2005, 42 U.S.C. §322. (2005), http://www1.eere.energy.gov/femp/pdfs/epact_2005.pdf (accessed July 26, 2012).
26. Environmental Conservation Law Section 27-0900 et seq, Part 371.1 (e) (2) (v)—Identification and Listing of Hazardous Wastes, Exclusions: Solid Wastes Which are Not Hazardous Wastes (2006), http://www.dec.ny.gov/regs/14897.html#14902 (accessed July 26, 2012).
27. C. Gouveia et al., “Promoting the Use of Environmental Data Collected by Concerned Citizens Through Information and Communication Technologies,” *Journal of Environmental Management* 71 (2) (2004): 135-154, doi: 10.1016/j.jenvman.2004.01.009.
28. L. S. Fore, K. Paulsen, and K. O’Laughlin, “Assessing the Performance of Volunteers in Monitoring Streams,” *Freshwater Biology* 46 (1) (2001): 109-123, doi: 10.1111/j.1365-2427.2001.00640.x.
29. C. C. Conrad and K. G. Hilchey, “A Review of Citizen Science and Community-Based Environmental Monitoring: Issues and Opportunities,” *Environmental Monitoring and Assessment* 176 (1-4) (2010): 273-291, doi: 10.1007/s10661-010-1582-5.
30. E. Nicholson, J. Ryan, and D. Hodgkins, “Community Data-Where Does the Value Lie? Assessing Confidence Limits of Community Collected Water Quality Data,” *Water Science & Technology* 45 (11) (2002): 193-200.
31. F. Danielsen, N. D. Burgess, and A. Balmford, “Monitoring Matters: Examining the Potential of Locally-Based Approaches,” *Biodiversity and Conservation* 14 (11) (2005): 2507-2542, doi: 10.1007/s10531-005-8375-0.
32. W. M. Kappel and E. A. Nystrom, *Dissolved Methane in New York Groundwater, 1999-2011* (U.S. Geological Survey Open-File Report 2012-1162), 2012.
33. Committee on Toxicology, Board on Toxicology and Environmental Health Hazards, Commission on Life Sciences, National Research Council, *Emergency and Continuous Exposure Limits for Selected Airborne Contaminants Volume 1* (Washington, DC: National Academy Press, 1984).
34. Air Products and Chemicals, Inc., “Material Safety Data Sheet—Methane.” [Material Safety Data Sheet], April 2006, https://apdirect.airproducts.com/msds/DisplayPDF.aspx?docid=63396 (accessed July 28, 2012).

Direct reprint requests to:

Dr. Stephen Penningroth
Community Science Institute
284-284 Langmuir Lab/Box 1044
95 Brown Road
Ithaca, NY 14850
e-mail: spenningroth@communityscience.org

NEW SOLUTIONS, Vol. 23(1) 167-187, 2013

Features

DISCLOSURE OF HYDRAULIC FRACTURING FLUID CHEMICAL ADDITIVES: ANALYSIS OF REGULATIONS

ALEXIS L. MAULE
COLLEEN M. MAKEY
EUGENE B. BENSON
ISAAC J. BURROWS
MADELEINE K. SCAMMELL

ABSTRACT

Hydraulic fracturing is used to extract natural gas from shale formations. The process involves injecting into the ground fracturing fluids that contain thousands of gallons of chemical additives. Companies are not mandated by federal regulations to disclose the identities or quantities of chemicals used during hydraulic fracturing operations on private or public lands. States have begun to regulate hydraulic fracturing fluids by mandating chemical disclosure. These laws have shortcomings including nondisclosure of proprietary or "trade secret" mixtures, insufficient penalties for reporting inaccurate or incomplete information, and timelines that allow for after-the-fact reporting. These limitations leave lawmakers, regulators, public safety officers, and the public uninformed and ill-prepared to anticipate and respond to possible environmental and human health hazards associated with hydraulic fracturing fluids. We explore hydraulic fracturing exemptions from federal regulations, as well as current and future efforts to mandate chemical disclosure at the federal and state level.

Keywords: groundwater, Safe Drinking Water Act, contamination, legislation, fracking

doi: http://dx.doi.org/10.2190/NS.23.1.j
http://baywood.com

Hydraulic fracturing, also known as fracking, is an increasingly widespread practice used to extract natural gas and oil from shale formations deep below the surface of the earth. Optimization of recovery technologies and lucrative natural gas prices led to a 48 percent increase in U.S. shale gas production from 2006 to 2010 with an estimated 35,000 wells drilled annually [1, 2]. Hydraulic fracturing involves drilling a vertical well approximately 5,000 to 9,000 feet into a shale formation [3]. Horizontal drilling, when appropriate, stems perpendicularly from the base of the vertical well and may extend outwards up to 10,000 feet [4]. Wells are drilled and lined by a steel pipe and cemented into place. After placement, electric currents are sent to a perforating gun located near the base of the well, where a charge shoots small holes through the steel and cement into the shale [3]. This allows the highly pressurized fluid-and-proppant mixture injected into the well to escape the well and create cracks and fractures in the surrounding shale layers [5]. Proppants are size-graded, rounded and nearly spherical white sand, ceramic, or man-made particles which are suspended in pressurized fluid [6]. The resultant fractures allow gas trapped within the shale to escape, along with some fracturing fluid and naturally occurring mineral deposits, and flow back up the well to the surface for capture [3].

FRACTURING FLUIDS AND ENVIRONMENTAL HEALTH

Hydraulic fracturing is controversial. Proponents argue that fracking creates a novel source of cheap, domestic energy and may replace some “dirty” energy sources like coal-fired power plants [5]. They claim that using natural gas as a “clean” energy source will make it easier to meet federal air and water quality standards [7] while also reducing our dependence on foreign oil [4]. The website of Halliburton, one of the major corporate proponents of fracking, states: “fracture stimulation is a safe and environmentally sound practice based on the industry’s decades-long track record, as well as the conclusions of government and industry studies and surveys” [8]. In 2009, industry estimated undeveloped but recoverable shale gas reserves in the lower 48 states amounting to 24 billion barrels: enough to heat U.S. homes for 30 years [9, 10].

Use of Fracturing Fluids

Opponents of hydraulic fracturing primarily cite concerns related to the environment, human health, and questions about the reality of promised long-term economic benefits in areas that are heavily drilled. The primary threat and controversy surrounding hydraulic fracturing, as it pertains to human health and groundwater contamination, is the use of fracturing fluids. Current estimates place the volume of fracturing fluid pumped into each well between 2 million and 4 million gallons, with the major components being water (90%), sand or proppants (8-9.5%), and chemicals (0.5-2%) [11]. Chemicals are added to fracturing fluids to increase well productivity by creating fractures in the rock (mostly shale) formation and holding the fractures open for the release of natural gas. Fracturing fluid additives include proppants (particles that keep fractures open), acids, gelling agents (which thicken the fracturing fluid), gel breakers (which allow fracturing fluid and gas to flow easily back to surface), bactericides, biocides, clay stabilizers, corrosion inhibitors, crosslinkers (which help maintain viscosity of fracturing fluid), friction reducers, iron controls, scale inhibitors, and surfactants. The composition of the fluid is determined based on characteristics of the well (e.g., geology of area) and production objectives. Some of the identified chemicals have known human health effects. For example, the surfactant benzene is classified by the U.S.EPA as a known human carcinogen (Group A), and xylene is a central nervous system depressant [12, 13]. Since companies invest time and resources into perfecting their fluid technologies, industry views chemical recipes as proprietary information that should be protected as trade secrets; thus many of the chemicals used remain unknown [5, 14].

The use of chemicals in the natural gas extraction process is not limited to the injection of fracking fluids. During the initial process of drilling the vertical well, chemicals are added to "drilling muds" to reduce friction, ease the drilling process, and shorten drilling time [14]. In addition to concerns regarding contamination of water during the drilling and fracturing process, there are concerns about groundwater contamination from the salts, chemicals, and naturally occurring radioactive material present in flowback, which is usually temporarily pumped into wastewater ponds and then moved off-site, where it is re-injected back into the ground or transferred to wastewater treatment facilities for treatment and disposal. The practice of treating flowback and "produced water" at publicly owned treatment works (POTWs) has largely ended; particularly in Pennsylvania, where less than 1 percent of fracking wastewater is treated in this manner after the state's Department of Environmental Protection (PaDEP) asked POTWs to voluntarily stop accepting fracking wastewater [15]. Now, the majority of flowback or "produced water" that is not disposed of in injection wells is treated at centralized waste treatment (CWT) facilities that are designed to treat industrial wastewater, and which may then discharge into sewers or surface water bodies. However, a report by the Natural Resources Defense Council (NRDC) found that wastewater discharged from these CWT facilities into surface water bodies still contained high levels of salts, bromides, and other pollutants [15].

Between 2009 and 2011, the EPA investigated potential groundwater contamination due to fracking in Pavilion, WY, and released its draft report in December 2011 [16]. EPA detected high concentrations of benzene, xylenes, and other gasoline and diesel range organics (types of petroleum hydrocarbon compounds), indicating a source of shallow groundwater contamination [16].

This EPA report is one of the few investigations of possible environmental contamination by hydraulic fracturing fluid injection. A single EPA report from 2004 found minimal risk to underground sources of groundwater due to hydraulic fracturing; however, this study was conducted in an area where coalbeds were being fractured, and not shalebeds, where the vast majority of fracturing occurs today [17]. No EPA reports to date have been released regarding the risks to groundwater and air associated with hydraulic fracturing in shalebeds. However, in 2011, Osborn and colleagues at Duke University published a study that showed increased concentrations of methane, ethane, and propane in private drinking-water wells directly attributable to the gas-well drilling in the Marcellus shale formation of Pennsylvania and New York [18]. The same research group did not find evidence of increased salinity or contamination from fracking fluids in a sample of private drinking-water wells [19]. However, these two studies and others acknowledge that hydraulic fracturing increases the permeability of shalebeds, creating new flow paths and enhancing natural flow paths for gas leakage into aquifers; these same pathways create a possible, although unlikely, contamination pathway for fracturing fluids [18-20]. The creation of additional fractures in the shalebeds and the drilling of wastewater disposal injection wells also change the hydrostatic pressure of the shale formation, possibly speeding up the normally extremely slow vertical flow of native and injected fluids closer to aquifers and the surface [20].

Voluntary Chemical Disclosure

With the exception of state-specific laws, disclosure of the chemicals present in fracturing fluid is primarily based on self-regulation: that is, voluntary reporting by the natural gas companies. Starting in January 2011, the Groundwater Protection Council and the Interstate Oil and Gas Compact joined forces to create the website FracFocus.org. Natural gas companies can provide well-specific information including the chemical composition of the fracturing fluid used at that particular well [21]. The chemical information may include Chemical Abstract Service (CAS) numbers, the purpose of an additive (e.g., proppant, biocide, gelling agent), and the maximum volume of the additive in hydraulic fracturing fluid [21]. The reporting of hydraulic fracturing chemicals is completely voluntary, and thus the accuracy and completeness of the information reported is unknown. The website does provide guidance stating that any chemical that has a Material Safety Data Sheet (MSDS) and is deemed nonproprietary should be reported [21]. However, chemicals are often reported as classes of chemicals (e.g., carbohydrate polymer, aliphatic alcohol), so that the exact identity of the chemical is unknown. While voluntary reporting is a first step toward increasing disclosure and public knowledge—and industry and some state governments view it as sufficient—the website does not have any government oversight nor does it provide complete information for lawmakers, regulators, or communities regarding the specific chemicals that are being injected during hydraulic fracturing.

Recently, The Endocrine Disruption Exchange (TEDX)[1] conducted a study to determine chemical mixtures present in fracturing fluids [14]. TEDX created a list of 944 products currently used in natural gas operations as reported by a variety of sources including the U.S. Bureau of Land Management, the U.S. Forest Service, state government departments, and the natural gas industry. Among those products, 632 different chemicals were identified (e.g., methanol, ethylene glycol) [14]. More than 75 percent of the chemicals identified in the TEDX report are known to affect the skin, respiratory system, and/or the gastrointestinal system. Further, approximately 50 percent of the chemicals are known to have effects on the nervous system, immune system, and/or cardiovascular/circulatory system [14].

The chemical additives are undeniably a small fraction of the fluid composition. However, they consist of up to 2 percent of approximately 2 million gallons of fluid used in each operation; which results in nearly 40,000 gallons of undisclosed chemicals used at each well [11]. TEDX was able to identify many chemicals commonly used in fracturing fluid; however, it reports that for 43 percent of the products it investigated, only 1 percent of the total chemical composition of the product was identified [14]. This demonstrates that the precise chemical makeup of most fracturing fluids remains largely unknown. Lawmakers and the public lack information regarding the chemical mixtures used in fracturing fluid because companies are largely not required to release this information to regulators or the public. There is no federal regulation that mandates chemical disclosure, and state regulations exist but are varied. Lack of full chemical disclosure prevents us from understanding possible health and environmental effects associated with hydraulic fracturing and injection of fracturing fluids, as well as preventing proper monitoring of chemical contamination as a result of hydraulic fracturing operations.

HYDRAULIC FRACTURING EXEMPTIONS IN FEDERAL REGULATIONS

Currently there are no federal regulations requiring natural gas companies to disclose information about chemicals used in hydraulic fracturing fluids. As a technology used by the natural gas industry, hydraulic fracturing is often considered a protected practice in laws from which the oil and gas exploration industry as a whole is exempt from regulation, including the Emergency

[1] TEDX (www.endocrinedisruption.com) is a nonprofit organization whose mission is to prevent harmful exposures to endocrine-disrupting chemicals by seeking out, selecting, organizing, reviewing, and interpreting scientific research.

Planning and Community Right-to-Know Act of 1986 (EPCRA) [22]. Hydraulic fracturing as an injection process is specifically exempt from the Safe Drinking Water Act (SDWA) [23, 24].

Emergency Planning and Community Right-to-Know Act

Hydraulic fracturing and reporting of the chemicals used in fracturing fluid is exempt from EPCRA [24]. Section 313 of EPCRA created the Toxic Release Inventory (TRI), which requires companies that manufacture and/or use toxic chemicals to report information on chemicals, including identities and quantities that are stored, released, transferred, or "otherwise used" [25, 26]. The reporting requirements for toxic chemical releases include any intentional or unintentional discharge of toxic chemicals into the air, water, and/or soil [25]. Except for chemicals claimed as trade secrets, the information reported to TRI is deemed public knowledge, so that communities remain informed about possible chemical exposures [26]. However, the North American Industry Classification System (NAICS) code for Oil and Gas Extraction is not listed under Section 313 of EPCRA, exempting this industry from reporting information on the release of toxic chemicals [26]. Consequently, quantities of chemicals used in hydraulic fracturing fluid are not subject to TRI reporting guidelines.

Safe Drinking Water Act

Historically, the EPA did not regulate hydraulic fracturing under the Underground Injection Control (UIC) Program of the SDWA because the combined processes (well-drilling, injection of hydraulic fracturing fluids, and natural gas extraction) were considered primarily "extraction" processes rather than "injection" processes [17]. The UIC Program is responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal [27].

However, a 1997 decision by the11th Circuit Court of Appeals in a lawsuit brought by the Legal Environmental Assistance Foundation (LEAF) against EPA required the agency to regulate hydraulic fracturing in Alabama as a Class II injection well (injection related to the production of oil and gas) under the UIC Program of the SDWA [28].

LEAF originally petitioned the EPA on behalf of the McMillian family, who claimed that nearby fracking had contaminated their well water [29]. The petition requested that the EPA withdraw Alabama's primary enforcement responsibility (known as primacy) for the state's UIC program until the state included regulations for the injection of hydraulic fracturing fluids as part of the program plan [29]. If included under this regulation, injection of fracturing fluid would be subject to a permitting, reporting, and monitoring process [26]. The EPA asserted that the UIC Program under the SDWA does not specifically require regulation of hydraulic fracturing and maintained that it had no legal requirement to regulate hydraulic fracturing as an injection process [30]. The 11th Circuit Court of Appeals disagreed with the EPA. Following the court's decision, the EPA was required to conduct a study to assess the risk posed to human health by the process of hydraulic fracturing.

While EPA's study was ongoing, in 2003, the agency entered into Memorandum of Agreement (MOA) with three companies which are together responsible for 95 percent of the hydraulic fracturing projects in the United States. As part of the MOA, these companies would not use diesel as part of the fracturing fluid mixture when they are removing natural gas from areas near underground drinking water sources. However, this MOA is not enforceable, and there is no penalty for a company should it wish to terminate the agreement [31].

EPA's court-mandated report, issued in 2004, determined that no further study into the health effects of hydraulic fracturing was necessary. Critics have questioned the legitimacy of this study because it did not involve any data collection, instead depending on existing literature and interviews with industry representatives and state and local government officials. In addition, the study considered effects on drinking water only from drilling in coal beds, but fracking takes place in additional types of substrates [32].

Regardless of the alleged flaws in the EPA report, in August 2005 Congress passed the Energy Policy Act exempting fracking from regulation under the 1974 Safe Drinking Water Act [17]. Specifically, the Energy Policy Act included in Section 322 an amendment to Section 1421(d)(1) of the SDWA exempting hydraulic fracturing as an underground injection process (42 USC 15801 § 322). The amendment states that underground injection "excludes – (i) the underground injection of natural gas for purposes of storage; and (ii) 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" [23].

FAILED ATTEMPTS AT FEDERAL REGULATION

Two acts introduced in the last five years, and one proposed rule by the Obama Administration [33], attempted to amend federal exemptions of hydraulic fracturing and/or introduce provisions mandating the disclosure of the chemical composition of fracturing fluid. All three attempts to regulate chemicals in fracturing fluid at the federal level failed. A third act has proposed to specifically designate this as a responsibility of states.

The American Power Act

In 2010, Senators John Kerry (D-MA) and Joseph Lieberman (I-CT) introduced the American Power Act, which included a section amending Section 324 of the Emergency Planning and Community Right-to-Know Act of 1986 [34]. As mentioned previously, as a practice of the oil and gas extraction industry, hydraulic fracturing is not included in the list of activities/industries required to report toxic chemical releases under EPCRA. Section 4131, Notice of Hydraulic Fracturing Operations, of the proposed American Power Act stipulated that “a hydraulic fracturing service company shall disclose all chemical constituents used in a hydraulic fracturing operation to the public” [35]. The bill would have required information to be distributed to the public via the internet, for the benefit of both private citizens and state and local authorities who are often unaware of the fracturing chemicals being used in their regions [35]. The Act was reportedly opposed for reasons unrelated to the hydraulic fracturing amendment clause and never made it out of committee [34].

The Fracturing Responsibility and Awareness Act

The Fracturing Responsibility and Awareness (FRAC) Act entered House and Senate committees in both the 111th and 112th Congressional Sessions with the sole purpose of regulating hydraulic fracturing at a federal level [36]. The FRAC Act had two major purposes: (1) to amend Section 1421(d)(1) of the SDWA by removing the clause that exempts hydraulic fracturing from regulation under the UIC program; and (2) to mandate the disclosure of fracturing fluid chemical composition by adding regulations to Section 1421(b) of the SDWA, which outlines requirements for State UIC programs [37].

The chemical disclosure requirements in the FRAC Act had four specific objectives. First, operators of a well site must disclose to a designated federal or state regulator a list of chemicals intended for use before the fracturing fluid is injected [36]. When injection and extraction operations are complete, the operator must disclose the list of chemicals that were present in the fracturing fluid that was actually used [36]. Specifically, for every chemical being used (intended and actual), companies must disclose names (including CAS numbers), safety information (MSDS), and specific volumes of each chemical used. Second, the disclosure clause stipulated that information on nonproprietary chemicals be released to the public [36]. Third, if a spill occurs or an emergency situation arises, well operators must disclose the specific identity of all proprietary chemicals so that regulators and emergency personnel can properly address the situation [36]. Finally, the bill allows for proprietary information to be excluded from public disclosure in emergency and non-emergency situations [36]. Only information on nonproprietary chemicals will be released into public domain.

Supporters of the FRAC Act emphasized that the proposed amendment to the SDWA made certain that hydraulic fracturing would be regulated under “a consistent set of federally enforceable regulatory requirements” [38]. Senator Casey (D-PA) released a statement saying, “Disclosure will ensure that if drinking water supplies, surface waters, or human health are compromised, the public and first responders will know how to respond properly. I view disclosure as a simple matter of citizens having a right to know about all risks in their community" [38].

Opponents of the act included state lawmakers, industry representatives, and even some environmental groups. State lawmakers made arguments against the FRAC Act, asserting that states where hydraulic fracturing is common practice already effectively regulate operators [39]. Furthermore, they argued that each state is best equipped to create laws that address the state's geologic subtleties, which may necessitate differing operating practices [40]. Despite a specific clause protecting proprietary chemical identity from public release, industry expressed concerns over the disclosure of proprietary chemicals to federal regulators [39]. They feared protection of the information would not be sufficient and release of trade secret information would damage their competitive edge in the natural gas market. Some environmental groups were also critical of the FRAC Act, saying it did not go far enough in regulating hydraulic fracturing. Environmental groups disagreed with the continued protection of proprietary chemical information and cited shortcomings of the information being released about nonproprietary chemicals [36]. Their main concern is the lack of information provided by the MSDS, which often does not include health effects from environmental exposure to chemicals [36]. In addition, MSDS information exists for only a limited number of chemicals; only chemicals deemed hazardous by the Occupational Safety and Health Administration (OSHA) will have an MSDS [26, 41]. The bill was not passed into law; indeed, it did not make it out of committee during either Congressional session.

Fracturing Regulations are Effective in State Hands Act

On March 28, 2012, Senator Inhofe (R-OK) and Senator Murkowski (R-AK) introduced the Fracturing Regulations are Effective in State Hands (FRESH) Act [42]. This act is designed to guarantee that states, not the federal government, have exclusive authority to regulate hydraulic fracturing activities within state boundaries [42]. Justification of sole state regulatory authority is based on a "lack of evidence" that hydraulic fracturing in one state presents a contamination risk to groundwater in another state [42].

FRACTURING REGULATIONS AT THE STATE LEVEL

Arkansas, Colorado, Montana, Ohio, Oklahoma, Pennsylvania, Texas, and Wyoming have enacted fracturing disclosure laws [43, 44]. As of this writing, Ohio's disclosure law is the most recent to pass, effective August 1, 2012, and reflects some lessons learned from other states [44]. We draw on the examples of Texas and Pennsylvania, periodically referring to Ohio, to illustrate the issues of contention among environmental health professionals and advocates, regulators, and industry.

State of Texas

Texas is one of the first states to enact a chemical disclosure regulation specific to fracking. The "Hydraulic Fracturing Chemical Disclosure" rules adopted in Texas have become the blueprint for regulation in other states. Many of the technologies responsible for increasing natural gas yields were borrowed from the Texas offshore oil and gas industry. Hence, Barnett Shale natural gas production increased 3000 percent from 1998 to 2007, making Texas the unofficial leader in energy resource recovery through hydraulic fracturing [4]. Texas has fought aggressively to maintain state control over regulations, with some Texans arguing that potential impacts of hydraulic fracturing such as "groundwater contamination, wastewater disposal, impacts to local character, and seismic impacts are essentially local in nature . . . and do not cross state boundaries," and thus should be regulated at the state instead of at the federal level [45].

The Rail Road Commission (RRC) is the primary agency that regulates Texas' oil and gas industry. Regulations prior to 2012 primarily identified and established a clear definition of well operators (i.e., owners or managers), confirming the financial security of a well operator, and establishing procedures for public notice of new applications for injection well permits received on or after September 1, 2005 [46]. Areas surrounding aquifers, usually protected from drilling activities, may be used for underground injection wells if the well operator applies for an aquifer exemption [46].

In response to public pressure and possibly as a mechanism of preempting federal oversight, the RRC adopted new rules on December 13, 2011, requiring the disclosure of the intended, nonproprietary chemicals used in hydraulic fracturing fluids [47]. These rules apply to treatments occurring on wells that have been issued an initial drilling permit on or after February 1, 2012, but do not place disclosure requirements on wells with prior permits [46]. This regulation requires the operator of the well to provide general information about the well's location and dates of drilling activities, volume of water used, and each intended additive—its CAS number, intended use, and its maximum concentration by mass [46]. There is no requirement to report chemical components of hydraulic fracturing fluid before the fracturing activities begin. Instead, no later than 15 days *after* completion of a hydraulic fracturing treatment, the operator is required to file the chemical disclosure report with the RRC, and this information will be uploaded to the FracFocus website and henceforth be considered public information [46]. The RRC is responsible for enforcement, and violations may result in "monetary penalty and/or lead to the revocation of a well's certificate of compliance" [47].

The chemical disclosure requirements in Texas, as in many of the other states with disclosure rules, have significant loopholes, which provide allowances for incomplete disclosure of the chemicals and quantities used, as well as the disclosure of inaccurate information. First, the rule requires reporting of only "actual or the maximum concentration of each chemical ingredient . . . in percent by mass" [48], instead of the total amount of the chemical used at the site. Second, chemicals that are "unintentionally added" or "occur incidentally" are exempt from disclosure [48]. Another caveat of the disclosure law is that suppliers, service companies, and operators are not held responsible for the reporting of inaccurate information to the RRC [48]. Chemicals entitled to trade secret protection can be entirely exempt from public disclosure, unless disclosure is considered necessary during an emergency situation [47]. In Texas, certain commercial or financial information can be exempted from public disclosure laws if, "based on specific factual evidence, disclosure would cause substantial competitive harm" [49]. The factors that determine if information qualifies for trade secret protection are: the extent to which the information is known by employees within or people outside of the company; the measures taken or amount of money expended by the company in developing and guarding the secrecy of the information; the value of the information to the company; and the ease with which the information could be acquired or duplicated by others [50]. If an emergency situation arises, the presence of additives protected by trade secret must be disclosed to emergency responders or health professionals to allow for proper cleanup and/or medical treatment for exposed individuals [48]. In the case of Texas, first responders must sign a statement of confidentiality, and are allowed to discuss chemical identities only with other first responders or accredited laboratories; they are not permitted to disclose chemical identities to the person(s) receiving medical care [48]. In contrast, Ohio's recently passed law provides that "Doctors may share even proprietary chemical information with the patient and other medical professionals directly involved in treating a patient" [51]. While these state regulations are intended to establish transparency, they each fall short of full chemical disclosure and provide effective immunity to companies reporting inaccurate data.

Commonwealth of Pennsylvania

It has been known since the 1930s that natural gas existed in the Marcellus Shale formation in Pennsylvania; however, conventional vertical drilling was not successful because the gas occurs in "pockets," and therefore flows could not be sustained [2, 52]. In 2003, Range Resources–Appalachia began drilling wells, modifying the horizontal drilling techniques utilized in the Barnett Shale; by 2005, Marcellus gas was flowing [52]. Some assessments estimate more than $500 billion in recoverable natural gas exists in Pennsylvania alone, bringing on a drilling frenzy and leading to the creation of more than 350,000 active and inactive gas wells in Pennsylvania [7].

In Pennsylvania the Public Utilities Commission and the PaDEP are responsible for policing oil and gas activities. In 2008, a state investigation found 18 methane-contaminated wells after drilling activities began in the Susquehanna County area [53]. PaDEP fined the drilling company $120,000 and required potable water be brought in until the company installed gas mitigation devices at each residence [53]. In a 2009 incident, gas migrated into a residential water well and exploded, spewing fracturing fluid, brine, unknown chemicals, and gas into a forest about 90 miles outside of Pittsburgh [4]. These and other spill events have intensified public pressure on the pro-drilling Pennsylvania administration to require disclosure of the chemicals used in hydraulic fracturing fluids.

Pennsylvania General Assembly signed a new reform amendment into law on February 14, 2012, providing updates to the 1984 Oil and Gas Act [54]. The new act is designed to update environmental regulations, drilling fees, and local regulations for conventional and unconventional (i.e., hydraulic fracturing) oil and gas operations in the state. Within 60 days of commencement of drilling activities, well operators must complete a chemical disclosure form and post it to the industry-run registry [55]. The chemical disclosure form requirements are essentially identical to those of Texas; for example, they do not require disclosure prior to the start of fracking activities, they include exemptions from disclosure of proprietary information, and they do not hold operators, vendors, or service providers responsible for providing inaccurate data to the registry [55].

REGULATORY CHALLENGES AND FUTURE REGULATORY PROSPECTS

Enforcement

In some states, including Texas, companies have been slow to comply with the disclosure regulations [56, 57]. The NRDC found that state regulators were consistently accepting disclosure reports that were missing information required by Texas's hydraulic fracturing chemical disclosure rules [56]. Further, other investigations have found that almost half of new wells drilled in Texas go completely unreported and disclosure reports are not submitted to FracFocus [57]. These failures to comply indicate that some states are not providing adequate oversight.

In 22 states, the number of new oil and gas wells grew 45 percent between 2004 and 2009, leaving regulators scrambling to keep up. Complaints of understaffing within the responsible departments persist. Common jobs of state regulators include "policing" gas wells, oil wells, waste injection wells, disposal pits, compressor stations, and access roads. In addition, they are responsible for approving new permits, visiting new wells and old ones before they are sealed, and responding to complaints of all kinds [58]. An example of the insufficiency of state staffing of regulatory agencies can be found in Texas. In 2009, Texas had 273,660 wells and 106 regulators charged with overseeing them. In 2007, the Texas state auditor issued a report on the RRC's enforcement record. The auditor found that between 2001 and 2006, about half of the state's wells had not been inspected. The report also found that 30 percent of all spills were inspected late or not at all. Despite the growing workload, the budget is getting smaller. Between 2005 and 2009 the commission's budget for monitoring and inspections decreased by 10 percent. Even when regulators conduct inspections, there are sometimes flaws in their work [58].

While regulation of chemical disclosure is occurring at the state level, the examples of Texas and Pennsylvania highlight shortcomings and loopholes that result in the provision to the public of inadequate information—or misinformation—regarding the chemical composition of hydraulic fracturing fluids. The above examples also point to a lack of compliance due to failed state oversight. Federal regulation and oversight may be necessary to ensure that sufficient and accurate information is being reported. We suggest that the federal government not preempt state regulation of fracking, but at a minimum require adequate chemical disclosure to federal, state, and local regulators, and to the public.

Future Prospects

In the FY2010 Budget, the U.S. House of Representatives Appropriations Conference Committee included funds for a new EPA study on the effects on drinking water of hydraulic fracturing of shale formations [26]. EPA's first action was to request the chemical composition of drilling muds and fracturing fluids from nine of the largest natural gas and hydraulic fracturing companies [59]. The EPA recognized this as the fundamental first step in completing "a more thorough assessment of the potential impact of hydraulic fracturing," which underscores the importance of chemical disclosure [59]. The EPA study is underway and an initial progress report is expected in late 2012.

In March 2011, President Obama instructed the Secretary of Energy Advisory Board (SEAB) to create a subcommittee focused on exploring options for improving the safety of and public support for shale gas development [40]. From this charge, the Shale Gas Production Subcommittee completed two reports in which disclosure of fracturing fluid composition is a recommendation on the list "for immediate implementation" [40]. The Subcommittee recognized the work done by industry on the FracFocus.org website as a first step and believes that "disclosure should include all chemicals, not just those that appear on MSDS" [40]. They also envision that disclosure of the chemical composition of fracturing fluid will appear on a well-by-well basis and that this information will be made publicly available via a website. While this call for complete disclosure is encouraging, the Subcommittee's implementation plan is lacking.

The Subcommittee recommends relying on the Department of Interior to design and implement a plan for requiring chemical identity disclosure of fracturing fluids on federal lands [40].

The Department of Interior Bureau of Land Management controls all federal and public lands and has historically allowed natural gas extraction, including the use of hydraulic fracturing on public lands. In May 2012 the Bureau of Land Management issued a proposed rule [33] that would have required industry to report fracturing fluid composition prior to drilling on public lands, but the Obama Administration reportedly backed off from this demand, agreeing to allow companies to reveal the contents of drilling fluids after the fact [61].

Efforts also continue to update federal regulations to include hydraulic fracturing under some of the major environmental laws. In August 2011, the environmental group Earthjustice petitioned the EPA on behalf of over 100 community and environmental groups across the country [62] calling for EPA to pursue regulation of hydraulic fracturing (including drilling muds and fracturing fluids) under Section 4 and Section 8 of the Toxic Substances Control Act (TSCA) (15 USC § 2620) in order to protect "public health and the environment from the serious risks posed by chemical substances and mixtures used in oil and gas exploration and production" [62]. The group requested that EPA pursue, under TSCA Section 4, a requirement for manufacturers and users of fracturing fluids to identify all chemicals used and to conduct toxicity testing on those chemicals [62]. The information gained from the disclosure of chemicals and toxicity testing would be used to evaluate impacts on human health and the environment. Under TSCA Section 4, the EPA has "authority to require testing of chemicals which may present a significant risk or which are produced in substantial quantities and result in substantial human or environmental exposure" [26]. Additionally, Earthjustice asked EPA to adopt a rule under TSCA Section 8(a) requiring manufacturers and users of fracturing fluids to maintain, update, and submit records to EPA regarding specific chemical identities, proposed categories of use, potential byproducts, and existing and/or new environmental and health effects data [62]. Under TSCA Section 8 the EPA can implement "recordkeeping and reporting requirements to ensure that the EPA administrator would continually have access to new information on chemical substances" [26].

In November 2011, the EPA Assistant Administrator Stephen Owens responded to the Earthjustice petition in two separate memos [63, 64]. First, the EPA denied the petition's first request for adoption of a rule under TSCA Section 4 requiring toxicity testing for all chemicals used in fracturing fluid [63]. The EPA stated that the petition "did not set forth facts sufficient to support the required findings under TSCA Section 4(a)(1)(A) or 4(a)(1)(B) for issuance of a test rule" [63]. The EPA response memo suggests Earthjustice did not sufficiently identify a "risk trigger" (TSCA Section 4(a)(1)(A)) or an "exposure trigger" [26]. A *risk trigger* is defined under TSCA as a chemical that the EPA determines presents an "unreasonable risk of injury to human health or the environment"

[26]. An *exposure trigger* is defined under TSCA as chemical that is "produced or released into the environment in substantial quantities" [26].

The burden for EPA of proving that a chemical (or a group of chemicals) is either a risk trigger or exposure trigger is very high. The catch-22 for both of these rules is that often data do not exist that would allow the EPA to conduct a risk determination for a chemical. While the EPA can require testing if it finds that insufficient data exist, often the agency must still prove "unreasonable risk" for the risk trigger and "substantial quantities" for the exposure trigger. In essence: no data, no risk; no risk, no data.

In the EPA's second memo, it partially granted petitioners' request for initiating a "rulemaking process" under TSCA Section 8(a) requiring some reporting on chemicals used in fracturing fluids [64]. As a first step, the EPA will convene a "stakeholder process" to determine an approach for reporting that will involve minimal cost and duplication of effort while maximizing information, transparency, and public understanding [64]. States, industry, and public interest groups will be allowed to participate in the dialogue [65].

While there is some movement toward regulating hydraulic fracturing, and mandating chemical disclosure appears to be high on the list of priorities for environmental and community groups as well as some federal legislators, the process of changing federal regulations is slow and will continue to be challenged by industry and some lawmakers.

CONCLUSIONS

Advancements in natural gas recovery technologies and attractive prices have spurred a modern day "gas rush," leading to a 48 percent increase in U.S. shale gas production from 2006 to 2010 [1]. Natural gas extraction using hydraulic fracturing does provide benefits, such as a domestic energy source that may be cleaner than coal. However, these benefits should not exempt the industry from federal environmental laws that are put in place to protect public health and the environment. Hydraulic fracturing activities come with a cost—incidents of leaking pipelines, wellhead explosions, lack of wastewater treatment, and toxic air emissions, which can lead to significant cleanup costs and environmental health impacts—so regulation is necessary [4]. To mitigate these environmental and human health costs, all hydraulic fracturing activities should be better regulated. The SEAB recommended regulations to reduce air emissions from hydraulic fracturing practices and also regulations to ensure water management and groundwater safety [40]. We view regulation of hydraulic fracturing fluid chemical disclosure as a first step towards other hydraulic fracturing regulations. To create an enforceable and protective regulatory program, lawmakers should first have knowledge of the chemicals used in these processes and then determine whether the chemicals require regulation to protect public health and safety and the environment.

Shortcomings of state regulations, their variable enforcement, and limitations of the current voluntary reporting mechanism lead us to recommend federal regulations requiring full disclosure of chemical additives in hydraulic fracturing fluids. A federal law that both lifts current federal exemptions for hydraulic fracturing and mandates complete disclosure of chemicals (including proprietary and nonproprietary chemicals, and MSDS and non-MSDS chemicals) is essential. Federal regulations are crucial for setting a baseline of disclosure requirements that all states are required to follow. The foundation for creating federal regulation is a strong scientific base and the consideration and protection of human dignity, equity, and distributional impacts that are not requirements for state regulations or voluntary guidance [66]. Without information on the chemicals of concern, our regulations cannot be informed by scientific information or other knowledge regarding health risks. Oversight at the federal level could ensure that a standard set of regulations will be applied to hydraulic fracturing operations across the country.

Lastly, federal oversight of hydraulic fracturing will standardize and streamline regulatory processes, which can lead to economic benefits. In fact, the U.S. Office of Management and Budget recently reported the estimated cost and benefits associated with federal regulations [66]. The report concluded that, over the course of a decade (FY2001-FY2010), major federal regulations provided an estimated $132-$655 billion in net positive benefits while costing taxpayers between $44 billion and $62 billion [66]. Federal regulations enforcing the EPA's Clean Water Act, SDWA, and Clean Air Act were among the regulations that produced the highest net benefits compared to costs [66].

The current status of disclosure prevents the public, lawmakers, and scientists from understanding possible health and environmental effects, and also prevents proper monitoring of chemical contamination as a result of hydraulic fracturing operations. We believe federal regulations are essential to ensure that air and water quality will not be compromised, minimum requirements for chemical disclosure will be standardized across all states, and responsible parties will be held accountable if the natural environment or public health is harmed.

ACKNOWLEDGMENT

The authors wish to thank Nora Doyle-Burr for her contributions.

AUTHORS' BIOGRAPHIES

EUGENE B. BENSON is an attorney who works with community groups on environmental justice issues and teaches environmental law and policy courses at several Boston area universities. Email him at ebbenson@verizon.net

ISAAC J. BURROWS is a recent graduate of Boston University's School of Public Health and its MPH program. Email address is isaacj81@gmail.com

COLLEEN MARIE MAKEY has her Master's of Science in Public Health and is a doctoral student at Boston University's School of Public Health. Contact her at cmakey@bu.edu

ALEXIS L. MAULE has her Master's of Public Health and is presently an Environmental Health doctoral student at Boston University. She's at lex0210@gmail.com on the internet.

MADELEINE KANGSEN SCAMMELL is an Assistant Professor of Environmental Health in the School of Public Health at Boston University. Her research includes the use of qualitative methods in the area of community-driven environmental health, epidemiologic studies, and cumulative risk analysis. Send email to her at mls@bu.edu

NOTES

1. U.S. Energy Information Administration, *Annual Energy Outlook 2011 with Projections to 2035* (DOE/EIA-0383), 2011, http://www.eia.gov/oiaf/aeo/gas.html (accessed May 5, 2012).
2. C. W. Schmidt, "Blind Rush? Shale Gas Boom Proceeds amid Human Health Questions," *Environmental Health Perspectives* 119 (8) (2011): A348-A353, doi: 10.1289/ehp.119-a348.
3. National Public Broadcasting, "Explore Shale: An Exploration of Natural Gas Drilling," http://exploreshale.org/index.html (accessed April 4, 2012).
4. R. Kerr, "Natural Gas from Shale Bursts onto the Scene," *Science* 328 (2010): 1624-1626, doi: 10.1126/science.328.5986.1624.
5. C. T. Montgomery and M. B. Smith, "Hydraulic Fracturing: History of an Enduring Technology," *Journal of Petroleum Technology* (2010): 26-41, http://www.spe.org/jpt/print/archives/2010/12/10Hydraulic.pdf (accessed April 8, 2012).
6. Randy LaFollette, *Key Considerations for Hydraulic Fracturing of Gas Shales*, 2010, http://www.pttc.org/aapg/lafollette.pdf (accessed July 31, 2012).
7. M. L. Finkel and A. Law, "The Rush to Drill for Natural Gas: A Public Health Cautionary Tale," *American Journal of Public Health* 101 (5) (2011): 784-785, doi: 10.2105/AJPH.2010.300089.
8. Halliburton, "Fracture Stimulation Position Statement," http://www.halliburton.com/aboutus/Default.aspx?navid=981&pageid=2720 (accessed May 3, 2012).
9. U.S. Energy Information Administration, *Review of Emerging Resources: U.S. Shale Gas and Oil Plays*, 2011, http://ftp.eia.doe.gov/natgas/usshaleplays.pdf (accessed July 29, 2012).
10. Joel Kirkland and ClimateWire, "Department of Energy Wades into Fracking Debate," *Scientific American,* July 2011, http://www.scientificamerican.com/article.cfm?id=department-of-energy-wades-into-fracking-debate (accessed April 24, 2012).
11. C. G. Struchtemeyer and M. S. Elshahed, "Bacterial Communities Associated with Hydraulic Fracturing Fluids in Thermogenic Natural Gas Wells in North Central Texas, USA," *Federation of European Microbiological Societies, Microbiology Ecology,* 81 (1) (2011): 13-25, doi: 10.1111/j.1574-6941.2011.01196.
12. U.S. Environmental Protection Agency, "Integrated Risk Information System/Benzene," 2003, http://www.epa.gov/iris/subst/0276.htm (accessed October 4, 2012).

13. U.S. Environmental Protection Agency, "Integrated Risk Information System/ Xylenes," 2000, http://www.epa.gov/iris/subst/0270.htm (accessed October 4, 2012).
14. T. Colborn et al., "Natural Gas Operations From a Public Health Perspective," *Human and Ecological Risk Assessment*, 17 (5) (2011): 1039-1056, doi: 10.1080/ 108070392011.605662.
15. Natural Resource Defense Council, *In Fracking's Wake: New Rules are Needed to Protect Our Health and Environment from Contaminated Wastewater* (IB:12-05-A), May 2012, http://www.nrdc.org/energy/files/Fracking-Wastewater-IssueBrief.pdf (accessed October 15, 2012).
16. U.S. Environmental Protection Agency, *Expanded Site Investigation, Analytic Results Report* (TDD No. 0901-01), August 30, 2010, http://www.epa.gov/region8/superfund/ wy/pavillion/PavillionAnalyticalResultsReport.pdf (accessed May 4, 2012).
17. Western Organization of Resource Councils, *History and Analysis of EPA Hydraulic Fracturing Study*, July 2009, http://www.worc.org/userfiles/file/EPA-FracStudyFact Sheet.pdf (accessed April 20, 2012).
18. S. G. Osborn et al., "Methane Contamination of Drinking Water Accompanying Gas-Well Drilling and Hydraulic Fracturing," *Proceedings of the National Academy of Sciences of the Untied States of America,* 108 (20) (2011): 8172-8176, doi: 10.1073/ pnas.1100682108.
19. N. R. Warner et al., "Geochemical Evidence for Possible Natural Migration of Marcellus Formation Brine to Shallow Aquifers in Pennsylvania," *Proceedings of the National Academy of Sciences of the Untied States of America,* 109 (30) (2012): 11961-11966, doi: 10.1073/pnas.1121181109.
20. T. Myers, "Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers," *Ground Water*, 50 (6) (2012): 872-882, doi: 10.1111/j.1745-6584.2012. 00933.x.
21. Groundwater Protection Council and the Interstate Oil and Gas Compact Commission, "FracFocus Chemical Disclosure Registry/Chemical Use," http://fracfocus.org/ chemical-use (accessed April 28, 2012).
22. *Emergency Planning and Community Right-to-Know Act*, 42 U.S.C. 11042, 11023 (1986), http://hand.sdcounties.org/files/2012/01/EPCRA-LEPC-FedStatute.pdf (accessed April 28, 2012).
23. *Safe Drinking Water Act*, 42 U.S.C. §300H(d)(1) (2002), http://epw.senate.gov/ sdwa.pdf (accessed April 28, 2012).
24. The Oil and Gas Accountability Project and Earthworks, *The Oil and Gas Industry's Exclusions and Exemptions to Major Environmental Statutes,* October 2007, http:// www.earthworksaction.org/files/publications/PetroleumExemptions1c.pdf?pubs/ PetroleumExemptions1c.pdf (accessed April 20, 2012).
25. *Emergency Planning and Community Right-to-Know Act*, 42 U.S.C. 11044 §313 (1986), http://hand.sdcounties.org/files/2012/01/EPCRA-LEPC-FedStatute.pdf (accessed April 28, 2012).
26. Thomas Sullivan, ed., *Environmental Law Handbook,* 21st ed. (Lanham, MD: Government Institutes, 2011).
27. U.S. Environmental Protection Agency, "Underground Injection Control Program," http://water.epa.gov/type/groundwater/uic/index.cfm (accessed April 12, 2012).
28. LEAF v EPA, 118 F.3d 1467 (11th Cir. 1997).

29. Coalbed Methane Association of Alabama, *LEAF v. EPA: A Challenge to Hydraulic Fracturing of Coalbed Methane Wells in Alabama,* 2001, http://www.energyindepth.org/PDF/LEAF_v_EPA.pdf (accessed April 13, 2012).
30. LEAF v EPA, 118 F.3d 1473 (11th Cir. 1997).
31. H. Wiseman, "Untested Waters: The Rise of Hydraulic Fracturing in Oil and Gas Production and the Need to Revisit Regulation," *Fordham Environmental Law Review* 20 (2009): 115.
32. J. Manuel, "EPA Tackles Fracking," *Environmental Health Perspectives* 118 (5) (2010): A199, doi: 10.1289/ehp.118-a199.
33. U.S. Department of Interior, Bureau of Land Management, "Proposed Rule 43 CFR Part 3160," http://www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&pageid=293916 (accessed July 30, 2012).
34. Worldwatch Institute, *Addressing the Environmental Risks from Shale Gas Development*, July 2010, http://www.worldwatch.org/files/pdf/Hydraulic%20Fracturing%20Paper.pdf (accessed April 13, 2012).
35. *Clean Energy Jobs and American Power Act*, S.1733, 111th Cong., 2nd sess.
36. Columbia University School of International and Public Affairs, *The FRAC Act: The Fracturing Responsibilities and Awareness of Chemicals Act of 2011*, 2011, http://mpaenvironment.ei.columbia.edu/sitefiles/file/Summer%2011%20reports/Fall%20reports/FRAC%20Act.pdf (accessed April 1, 2012).
37. *Fracturing Responsibilities and Awareness of Chemicals Act*, H.R.1084, 112th Cong., 1st sess.
38. Robert P. Casey, Jr., "Robert P. Casey, Jr./Marcellus Shale," http://www.casey.senate.gov/issues/issue/?id=ce690501-bb77-4195-a6d1-87152b9ae298 (accessed May 1, 2012).
39. S. Negro, "Fracking Wars: Federal, State and Local Conflicts over the Regulation of Natural Gas Activities," *Zoning and Planning Law Report* 35 (2) (2012): 1-15.
40. Secretary of Energy Advisory Board (SEAB) Shale Gas Production Subcommittee, *Second Ninety Day Report,* November 2011, http://www.shalegas.energy.gov/resources/111011_90_day_report.pdf (accessed April 1, 2012).
41. *Occupational Safety and Health Act*, 29 C.F.R. §1910.1200(c) (1970), http://www.osha.gov/law-regs.html/ (accessed May 1, 2012).
42. *Fracturing Regulations are Effective in State Hands Act*, DEC12318, 112th Cong., 2nd sess.
43. Kate Galbraith, "Seeking Disclosure on Fracking," *New York Times,* May 30, 2012.
44. United Press Institute, Inc. "Ohio Passes Fracking Law," June 12, 2012, http://www.upi.com/Business_News/Energy-Resources/2012/06/12/Ohio-passes-fracking-law/UPI-51971339497616/ (accessed August 1, 2012).
45. David Spence, "Energy Management Brief: Is it Time for Federal Regulation of Shale Gas Production," *Energy Management and Information Center,* April 19, 2012, http://www.mccombs.utexas.edu/Centers/EMIC/Resources.aspx (accessed May 1, 2012).
46. Texas Commission on Environmental Quality, "Texas Administrative Code: Public Notice of Injection Well and Other Specific Applications: Application for Injection Well Permit," 1999, Title 30 Rule §39.651.
47. B. K. Hatef, "Texas Commission Requires Public Disclosure of Fracking Chemicals," *National Law Review,* January 29, 2012, http://www.natlawreview.com/article/texas-commission-requires-public-disclosure-fracking-chemicals (accessed May 1, 2012).

48. Railroad Commission of Texas, Texas Administrative Code: Hydraulic Fracturing Chemical Disclosure Requirements, 2011, Title 16 Rule §3.29.
49. Texas Constitution and Statutes, Texas Government Code, Title 5, Subtitle A, Chapter 552, Public Information, http://www.statutes.legis.state.tx.us/SOTWDocs/GV/htm/GV.552.htm (accessed April 20, 2012).
50. Hyde Corporation v. Huffins, 314 S.W.2d 763, 776 (Texas, 1958).
51. Ohio Department of Natural Resources, "Senate Bill 315—Improving Regulatory Framework," http://www.ohiodnr.com/tabid/23947/Default.aspx (accessed July 30, 2012).
52. Pennsylvania Department of Conservation and Natural Resources, *Pennsylvania Geology,* Spring 2008, http://www.dcnr.state.pa.us/topogeo/pub/pageolmag/pdfs/v38n1.pdf (accessed November 26, 2012).
53. StateImpact, "Dimock, PA: 'Ground Zero' in the Fight Over Fracking," http://stateimpact.npr.org/pennsylvania/tag/dimock/ (accessed on May 1, 2012).
54. Pennsylvania General Assembly, "House Bill 1950," 2011-2012, http://www.legis.state.pa.us/cfdocs/billinfo/bill_history.cfm?syear=2011&sind=0&body=H&type=B&bn=1950 (accessed May 1, 2012).
55. Pennsylvania General Assembly, "House Bill 1950 §58 PA C.S. 3222.1.," 2011-2012, http://www.legis.state.pa.us/cfdocs/billinfo/bill_history.cfm?syear=2011&sind=0&body=H&type=B&bn=1950 (accessed May 1, 2012).
56. Natural Resource Defense Council, *State Hydraulic Fracturing Disclosure Rules and Enforcement: A Comparison* (IB:12-06-A), July 2012, http://www.nrdc.org/energy/files/Fracking-Disclosure-IB.pdf (accessed September 12, 2012).
57. Benjamin Haas, Jim Polson, Phil Kuntz, and Ben Elgin, "Fracking Hazards Obscured in Failure to Disclose Wells," *Bloomberg.com*, August 14, 2012, http://www.bloomberg.com/news/print/2012-08-14/fracking-hazards-obscured-in-failure-to-disclose-wells.html (accessed September 12, 2012).
58. Abrahm Lustgarten, "State Oil and Gas Regulators Are Spread Too Thin to Do Their Jobs," *ProPublica,* Dec. 30, 2009, http://www.propublica.org/article/state-oil-and-gas-regulators-are-spread-too-thin-to-do-their-job (accessed May 3, 2012).
59. U.S. Environmental Protection Agency, *EPA Letter to Companies on Voluntary Information Request,* 2011, http://www.epa.gov/hfstudy/HFvoluntaryinformationrequest.pdf (accessed April 27, 2012).
60. Natural Resources Committee (NRC) Blog, "Natural Resources Committee Maintains Aggressive Oversight of Obama Administration's Overregulation of Hydraulic Fracturing," http://naturalresources.house.gov/Blog/?postid=278317 (accessed April 1, 2012).
61. *New York Times*, "New Proposal on Fracking Gives Ground to Industry," May 4, 2012, http://www.nytimes.com/2012/05/05/us/new-fracking-rule-is-issued-by-obama-administration.html/?_r=1&adxnnl=1&adxnnlx=1343998800-6fSWKGTh+TecfCPbIuVRYQ (accessed May 1, 2012).
62. Earthjustice, *Memo to EPA: Citizen Petition under Toxic Substances Control Act Regarding the Chemical Substances and Mixtures Used in Oil and Gas Exploration or Production*, August 4, 2011, http://www.epa.gov/oppt/chemtest/pubs/Section_21_Petition_on_Oil_Gas_Drilling_and_Fracking_Chemicals8.4.2011.pdf (accessed May 1, 2012).

63. U.S. Environmental Protection Agency, *Memo to Ms. Deborah Goldberg: Re: TSCA Section 21 Petition Concerning Chemical Substances and Mixtures Used in Oil and Gas Exploration or Production,* November 2, 2011, http://www.epa.gov/oppt/chemtest/pubs/SO.Earthjustice.Response.11.2.pdf (accessed May 1, 2012).
64. U.S. Environmental Protection Agency, *Memo to Ms. Deborah Goldberg: Re: TSCA Section 21 Petition Concerning Chemical Substances and Mixtures Used in Oil and Gas Exploration or Production,* November 23, 2011, http://www.epa.gov/oppt/chemtest/pubs/EPA_Letter_to_Earthjustice_on_TSCA_Petition.pdf (accessed May 1, 2012).
65. U.S. Environmental Protection Agency, "Hydraulic Fracturing; TSCA Section 8(a) and 8(d) Reporting," http://yosemite.epa.gov/opei/rulegate.nsf/byrin/2070-aj93?opendocument (accessed May 1, 2012).
66. U.S. Office of Management and Budget, *2011 Report to Congress on the Benefits and Costs of Federal Regulations and Unfunded Mandates on State, Local, and Tribal Entities*, 2011, http://www.whitehouse.gov/sites/default/files/omb/inforeg/2011_cb/2011_cba_report.pdf (accessed May 2, 2012).

Direct reprint requests to:

Madeleine Kangsen Scammell
Boston University School of Public Health
715 Albany Street, T4W
Boston, MA 02118
e-mail: MLS@bu.edu

NEW SOLUTIONS, Vol. 23(1) 189-201, 2013

Features

MARCELLUS SHALE DRILLING'S IMPACT ON THE DAIRY INDUSTRY IN PENNSYLVANIA: A DESCRIPTIVE REPORT

MADELON L. FINKEL
JANE SELEGEAN
JAKE HAYS
NITIN KONDAMUDI

ABSTRACT

Unconventional natural gas drilling in Pennsylvania has accelerated over the past five years, and is unlikely to abate soon. Dairy farming is a large component of Pennsylvania's agricultural economy. This study compares milk production, number of cows, and production per cow in counties with significant unconventional drilling activity to that in neighboring counties with little or no unconventional drilling activity, from 1996 through 2011. Milk production and milk cows decreased in most counties since 1996, with larger decreases occurring from 2007 through 2011 (when unconventional drilling increased substantially) in five counties with the most wells drilled compared to six adjacent counties with fewer than 100 wells drilled. While this descriptive study cannot draw a causal association between well drilling and decline in cows or milk production, given the importance of Pennsylvania's dairy industry and the projected increase in unconventional natural gas drilling, further research to prevent unintended economic and public health consequences is imperative.

QA: Please supply 3-5 key words

Keywords: fracking, dairy industry

doi: http://dx.doi.org/10.2190/NS.23.1.k
http://baywood.com

The search for clean, efficient, and economic energy sources is a high priority for most nations, industrial and emerging. While oil and coal remain the predominant energy sources worldwide (34% and 30%, respectively), each has its advantages and disadvantages. Natural gas (24% of the world's energy source), hydropower (6%), and nuclear energy (5%) are being promoted as energy options [1]. While there are pros and cons to each of these energy sources, natural gas in particular is abundant around the world and has a "clean" reputation—in that it burns cleaner than coal, for example. It is easy to transport, reasonably economical, requires comparatively quick construction timelines and low capital costs, and has the added advantage of bringing jobs to economically depressed regions where natural gas reserves are plentiful. Because of these benefits, natural gas has emerged as a key energy source around the world.

Most natural gas is currently extracted from conventional deposits, where it has migrated from a source rock and been trapped. However, a significant amount of natural gas is found distributed in relatively impermeable rock formations such as shale. Shale gas, once extracted, is identical to conventional natural gas.

For years, extracting natural gas from vast shale deposits was too costly and technologically challenging. Technical advances, however, have allowed the extraction of fossil fuels that in the past were logistically impossible and/or economically prohibitive (e.g., deep-ocean drilling for gas and oil, extracting oil from tar sands, and deep mining for coal, minerals, and ore). Today, extracting natural gas from vast shale deposits is possible by means of high-volume hydraulic fracturing of shale formations, using slick-water and multiple long, horizontal laterals from clustered, multi-well pads generally referred to in the media as fracking, hydraulic fracturing, or unconventional drilling.

In 2001, shale gas accounted for 2 percent of total natural gas production. As of 2010, it accounted for 23 percent of U.S. natural gas production, and this share is projected to increase to nearly half of the total production by 2035. Ironically, the shale gas boom has positioned the United States to become an overall net exporter of natural gas [2]. Indeed, the natural gas industry now has a glut so vast that import facilities are applying for licenses to export gas to Europe and Asia [3].

Unconventional drilling injects under high pressure huge volumes of fracturing fluid (referred to as slick-water), which is comprised of water, sand, and chemicals, many known to be toxic, several thousand feet underground to create or re-open cracks or fissures in the shale formation to release trapped shale gas. Gas operators in the United States are allowed to protect their proprietary formulas, and they do not have to disclose the chemical compounds used in the drilling process, thus making it difficult if not impossible to assess the full scope of the contents of the fluid that is returned to the surface ("flowback" fluid). Thirty to 70 percent of the fluid will resurface, bringing back with it toxic substances, including heavy metals, naturally occurring radioactive materials (NORMs), and toxic and volatile organic compounds including benzene, a known carcinogen. Flowback waste fluids, held in open reserve pits or in non-airtight metallic containers, must be disposed of safely because they can potentially contaminate air and soil as well as waterways and watersheds. Despite a recent Environmental Protection Agency (EPA) study of groundwater contamination near the town of Pavillion, Wyoming, that suggests a pathway for exposure [4], no state has adequate regulations on drilling, particularly related to the disposal of the toxic wastewater fluids.

Despite the paucity of studies evaluating the potential impact on human health, unconventional drilling has accelerated at a rapid pace in many areas in the United States. In particular, Pennsylvania, through which the Marcellus Shale extends, has embraced an aggressive policy of unconventional drilling. Almost 6,000 wells have been drilled in a six-year period, and thousands more drilling permits have been issued [5]. In 2011 alone, 2,096 drilling permits were issued in five counties in which there already is substantial ongoing unconventional drilling activity (Bradford, Lycoming, Susquehanna, Tioga, and Washington). Tens of thousands of permits are expected to be issued over the next decade in Pennsylvania.

Agricultural activity in Pennsylvania is important to its economy, and dairy farming is a large component of the state's agricultural economy. The state ranks fifth in milk production in the United States after California, Wisconsin, Idaho, and New York [6]. One of the top milk-producing counties, Bradford, happens to be located within the Marcellus Shale and as of 2011 has the greatest number of unconventional wells drilled of all Pennsylvania counties.

The economic implications of unconventional drilling activity have not been well studied, nor have studies been conducted to assess the impact on the environment or on human and animal health. In the absence of health impact assessments for human health, animal studies can shed light on the potential harmful effects of drilling. Like the canary in the coal mine, cows, horses, poultry, and other wildlife can be used as sentinels to foreshadow impacts to human health. Animals tend to suffer more direct exposure and have shorter life and reproductive cycles, making it easier to document effects.

A recent qualitative study, published in a peer-reviewed journal, focused on the impact of gas drilling on animal health (interviews conducted with animal owners in Colorado, Louisiana, New York, Ohio, Pennsylvania, and Texas), documenting reproductive (irregular cycles, failure to breed, stillbirths), neurological (seizures, incoordination, ataxia), gastrointestinal (vomiting, diarrhea), and dermatological (hair and feather loss, rashes) problems among livestock [7].

Another recently completed study investigating changes in milk production and cow numbers in Pennsylvania counties between 2007 and 2010 found an association between drilling and declining cow numbers, with higher drilling activity associated with larger average declines in cow numbers. Further, counties with 150 or more Marcellus Shale wells on average experienced an 18.5 percent decrease in total milk production compared to an average increase of 0.9 percent in counties with no Marcellus Shale wells drilled [8]. While the study could not fully explain the findings, the implications for Pennsylvania, with its large dairy industry, need to be more fully investigated.

This descriptive study seeks to lay the basis for observing trends in a longitudinal approach and to raise questions that can be tested in a more analytic manner. We focus on Pennsylvania primarily because there has been an explosive increase in unconventional drilling in this state since 2006 (unlike in neighboring New York, which as of 2012 has a moratorium on drilling in place), and because the implications for its agricultural and dairy industries could be significant.

METHODS

From 1996 through 2006 there was essentially no unconventional drilling for natural gas in any county in Pennsylvania. From 2007 forward, however, there was a substantial increase in the number of wells drilled in counties that have Marcellus Shale beneath them. We focus on comparing milk production (in thousand of pounds), number of cows, and average milk production per cow in counties with the most unconventional drilling activity to neighboring counties with less unconventional drilling activity (defined as fewer than 100 wells drilled) from 1996 through 2011, with particular focus on the years 2007 through 2011. Five counties with the greatest amount of drilling activity were selected (Bradford, Lycoming, Susquehanna, Tioga, and Washington) and six neighboring counties with fewer than 100 wells drilled were chosen for comparison (Beaver, Clinton, Lackawanna, Potter, Somerset, and Sullivan). Data on milk production per cow, total milk production, and total number of milk cows, by county by year, were obtained from the U.S. Department of Agriculture's National Agricultural Statistics Service (NASS) [9]. The number of drilled wells, measured through spud well data provided by the Pennsylvania Department of Environmental Protection, was obtained for each county by year [10]. In oil and gas parlance, *spud* refers to the actual start of drilling of an unconventional gas well, and this is how Pennsylvania drilling data are compiled.

As noted above, NASS updates statistics on milk production yearly, and Pennsylvania census data on the number of farms become available every five years (the next update is expected in 2014). However, a finer-grained analysis that would relate milk production or herd numbers to distance to active wells is not possible because data are not reported on the level of individual farms.

FINDINGS

Figure 1 shows the increase in number of wells drilled by county by year for the five counties with the most wells. Of counties with drilling activity, Bradford has the greatest number of wells by far.

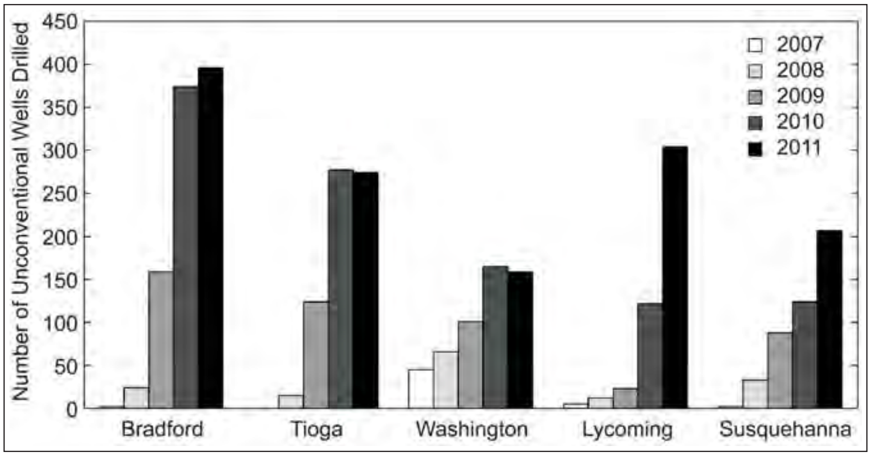


Figure 1. Unconventional wells drilled by county by year.

Table 1 shows, by county, the percent change from 2007 to 2011 in number of milk cows and total milk production (in thousands of pounds), and also the number of wells drilled during these years. The number of milk cows in each of the counties with the most wells drilled declined substantially during this time period, ranging from –18.3 percent in Tioga county to –46.7 percent in Washington county. In the counties with fewer than 100 wells, the percentage change in number of milk cows varied, showing no change in two of the counties, a modest decrease in three of the counties, and an 11.5 percent increase in Potter County. For those counties that showed a decrease in the number of milk cows, there was a corresponding decrease in the total milk production. Similarly, each county in the group with the most drilled wells posted a decrease in total milk production, whereas the change among the adjacent counties with fewer than 100 wells was varied. In this group, the three counties that had a reduction in the number of milk cows also had a reduction in milk production. The two counties with no change in the number of milk cows posted increases in total milk production, and the only county to show an increase in the number of milk cows also showed an increase in total milk production. There does not seem to be a clear relationship between the percentage changes in dairy indicators and the number of wells drilled. For example, Washington County showed the largest decline in the number of milk cows and total milk production, but has far fewer drilled wells than Bradford County. The following tables present the data with more detail.

Tables 2a and 2b show the mean, median, standard deviation, and range in the annual number of milk cows for each county. In all five counties with the most wells drilled, the data show a substantial decrease in the number of milk cows

Table 1. Percent Change in Number of Milk Cows, Total Milk Production, and Number of Wells Drilled by County, 2007-2011

County	Percent change in number of milk cows	Percent change in total milk production (pounds)	Number of wells drilled
Counties with most wells drilled (*N* = 5)			
Bradford	–25.6	–20.6	955
Tioga	–18.3	–16.8	690
Washington	–46.7	–28.9	536
Lycoming	–36.0	–26.5	466
Susquehanne	–25.0	–23.9	454
Adjacent counties with fewer than 100 wells drilled (*N* = 6)			
Sullivan	–5.3	–2.5	41
Clinton	0	+ 1.4	88
Potter	+ 11.5	+ 8.7	72
Lackawanna	0	+ 10.0	2
Somerset	–12.1	–10.5	19
Beaver	–11.1	–10.1	7

both from 1996 through 2006 (prior to active drilling) and from 2007 through 2011. With the exception of Clinton County, adjacent counties with fewer than 100 wells drilled also showed a decrease in the number of milk cows from 1996 through 2006. From 2007 through 2011, the outcome was more mixed: some of the counties experienced a modest decrease (Sullivan, Somerset, Beaver), some experienced no change (Clinton, Lackawanna), and one experienced a modest increase (Potter). Overall, these findings seem to indicate that drilling did not accelerate a decline in the number of milk cows, as the decline was underway before wells were drilled; however, even though drilling had not commenced prior to 2007, the sale and leasing of land most certainly had.

A decrease in the number of cows could explain a decrease in milk production. Tables 3a and 3b show the mean, median, standard deviation, and range in total milk production (in thousands of pounds) by county by year. Data show that during the years 1996 through 2006 in counties with the most wells drilled, there was a decline in total milk production ranging from –15.7 percent in Bradford county to –53.3 percent in Washington County. Only Lycoming County showed a modest increase (+7.6%). From 2007 through 2011 the trend continued, with every county showing a decline in total milk production. Among adjacent counties with fewer than 100 wells drilled, the picture is more mixed (Table 3b). From 1996 through 2006, some counties posted increases (notably Clinton with

Table 2a. Number of Milk Cows in the Five Counties with Most Wells Drilled, 1996-2011

	Counties				
	Bradford	Tioga	Washington	Lycoming	Susquehanna
Mean	25,843.8	13,387.5	4,640[a]	6,706.7[a]	12,481.3
Median	24,850	12,250	4,200	6,800	11,300
SD	3638.9	2555.7	1105.7	859.0	2889.1
Range	19,500-31,500	10,400-18,000	3,000-6,600	5,000-7,900	8,400-16,800
Percent change, 1996 to 2006	–30.7%	–52.5%	–73.7%	–16.2%	–58.5%
Percent change, 2007 to 2011	–25.6%	–18.3%	–46.7%	–36.0%	–25.0%

[a]Missing data for some years.

Table 2b. Number of Milk Cows in Six Adjacent Counties with Fewer than 100 Wells Drilled, 1996-2011

	Counties					
	Sullivan	Clinton	Potter	Lackawanna	Somerset	Beaver
Mean	2,243.8	5,593.3[a]	5,062.5	1,531.3	18,881.3	2,450
Median	2,100	5,600	5,100	1,500	19,250	2,300
SD	316.2	584.9	239.1	343.9	1098.0	539.1
Range	1,900-2,800	4,700-6,500	4,600-5,400	1,100-2,300	16,500-20,100	1,800-3,300
Percent change, 1996 to 2006	–19.0%	+20.3%	–10.4%	–81.8%	–10.4%	–60.0%
Percent change, 2007 to 2011	–5.3%	0%	+ 11.5%	0%	–12.1%	–11.1%

[a]Missing data for some years.

Table 3a. Total Milk Production (in Thousand Pounds) by Year in the Five Counties with Most Wells Drilled, 1996-2011

	Counties				
	Bradford	Tioga	Washington	Lycoming	Susquehanna
Mean	471,144.4	229,336.9	69,472[a]	105,249.3[a]	204,142.5
Median	463,795	216,110	64,500	114,600	195,950
SD	51,612.1	31,449.8	13,289.6	25,953.1	42,612.8
Range	380,000-539,300	190,000-282,400	52,000-93,800	95,000-122,700	155,000-275,800
Percent change, 1996 to 2006	–15.7%	–27.7%	–53.3%	+ 7.6%	–45.9%
Percent change, 2007 to 2011	–20.6%	–16.8%	–28.9%	–26.5%	–23.9%

[a]Missing data for some years.

Table 3b. Total Milk Production (in Thousand Pounds) for Six Adjacent Counties with < 100 Wells Drilled, 1996-2011

	Counties					
	Sullivan	Clinton	Potter	Lackawanna	Somerset	Beaver
Mean	38,821.9	161,134.7[a]	92,185	23,540.6	304,555.6	39,385.6
Median	38,200	100,800	94,320	22,250	305,200	37,650
SD	3,604.9	260,086.5	6,057.6	4,552.8	12,569.5	4,709.6
Range	34,400-45,600	69,600-110,050	82,700-102,200	18,000-33,200	285,000-327,000	33,500-46,600
Percent change, 1996 to 2006	–7.9%	+ 32.7%	+ 3.0%	–67.5%	+ 7.8%	–23.1%
Percent change, 2007 to 2011	–2.5%	+ 1.4%	+ 8.7%	+ 10.0%	–10.5%	–10.1%

[a]Missing data for some years.

a 32.7 percent increase during this time period) while other counties showed declines (notably Lackawanna with a 67.5% decrease). From 2007 through 2011, some counties posted modest increases (Clinton, Potter, Lackawanna) while others showed declines ranging from 10.5 and 10.1 percent declines in Somerset and Beaver Counties, respectively, a to 2.5 percent decline in Sullivan county.

To understand better the implications of these findings, data on average milk production per cow were obtained for the years 1996 through 2011. Table 4 compares the five counties with the most drilling to the adjacent counties with fewer than 100 wells drilled. Average annual milk production per cow remained fairly constant from year to year in the five counties with the most wells drilled and the six adjacent counties with fewer than 100 wells drilled. Tables 5a and 5b show the data in greater detail. In all counties with the most wells drilled there were modest increases in average milk production per cow between 1996 through 2006, and this trend continued during the 2007 through 2011 time period. In adjacent counties with fewer than 100 wells drilled, a similar picture emerges for the period 1996 through 2006, when every county posted an increase; however, for the time period 2007 through 2011, the situation is more mixed. Lackawanna county showed a greater increase in average milk production per cow (+10%) than the other counties, which either showed very modest increases or in the case of Potter and Sullivan Counties a slight decrease (–3.3%).

Table 4. Average Milk Production per Cow, by Year and County Group, 2007-2011

	Average milk production per cow	
Year	Counties with most wells drilled (N = 5)	Adjacent counties with fewer than 100 wells drilled (N = 6)
2007	17,949.4	17,734.8
2008	18,407.0[a]	17,868.6[a]
2009	17,848.2	17,561.5
2010	18,763.7	18,308.5
2011	18,970.3	17,931.2
Average, 2007-2011	18,386.1	17,881.3

[a]Missing data for some counties.
Note: t-value = 2.33, p = 0.05.

Table 5a. Average Annual Milk Production per Cow, for Five Counties with Most Wells Drilled 1996-2011 (N = 5)

	Counties				
	Bradford	Tioga	Washington	Lycoming	Susquehanna
Mean	18,311	17,291	15,181[a]	16,864[a]	17,236
Median	18,076	17,100	14,450	16,500	16,750
SD	834.43	996.22	1400	1293	1020.5
Range	17,000-19,744	15,400-18,868	13,881-18,667	15,000-19,400	16,000-18,966
Percent change, 1996 to 2006	+ 11.8%	+ 16.3%	+ 11.8%	+ 15.7%	+ 8.1%
Percent change, 2007 to 2011	+ 4.0%	+ 1.2%	+ 12.1%[a]	+ 7.0%	+ 1.4%

[a]Missing data for some years.

Table 5b. Average Annual Milk Production per Cow for Six Adjacent Counties with Fewer than 100 Wells Drilled, 1996-2011 (N = 6)

	Counties					
	Sullivan	Clinton	Potter	Lackawanna	Somerset	Beaver
Mean	17,345.6	16,959[a]	18,289.4	15,484.5	16,184.5	16,413.1
Median	17,400	16,900	18,402	15,000	16,050	16,063
SD	941.2	1237.8	1035.1	961.6	1195.0	1724.4
Range	15,700-18,648	14,800-18,750	16,200-19,800	14,400-17,500	14,400-18,155	14,000-18,611
Percent change, 1996 to 2006	+ 15.1%	+ 19.6%	+ 18.2%	+ 7.9%	+ 16.7%	+ 23.1%
Percent change, 2007 to 2011	–3.2%	+ 1.4%	–3.3%	–10.0%	+ 1.5%	+ 0.9%

[a]Missing data for some years.

DISCUSSION

Data based on U.S. Department of Agriculture statistics show a greater decrease in milk production (in thousands of pounds) and number of milk cows in counties with the most drilling activity compared to neighboring counties with fewer than 100 wells drilled. Similar findings were reported in the Kelsey report [11]. Our study shows that between 1996 and 2006, prior to active well drilling, there was a decrease in the number of cows and in milk production in counties with the most drilling and a more mixed picture in adjacent counties with fewer than 100 wells drilled. Counties with the most wells drilled during 2007 through 2011 uniformly had declines in total milk production ranging from –16.8 percent in Tioga county to –28.9 percent in Washington county. The number of wells drilled did not appear to explain the differences in this decline. Bradford County, for example, had the greatest number of wells drilled yet did not have the highest percent change in either the number of milk cows or total milk production. In fact, Washington County, with fewer wells drilled, posted the highest percentage changes.

This study could not determine whether milk production on farms whose owners had leased or sold land to drilling companies was less than on farms whose owners had not leased or sold part of their land. We do not know either the proportion of farms whose owners have leased or sold land or the proportion on which wells have been drilled. Our data could not explain the extent to which milk production and number of cows on farms in counties with the most drilling decreased compared to the same measures on farms where land had not been leased or sold in adjacent counties with less drilling activity.

Our analysis cannot explain whether dairy farmers downsized their herds, quit dairy farming, or some combination thereof. We also cannot determine how many dairy farmers in counties with the most active well drilling "took the money and ran." That is, with money earned from selling or leasing their land, what proportion of dairy farmers downsized or left the dairy business entirely? While our data clearly show differences among counties, this descriptive study cannot assume that there is a causal association between well drilling and decline in cow numbers or milk production. Clearly, further investigation should be initiated to better understand what is happening in Pennsylvania counties.

The dairy industry is very important in Pennsylvania, and implications for milk prices could be significant. Many factors probably influence the number of cows, milk production, and even milk prices; yet, the impact a downsized dairy industry would have on the economics of Pennsylvania should be analyzed. Given that the other major milk-producing state in the Northeast, New York, seems poised to begin allowing unconventional gas drilling, the effects on the dairy industry could become a major area of regional, if not national, concern. What is clear is that well drilling in Pennsylvania, based on the number of permits already issued, will continue, if not accelerate, over the next few years. It will be important for the State of Pennsylvania to monitor changes in milk production over time to see if the downward trend continues, both in counties with more wells drilled and in counties with fewer wells drilled, and to assess the potential effect of this situation on the state's economy.

ACKNOWLEDGMENT

Many thanks to Maritza Montalvo for help in manuscript preparation.

AUTHORS' BIOGRAPHIES

MADELON FINKEL is Professor of Clinical Public Health, Director Office of Global Health Education, Weill Cornell Medical College in New York City. Dr Finkel's professional career has been spent at Cornell University's medical college. She holds the rank of Professor of Clinical Public Health as well as Course Director for the Department (Epidemiology, Biostatistics, Evidence-Based Medicine, Introduction to the Health Care System, and Clinical Clerkship in Health Care Policy). She was named the medical school's first Director of the Office of Global Health Medical Education in 2004. She was instrumental in establishing Cornell Analytic Consulting Services, a division within the Department of Public Health designed to provide epidemiological consulting services. Dr. Finkel has been involved in epidemiological research and health care policy studies. Her pioneering work on second surgical opinion programs led to the widespread adoption and implementation of the second-opinion benefit required by almost all insurance companies, corporations, and unions. She has been examining the epidemiologic and public health implications of unconventional natural gas development for two years. Her address is maf2011@med.cornell.edu

JAKE HAYS is Program Director of Physicians, Scientists, and Engineers (PSE) for Healthy Energy in Ithaca, New York. He is the program director for the public-health energy nexus of PSE. He has worked as a research associate for Weill Cornell Medical College in New York City on several projects concerning unconventional natural gas development. He will continue to examine various public health aspects of shale gas development and other novel energy production methods. Contact him at jake.hays@gmail.com

NITIN KONDAMUDI is a second-year medical student at the University of Medicine and Dentistry of New Jersey (UMDNJ) in Newark. He is unsure about the specialty he wishes to pursue, but wants to affect policy regarding medical issues. He hopes to continue research that is related to public health policies. Write to him at sunnyd1026@gmail.com

JANE SELEGEAN is an Eleanor Roosevelt Scholar at the Public Policy Institute at Hunter College, New York, NY. She is an undergraduate student at Hunter College-City University of New York. She is studying to acquire degrees concentrated in neuroscience, public policy and the special honors curriculum with minors in chemistry and English. She hopes to continue researching environmental and public health with relation to current political policy issues. Email her at jselegean@gmail.com

NOTES

1. U.S. Energy Information Administration, *The International Energy Outlook 2010 with Projections to 2035*, 2010, http://csis.org/files/attachments/100525_HGruenspecht_IEO2010.pdf (accessed April 23, 2012).
2. U.S. Energy Information Adminstration, *Annual Energy Outlook 2012,* 2012, www.eia.gov/forecasts/aeo/ (accessed April 23, 2012).
3. Clifford Krauss and Eric Lipton, "Inching Toward Energy Independence in America," *New York Times*, March 22, 2012, http://www.nytimes.com/2012/03/23/business/energy-environment/inching-toward-energy-independence-in-america.html?pagewanted=all&_r=0 (accessed March 23, 2012).
4. U.S. Environmental Protection Agency, *Investigation of Groundwater Contamination near Pavillion, WY* (Draft), December 9, 2010.
5. Pennsylvania Department of Environmental Protection, Bureau of Oil and Gas Management, *Year to Date Workload Report*, 2010, http://www.portal.state.pa.us/portal/server.pt/community/oil_and_gas_reports/20297 (accessed July 1, 2012).
6. National Agricultural Statistics Service (NASS), *Milk Production*, 2012, http://usda01.library.cornell.edu/usda/nass/MilkProd//2010s/2012/MilkProd-10-19-2012.txt (accessed July 1, 2012).
7. M. Bamberger and R. E. Oswald, "Impacts of Gas Drilling on Human and Animal Health," *New Solutions: A Journal of Environmental and Occupational Health Policy* 22 (2012): 51-77, doi: 10.2190/NS.22.1.e.
8. R. Adams and T. W. Kelsey, *Pennsylvania Dairy Farms and Marcellus Shale, 2007-2010*, 2012, Penn State Cooperative Extension, College of Agricultural Sciences; Marcellus Education Fact Sheet, http://pubs.cas.psu.edu/freepubs/pdfs/ee0020.pdf (accessed June 15, 2012).
9. National Agricultural Statistics Service (NASS), Quick Stats, 2012, http://quickstats.nass.usda.gov/?long_desc__LIKE=Milk+Production&x=0&y=0 (accessed July 15, 2012).
10. http://www.dep.state.pa.us/dep/deputate/minres/oil-gas/2011_Wells_Drilled_by_County.htm Pennsylvania Department of Environmental Protection, Oil and Gas Reports, SPUD data report, 2012, http://www.portal.state.pa.us/portal/server.pt/community/oil_and_gas_reports/20297 (accessed July 15, 2012)
11. Timothy Kelsey (Professor of Agricultural Economics, Pennsylvania State University), personal communication, July 30, 2012.

Direct reprint requests to:

Madelon L. Finkel, Ph.D.
Weill Cornell Medical College
402 East 67th Street, LA-213
New York, NY 10065-6304
e-mail: maf2011@med.cornell.edu

NEW SOLUTIONS, Vol. 23(1) 203-208, 2013

Voices

INSIGHTS ON UNCONVENTIONAL NATURAL GAS DEVELOPMENT FROM SHALE: AN INTERVIEW WITH ANTHONY R. INGRAFFEA

ADAM LAW
JAKE HAYS

ABSTRACT

Adam Law, M.D., interviewed Anthony R. Ingraffea, Ph.D., P.E., as part of a series of interviews funded by the Heinz Endowment. Dr. Ingraffea is the Dwight C. Baum Professor of Engineering at Cornell University, and has taught structural mechanics, finite element methods, and fracture mechanics at Cornell for 33 years. He discusses issues related to hydraulic fracturing, including inherent risks, spatial intensity, and the importance of a multi-disciplinary organization in establishing a chain of evidence.

Keywords: hydraulic fracturing, fracking, shale gas, spatial intensity, unconventional gas drilling

LAW: Tony, I wanted to discuss hydraulic fracturing and shale gas development with you since you're an engineer and a long-standing researcher in how objects and faults fracture. Specifically, I am interested in what insights you might have in addition to the information you typically provide regulators, policy makers, and others.

doi: http://dx.doi.org/10.2190/NS.23.1.l
http://baywood.com

INGRAFFEA: There is one very important aspect of unconventional gas developed from shale that hardly anybody understands, and I'm talking about the general public, policymakers, even regulators. The only entities that get it are the operators and a few individuals like myself who really understand the nexus between geology, geochemistry, engineering, science, and technology. And let me tell you what that issue is. It's called *spatial intensity*.

As you know, people are a bit upset about how things have progressed with shale gas development in a place like Pennsylvania. What people don't understand yet is that we haven't even started. Pennsylvania's been developing shale gas since 2007. And in that period of time there've been roughly 5,500 wells drilled, and people think, well, that's a lot.

But of those 5,500 wells that have been drilled, only about half have been fracked. And that half that's been fracked constitute about 2 percent of the eventual so-called build-out of Pennsylvania. So someone could fly over all of the areas of Pennsylvania right now that have been developed in Marcellus and say, that's not so bad, that's not like mountaintop removal in West Virginia. Well, not yet. Only about 2 percent of the wells that are going to be fracked have been fracked.

Yet, if we look at the consequences already—the number of individual private water wells that have already been contaminated, the number of health incidents that have occurred, the number of spills that have occurred, the number of truck accidents that have occurred—it's pretty simple now to start forecasting and crystal-ball–gazing and say what's it going to be like. If it's like this with 2 percent, what's it going to be like at 10 percent? What's it going to be like at 20 percent? It's going to be hellacious. The industry knows it. The gas is everywhere there's shale. Not in uniform quantities, of course. They still have to drill exploration wells to find their so-called hot spots—a county here, a county there.

But all of the prognoses that I'm reading out of the industry literature are that New York, Pennsylvania, Ohio, West Virginia, Maryland, a little bit of Virginia, are going to be subjected to at least 200,000 Marcellus Shale gas wells. And that's just the Marcellus. Of course they promise us there's also the Utica and a couple of others. So I'm repeating myself, but the single most important aspect that nobody gets is that it hasn't even started yet.

LAW: For those of us following up on this who are in the health care area, one of the big concerns has to do with pathways of exposure. In other words, in either the chemicals that we're putting into slick water or into drilling muds, or the flowback-produced waters, or the emissions coming back out as fugitive emissions—is there any way people can be exposed to that?

INGRAFFEA: Sure. The pathways are numerous and obvious. I categorize them as: from deep underground, from the surface, and from the air. And this kind of intense spatial development, number one, as I just said, is going to poke a few hundred holes in the ground that weren't there. Three hundred and thirty million years of sequestration of hydrocarbons, heavy metals, salts, and naturally occurring radioactive material is being de-sequestered. We're taking all that out and putting fresh water down.

Brilliant. What an exchange. What we just spent the last 30 or 40 million years doing, which is sequestering a lot of carbon dioxide, and putting a lot of water, drinkable water on the surface of the earth—we're reversing it. So yeah, poking a couple hundred thousand holes in the Marcellus, every one of those holes has to have a gasket. It's called a cement job. And we know that those gaskets fail at an alarming rate initially because they're really hard to put in place.

And most of them will fail eventually. By "eventually," I mean within a lifetime of a human, which means we're going to have tens of thousands of leaky gaskets. Which means that everything [that] was down there sequestered now has a pathway upwards into an underground source of drinking water or all the way to the surface. So that's pathway number one—poking all those holes and not being able to gasket them while they're operating and then successfully plug them when all these wells go out of operation. So we're postponing a major part of the problem.

At the surface, you have to bring chemicals to a well pad, and then you have to bring those chemicals and all the other waste products away from the well pad. That means transporting and storing. Anytime you transport and store hazardous material, you run the risk of spills. And obviously since it's spatially intense, we're going to have a lot of trucks, we're going to have lots of waste pits, we're going to have lots of pipelines, all of which at some point or another are going to cause some level of problem.

And then finally, air. What comes up out of the well is a gas, not just one gas, but all the other sisters and brothers of methane that want to come along for the ride. And not all of it goes into the pipeline, right? As we know, and as we're learning, a significant amount of it gets into the air in the form of hydrocarbon-based pollutants near the well pads that is capable of influencing people within a few miles, but also on a global scale. Again, spatial intensity. You've got the 200,000 wells in Pennsylvania, New York, West Virginia, Ohio, all those wells and all their ancillary infrastructure—compressor stations, processing stations, pipelines, storage units—they leak.

So we're going to be contributing to climate change in a way and at a time that we can least afford to. And to then say that this is the transition fuel that gets us to a sustainable and clean and climate-friendly future is absurd. It's walking the plank. It's not a bridge. A bridge has a near end and a far end. You want to get to the other end. This is a plank. Here we are, that's where we're going with this.

LAW: You're one of the founding board members of Physicians, Scientists, and Engineers for Healthy Energy (PSE), alongside myself. This organization is conceived as a multi-disciplinary group with people from a range of different backgrounds. How would you say this type of collaboration is important in addressing the science and the evidence of this new technology?

INGRAFFEA: It's fundamentally the right combination of expertise. As I tell the various aggrieved landowners, sometimes their lawyers who contact me for information, how can we prove the case? No one person has all the expertise.

Case in point, any one of these 200,000 wells that are going to be drilled in the Marcellus over the next *N* years can leak initially. Well, somebody has to be able to say, I understand the technology and the engineering of drilling, casing, cementing, and fracking a well. And I understand all the things that can go wrong, I understand why they go wrong, I understand when they go wrong, and I understand where they go wrong.

So if I read a well record, a daily diary that's kept by the operator of every single thing that happens on the well, then I can pinpoint, this is what went wrong, this is why it went wrong, this is where it went wrong, and this is when it went wrong. But that's insufficient. OK. The next thing you have to have is a geohydrologist who can say, well, if that went wrong there, then here are the consequences from the groundwater flow point of view.

If the gas well is upgradient of somebody's water well and I can say what leaked from this well, when it started leaking, and where it started leaking, then the next person in the chain, another kind of engineer, or scientist, geohydrologist, can say: and one, two, three days later, or three weeks later, or one year later, we can expect this concentration of contaminants to arrive in this person's well water. And *that's* not sufficient. OK, so—

LAW: What else do we need?

INGRAFFEA: Well, we need an engineer to say what went wrong, we need a scientist to say what the consequence was, and somebody down there has to be a professional who says, I can match up the contaminants, the chemistry of those contaminants, the hazardous nature of those contaminants with the health consequences of the people who drank the water or breathed that air. That's called chain of evidence, from my point of view. OK? You got at least those three, engineer, scientist, physician, working together to show causality.

There's a lot of coincidence-making—the industry always says, well, it's just a coincidence. Your well was always contaminated; you just noticed it now because we came into town. And on the other side, the extremist environmentalists, the people who don't think it all through, immediately draw causality conclusions from what might just be coincidence. But you really need an organization like PSE and its constituents, its advisors, its board, its members, who have all the kinds of technical expertise necessary to observe, determine the cause, and prove effect.

LAW: And one of the things that PSE is very concerned about as an organization is that the evidence is presented in vetted, peer-reviewed publications. Why is that so important?

INGRAFFEA: It's fundamentally important because in our society, in our civilization, the cornerstone, the wellspring, the gold standard of evidence is anonymous peer review. Without it, we're all bloggers. We're just opinionators. My opinion's as good as yours. My blog has fancier graphics, more people read my blog, therefore I should be believed. I'm sorry, no, that's not the way it works.

I'm very concerned that not only do we have the kinds of pollution that we've all been talking about—water pollution, air pollution, people pollution—we're seeing science pollution. The diminution of the importance of anonymous peer review, as exercised by the very best journals, administered by the best editorial boards. People who have not, are not going to be influenced by financial conflict of interest or by personal aggrandizement.

On average, that's the whole idea. You have enough people working at any journal on the editorial boards in their reviewer suite and in their publisher to know that they have, in that journal, a very grave responsibility for society. It's at least as important as the responsibility that the media have. I would argue it's even more important, because without the ability for—I'm bringing the conversation to an end here—the people, the citizenry, the policymakers, the legislators, the regulators to discern best science from somebody's opinion, it's hopeless.

LAW: Thanks very much, Tony.

AUTHORS' BIOGRAPHIES

JAKE HAYS is Program Director of Physicians, Scientists, and Engineers (PSE) for Healthy Energy in Ithaca, New York. He is the program director for the public-health energy nexus of PSE. He has worked as a research associate for Weill Cornell Medical College in New York City on several projects concerning unconventional natural gas development. He will continue to examine various public health aspects of shale gas development and other novel energy production methods. Contact him at jake.hays@gmail.com

ADAM LAW is a specialist in endocrinology and diabetes in Ithaca, New York. Dr. Law, a Fellow of the U.K.'s Royal College of Physicians, is also Clinical Assistant Professor of Medicine at Weill Cornell Medical College. He trained in medicine at The Middlesex Hospital Medical School at the University of London, where he won all eight major clinical prizes offered by the school. After gaining membership in the Royal College of Physicians, he turned his attention to medical science, and received a master's degree in biochemistry and a doctorate from the University of London. He has held post-doctoral fellowships at the University of California, San Francisco, and Cornell and has published 13 research papers in clinical medicine and basic molecular biology. He has been in clinical practice in Ithaca since 2004. In January 2007, he took a two-year appointment as Chair of the Department of Medicine at Ithaca's Cayuga Medical Center, and led the medical staff in 2009. Send mail to him at law@ithacamed.com

Direct reprint requests to:

Jake Hays
Program Director
Physicians Scientists & Engineers for Healthy Energy
452 W. 57th St., Apt 3E
New York, NY 10019
e-mail: hays@psehealthyenergy.org

NEW SOLUTIONS, Vol. 23(1) 209-221, 2013

Movement Solutions

NAVIGATING MEDICAL ISSUES IN SHALE TERRITORY

POUNÉ SABERI

ABSTRACT

The introduction of natural gas drilling with high-volume hydraulic fracturing to Pennsylvania and neighboring states since 2004 has been accompanied by numerous reports of varied symptoms and illnesses by those living near these operations. Pollutants with established toxic effects in humans may be introduced into the environment at various points during gas extraction and processing. Some community residents, as well as employees of the natural gas industry, believe that their health has deteriorated as a result of these operations and have sought medical care from local practitioners, who may have limited access to immediate toxicological consultations. This article reviews taking an environmental exposure history in the context of natural gas activities, underscoring the importance of thorough and guided history-taking in the discovery of environmental exposure clusters. It also highlights the critical need for funding, research, and peer-reviewed studies to help generate the body of evidence that is needed by practitioners.

Keywords: hydraulic fracturing, exposure history, natural gas, health symptoms

Most health care practitioners know what to do when they do not have the answer to a set of symptoms presented by a patient or when they are puzzled about a clinical case. They discuss it with a colleague, look it up in a medical library or online resource, or send the patient to a specialist for a formal consultation.

doi: http://dx.doi.org/10.2190/NS.23.1.m
http://baywood.com

But what happens when there is no expert or consultant to give advice about the problem the patient is facing? What happens when there is no literature to reference and most colleagues are just as baffled about the problem? That is the situation facing some health care practitioners in Pennsylvania who work in counties where high-volume hydraulic fracturing (also referred to as "fracking" in popular media) for natural gas along with related activities (chemical mixing; silica sand use; waste storage and handling; pipeline drilling, gas processing, compressor stations, and more) is occurring.

These practitioners have patients—both workers and residents—who report symptoms they believe are related to some part of the chain of shale gas operations. The practitioners hear about symptoms such as shortness of breath associated with odors in ambient air occurring after seismic testing; palpitations associated with being in the vicinity of a hydraulic fracturing flow-back waste impoundment; or black particles observed in tap water after a gas well was drilled, followed by an outbreak of a rash when showering. But are these actually related to fracking? The practitioners don't know, and they don't know whom to ask. There are no textbooks to consult, no experts to call upon, no adequate body of research to evaluate. They are stumped.

The underlying problem results from several factors. First of all, several of the special techniques essential to unconventional oil and gas extraction are nascent, with less than 10 years of use in Pennsylvania. While data exist on some of the routes of exposure resulting from these techniques, such as the vibration of compressor stations or the noise of truck traffic, the comprehensive environmental monitoring that could lead to informed exposure profiles is lacking. In addition, epidemiological longitudinal studies that would assist in the development of evidence-based clinical recommendations, at this time, have not been funded, conducted or published. Lastly, very few health care providers are trained in how to obtain an occupational history and fewer still are trained in obtaining an environmental exposure history, resulting in a general dearth of experience to guide practitioners in addressing their patients' symptoms and concerns.

TAKING AN ENVIRONMENTAL HISTORY IN SHALE TERRITORY

This article does not engage in a full discussion of the first two factors. Here, we will attempt to address the third in more detail: how does a health care provider take an environmental history when faced with a health complaint the patient, the provider, or both believe is due to shale gas extraction, processing, or transport infrastructure? Pennsylvania and the Marcellus Shale are chosen as the setting to address the health concerns that have surfaced in recent years. But health practitioners in any region where unconventional extractive techniques are in effect may use the principles outlined as a guide. Natural gas output from

Marcellus has increased tenfold since 2009 [1], and pipeline plans for domestic and global transportation have been expanding daily. I intend to illustrate the point that given the increase in this extractive industry, education about health concerns would be very timely for many clinicians.

To this end, in this article, I will review when and how the health care professional should obtain an environmental history. I hope to demonstrate that obtaining an accurate environmental history is a fundamental step in establishing the epidemiology of specific health issues, and it follows that the step taken by the health professional will be vital in building this foundation. I will end with a brief commentary on the current state of public health research and make the case that all literature related to shale gas, generated in academic and non-academic settings, should be given priority for peer reviewing and analysis to help generate the body of evidence that is needed by practitioners.

A note about terminology is in order. First, while generally "hydraulic fracturing" is used as a catch-all term for the unconventional extraction of methane gas (commonly referred to as "natural gas") or oil, the more appropriate term would be "natural gas activities" or even more broadly, "unconventional resource extraction." The message here is that the extraction, production, and transmission of fossil fuels, in this case natural gas, involve many steps during which exposure of residents and workers can occur, and it is important to utilize terminology that includes impacts from the entire life cycle of shale gas production.

Second, while we refer to "chemical" exposure, toxic and hazardous substances, and so forth, it is important for the clinician to realize that despite the attention to the additives in hydraulic fracturing fluid (also referred to as flow-back), an appreciable portion of the mixtures in drilling muds, drill cuttings, flow-back or other waste products are in fact endogenous to the subterranean layer and are therefore considered "naturally occurring." These substances range from radioactive compounds such as radon, to hydrocarbons such as benzene, heavy metals such as arsenic, or salts (e.g., strontium salts), and can be as hazardous as the additives. The attention given to the additives may be due to the proprietary nature of the mix, but just as many of the chemicals are naturally occurring. What may make them hazardous is that they are mobilized to the surface by the processes involved in the extraction of natural gas [2]. Thus, the practitioner must be alert to all possibilities with regards to the scope of substances and potential migratory pathways. I will expand more on this concept below.

> *Vignette:* A health care professional sees a patient who works for the natural gas industry on site. The worker wants a blood test for a certain chemical. The review of physical symptoms is negative. The worker is concerned because he has worked with a mixture of fluids without gloves. He does not know the name of the mixture. What should the health professional do?

The first and most fundamental concept to follow as a guide is the distinction between a hazard and a health risk. For a hazardous substance to pose a health risk it must first be transported through the environment, creating an exposure point where it can be absorbed through inhalation, ingestion, or dermal contact. The range of potential migratory pathways can be demonstrated by the cases that Bamberger and Oswald report [3]: failed well casings, leaking flow-back waste impoundments, dumping of toxic liquids in waterways, and emissions from compressor stations.

The goal is not always to nail down a "smoking gun" chemical to blame for a reported symptom. Insist on performing the routine history and physical exam, because a health problem may very well be uncovered that is unrelated to any environmental exposure. At the same time, incorporate questions about environmental exposures, since the testing should be guided by what the worker was exposed to.

Establishing the chronology of symptoms in the context of external exposures is vital. Precise questions that guide in the determination of the temporal relation between the introduction of an exposure and the appearance of health symptoms will help both the patient and the provider. The patient will recall the events in better detail and the provider is better able to generate possible connections that are biologically valid. Most patients remember that there was a gas well drilled, seismic testing was done, pipelines were dug in their vicinity, etc. They also remember their symptoms, but to fine-tune the temporal relation between these two events is crucial.

On the other hand, some operations are less obvious; for example, people may not be able to tell the approximate date a well is fractured, or be aware that a large out-of-sight waste impoundment is close by. Other examples of less evident connections are those between symptoms that are noticed in daytime but in fact result from exposure to night-time activities such as flaring. Examples of some of the questions are:

- When did you move into your current residence?
- When was the well drilled? When fractured, if known?
- When was the impoundment pit created, the compressor station built, or the wastewater spilled?

The challenge is then to see whether that background information correlates with specific environmental observations, using questions such as these:

- When did you notice your water's color changing?
- When did you notice the odors in the air?

Clearly medical events that precede the exposure, or illnesses that require a longer lead time than was experienced, will not be related to the exposures under discussion. For example, it is biologically plausible for certain cancers to develop within a given time frame, while for other cancers it is not. A caveat to the issue of timing deserves mention. The veterinary literature indicates that animal health is a sentinel for human health [3, 4]. Many companion animals may share the same exposures but manifest symptoms more rapidly. While many health care practitioners may not feel comfortable with zoological conditions, simple questions about the health of animals in the household and their behavior can be illuminating. Inquiring after diagnoses given by veterinarians is also helpful in establishing clues.

After obtaining subjective data, obtaining objective data is standard. The physical exam is dictated by the history and review of symptoms. Documenting vital signs as always is essential. For example, some chemicals have cardiotoxic effects that may not be apparent in the short term. But once the trend is reviewed over time it may reveal persistently increasing heart rate and necessitate further workup by electrocardiography. For example, long-term exposure to carbon monoxide, measured in air by well pads and compressor stations [5], worsens symptoms in people with prior cardiovascular disease [6]. Supplemental aids such as obtaining pictures of dermatological rashes can also be helpful.

In assessing the clinical scenario, one of the major pitfalls in interpreting toxicological data is the assumption that the same level of evidence can be applied to these data as to routine laboratory testing. The existing data bank for routine blood work is significantly larger, and therefore the strength of evidence for recommendations on when to order the test, how and when to collect it, and how to interpret it, is similarly much greater. Given the challenges in applying the results of toxicological data to a clinical case, the health care provider must carefully consider the reasons for ordering a test and do so only when sufficient suspicion for an exposure and a potential route of absorption exists. Having a sense of the pre-test probability of a health condition is useful to clinicians in understanding the predictive value of a negative or positive test result.

The health care provider may feel pressured to obtain biomonitoring as promptly as possible, given the time limits of the patient-doctor visit, the time-sensitive nature of the tests, and the desire to alleviate patient concerns. Biomonitoring is the assessment of human exposure to chemicals by measuring the chemicals or their metabolites in human specimens such as blood or urine [7]. It is challenging to balance prompt ordering with unearthing the appropriate tests. Generally in ordering blood and urine tests, obtaining the sample as close as possible to the time of exposure increases the validity of the result. On the one hand, some chemicals have such short half-lives in the body that a negative result obtained long after the exposure will provide false reassurance that the individual was not exposed. On the other hand, some exposures are so ubiquitous in the environment that a positive result obtained long after the exposure of concern may reflect only an unrelated environmental exposure. A key to reaching this balance, and to avoiding missed opportunities by ordering the wrong panel, is establishing a system of fact-finding with a network of medical toxicology consultants in advance. Governmental labs, such as that of the U.S. Centers for Disease Control and Prevention (CDC) and state labs, as well as private labs, may perform services for specialized biomonitoring tests. For example, National Medical Services performs a significant amount of toxicological testing, and toxicologists at the laboratory can be contacted with clarifying questions to help with appropriate testing (www.nmslabs.com). The website lists the phone number for client services, and providers can speak to support staff or request consultation. As with all other consultations, focused questions will receive more useful answers.

The cost of specialized testing may be a barrier for residents who are uninsured. The cost of the testing is variable depending on the type of testing requested, and providers may contact their chosen lab for the exact price. Depending on the test the price may vary from a few hundred to a few thousand dollars no matter which lab performs it. Specialized testing may not be covered by all medical insurances, and many insured residents may find themselves having to pay the expenses out of pocket.

The balancing act by the health care provider extends to recognizing the importance of mental health impacts of the natural gas activities. In the health impact assessment performed by Witter et al. [8] in Colorado in 2007, fear of unknown chemicals was listed as a stressor identified by community members. This illustrates the awareness that the health care provider must have toward appropriate counseling about environmental exposures. The balance lies in not disregarding the concerns raised by the patient and not causing undue alarm at the same time.

SOME CONCERNS

The symptoms, alone and in clusters, that have been repeatedly seen in different parts of the state of Pennsylvania may be cause for concern. The Environmental Health Project has documented dermal, gastrointestinal, and respiratory symptoms as the most commonly occurring complaints [9]. Bamberger and Oswald [3] have reported similar profiles: burning of the nose, throat and eye, headaches, gastrointestinal symptoms such as vomiting and diarrhea, rashes, and nosebleeds.

The following summarizes the problems most commonly reported to me and to other researchers by residents and workers, in order of frequency with the most common problems listed first [10]. As of July 2012, there were about 50 such reports. When evaluated in the context of a possible natural gas operation exposure, these symptoms may be noted as potential “sentinel” symptoms for toxic agents with more serious, but possibly delayed, clinical impacts:

- rashes or skin irritation,
- abdominal pain and cramping,

- shortness of breath,
- recurrent sinusitis, and
- diarrhea.

Looking back at the history of environmental health hazards, a health professional may pause to consider the future implications of toxic exposure from unconventional natural gas operations. For instance, the history of asbestosis shows a lag time between clinical observation (first case of asbestosis documented in the 1920s) and epidemiological proof (asbestosis is shown to cause lung cancer in the 1950s), and regulatory enforcement. Asbestos production plants were shut down in the 1980s after numerous unnecessary deaths from asbestosis and asbestos-related cancers had occurred. Even today, new diagnoses of asbestosis, mesothelioma, and other asbestosis-related cancers are still being made.

A reasonable concern is that in 10 to 80 years, the public will be paying for exposure to both established and new toxic substances, when current symptoms and the lack of public health scrutiny should have been red flags. McKenzie et al. [11], for example, concluded that residents who live closer to gas pads have higher predicted risks of respiratory and neurological conditions in addition to excess lifetime risk of developing cancer. A March 2012 press release issued by the Environmental Protection Agency (EPA) addressed a groundwater investigation in Pavillion, Wyoming, stating [12]: "We believe that collaboration and use of the best available science are critical in meeting the needs of Pavillion area residents and resolving longstanding issues surrounding the safety of drinking water and groundwater." The collaboration among the EPA, United States Geological Survey (USGS), and the State of Wyoming was an excellent example of using best available science in a speedy manner to identify red flags for the community residents. The EPA report showed benzene concentrations in an aquifer at 50 times the Maximum Contaminant Level (MCL) [13]. What happened subsequently may provide a clue as to the lag time between scientific findings and policy, as seen with the timeline of asbestos regulations. EPA and USGS were made to resample and repeat their findings; their results were questioned, and eventually the oil and gas industry demanded that new tests be done [14].

This story raises several points. One is that when the stakes are so high that the health of residents is dependent on them, red flags should be sufficient to protect the people rather than wait for conclusive evidence. The second point is that conducting health impact studies prior to engaging in operations with potential high-stake outcomes allows dialogue for establishing safeguards ahead of time. Lastly, despite the amount of time spent on hazard assessment, experts remain unable to provide clinicians with guidance for risk communication to patients.

No state to date has attempted a health impact assessment prior to allowing unconventional extraction of shale to begin, nor has any state engaged in creating a disease or health complaint registry after the process has begun. Unlike the use of asbestos, which exposed workers to a single substance, in unconventional natural gas operations, populations are exposed to a multitude of chemicals that vary both within and between shale gas fields. Time is passing, and there is a strong need for health impact studies in states and areas where natural gas activities have not yet begun, for collaborations to screen for red flags in areas where natural gas activities have begun, and for comprehensive studies that offer both policy recommendations and clinical guidelines.

SPECIAL CHALLENGES AND SPECIAL POPULATIONS

There are special populations with added vulnerability that deserve different considerations by medical professionals [15]. Pregnant women, people whose occupation is working in the industry, and children are examples of such populations. The teratogenicity of many compounds, such as mercury, which occur naturally in the deeper geological formations but are brought up either with natural gas operations or burning of coal, has been firmly established. The adverse embryonic effects of the same chemical may be different depending on the gestational age at exposure. Institutions that are dedicated to such special populations include Pediatric Environmental Health Specialty Units (PEHSU) (http://aoec.org/pehsu). A large body of data demonstrates disproportionate impacts on another vulnerable population, the elderly. Ground-level ozone, for example, has been linked to premature death in this cohort [16].

While some special populations, such as pregnant women or children, are rarely unrecognized as such by health care providers, many practitioners may not be aware of regulations surrounding providing care for the workers. The National Institute for Occupational Safety and Health (NIOSH) (http://www.cdc.gov/niosh) has an important hazard alert for health care professionals regarding worker exposure to silica during hydraulic fracturing [17]. Medical practitioners should ask patients who are natural gas operation workers if they are involved in dusty drilling operations, and if so, a pulmonary evaluation should be recommended and an onsite inspection made, as explained below.

The Occupational Safety and Health Administration (OSHA) has specific rules and regulations regarding reporting work-related injuries and hazards in the workplace. OSHA requires that most industries keep logs of occupational injuries and illnesses, which must be made available to OSHA during inspections. Injuries that result in fatalities or multiple hospitalizations must be immediately reported to OSHA. The health care practitioner may act as the representative of a worker when faced with the knowledge of a workplace hazard and file a request for onsite work inspections (www.osha.gov/as/opa/worker/complain.html). For example, an emergency medicine provider may treat several workers for heat stroke and recognize that the recurrent episodes are related to working extended hours in the heat on a well pad. The physician may then contact the regional office of OSHA, anonymously or otherwise, to report the hazardous working conditions. Studying the logs will help locate areas where possible exposures are occurring with the goal of preventing them.

SOME RESOURCES

The environmental medicine literature demonstrates the importance of including questions about potential toxic exposure when taking a clinical history. Authors give examples of common symptoms that are found to be due to an environmental exposure [18]. For example, a recurrent headache leads to the discovery of indoor carbon monoxide levels, or a non-resolving rash points to the patient's hobby of working with treated wood. Environmental medicine authorities point out that the key to solving the puzzle is to include the environmental or occupational exposure in the differential diagnosis and ask the relevant questions [19]. If the health care practitioner sees patients in an area where there is natural gas activity, it is reasonable to consider the steps involved in the exposure as a possible etiological factor.

Establishing a connection between an environmental exposure and health symptoms is easier when population-based data are available. At this time in our medical knowledge of the health effects of unconventional shale operations, the relevant questions are far broader than are usually considered in the outpatient setting, and the conclusions not tremendously gratifying. That is why the significance of clinicians participating in the collection of population-based data cannot be understated. A solid investigation at the individual level appreciably contributes to population-level data gathering for such phenomena as cluster investigations or disease registries.

> *Vignette:* Two small children are brought in for rashes on their hands. The well nearest to their home has been flared for the last week. The family believes that the rashes are due to flaring, as the symptoms did not exist prior to this event.

This case illustrates the importance of remembering to follow the medical teachings of entertaining all possible differential diagnoses. Childhood viral exanthems (rash) are common, as are other possibilities such as irritant dermatitis in reaction to a new compound in the environment. Some of the resources available are online and include the Case Studies in Environmental Medicine prepared by the federal Agency for Toxic Substances and Disease Registry (ATSDR) (http://www.atsdr.cdc.gov/csem/csem.html). They guide the practitioner step by step on how to take an exposure history, and include monographs on a variety of chemicals. ATSDR has also created a summary of key questions to ask, which can either be incorporated into a visit or asked by the ancillary staff. Various environmental organizations also offer questionnaires that may be helpful. For example, the Southwestern Pennsylvania Environmental Health Project contains some good examples of medical history questions to ask in the context of natural gas operations (http://www.environmentalhealthproject.org/). This website also lists resources for environmental monitoring and recommendations for minimizing exposure to many of the sources present in activities associated with the life cycle of hydraulic fracturing. The site also offers helpful brochures explaining how to interpret water test results and other instruction sheets that clinicians can give to their patients (3 Good Things To Do: http://www.environmentalhealthproject.org/health/steps-you-can-take-now/). For example, practical advice for the family in the above scenario may be to take steps to purify the indoor air, in order to reduce the load of particulates and other pollutants that have migrated into the home from outside air.

REGULATIONS

Health care providers are no stranger to the interface of legal matters and medicine. Most education about the medical/legal field achieves the goal of protecting the provider from inadvertently breaking a law. In the context of unconventional natural gas activities, however, it behooves the clinician to become well versed in the intricacies of the legalese that protect both the patient and the patient-doctor relationship. At the time of writing this article, in Pennsylvania, Act 13, the 2012 state law addressing shale gas extraction issues, contains medical provisions addressing disclosure of proprietary chemical mixtures by the industry. If a provider suspects potential exposure to an unknown compound, he or she may request release of data in writing in order to appropriately treat the exposed patient, but must agree not to disclose the information received. Similar regulation is also in effect in other states such as Colorado and is modeled after OSHA's Hazard Communication Standard.

The medical provisions in Act 13 bring up several issues. OSHA regulations have been written to protect workers in their workplace. Historically EPA has been tasked with having a similar role for residents in their living environment. In the context of natural gas exploration and extraction, the bulk of enforcing power has fallen on state government agencies. The federal Energy Policy Act of 2005 has minimized EPA's oversight by exempting the oil and gas companies engaged in hydraulic fracturing from key portions of some fundamental environmental laws. Despite the limitation of jurisdiction, EPA asserts that it has acted when stakeholders have made inquiries.

In Pennsylvania, the application of the medical provision of Act 13 is not well understood, since it has not been effectively tested. Very few providers desire to be the pioneers in applying the complexities of legal procedures such as sharing the data obtained from the company with their patients. Efforts made by medical professionals to understand the scope of action permitted under the law will improve their capacity to help patients obtain valuable chemical information. The Network for Public Health Law is one resource. While its staff are not able to provide direct advice about the application of the law to a specific circumstance, they can provide technical legal assistance to access and understand the law. They can be contacted via phone at 410-706-5575 or email at eastern@networkforphl.org. If a provider has questions about local application of the law, The American Medical Association Litigation Center, (http://www.ama-assn.org/ama/pub/physician-resources/legal-topics/litigation-center/about-us.page?) may be able to direct inquiries to lawyers in the state who can provide answers.

CONCLUSION

In summary, what does a practitioner do when the patient says a health problem is due to unconventional gas drilling operations? The practitioner must be adept at taking a relevant exposure history, and include toxic exposure as a potential cause for the patient's symptoms, while not prematurely arriving at a conclusion of causation. Clinicians may need to think about multiple exposures to chemicals, each of which can create multiple overlapping symptoms, and to deal with the frustration brought on by the uncertainty about which substances are involved. Despite the multiple barriers to obtaining high-quality epidemiological data, every health practitioner who takes a complete case history, including a history of environmental exposure, is providing a tremendous service both for the patient and for public health. The documentation by clinicians has been the foundation of such established and widely used databases as the Surveillance Epidemiology and End Results (SEER) registry. The present-day effort will result in tomorrow's payback of information that will be reliably used in evaluating puzzling environmental clinical scenarios. Health care providers are empowered to see themselves as a vital link in the chain of constructing future epidemiological data banks. The field of public health will ideally be transformed from the perspective of collection of disease counts to one with infrastructure for monitoring and mitigating toxic substances before they have had the chance to cause harm.

ACKNOWLEDGMENTS

I would like to thank Dr. Leslie Walleigh, Ms. Iris Marie Bloom, Ms. Martha Powers, and Dr. Parya Saberi for their undeterred dedication and timely expertise in making this article a reality. I also would like to thank the Department of Occupational and Environmental Medicine at the University of Pennsylvania for presenting me with the exceptional opportunity of learning this exciting field.

AUTHOR'S BIOGRAPHY

POUNÉ SABERI, M.D., M.P.H., is adjunct faculty in the Occupational and Environmental Medicine section of the Emergency Department at the University of Pennsylvania. She has ten years of clinical experience as a family physician. Her passion is learning and teaching about the effects of environmental factors and toxicology on personal health. She is conducting a study at the Center of Excellence in Environmental Toxicology about health perceptions of environmental exposures. As a public health specialist and advocate for clean air and water, she works to bridge the gap between policy and research. Write to her at pounesaberi@yahoo.com

NOTES

1. E. Houlihan and E. McAllister, "Analysis: Waking Giant-Marcellus Shale Bullies U.S. Gas Market," October 15, 2012, http://www.reuters.com/article/2012/10/15/us-energy-natgas-marcellus-idUSBRE89E12B20121015 (accessed October 19, 2012).
2. T. Colborn et al., "Natural Gas Operations from a Public Health Perspective," *International Journal of Human and Ecological Risk Assessment* 17 (2011): 1039-1056, doi: 10.1080/10807039.2011.605662.
3. M. Bamberger and R. E. Oswald, "Impacts of Gas Drilling on Human and Animal Health," *New Solutions: A Journal of Environmental and Occupational Health Policy* 22 (1) (2012): doi: 10.2190/NS.22.1.e.
4. P. Rabinowitz, M. Scotch, and L. Conti, "Human and Animal Sentinels for Shared Health Risks," *Veterinalia Italiana* 45 (1) (2009): 23-24.
5. Eastern Research Group, Inc. and Sage Environmental Consulting LP, *City of Fort Worth Natural Gas Air Quality Study Final Report*, 2011, http://fortworthtexas.gov/uploadedFiles/Gas_Wells/AirQualityStudy_final.pdf (accessed December 17, 2012).
6. Y. Adir et al., "Effects of Exposure to Low Concentrations of Carbon Monoxide on Exercise Performance and Myocardial Perfusion in Young Healthy Men," *Occupational & Environmental Medicine* 56 (8) (1999): 535-538, doi: 10.1136/ oem.56.8.535.
7. Centers for Disease Control and Prevention, *Third National Report on Human Exposure to Environmental Chemicals*, 2005, http://clu-in.org/download/contaminant focus/pcb/third-report.pdf (accessed December 12, 2012).
8. R. Witter et al., *Health Impact Assessment for Battlement Mesa, Garfield County Colorado*, 2010, www.tcgasmap.org/media/Health%20Impacts%20Assessment%20 Garfield%20Ritter%20Final%20Draft%209-10.pdf (accessed October 22, 2012).
9. L. Walleigh, personal communication, July 20, 2012.
10. SWPA-EHP, "Medical Resources/Medical Toolkit," http://www.environmentalhealth project.org/resources/medical-resources/ (accessed December 12, 2012).
11. L. M. McKenzie et al., "Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources," *Science of the Total Environment* 424 (2012): 79-87, doi: 10.1016/j.scitotenv.2012.02.018.
12. R. Mylott and R. MacKay, *Statement on Pavillion, Wyoming Groundwater Investigation*, 2012, http://yosemite.epa.gov/opa/admpress.nsf/d0cf6618525a9efb85257359 003fb69d/17640d44f5be4cef852579bb006432de!opendocument (accessed October 22, 2012).

13. D. C. DiGiulio, R. T. Wilkin, and C. Miller, *Investigation of Ground Water Contamination near Pavillion, Wyoming*, 2011, http://www.epa.gov/region8/superfund/wy/pavillion/EPA_ReportOnPavillion_Dec-8-2011.pdf (accessed October 22, 2012).
14. P. Dittrick, "API: USGS Did Better Job Testing Pavillion Water Than EPA," October 18, 2012, http://www.ogj.com/articles/2012/10/api-usgs-did-better-job-testing-pavillion-water-than-epa.html (accessed December 9, 2012).
15. World Heath Organization, *Principles for Evaluating Health Risks in Children Associated with Exposure to Chemicals*, 2007.
16. U.S. Environmental Protection Agency, *Third External Review Draft of Air Quality Criteria for Particulate Matter*, 2002, http://www.epa.gov/ncea/pdfs/partmatt/VOL_I_AQCD_PM_3rd_Review_Draft.pdf (accessed October 14, 2012).
17. U.S. Occupational Health and Safety Administration and National Institute for Occupational Safety and Health, "OSHA-NIOSH Hazard Alert: Worker Exposure to Silica During Hydraulic Fracturing," 2012, www.osha.gov/dts/hazardalerts/hydraulic_frac_hazard_alert.html (accessed October 22, 2012).
18. J. N. Thompson et al., "Use of a Questionnaire to Improve Occupational and Environmental History Taking in Primary Care Physicians," *Journal of Occupational and Environmental Medicine* 42 (12) (2000): 1188-1194, doi: 10.1097/00043764-200012000-00014.
19. A. L. Frank, "Approach to the Patient with an Occupational or Environmental Illness," *Primary Care* 27 (4) (2000): 877-894, doi: 10.1016/S0095-4543(05)70182-2.

Direct reprint requests to:

Pouné Saberi, MD, MPH
One Convention Ave.
4 Penn Tower
Philadelphia, PA 19146
e-mail: poune@psrphila.org

Impact of Shale Gas Development on Regional Water Quality

R. D. Vidic *et al.*

Science **340**, (2013);
DOI: 10.1126/science.1235009

REVIEW SUMMARY

Impact of Shale Gas Development on Regional Water Quality

R. D. Vidic,[1]* S. L. Brantley,[2] J. M. Vandenbossche,[1] D. Yoxtheimer,[2] J. D. Abad[1]

READ THE FULL ARTICLE ONLINE
http://dx.doi.org/10.1126/science.1235009

Cite this article as R. Vidic *et al.*, *Science* **340**, 1235009 (2013). DOI: 10.1126/science.1235009

Background: Natural gas has recently emerged as a relatively clean energy source that offers the opportunity for a number of regions around the world to reduce their reliance on energy imports. It can also serve as a transition fuel that will allow for the shift from coal to renewable energy resources while helping to reduce the emissions of CO_2, criteria pollutants, and mercury by the power sector. Horizontal drilling and hydraulic fracturing make the extraction of tightly bound natural gas from shale formations economically feasible. These technologies are not free from environmental risks, however, especially those related to regional water quality, such as gas migration, contaminant transport through induced and natural fractures, wastewater discharge, and accidental spills. The focus of this Review is on the current understanding of these environmental issues.

Advances: The most common problem with well construction is a faulty seal that is emplaced to prevent gas migration into shallow groundwater. The incidence rate of seal problems in unconventional gas wells is relatively low (1 to 3%), but there is a substantial controversy whether the methane detected in private groundwater wells in the area where drilling for unconventional gas is ongoing was caused by well drilling or natural processes. It is difficult to resolve this issue because many areas have long had sources of methane unrelated to hydraulic fracturing, and pre-drilling baseline data are often unavailable.

Water management for unconventional shale gas extraction is one of the key issues that will dominate environmental debate surrounding the gas industry. Reuse of produced water for hydraulic fracturing is currently addressing the concerns regarding the vast quantities of contaminants that are brought to the surface. As these well fields mature and the opportunities for wastewater reuse diminish, the need to find alternative management strategies for this wastewater will likely intensify.

Outlook: Improved understanding of the fate and transport of contaminants of concern and increased long-term monitoring and data dissemination will help effectively manage water-quality risks associated with unconventional gas industry today and in the future. Confidentiality requirements dictated by legal investigations combined with the expedited rate of development and the limited funding for research are major impediments to peer-reviewed research into environmental impacts. Now is the time to work on these environmental issues to avoid an adverse environmental legacy similar to that from abandoned coal mine discharges in Pennsylvania.

Drilling multiple horizontal wells from a single well pad allows access to as much as 1 square mile of shale that is located more than a mile below. [Image courtesy of Range Resources Appalachia]

ARTICLE OUTLINE

BACKGROUND READING

General overview that includes geology of major shale plays, description of the extraction process, relevant regulations, and environmental considerations: www.netl.doe.gov/technologies/oil-gas/publications/EPreports/Shale_Gas_Primer_2009.pdf

Detailed information about individual shale gas wells, including chemical additives used in each hydraulic fracturing treatment: http://fracfocus.org

Findings of the U.S. Environmental Protection Agency study on the potential impact of hydraulic fracturing on drinking water resources: www.epa.gov/hfstudy

Comprehensive information from the British Geological Survey about shale gas (including articles and videos): www.bgs.ac.uk/shalegas

Site developed in collaboration with the Geological Society of America promoting the rational debate about energy future: www.switchenergyproject.com

Latest news and findings about shale gas. www.shale-gas-information-platform.org

[1]Department of Civil and Environmental Engineering, University of Pittsburgh, Pittsburgh, PA 15261, USA. [2]Earth and Environmental Systems Institute and Department of Geosciences, Pennsylvania State University, University Park, PA 16802, USA.
*Corresponding author. E-mail: vidic@pitt.edu

Impact of Shale Gas Development on Regional Water Quality

R. D. Vidic,[1]* S. L. Brantley,[2] J. M. Vandenbossche,[1] D. Yoxtheimer,[2] J. D. Abad[1]

Unconventional natural gas resources offer an opportunity to access a relatively clean fossil fuel that could potentially lead to energy independence for some countries. Horizontal drilling and hydraulic fracturing make the extraction of tightly bound natural gas from shale formations economically feasible. These technologies are not free from environmental risks, however, especially those related to regional water quality, such as gas migration, contaminant transport through induced and natural fractures, wastewater discharge, and accidental spills. We review the current understanding of environmental issues associated with unconventional gas extraction. Improved understanding of the fate and transport of contaminants of concern and increased long-term monitoring and data dissemination will help manage these water-quality risks today and in the future.

Natural gas has recently emerged as an energy source that offers the opportunity for a number of regions around the world to reduce their reliance on energy imports or strive toward energy independence (*1*, *2*). It may also be a potential transition fuel that will allow for the shift from coal to renewable energy resources while helping to reduce the emissions of CO_2, criteria pollutants, and mercury by the power sector (*3*). The driving force behind this shift is that it has become economically feasible to extract unconventional sources of gas that were previously considered inaccessible. Conventional gas is typically extracted from porous sandstone and carbonate formations, where it has generally been trapped under impermeable caprocks after migration from its original source rock. In contrast, unconventional gas is usually recovered from low-permeability reservoirs or the source rocks themselves, including coal seams, tight sand formations, and fine-grained, organic-rich shales. Unconventional gas formations are characterized by low permeabilities that limit the recovery of the gas and require additional techniques to achieve economical flow rates (*2*).

The archetypical example of rapidly increasing shale gas development is the Marcellus Shale in the eastern United States (Fig. 1). Intensive gas extraction began there in 2005, and it is one of the top five unconventional gas reservoirs in the United States. With a regional extent of 95,000 square miles, the Marcellus is one of the world's largest known shale-gas deposits. It extends from upstate New York, as far south as Virginia, and as far west as Ohio, underlying 70% of the state of Pennsylvania and much of West Virginia. The formation consists of black and dark gray shales, siltstones, and limestones (*4*). On the basis of a geological study of natural fractures in the formation, Engelder (*5*) estimated a 50% probability that the Marcellus will ultimately yield 489 trillion cubic feet of natural gas.

[1]Department of Civil and Environmental Engineering, University of Pittsburgh, Pittsburgh, PA 15261, USA. [2]Earth and Environmental Systems Institute and Department of Geosciences, Pennsylvania State University, University Park, PA 16802, USA.

*Corresponding author. E-mail: vidic@pitt.edu

Concerns that have been voiced (*6*) in connection with hydraulic fracturing and the development of unconventional gas resources in the United States include land and habitat fragmentation as well as impacts to air quality, water quantity and quality, and socioeconomic issues (*3*, *5*, *7*). Although shale gas development is increasing across several regions of the United States and the world (such as the United Kingdom, Poland, Ukraine, Australia, and Brazil), this review focuses on the potential issues surrounding water quality in the Appalachian region and specifically the Marcellus Shale, where the majority of published studies have been conducted. Our Review focuses on chemical aspects of water quality rather than issues surrounding enhanced sediment inputs into waterways, which have been discussed elsewhere (*4*, *7*, *8*).

Cause of the Shale Gas Development Surge

Recent technological developments in horizontal drilling and hydraulic fracturing have enabled enhanced recovery of unconventional gas in the United States, increasing the contribution of shale gas to total gas production from negligible levels in 1990 to 30% in 2011 (*1*). Although the first true horizontal oil well was drilled in 1929, this technique only became a standard industry practice in the 1980s (*9*). Whereas a vertical well allows access to tens or hundreds of meters across a flat-lying formation, a horizontal well can be drilled to conform to the formation and can therefore extract gas from thousands of meters of shale. Horizontal wells reduce surface disturbance by limiting the number of drilling pads and by enabling gas extraction from areas where vertical wells are not feasible. However, horizontal drilling alone would not have enabled exploitation of the unconventional gas resources because the reservoir permeability is not sufficient to achieve economical gas production by natural flow. Hydraulic fracturing—"hydrofracking," or "fracking"—was developed in the 1940s to fracture and increase permeability of target formations and has since been improved to match the characteristics of specific types of reservoirs, including shales.

Hydraulic fracturing fluids consist of water that is mixed with proppants and chemicals before injection into the well under high pressure (480 to 850 bar) in order to open the existing fractures or initiate new fractures. The proppant (commonly sand) represents generally ~9% of the total weight of the fracturing fluid (*10*) and is required to keep the fractures open once the pumping has stopped. The number, type, and concentration of chemicals added are governed by the geological characteristics of each site and the chemical characteristics of the water used. The fracturing fluid typically used in the Marcellus Shale is called slickwater, which means that it does not contain viscosity modifiers that are often added to hydrofracture other shales so as to facilitate better proppant transport and placement.

Chemical additives in the fluids used for hydraulic fracturing in the Marcellus Shale include friction reducers, scale inhibitors, and biocides (Table 1 and Box 1). Eight U.S. states currently require that all chemicals that are not considered proprietary must be published online (*11*), whereas many companies are voluntarily disclosing this information in other states. However, many of the chemicals added for fracturing are not currently regulated by the U.S. Safe Drinking Water Act, raising public concerns about water supply contamination. From 2005 to 2009, about 750 chemicals and other components were used in hydraulic fracturing, ranging from harmless components, including coffee grounds or walnut hulls, to 29 components that may be hazardous if introduced into the water supply (*6*). An inorganic acid such as hydrochloric acid is often used to clean the wellbore area after perforation and to dissolve soluble minerals in the surrounding formation. Organic polymers or petroleum distillates are added to reduce friction between the fluid and the wellbore, lowering the pumping costs. Antiscalants are added to the fracturing fluid so as to limit the precipitation of salts and metals in the formation and inside the well. Besides scaling, bacterial growth is a major concern for the productivity of a gas well (quantity and quality of produced gas). Glutaraldehyde is the most common antibacterial agent added, but other disinfectants [such as 2,2-dibromo-3-nitrilopropionamide (DBNPA) or chlorine dioxide] are often considered. Surfactants (alcohols such as methanol or isopropanol) may also be added to reduce the fluid surface tension to aid fluid recovery.

Methane Migration

As inventoried in 2000, more than 40 million U.S. citizens drink water from private wells (*12*). In some areas, methane—the main component of natural gas—seeps into these private wells from either natural or anthropogenic sources. Given its low solubility (26 mg/L at 1 atm, 20°C), methane that enters wells as a solute is not considered a health hazard with respect to ingestion and is therefore not regulated in the United States. When present, however, methane can be oxidized by bacteria, resulting in oxygen depletion. Low oxygen concentrations can result in the increased solubility of elements such as arsenic or iron. In addition, anaerobic bacteria that proliferate under such conditions may reduce sulfate to sulfide, creating water- and air-quality issues. When methane degasses, it can also create turbidity and, in extreme cases, explode (*13*, *14*). Therefore, the U.S. Department of the Interior recommends a warning if water contains 10 mg/L of CH_4 and immediate action if concentrations reach 28 mg/L (*15*). Methane concentrations above 10 mg/L indicate that accumulation of gas could result in an explosion (*16*).

The most common problem with well construction is a faulty seal in the annular space around casings that is emplaced to prevent gas leakage from a well into aquifers (*13*). The incidence rate of casing and cement problems in unconventional gas wells in Pennsylvania has been reported previously as ~1 to 2% (*17*). Our count in Pennsylvania from 2008 to March 2013 for well construction problems [such as casing or cementing incidents (*18*)] cited by the Pennsylvania Department of Environmental Protection (DEP) revealed 219 notices of violation out of 6466 wells (3.4%) (*19*). Of these, 16 wells in northern Pennsylvania were given notices with respect to the regulation that the "operator shall prevent gas and other fluids from lower formations from entering fresh groundwater" (violation code 78.73A). Most of the time, gas leakage is minor and can be remedied. However, in one case attributed to Marcellus drilling and leaky well casings, stray gas that accumulated in a private water well exploded near the northeastern Pennsylvania town of Dimock. A study of 60 groundwater wells in that area, including across the border in upstate New York (*20*), showed that both the average and maximum methane concentrations were higher when sampled from wells within 1 km of active Marcellus gas wells as compared with those farther away. Much discussion has since ensued as to whether the methane detected in these wells was caused by drilling or natural processes (*21*–*24*) because the area has long had sources of both thermogenic and biogenic methane unrelated to hydraulic fracturing, and no predrilling baseline data are available. The averages reported in that study for sites both near and far from drilling are not dissimilar from values for groundwater from areas of Pennsylvania and West Virginia sampled by the U.S. Geological Survey (USGS) before the recent Marcellus Shale development began, or samples in New York state where high-volume hydrofracturing is currently banned (Fig. 2).

The reason gas is found so often in water wells in some areas is because methane not only forms at depth naturally, owing to high-temperature maturation of organic matter, but also at shallow depths through bacterial processes (*25*, *26*). Both these thermogenic and biogenic gas types can migrate through faults upward from deep formations or laterally from environments such as swamps (swamp gas) or glacial till (drift gas) (*14*, *27*). In addition, gas can derive from anthropogenic sources such as gas storage fields, coal mines, landfills, gas pipelines, and abandoned gas wells (*28*). In fact, ~350,000 oil and gas wells have been drilled in Pennsylvania, and the locations of ~100,000 of these are unknown (*29*). Thus, it is not surprising that gas problems have occurred in Pennsylvania long before the Marcellus development (*30*). Pennsylvania is not the only state facing this problem because about ~60,000 documented orphaned wells and potentially more than 90,000 undocumented orphaned wells in the United States have not been adequately plugged and could act as vertical conduits for gas (*31*).

As natural gas moves in the subsurface, it can be partially oxidized, mixed with other gases, or diluted along flow paths. To determine its provenance, a "multiple lines of evidence approach" must be pursued (*24*). For example, researchers measure the presence of other hydrocarbons as well as the isotopic signatures of H, O, and C in the water or gas (*16*, *27*, *31*). Thermogenic gas in general has more ethane and a higher $^{13}C/^{12}C$ ratio than that of biogenic gas. Stable isotopes in thermogenic gas may sometimes even yield clues about which shale was the source of the gas (*24*, *32*). In northeastern Pennsylvania, researchers argue whether the isotopic signatures of the methane in drinking-water wells indicate the gas derived from the Marcellus or from shallower formations (*20*, *24*).

Although determining the origin of gas in water wells may lead to solutions for this problem, the source does not affect liability because gas companies are responsible if it can be shown that any gas—not just methane—has moved into a water well because of shale-gas development activity. For example, drilling can open surficial fractures that allow preexisting native gas to leak into water wells (*13*). This means that pre- and post-drilling gas concentration data are needed to determine culpability. Only one published study compares pre- and post-drilling water chemistry in the Marcellus Shale drilling area. In that study, a

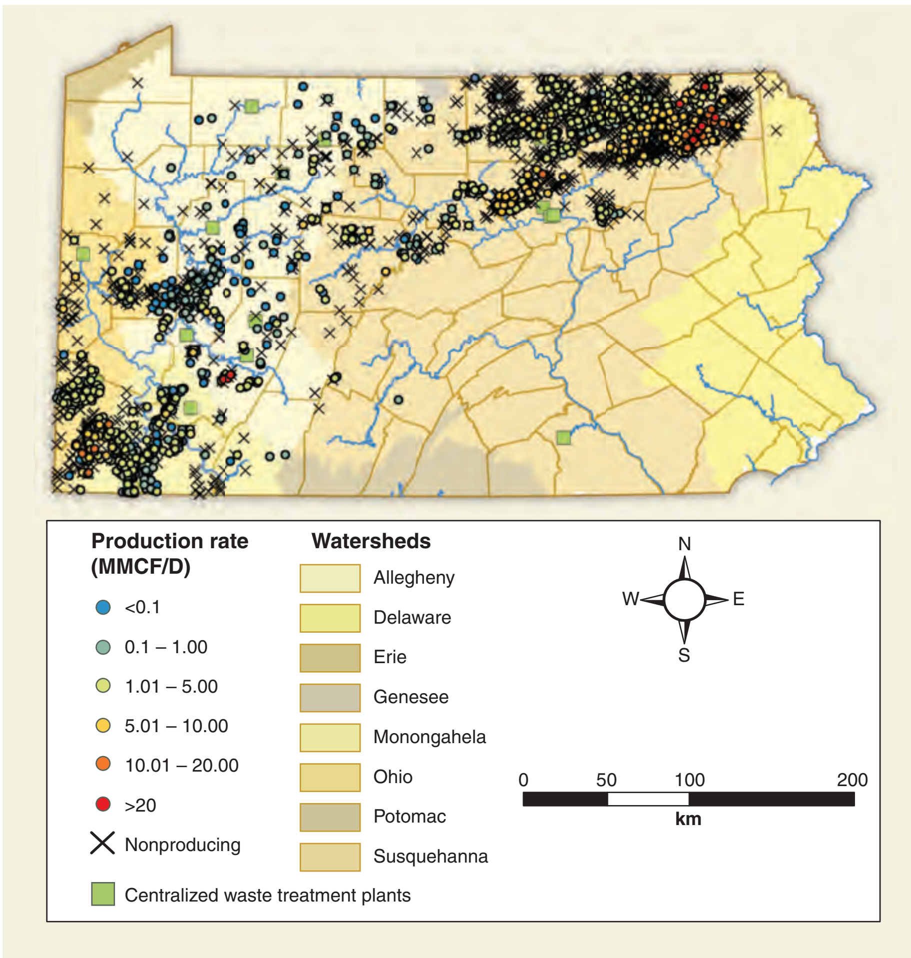


Fig. 1. Marcellus Shale wells in Pennsylvania. Rapid development of Marcellus Shale since 2005 resulted in more than 12,000 well permits, with more than 6000 wells drilled and ~3500 producing gas through December 2012 (average daily production ranged from <0.1 to >20 million cubic feet/day (MMCF/D). Current locations of centralized wastewater treatment facilities (CWTs) are distributed to facilitate treatment and reuse of flowback and produced water for hydraulic fracturing.

sample of 48 water wells in Pennsylvania investigated between 2010 and 2011 within 2500 feet of Marcellus wells showed no statistical differences in dissolved CH_4 concentrations before or shortly after drilling (33). In addition, no statistical differences related to distance from drilling were observed. However, that study reported that the concentration of dissolved methane increased in one well after drilling was completed nearby, which is possibly consistent with an average rate of casing problems of ~3%.

The rate of detection of methane in water wells in northeast Pennsylvania [80 to 85% (20, 24)] is higher than in the wider region that includes southwestern Pennsylvania [24% (33)], where pre- and post-drilling concentrations were statistically identical. This could be a result of the small sample sizes of the two studies or because the hydrogeological regime in the northeast is more prone to gas migration (34). Such geological differences also may explain why regions of the Marcellus Shale have been characterized by controversy in regard to methane migration as noted above, whereas other shale gas areas such as the Fayetteville in Arkansas have not reported major issues with respect to methane (35). Reliable models that incorporate geological characteristics are needed to allow prediction of dissolved methane in groundwater. It is also critical to distinguish natural and anthropogenic causes of migration, geological factors that exacerbate such migration, and the likelihood of ancillary problems of water quality related to the depletion of oxygen. Answering some of these questions will require tracking temporal variations in gas and isotopic concentrations in groundwater wells near and far from drilling by using multiple lines of evidence (16, 24). Research should also focus on determining flow paths in areas where high sampling density can be attained.

Table 1. Common chemical additives for hydraulic fracturing.

Additive type	Example compounds	Purpose
Acid	Hydrochloric acid	Clean out the wellbore, dissolve minerals, and initiate cracks in rock
Friction reducer	Polyacrylamide, petroleum distillate	Minimize friction between the fluid and the pipe
Corrosion inhibitor	Isopropanol, acetaldehyde	Prevent corrosion of pipe by diluted acid
Iron control	Citric acid, thioglycolic acid	Prevent precipitation of metal oxides
Biocide	Glutaraldehyde, 2,2-dibromo-3-nitrilopropionamide (DBNPA)	Bacterial control
Gelling agent	Guar/xanthan gum or hydroxyethyl cellulose	Thicken water to suspend the sand
Crosslinker	Borate salts	Maximize fluid viscosity at high temperatures
Breaker	Ammonium persulfate, magnesium peroxide	Promote breakdown of gel polymers
Oxygen scavenger	Ammonium bisulfite	Remove oxygen from fluid to reduce pipe corrosion
pH adjustment	Potassium or sodium hydroxide or carbonate	Maintain effectiveness of other compounds (such as crosslinker)
Proppant	Silica quartz sand	Keep fractures open
Scale inhibitor	Ethylene glycol	Reduce deposition on pipes
Surfactant	Ethanol, isopropyl alcohol, 2-butoxyethanol	Decrease surface tension to allow water recovery

Box 1. Glossary of Terms

Casing: steel pipe that is inserted into a recently drilled section of a borehole to stabilize the hole, prevent contamination of groundwater, and isolate different subsurface zones.

Cementing: placing a cement mixture between the casing and a borehole to stabilize the casing and seal off the formation.

Class II disposal wells: underground injection wells for disposal of fluids associated with oil and gas production.

Flowback water: water that returns to the surface after the hydraulic fracturing process is completed and the pressure is released and before the well is placed in production; flowback water return occurs for several weeks.

Produced water: water that returns to the surface with the gas after the well is placed in production; production water return occurs during the life of a well.

Proppant: granular material, such as silica sand, ceramic media, or bauxite, that keeps the fractures open so that gas can flow to the wellbore.

Slickwater fracturing: fracturing with fluid that contains mostly water along with friction reducers, proppants, and other additives; used for predominantly gas-bearing formations at shallower depths.

Source rock: organic-rich sedimentary rocks, such as shale, containing natural gas or oil.

Stray gas: gas contained in the geologic formation outside the wellbore that is accidentally mobilized by drilling and/or hydraulic fracturing.

How Protective Is the "Well Armor"?

The protective armor shielding the freshwater zones and the surrounding environment from the contaminants inside the well consist of several layers of casing (hollow steel pipe) and cement (Fig. 3). When the integrity of the wellbore is compromised, gas migration or stray gas can become an issue (14). Gas migration out of a well refers to movement of annular gas either through or around the cement sheath. Stray gas, on the other hand, commonly refers to gas outside of the wellbore. One of the primary causes of gas migration or stray gas is related to the upper portion of the wellbore when it is drilled into a rock formation that contains preexisting high-pressure gas. This high-pressure gas can have deleterious effects on the integrity of the outer cement annulus, such as the creation of microchannels (36). Temperature surveys can be performed shortly after the cementing job is completed in order to ensure that cement is present behind the casing. Acoustic logging tools are also available to evaluate the integrity of the cement annulus in conjunction with pressure testing.

It is well known that to effectively stabilize wellbores with cement in areas with zones of overpressurized gas, proper cement design and proper mud removal are essential (37, 38). If the hydrostatic pressure of the cement column is not higher than the gas-bearing formation pressure, gas can invade the cement before it sets. Conversely, if this pressure is too high, then the formation can fracture, and a loss of cement slurry can occur. Even when the density is correct, the gas from the formation can invade the cement as it transitions from a slurry to a hardened state (39). The slurry must be designed to minimize this transition time and the loss of fluid from the slurry to the formation. Also, if drilling mud is not properly cleaned from the hole before cementing, mud channels may allow gas migration through the central portion of the annulus or along the cement-formation interface. Even if the well is properly cleaned and the cement is placed properly, shrinkage of the cement during hydration or as a result of drying throughout the life of the well can result in crack development within the annulus (40, 41).

Although the primary mechanisms contributing to gas migration and stray gas are understood, it is difficult to predict the risk at individual sites because of varying geological conditions and drilling practices. To successfully protect fresh water and the surrounding environment from the contaminants inside the well, the site-specific risk factors contributing to gas migration and stray gas must be better understood, and improvements in the diagnostics of cement and casing integrity are needed for both new and existing wells. Finding solutions to these problems will provide environmental agencies the knowledge needed to develop sound regulations related to the distances around gas wells that can be affected. It will also provide operators the ability to prevent gas migration and stray gas in a more efficient and economical manner.

The Source and Fate of Fracturing Fluid

The drilling and hydraulic fracturing of a single horizontal well in the Marcellus Shale may require 2 million to 7 million gallons of water (42). In contrast, only about 1 million gallons are needed for vertical wells because of the smaller formation contact volume. Although the projected water consumption for gas extraction in the Marcellus Shale region is 18.7 million gallons per day in 2013 (39), this constitutes just 0.2% of total annual water withdrawals in Pennsylvania. Water withdrawals in other areas are similarly low, but temporary problems can be experienced at the local level during drought periods (3). Furthermore, water quantity issues are prevalent in the drier shale-gas plays of the southwest and western United States (43). It is likely that water needs will change from these initial projections as the industry continues to improve and implement water reuse. Nevertheless, the understanding of flow variability—especially during drought conditions or in regions with already stressed water supplies—is necessary to develop best management practices for water withdrawal (44). It is also necessary to develop specific policies regarding when and where water withdrawals will be permitted in each region (45).

After hydraulic fracturing, the pressure barriers such as frac plugs are removed, the wellhead valve is opened, and "flowback water" is collected at the wellhead. Once the well begins to produce gas, this water is referred to as "produced water" and is recovered throughout the life of the well. Flowback and produced waters are a mixture of injected fluids and water that was originally present in the target or surrounding formations (formation water) (42, 46–50). The fraction of the volume of injected water that is recovered as flowback water from horizontal wells in Pennsylvania ranges from 9 to 53% (9, 41), with an average of 10%. It has been observed that the recovery can be even lower than 10% if the well is shut-in for a period of time (51). The well is shut-in—or maintained closed between fracturing and gas production—so as to allow the gas to move from the shale matrix into the new fractures. Two of the key unanswered questions is what happens to the fracturing fluid that is not recovered during the flowback period, and whether this fluid could eventually contaminate drinking water aquifers (23, 33, 34, 52–54). The analyses of Marcellus Shale well logs indicate that the low-permeability shale contains very little free water (55, 56), and much of the hydraulic fracturing fluid may imbibe (absorb) into the shale.

Fracturing fluid could migrate along abandoned and improperly plugged oil and gas wells, through an inadequately sealed annulus between the wellbore and casing or through natural or induced fractures outside the target formation. Indeed, out-of-formation fractures have been documented to extend as much as ~460 m above the top of some hydraulically fractured shales (57), but still ~1.6 km or more below freshwater aquifers. Nonetheless, on the basis of the study of 233 drinking-water wells across the shale-gas region of rural Pennsylvania, Boyer *et al.* (33) reported no major influences from gas well drilling or hydrofracturing on nearby water wells. Compared with the pre-drilling data reported in that study, only one well showed changes in water quality (salt concentration). These changes were noticed within days after a well was hydrofractured less than ~460 m away, but none of the analytes exceeded the standards of the U.S. Safe Drinking Water Act, and nearly all the parameters approached pre-drilling concentrations within 10 months.

In the case of methane contamination in groundwater near Dimock, Pennsylvania, contamination

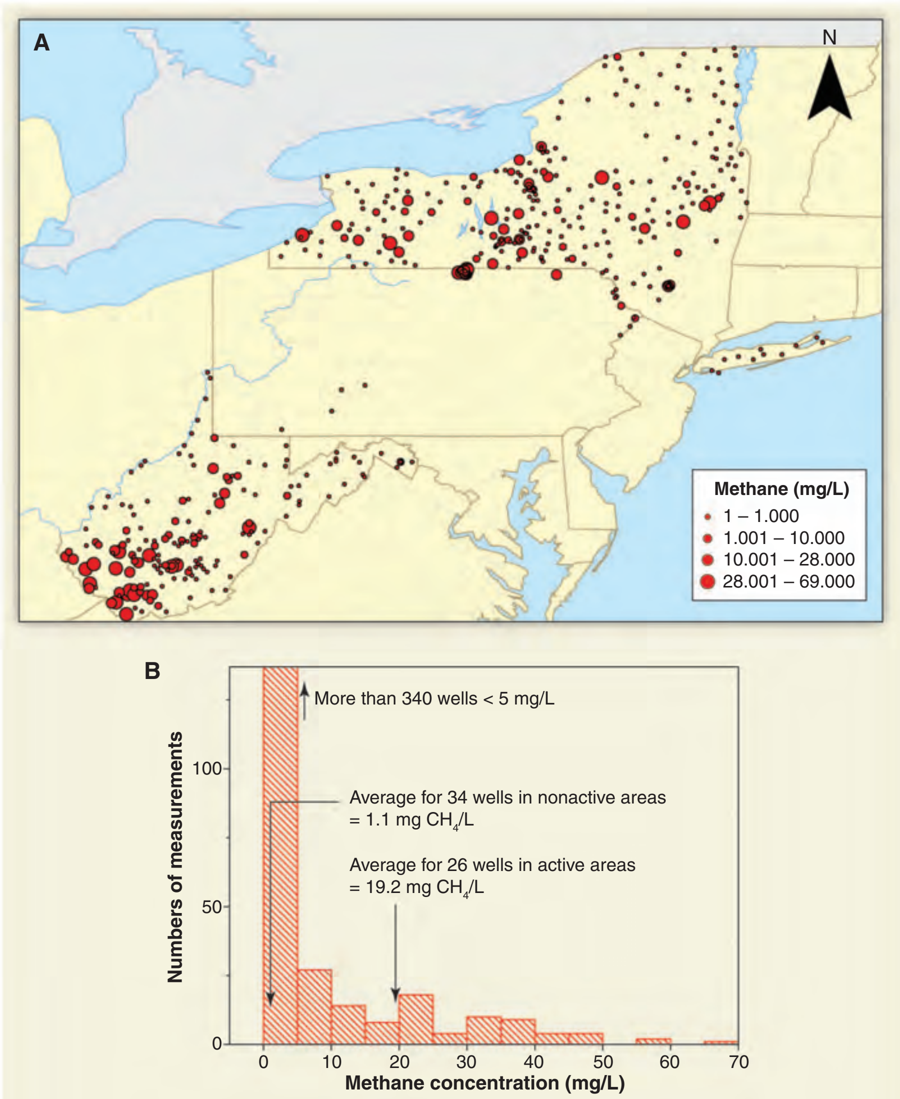


Fig. 2. Methane concentrations in groundwater and springs. (**A**) Published values for groundwater or spring samples include 239 sites in New York from 1999 to 2011 (84), 40 sites in Pennsylvania in 2005 (27), and 170 sites in West Virginia from 1997 to 2005 (85). Maxima varied from 68.5 mg/L in West Virginia, to 44.8 mg/L in Tioga County, Pennsylvania, where an underground gas storage field was leaking, to a value approaching 45 mg/L in New York. (**B**) Values shown with down arrows are averages for a set of wells in southeastern New York and northeastern Pennsylvania located <1 km (26 wells) and >1 km (34 wells) from active gas drilling (20).

by saline flowback brines or fracturing fluids was not observed (*20*). One early U.S. Environmental Protection Agency (EPA) report (*54*) suggested that a vertically fractured well in Jackson County, West Virginia, may have contaminated a local water well with gel from fracturing fluid. This vertical well was fractured at a depth of just ~1220 m, and four old natural gas wells nearby may have served as conduits for upward contaminant transport. A recent EPA study (*53*) implicated gas production wells in the contamination of deep groundwater resources near Pavillion, Wyoming. However, resampling of the monitoring wells by the USGS showed that the flowrate was too small to lend confidence to water-quality interpretations of one well, leaving data from only one other well to interpret with respect to contamination, and regulators are still studying the data (*58*). The Pavillion gas field consists of 169 production wells into a sandstone (not shale) formation and is unusual in that fracturing was completed as shallow as 372 m below ground. In addition, surface casings of gas wells are as shallow as 110 m below ground, whereas the domestic and stock wells in the area are screened as deep as 244 m below ground. The risk for direct contaminant transport from gas wells to drinking-water wells increases dramatically with a decrease in vertical distance between the gas well and the aquifer.

A recent study applied a groundwater transport model to estimate the risk of groundwater contamination with hydraulic fracturing fluid by using pressure changes reported for gas wells (*52*). The study concluded that changes induced by hydraulic fracturing could allow advective transport of fracturing fluid to groundwater aquifers in <10 years. The model includes numerous simplifications that compromise its conclusions (*59*). For example, the model is based on the assumption of hydraulic conductivity that reflects water-filled voids in the geological formations, and yet many of the shale and overburden formations are not water-saturated (*60*). Hence, the actual hydraulic conductivity in the field could be orders of magnitude lower than that assumed in the study (*59*). Furthermore, although deep joint sets or fractures exist (*14*), the assumption of preexisting1500-m long vertical fractures is hypothetical and not based on geologic exploration. Hence, there is a need to establish realistic flow models that take into account heterogeneity in formations above the Marcellus Shale and realistic hydraulic conductivities and fracturing conditions.

Last, it has long been known (*14*, *34*, *47*, *48*, *61*, *62*) that groundwater is salinized where deeper ancient salt formations are present within sedimentary basins, including basins with shale gas. Where these brines are present at relatively shallow depths, such as in much of the northeastern and southwestern United States and Michigan, brines sometimes seep to the surface naturally and are unrelated to hydraulic fracturing. An important research thrust should focus on understanding these natural brine transport pathways to determine whether they could represent potential risk for contamination of aquifers because of hydraulic fracturing.

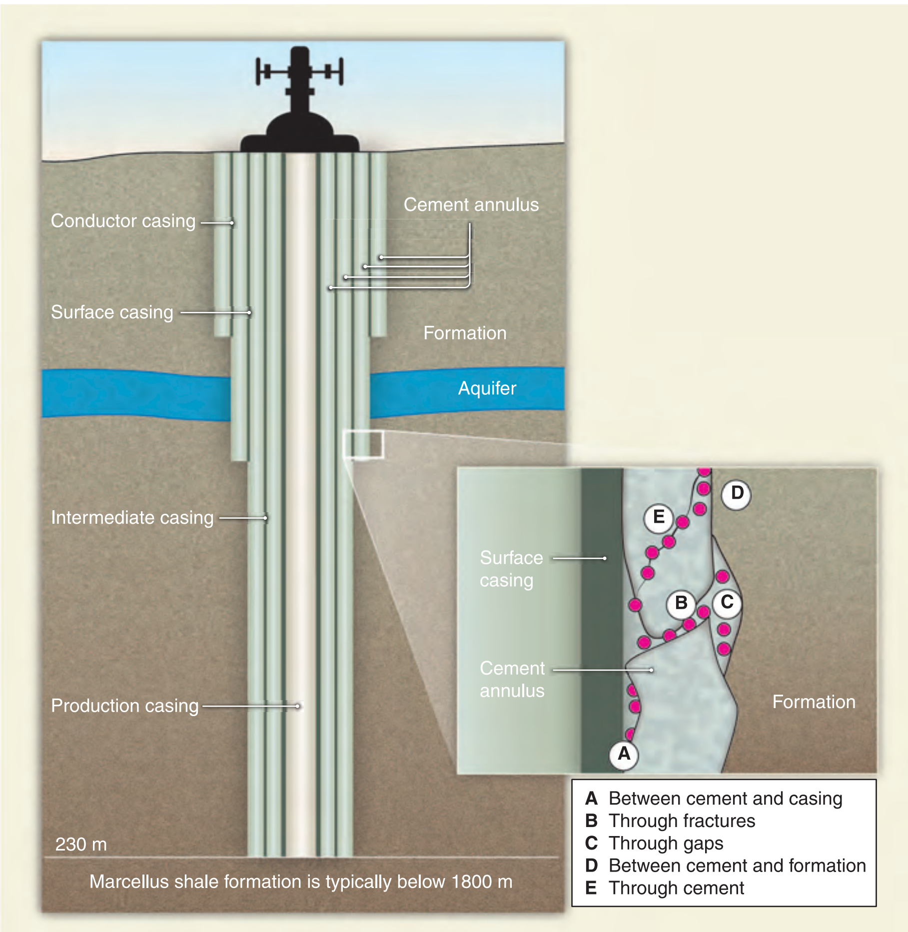


Fig. 3. Typical Marcellus well construction. (i) The conductor casing string forms the outermost barrier closest to the surface to keep the upper portion of the well from collapsing and it typically extends less than 12 m (40 ft) from the surface; (ii) the surface casing and the cement sheath surrounding it that extend to a minimum of 15 m below the lowest freshwater zone is the first layer of defense in protecting aquifers; (iii) the annulus between the intermediate casing and the surface casing is filled with cement or a brine solution; and (iv) the production string extends down to the production zone (900 to 2800 m), and cement is also placed in the annulus between the intermediate and production casing. Potential flaws in the cement annulus (Inset, "A" to "E") represent key pathways for gas migration from upper gas-bearing formations or from the target formation.

Appropriate Wastewater Management Options

The flowback and produced water from the Marcellus Shale is the second saltiest (*63*) and most radiogenic (*50*) of all sedimentary basins in the United States where large volume hydraulic fracturing is used. The average amount of natural gas-related wastewater in Pennsylvania during 2008 to 2011 was 26 million barrels per year (a fourfold increase compared with pre-Marcellus period) (*64*). Compared with conventional shallow wells, Marcellus Shale wells generate one third of the wastewater per unit volume of gas produced (*65*). However, the wastewater associated with Marcellus development in 2010 and 2011 accounted for 68 and 79%, respectfully, of the total oil and gas wastewater requiring management in Pennsylvania. Flowback/produced water is typically impounded at the surface for subsequent disposal, treatment, or reuse. Because of the large water volume, high concentration of dissolved solids, and complex physical-chemical composition of this wastewater, which includes organic and radioactive components, the public is becoming increasingly concerned about management of this water and the potential for human health and environmental impacts associated with the release of untreated or inadequately treated wastewater to the environment (*66*). In addition, spills from surface impoundments (*14*) and trucks or infiltration to groundwater though failed liners are potential pathways for surface and groundwater contamination by this wastewater.

Treatment technologies and management strategies for this wastewater are constrained by regulations, economics of implementation, technology performance, geologic setting, and final disposal alternatives (*67*). The majority of wastewater from oil and gas production in the United States is disposed of effectively by deep underground injection (*68*). However, the state of Pennsylvania has only five operating Class II disposal wells. Although underground injection disposal wells will likely increase in number in Pennsylvania, shale gas development is currently occurring in many areas where Class II disposal wells will not be readily available. Moreover, permissions for and construction of new disposal wells is complex, time-consuming, and costly. Disposal of Pennsylvania brines in Ohio and West Virginia is ongoing but limited by high transportation costs.

The lack of disposal well capacity in Pennsylvania is compounded by rare induced low-magnitude seismic events at disposal wells in other locations (69–71). It is likely that the disposal of wastewater by deep-well injection will not be a sustainable solution across much of Pennsylvania. Nonetheless, between 1982 and 1984, Texas reported at most ~100 cases of confirmed contamination of groundwater from oilfield injection wells, saltwater pits, and abandoned wells, even though at that time the state hosted more than 50,000 injection wells associated with oil and gas (72). Most problems were associated with small, independent operators. The ubiquity of wells and relative lack of problems with respect to brine disposal in Texas is one likely explanation why public pushback against hydraulic fracturing is more limited in Texas as compared with the northeastern United States.

Another reason for public pushback in the northeast may be that in the early stages of Marcellus Shale development, particularly in 2008 to 2009, flowback/produced water was discharged and diluted into publicly owned treatment works (POTWs, or municipal wastewater treatment plants) under permit. This practice was the major pathway for water contamination because these POTWs are not designed to treat total dissolved solids (TDS), and the majority of TDS passed directly into the receiving waterways (6, 73), resulting in increased salt loading in Pennsylvania rivers, especially during low flow (74). In response, the Pennsylvania DEP introduced discharge limits to eliminate disposal of Marcellus Shale wastewater to POTWs (75). In early 2010, there were 17 centralized waste treatment plants (CWTs) in Pennsylvania that were exempted from the TDS discharge limits. However, according to Pennsylvania DEP records none of these CWTs reported to be currently receiving Marcellus wastewater, although they may receive produced water from conventional gas wells. Nevertheless, the TDS load to surface waters from flowback/produced water increased from ~230,000 kg/day in 2006 to 350,000 kg/day in 2011 (64).

It is difficult to determine whether shale gas extraction in the Appalachian region since 2006 has affected water quality regionally, because baseline conditions are often unknown or have already been affected by other activities, such as coal mining. Although high concentrations of Na, Ca, and Cl will be the most likely ions detected if flowback or produced waters leaked into waterways, these salts can also originate from many other sources (76). In contrast, Sr, Ba, and Br are highly specific signatures of flowback and produced waters (34, 47). Ba is of particular interest in Pennsylvania waters in that it can be high in sulfate-poor flowback/produced waters but low in sulfate-containing coal-mine drainage. Likewise, the ratio of $^{87}Sr/^{86}Sr$ may be an isotopic fingerprint of Marcellus Shale waters (34, 77).

Targeting some of these "fingerprint" contaminants, the Pennsylvania DEP began a new monitoring program in 2011. Samples are collected from pristine watersheds as well as from streams near CWT discharges and shale-gas drilling. The Shale Network is collating these measurements with high-quality data from citizen scientists, the USGS, the EPA, and other entities in order to assess potential water quality impacts in the northeast (78, 79). Before 2003, mean concentrations in Pennsylvania surface waters in counties with unconventional shale-gas development were 27 ± 32, 550 ± 620, and 72 ± 81 μg/L for Ba, Sr, and Br (±1σ), respectively (Fig. 4). Most values more than 3σ above the mean concentrations since 2003 represent samples from areas of known brine effluents from CWTs. A concern has been raised over bromide levels in the Allegheny River watershed that may derive from active CWTs because of health effects associated with disinfection by-products formed as a result of bromide in drinking water sources (64, 80). Given the current regulatory climate and the fact that the majority of dissolved solids passes through these CWTs, it is expected that these treatment facilities will likely not play a major role in Marcellus Shale wastewater management.

The dominant wastewater management practice in the Marcellus Shale region nowadays is wastewater reuse for hydraulic fracturing [a review of Pennsylvania DEP data for the first 6 months of 2012 indicates 90% reuse rate (81)]. Wastewater is impounded at the surface and used directly, or after dilution or pretreatment. Reuse of wastewater minimizes the volume that must be treated and disposed, thus reducing environmental control costs and risks and enhancing the economic feasibility of shale-gas extraction (67). Currently, operators in the Marcellus region do not fully agree about the quality of wastewater that must be attained for reuse. Major concerns include possible precipitation of $BaSO_4$ and, to a lesser extent, $SrSO_4$ and $CaCO_3$ in the shale formation and the wellbore and the compatibility of wastewater with chemicals that are added to the fracturing fluid (such as friction reducers and viscosity modifiers). Hence, a better understanding of chemical compatibility issues would greatly improve the ability to reuse wastewater and minimize disposal volumes. In addition, radioactive radium that is commonly present in flowback/produced water will likely be incorporated in the solids that form in the wastewater treatment process and could yield a low-concentration radioactive waste that must be handled appropriately and has potential on-site human health implications.

The wastewater reuse program represents a somewhat temporary solution to wastewater management problems in any shale play. This program works only as long as there is net water consumption in a given well field. As the well field matures and the rate of hydraulic fracturing diminishes, the field becomes a net water producer because the volume of produced water will exceed the amount of water needed for hydraulic fracturing operations (82, 83). It is not yet clear how long it will take to reach that point in the Marcellus region, but it is clear that there is a need to develop additional technical solutions (such as effective and economical approaches for separation and use of dissolved salts from produced water and treatment for naturally occurring radioactive material) that would allow continued development of this important natural resource in an environmentally responsible manner. Considering very high salinity of many produced waters from shale gas development, this is truly a formidable challenge. Research focused on better understanding of where the salt comes from and how hydrofracturing might be designed to minimize salt return to the land surface would be highly beneficial.

Conclusions

Since the advent of hydraulic fracturing, more than 1 million hydraulic fracturing treatments have been conducted, with perhaps only one documented case of direct groundwater pollution resulting from injection of hydraulic fracturing chemicals used for shale gas extraction (54). Impacts from casing leakage, well blowouts, and spills of contaminated fluids are more prevalent but have generally been quickly mitigated (17). However, confidentiality requirements dictated by legal investigations, combined with the expedited rate of development and the limited funding for research, are substantial impediments to peer-reviewed research into environmental impacts. Furthermore, gas wells are often spaced closely within small areas and could result in cumulative impacts (5) that develop so slowly that they are hard to measure.

The public and government officials are continuing to raise questions and focus their attention on the issue of the exact composition of the hydrofracturing fluid used in shale formations. In 2010, the U.S. House of Representatives directed the EPA to conduct a study of hydraulic fracturing and its impact on drinking-water resources. This study will add important information to account for the fate of hydraulic fracturing fluid injected into the gas-bearing formation. It is well known that a large portion (as much as 90%) of injected fluid is not recovered during the flowback period, and it is important to document potential transport pathways and ultimate disposition of the injected fluid. The development of predictive methods to accurately account for the entire fluid volume based on detailed geophysical and geochemical characteristics of the formation would allow for the better design of gas wells and hydraulic fracturing technology, which would undoubtedly help alleviate public concerns. Research is also needed to optimize water management strategies for effective gas extraction. In addition, the impact of abandoned oil and gas wells on both fluid and gas migration is a concern that has not yet been adequately addressed.

Gas migration received considerable attention in recent years, especially in certain parts of the Appalachian basin (such as northeast Pennsylvania).

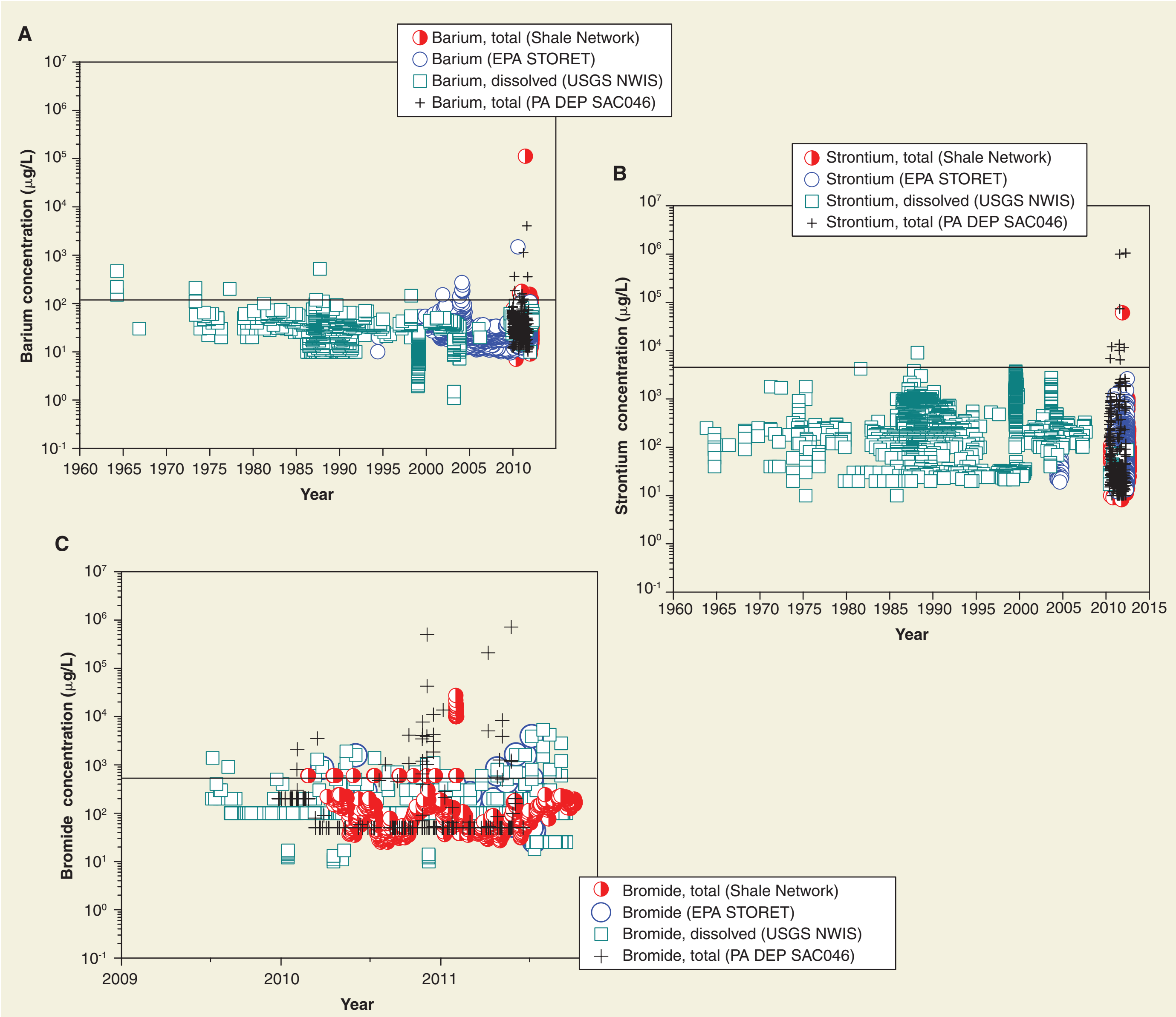


Fig. 4. Concentrations of three ions in surface waters of Pennsylvania in counties with unconventional shale-gas wells: (A) barium, (B) strontium, and (C) bromide. Data reported by EPA (STORET data), USGS (NWIS data), Susquehanna River Basin Commission, Appalachian Geological Consulting and ALLARM [from Shale Network database (*78*, *79*)], and from the Pennsylvania DEP (SAC046) include all rivers, streams, ponds, groundwater drains, lysimeter waters, and mine-associated pit, seep, and discharge waters accessed by using HydroDesktop (www.cuahsi.org) in the relevant counties (data before 2009 for bromide are not shown). Lines indicate 3σ above the mean of data from 1960 to 2003 for the longest duration dataset (USGS). Most values above the lines since 2003 represent targeted sampling in areas of known brine effluents from conventional oil and gas wells (such as Blacklick Creek receiving brine effluent from a CWT). The highest plotted Ba concentration was measured in Salt Springs in northern Pennsylvania. Three of the four samples with highest Sr and Br are from Blacklick Creek; next highest is from Salt Springs. Original values reported beneath the detection limit are plotted at that limit (10 to 100 µg Sr/L; 10 µg Ba/L; and 10 to 200 µg/L Br). The EPA maximum contaminant level (MCL) for Ba is 2000 µg/L. EPA reports no MCL for Sr or Br. Lifetime and 1-day health advisory levels for Sr are 4000 and 25000 µg/L, respectively, and a level under consideration for Br is 6000 µg/L.

It has been known for a long time that methane migrates from the subsurface (such as coal seams, glacial till, and black shales), and the ability to ignite methane in groundwater from private wells was reported long before the recent development of the Marcellus Shale (*14*). However, in the absence of reliable baseline information, it is easy to blame any such incidents on gas extraction activities. It is therefore critical to establish baseline conditions before drilling and to use multiple lines of evidence to better understand gas migration. It is also important to improve drilling and cementing practices, especially through gas-bearing formations, in order to eliminate this potential pathway for methane migration.

Water management for unconventional shale gas extraction is one of the key issues that will dominate environmental debate surrounding the gas industry. Reuse of flowback and produced water for hydraulic fracturing is currently addressing the concerns regarding the vast salt quantities that are brought to the surface (each Marcellus well generates as much as 200 tons of salt during the flowback period). However, there is a need for comprehensive risk assessment and regulatory oversight for spills and other accidental discharges of wastewater to the environment. As these well fields mature and the opportunities for wastewater reuse diminish, the need to find alternative management strategies for this wastewater will likely intensify. Now is the time to work on these issues in order to avoid an adverse environmental legacy similar to that from abandoned coal mine discharges in Pennsylvania.

References and Notes

1. U.S. Energy Information Administration, "Annual Energy Outlook 2013, Early Release" (U.S. Department of Energy, 2013); available at www.eia.gov/forecasts/aeo/erindex.cfm.
2. S. Holditch, K. Perry, J. Lee, "Unconventional Gas Reservoirs—Tight Gas, Coal Seams, and Shales, Working Document of the National Petroleum Council on Global Oil and Gas Study" (National Petroleum Council, 2007).
3. MIT, "The future of natural gas," http://mitei.mit.edu/publications/reports-studies/future-natural-gas. (Massachusetts Institute of Technology, 2011).
4. S. M. Olmstead, L. A. Muehlenbachs, J.-S. Shih, Z. Chu, A. J. Krupnick, *Proc. Natl. Acad. Sci. U.S.A.*, published online 11 March 2013. doi: 10.1073/pnas.1213871110
5. T. Engelder, *Fort Worth Basin Oil Gas Mag.* **20**, 18 (2009).
6. U.S. House of Representatives Committee of Energy and Commerce Minority Staff, "Chemicals used in Hydraulic Fracturing" (prepared for H. A. Waxman, E. J. Markey, D. DeGette, 2011).
7. S. Entrekin, M. Evans-White, B. Johnson, E. Hagenbuch, Rapid expansion of natural gas development poses a threat to surface waters. *Front. Ecol. Environ.* **9**, 503 (2011). doi: 10.1890/110053
8. P. J. Drohan, M. Brittingham, *Soil Sci. Soc. Am. J.* **76**, 1696 (20120).
9. Energy Information Administration, *Drilling Sideways–A Review of Horizontal Well Technology and Its Domestic Application, DOE/EIA-TR-0565* (U.S. Department of Energy, Washington, DC, 1993).
10. NYS DEC, "Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, Well Permit Issuance for Horizontal Drilling And High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs" (New York State Department of Environmental Conservation, 2009).
11. www.FracFocus.org.
12. S. Hutson *et al.*, *Geol. Surv. Circ.* **1268**, 1 (2004).
13. A. W. Gorody, Factors affecting the variability of stray gas concentration and composition in groundwater. *Environ. Geosci.* **19**, 17 (2012). doi: 10.1306/eg.12081111013
14. S. S. Harrison, Evaluating system for ground-water contamination hazards due to gas-well drilling on the glaciated Appalachian plateau. *Ground Water* **21**, 689 (1983). doi: 10.1111/j.1745-6584.1983.tb01940.x
15. K. K. Eltschlager, J. W. Hawkins, W. C. Ehler, F. J. Baldassare, "Technical measures for the investigation and mitigation of fugitive methane hazards in areas of coal mining" (U.S. Dept. of the Interior, Office of Surface Mining Reclamation and Enforcement, Pittsburgh, PA, 2001).
16. K. M. Révész, K. J. Breen, F. J. Baldassare, R. C. Burruss, Carbon and hydrogen isotopic evidence for the origin of combustible gases in water-supply wells in north-central Pennsylvania. *Appl. Geochem.* **25**, 1845 (2010). doi: 10.1016/j.apgeochem.2010.09.011
17. T. Considine, R. Watson, N. Considine, J. Martin, "Environmental Impacts during Marcellus Shale Gas Drilling: Causes, Impacts, and Remedies, Report 2012-1" (Shale Resources and Society Institute, State University of New York, Buffalo, 2012).
18. Total count included violations 78.73A, 78.81D1 and D2, 78.83A and B, 78.83GRNDWTR, 78.83COALCSG, 78.84, 78.85, 78.86, and 207B. Wells with multiple violations were counted only once.
19. PA DEP Office of Oil and Gas, "Oil and Gas Compliance Report, www.portal.state.pa.us/portal/server.pt/community/oil_and_gas_compliance_report/20299" (Pennsylvania Department of Oil and Gas, 2013).
20. S. G. Osborn, A. Vengosh, N. R. Warner, R. B. Jackson, Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing. *Proc. Natl. Acad. Sci. U.S.A.* **108**, 8172 (2011). doi: 10.1073/pnas.1100682108; pmid: 21555547
21. R. B. Jackson, S. G. Osborn, N. R. Warner, A. Vengosh, "Responses to frequently asked questions and comments about the shale-gas paper by Osborn *et al.*, June 15, 2011" (www.nicholas.duke.edu/cgc/FrackFAQ6_15_11.pdf, 2012).
22. S. C. Schon, Hydraulic fracturing not responsible for methane migration. *Proc. Natl. Acad. Sci. U.S.A.* **108**, E664 (2011).
23. R. J. Davies, Methane contamination of drinking water caused by hydraulic fracturing remains unproven. *Proc. Natl. Acad. Sci. U.S.A.* **108**, E871 (2011).
24. L. J. Molofsky, J. A. Connor, S. K. Farhat, A. S. Wylie Jr., T. Wagner, *Oil Gas Dev.* **109**, 54 (2011).
25. C. D. Laughrey, F. J. Baldassare, *Am. Assoc. Pet. Geol. Bull.* **82**, 317 (1998).
26. M. J. Whiticar, Carbon and hydrogen isotope systematics of bacterial formation and oxidation of methane. *Chem. Geol.* **161**, 291 (1999). doi: 10.1016/S0009-2541(99)00092-3
27. G. Etiope, A. Drobniak, A. Schimmelmann, *Marine and Petroleum Geology*, http://dx.doi.org/10/1016/j.marpetgeo.2013.02.009 (2013).
28. K. J. Breen, K. Revesz, F. J. Baldassare, S. D. McAuley, "Natural gases in ground water near Tioga Junction, Tioga County, North-central Pennsylvania–Occurrence and use of isotopes to determine origins, 2005" (U.S. Geological Survey, Scientific Investigations Report Series 2007-5085, 2007).
29. PA DEP, "Oil and Gas Well Drilling and Production in Pennsylvania" (Pennsylvania Department of Environmental Protection, PA DEP Fact Sheet, 2011).
30. W. R. Gough, B. A. Waite, in *Water Resources in Pennsylvania: Availability, Quality, and Management*, S. K. Majumdar, E. W. Miller, R. R. Parizek, Eds. (Pennsylvania Academy of Science, 1990), pp. 384–398.
31. IOGC, "Protecting our Country's Resources: The States' Case, Orphaned Well Plugging Initiative" (Interstate Oil and Gas Compact Commission, National Energy Technology Laboratory, 2008).
32. S. G. Osborn, J. C. McIntosh, Chemical and isotopic tracers of the contribution of microbial gas in Devonian organic-rich shales and reservoir sandstones, northern Appalachian Basin. *Appl. Geochem.* **25**, 456 (2010). doi: 10.1016/j.apgeochem.2010.01.001
33. E. W. Boyer, B. R. Swistock, J. Clark, M. Madden, D. E. Rizzo, "The impact of Marcellus gas drilling on rural drinking water supplies" (The Center for Rural Pennsylvania, Pennsylvania General Assembly, www.rural.palegislature.us/documents/reports/Marcellus_and_drinking_water_2011_rev.pdf, 2012).
34. N. R. Warner *et al.*, Geochemical evidence for possible natural migration of Marcellus Formation brine to shallow aquifers in Pennsylvania. *Proc. Natl. Acad. Sci. U.S.A.* **109**, 11961 (2012). doi: 10.1073/pnas.1121181109; pmid: 22778445
35. T. M. Kresse *et al.*, *U.S.G.S. Scientific Investigations Report 2012-5273* (2012).
36. G. Bol, H. Grant, S. Keller, F. Marcassa, J. de Rozieres, *Oilfield Rev.* **3**, 35 (1991).
37. A. Bonnett, D. Pafitis, *Oilfield Rev.* **8**, 36 (1996).
38. V. Gonzalo, B. Aiskely, C. Alicia, in *SPE Latin American and Caribbean Petroleum Engineering Conference, Society of Petroleum Engineers International* (Rio de Janeiro, Brazil, 2005).
39. M. J. Rogers, R. L. Dillenbeck, R. N. Eid, *Society of Petroleum Engineers*, 90829 (2004).
40. M. B. Dusseault, M. N. Gray, *Society of Petroleum Engineers*, 64733 (2000).
41. J. M. Tinsley, E. C. Miller, D. L. Sutton, *Society of Petroleum Engineers*, 8257 (1979).
42. T. D. Hayes, "Marcellus Shale water chemistry" (Appalachian Shale Water Conservation and Management Committee, 2009).
43. J.-P. Nicot, B. R. Scanlon, Water use for Shale-gas production in Texas, U.S. *Environ. Sci. Technol.* **46**, 3580 (2012). doi: 10.1021/es204602t; pmid: 22385152
44. D. Soeder, W. M. Kappell, "Water resources and natural gas production from the Marcellus Shale" (U.S. Geological Survey Fact Sheet 2009-3032, Reston, VA, 2009).
45. B. G. Rahm, S. J. Riha, Toward strategic management of shale gas development: Regional, collective impacts on water resources. *Environ. Sci. Policy* **17**, 12 (2012). doi: 10.1016/j.envsci.2011.12.004
46. E. Barbot, N. S. Vidic, K. B. Gregory, R. D. Vidic, Spatial and Temporal Correlation of Water Quality Parameters of Produced Waters from Devonian-Age Shale following Hydraulic Fracturing. *Environ. Sci. Technol.* **47**, 2562 (2013). doi: 10.1021/es304638h; pmid: 23425120
47. L. O. Haluszczak, A. W. Rose, L. R. Kump, Geochemical evaluation of flowback brine from Marcellus gas wells in Pennsylvania, USA. *Appl. Geochem.* **28**, 55 (2013). doi: 10.1016/j.apgeochem.2012.10.002
48. P. E. Dresel, A. W. Rose, Pennsylvania Geological Survey, 4th series Open File Report OFOG 10-01.0, www.dcnr.state.pa.us/topogeo/pub/openfile/ofog10_01.aspx (2010), p. 48.
49. M. E. Blauch, R. R. Myers, T. R. Moore, B. A. Lipinski, N. A. Houston, paper presented at the SPE Eastern Regional Meeting, Society of Petroleum Engineers SPE 125740, Charleston, WV, 2009.
50. E. L. Rowan, M. A. Engle, C. S. Kirby, T. F. Kraemer, "Radium content of oil- and gas-field produced waters in the Northern Appalachian Basin (USA): Summary and discussion of data" (U.S. Geological Survey, Scientific Investigation Report 2011-5135, 2011).
51. M. E. Mantell, in *EPA Hydraulic Fracturing Study Technical Workshop 4. Water Resources Management, Chesapeake Energy* (Oklahoma City, OK, 2011).
52. T. Myers, Potential contaminant pathways from hydraulically fractured shale to aquifers. *Ground Water* **50**, 872 (2012). doi: 10.1111/j.1745-6584.2012.00933.x; pmid: 22509908
53. D. C. DiGiulio, R. T. Wilkin, C. Miller, G. Oberly, "DRAFT: Investigation of Ground Water Contamination near Pavillion, Wyoming" (U.S. Environmental Prodection Agency Office of Research and Development, 2011).
54. U.S. Environmental Protection Agency, "Report to Congress: Management of wastes from the exploration, development, and production of crude oil, natural gas, and geothermal energy" (U.S. Environmental Protection Agency, Washington, DC, 1987).
55. T. Engelder, in *GSA Annual Meeting and Exposition* (Charlotte, NC, 2012); available at https://gsa.confex.com/gsa/2012AM/webprogram/Paper207549.html.
56. T. Engelder, Capillary tension and imbibition sequester frack fluid in Marcellus gas shale.. *Proc. Natl. Acad. Sci. U.S.A.* **109**, E3625 (2012). doi: 10.1073/pnas.1216133110
57. K. Fisher, N. Warpinski, *SPE Prod. Oper.* **27**, 8 (2012).
58. P. R. Wright, P. B. McMahon, D. K. Mueller, M. L. Clark, "Groundwater-Quality and Quality-Control Data for Two Monitoring Wells near Pavillion, Wyoming, April and May 2012" (U.S.G.S. Data Series 718, http://pubs.usgs.gov/ds/718/DS718_508.pdf, 2012).
59. J. E. Saiers, E. Barth, Potential contaminant pathways from hydraulically fractured shale aquifers. *Ground Water* **50**, 826, discussion 828 (2012). doi: 10.1111/j.1745-6584.2012.00990.x; pmid: 23003107
60. K. R. Bruner, R. A. Smosna, "Comparative study of the Mississippian Barnett Shale, Fort Worth Basin, and Devonian Marcellus Shale, Appalachian Basin, DOE/NETL-2011/1478" (Department of Energy, National Energy Technology Laboratory, 2011).
61. C. W. Poth, *Pennsylvania Geol. Surv. Bull.* **M47**, 1 (1962).
62. J. A. Williams, *U.S. Geological Survey Scientific Investigations Report 2010-5224* (2010).
63. US DOE, "Cost-Effective Recovery of Low-TDS Frac Flowback Water for Re-use" (U.S. Department of Energy, www.netl.doe.gov, 2011).
64. J. M. Wilson, J. M. VanBriesen, *Environ. Pract.* **14**, 288 (2012). doi: 10.1017/S1466046612000427
65. B. D. Lutz, A. N. Lewis, M. W. Doyle, Generation, transport, and disposal of wastewater associated with Marcellus Shale gas development. *Water Resour. Res.* **49**, 647 (2013). doi: 10.1002/wrcr.20096
66. D. M. Kargbo, R. G. Wilhelm, D. J. Campbell, Natural gas plays in the Marcellus Shale: challenges and potential opportunities. *Environ. Sci. Technol.* **44**, 5679 (2010). doi: 10.1021/es903811p; pmid: 20518558
67. K. B. Gregory, R. D. Vidic, D. A. Dzombak, Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing. *Elements* **7**, 181 (2011). doi: 10.2113/gselements.7.3.181

68. C. E. Clark, J. A. Veil, "Produced Water Volumes and Management Practices in the United States, ANL/EVS/R-09/1" (Environmental Science Division, Argonne National Laboratory, 2009).
69. C. J. de Pater, S. Baisch, "Geomechanical study of Bowland Shale seismicity, Synthesis Report" (Cuadrilla Resources, Ltd., 2011).
70. Reuters, "Ohio earthquake was not a natural event, expert says," *Reuters*, 2012.
71. National Academy of Sciences, *Induced Seismicity Potential in Energy Technologies* (National Academies Press, Washington, DC, 2012).
72. Texas Department of Agriculture, "Agricultural Land and Water Contamination from Injection Wells, Disposal Pits, and Abandoned Wells Used in Oil and Gas Production" (TX Department of Agriculture, Department of Natural Resources, 1985).
73. K. J. Ferrar *et al.*, *Environmental Science & Technology*, dx.doi.org/10.1021/es301411q (2013).
74. D. J. Rozell, S. J. Reaven, Water pollution risk associated with natural gas extraction from the Marcellus Shale. *Risk Anal.* **32**, 1382 (2012). doi: 10.1111/j.1539-6924.2011.01757.x; pmid: 22211399
75. PA DEP, "Wastewater Treatment Requirements, 25 PA Code 95" (Pennsylvania Department of Environmental Protection, 2010).
76. J. R. Mullaney, D. L. Lorenz, A. D. Arntson, "Chloride in Groundwater and Surface Water in Areas Underlain by the Glacial Aquifer System, Northern United States" (U.S. Department of the Interior, U.S. Geological Survey, Scientific Investigations Report 2009-5086, 2009).
77. E. C. Chapman *et al.*, Geochemical and strontium isotope characterization of produced waters from Marcellus Shale natural gas extraction. *Environ. Sci. Technol.* **46**, 3545 (2012). doi: 10.1021/es204005g; pmid: 22360406
78. S. L. Brantley, C. Wilderman, J. Abad, Workshop discusses database for Marcellus water issues. *Eos Trans. AGU* **93**, 328 (2012). doi: 10.1029/2012EO340006
79. Shale Network database is accessible through HydroDesktop (www.cuahsi.org).
80. S. States *et al.*, paper presented at the AWWA-WQTC, Phoenix, AZ, November 13 to 17, 2011.
81. K. O. Maloney, D. A. Yoxtheimer, Production and Disposal of Waste Materials from Gas and Oil Extraction from the Marcellus Shale Play in Pennsylvania. *Environ. Pract.* **14**, 278 (2012). doi: 10.1017/S146604661200035X
82. C. Kuijvenhoven *et al.*, paper presented at the Shale Gas Water Management Conference, Dallas, TX, November 30 to December 1, 2011.
83. R. D. Vidic, T. D. Hayes, S. Hughes, in *Shale Gas Water Management Marcellus Initiative* (Pittsburgh, PA, 2011).
84. W. M. Kappell, E. A. Nystrom, Dissolved methane in New York groundwater, 1999–2011. U.S. Geological Survey Open-File Report 2012-1162 (2012); available at http://pubs.usgs.gov/of/2012/1162.
85. J. S. White, M. V. Mathes, "Dissolved-gas concentrations in ground water in West Virginia" (U.S. Geological Survey Data Series 156, 2006).

Acknowledgments: R.D.V., S.L.B., D.Y., and J.D.A. acknowledge funding for the Shale Network from NSF grant OCE-11-40159.

10.1126/science.1235009

Here are the topics and speakers.

1. **Impacts of Unconventional Shale Gas Development on Municipal Wastewater Treatment Plant, Great Bend, PA**
from Bret Jennings, Director, Hallstead Great Bend Joint Sewer Authority, Presenter – Jeff Zimmerman
2. **Impacts of Unconventional Shale Gas Development on Municipal Water Supply Authority, Beaver Falls, PA**
from James Riggio,Beaver Falls Water Authority manager, Presenter – Buck Morehead
3. **PADEP Determination Letters Finding Impacts of Unconventional Shale Gas Development on Groundwater and Drinking Water Supply**
from PA DEP, Presenter – Shirley Masuo
4. **Geologic Methane Leakage in Wyalusing PA Area and Well Failure Rates Reported by PADEP**
Presenter – Barbara Arrindell
5. **Global Warming Effects of Unconventional Shale Gas Development**
from Professor Ingraffea, Presenter – Mav Moorhead
6. **Flowback and Produced Water Disposal by Underground Injection and Earthquakes**
Presenter – Joe Levine
7. **Update on Health Impacts of Unconventional Shale Gas Development**
Presenter – Dr Larysa Dryszka
8. **Biodiversity Impacts of Unconventional Shale Gas Development**
Presenter – David Burg
9. **Adverse Economic Effects of Unconventional Shale Gas Development**
from Elizabeth Radow, Presenter – Wendy Robinson
10. **Summary and Policy Conclusions**
Presenter – Al Appleton

September 10, 2013

Jeff Zimmerman
Zimmerman & Associates
13508 Maidstone Lane
Potomac, MD 20854

RE: Beaver Falls Municipal Authority

Atty. Zimmerman,

The Beaver Falls Municipal Authority (BFMA) is public drinking water system that pulls water from the Beaver River in Beaver Falls, PA, which is formed by the confluence of the Mahoning and Shenango Rivers near New Castle, PA. BFMA began experiencing elevated Brominated levels in 2009. These elevated levels caused BFMA to exceed the EPA's Maximum Contaminant Level (MCL) for Total Trihalomethanes (TTHM'S) for the first 3 quarters of 2010. The MCL for TTHM's is a running annual average (RAA) of .08mg/l, which is comprised of an average of the four most recent quarterly samples. The RAA for the first quarter of 2010 was .087mg/l, for the second quarter of 2010 was.097mg/l, and for the third quarter of 2010 was .0857mg/l. Each of these occurrences required BFMA to publically notify all of our 18,000 customers that we were in violation of an EPA drinking water standard. Beginning in September 2010 BFMA began using chloramines as its primary disinfectant over chlorine which had been used by BFMA for over 50 years. The main reason for this change was that chloramines produce lower levels of TTHM's. This change will also enable BFMA reduce TTHM levels in our drinking water and remain in compliance with EPA's drinking water standards. BFMA expended over $25,000 in capital for this conversion. Chloramine disinfection has been used for over 80 years but can cause problems to people on dialysis machines if not removed prior to dialysis. Chloramines may also be toxic to fish.

Over the past 4 years there have been at least 3 instances where individuals or companies have been prosecuted for illegally dumping frack water into the Mahoning, Shenango, or Beaver River. Unfortunately in every instance BFMA was not notified until a few days after each episode and are unsure if any of the frack water made it to our intake. While it has been documented many places that frack water has elevated levels of brominated disinfection byproducts, which are precursors to TTHM formation no correlation was traced back to any legal or illegal discharges up stream of our intake.

If you have any questions, please feel free to contact me at (724) 846-2400 Extension 231.

Sincerely,

James Riggio
General Manager

Damascus Citizens for Sustainability would like to present the DRBC Commissioners and staff over 100 Determination Letters from the Pennsylvania Department of Environmental Protection, sent to home and business owners whose water was affected by nearby gas well drilling. As there is both a time frame after the well is completed and a distance requirement that the home or business has to be from the well to have a challengeable presumption of responsibility by the gas drilling company apply, all of these cases are in both required limits. These limits were changed recently from 6 months to one year and from 1,000 feet to 2,500 feet but the older cases will not be revisited. There would be many more receiving a positive determination of impact with even this small widening of the two requirements. A positive determination means that the DEP has to do additional investigation and drilling company has to replace the water supply in some fashion satisfactory to the DEP.

The letters are from the years 2008 through 2012. They were obtained via a Right To Know request and a lawsuit filed by the Scranton Times, taking a year and a half to acquire them. They show that the Department's investigations indicate that the home or business owners' water supplies were impacted by gas well drilling with changes in either water quantity or quality based on testing done before drilling and after. The details in the letters show what these changes are including diminished quantity and increases in minerals, salts, changes in pH and clarity of the water and gasses, often methane, moving with the water.

In addition to these letters to individual home and business owners, there are on the supplied disc about 30 investigations and consent orders covering wide areas,whole neighborhoods with multiple homes and businesses. One of these was spoken of by my colleague and has 6 maps of impacted areas each covering about 24 square miles - that’s number 161 on the disc - areas where there we know the damage continues.

These letters are, at long last, proof that the hydraulic fracturing horizontal drilling process DOES impact water supplies and is doing so in Pennsylvania and that therefore, drilling should not be allowed in the Delaware River Basin.

Geologic Methane Leakage in Wyalusing PA Area and Well Failure Rates Reported by PADEP Presenter – Barbara Arrindell

First let’s start with well failure rates - these are based on Pennsylvania DEP reports of wells drilled, violations and failures as assembled by Prof. Ingraffea of Cornell University.

1,609 wells drilled in 2010. 97 well failures. 6% rate of failure.

1,972 wells drilled in 2011. 140 well failures. 7.1% rate of failure.

1,346 wells drilled in 2012 120 well failures. 8.9% rate of failure.

Consistent with previous industry data, and not improving

I would like to stress that these mistakes,errors, failures result in permanent damage that impacts real places and real communities and real people and their lives and hopes and families...to say nothing of their property values. And these are only the initial failures - as the drilling proceeds, though there are nine listed types of violations possible, for many more wells, “ The inspection reports indicate that many failed wells were not issued violations.“ according to Dr. Ingraffea’s research. To pretend that allowing drilling in the Delaware Basin would produce different results is foolish.

So now to look at one of those real places certified as an impacted area by PA DEP. This is along the Susquehanna River in Bradford County where PA DEP fined Chesapeake Appalachia, LLC $900,000. for causing “stray gas” conditions, impacting the area and contaminating water supplies. DCS sent GasSafetyUSA with a Picarro CRDS machine to record the methane levels from public roads where there were reports of bubbling in the Susquehanna River and in ponds, puddles and in residents drinking water sources. Though it is harder to record methane any distance away from it’s source we found elevated methane levels, as shown in figure which combines the roads covered in the June GasSafety run with two of the impact area maps in the “Consent Order” of May 16, 2011. Blue and orange markers indicate the Paradise Road and Sugar Run methane migration impact areas(4 mile radius each) mapped in that Consent Order and show about double the surrounding local methane baseline levels. There is definitely an ongoing methane leakage situation here and contamination of drinking water sources that has continued since September, 2010 through the GasSafety methane survey in June, 2013.

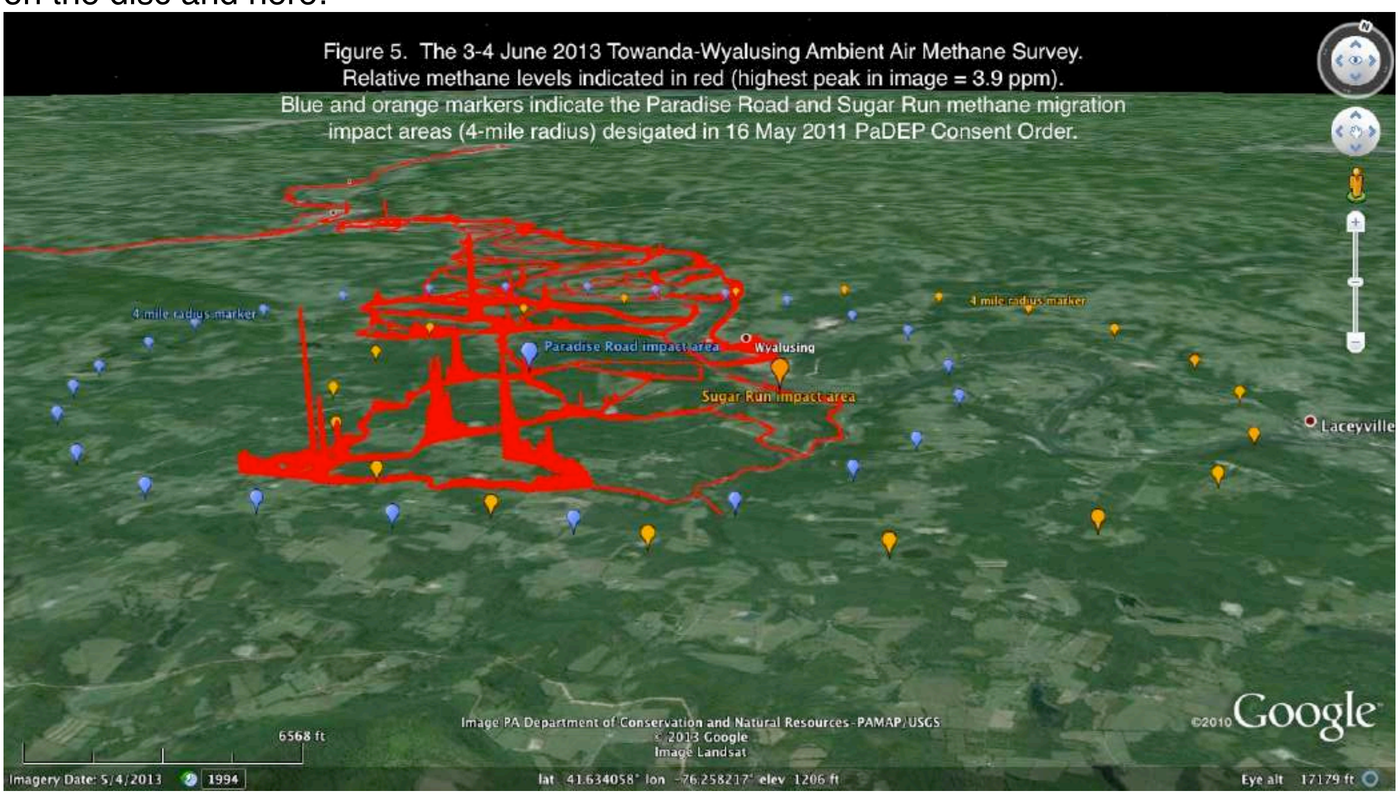
IN OTHER WORDS THE AREA IS STILL IMPACTED AND THE WATER SOURCES ARE STILL CONTAMINATED FROM DRILLING.

The Conclusion from the September, 2013, GasSafety Wyalusing Report

"Methane from any source rapidly diffuses and rises in the air. Consequently, detection of possible methane sources from any distance away requires extremely sensitive measurement capabilities. The GSI survey approach takes advantage of extremely sensitive measurement instrumentation to detect small increases in ambient air methane levels as an indication of probable methane emissions sources in a given area. Based on the data collected using that equipment, we conclude that the Towanda-Wyalusing area is probably substantially impacted by methane emissions from shale gas wells both within and beyond the survey area. The coincidence of two DEP methane migration impact areas, Paradise Road and Sugar Run, and the most marked elevated ambient air methane levels suggests there are still gas control problems associated with the shale gas wells there, as well as in another documented impact area in Leroy Township also cursorily measured following the main survey. A rapid water test in the Leroy area confirmed the water in that area is still contaminated with methane. These survey results suggest measures taken by gas well operators with regard to methane migration problems that have occurred in these three areas have likely been only partially effective."

IN OTHER WORDS THE AREA IS STILL IMPACTED AND THE WATER SOURCES ARE STILL CONTAMINATED FROM DRILLING.

The figure is from the GasSafety Report on these Wyalusing area measurements - found on the disc and here:



"Stray Gas" Definition • A gaseous material that is from an undetermined source that is located in area that may become hazardous. • Hazardous conditions can be flammable, toxic, or oxygen reducing that could cause suffocation. http://pa.water.usgs.gov/projects/energy/stray_gas/presentations/3_840_Graeser.pdf
-----
$900,000. fine - http://www.businessweek.com/ap/financialnews/D9N9C7981.htm
Consent order referenced here is #161 in this Determination letters folder on the disc and at this link: https://www.dropbox.com/s/ndgx7fe2hg8f2dg/161%20Consent%20Agreem%20Susquehana%20River.pdf

CRDS http://www.picarro.com/technology/cavity_ring_down_spectroscopy

http://www.damascuscitizensforsustainability.org/wp-content/uploads/2012/11/PSECementFailureCausesRateAnalysisIngraffea.pdf
Table 1. Violation Codes Used to Identify Wells with Violations for Figure 7.
78.73A - Operator shall prevent gas and other fluids from lower formations from entering fresh groundwater.
78.81D2 - Failure to case and cement properly through storage reservoir or storage horizon
78.83A - Diameter of bore hole not 1 inch greater than casing/casing collar diameter
78.73B - Excessive casing seat pressure
78.83GRNDWTR - Improper casing to protect fresh groundwater
78.83COALCSG - Improper coal protective casing and cementing procedures
78.85 - Inadequate, insufficient, and/or improperly installed cement
78.86 - Failure to report defective, insufficient, or improperly cemented casing
207B - Failure to case and cement to prevent migrations into fresh groundwater

HEALTH IMPACTS OF SHALE GAS EXTRACTION AND PRODUCTION

Larysa Dyrszka MD

Completed health studies, both in the peer-reviewed literature and those initiated or reported by grassroots groups and the press, indicate that significant negative health impacts occur near gas exploration and production activities. Emerging health studies, including the Geisinger and University of Pennsylvania studies will give a clearer picture over the next few years. Most importantly, there are many people who have already been impacted in states where gas extraction using high volume hydraulic fracturing is permitted. We must carefully study these cases and determine pathways of exposure and contamination – scientific information that is fundamental to making informed decisions about the process. As we review the studies already completed, and speak with impacted people, we are increasingly aware that there are stressors on health that cannot be mitigated.

For these reasons, explained in more detail below, a moratorium on permitting gas extraction using high volume hydraulic fracturing must continue. Only after we gain a clear understanding of why people become ill near gas development activities can a decision be made whether to permit this activity, or ban it altogether. We cannot gamble with people's health.

Over the past couple of years, the medical community in NY State has repeatedly called on our Governor to stop the process which would lead to permitting and pay heed to the science. In 2010 the American Academy of Pediatrics of NY State (AAPNYS) issued a Memo of Support for the moratorium tied to the EPA study. The AAPNYS, together with other medical organizations in NY—the American Academy of Family Physicians of NYS, the NYS chapter of the American Nurses Association, the Medical Society of the State of NY, and others—asked for additional health studies, including a comprehensive, inclusive and transparent Health Impact Assessment (HIA) to be undertaken in NY State where gas drilling has not yet begun.

The Governor recently stated that he is taking the science under advisement. And that's a good thing because science is confirming that gas drilling is too risky to human health to go forward as it's currently done. I hope that the Governor's representative on the Delaware River Basin Commission moves with the same caution.

Recent climate events have also served to convince our lawmakers that climate change is real. Recently, a paper was published whose authors from Stanford, Cornell and Physicians, Scientists and Engineers for Healthy Energy demonstrate how NY State can be totally fueled by renewables by 2030. The same could be true for the other states of the DRBC. http://www.psehealthyenergy.org/site/view/1083

Three major studies, which will shed light on health, are underway:

--the Geisinger study will use electronic records, which are already in place, to track certain diseases;
http://pipeline.post-gazette.com/news/archives/25056-1-million-grant-for-pa-gas-drilling-health-study
http://poststar.com/news/local/fb6c60aa-88de-11e2-8a9f-001a4bcf887a.html
The Geisinger study is a health outcomes design and plans to measure exposures through the use of geocoding;

--the U Penn study

http://green.blogs.nytimes.com/2013/01/21/taking-a-harder-look-at-fracking-and-health/

(This description of the UPenn study is from a personal communication):

Study [1] 'Field Survey of Health Perception and Complaints of PA Residents in the Marcellus Shale" led by Dr. Poune Saberi-Funded by UPenn-EHSCC, and will be published shorty;

Study [2] An inter-Center Pilot Project: "Groundwater Quality and health Outcomes in Adjacent Areas With and Without Hydrofracturing Activities" funded by Columbia EHSCC and UPenn EHSCC, with results in a year or two;

Study [3] An inter-Center Pilot Project: "Harvard WorldMap: Fracking Research Repository for All Concerned (HWM: FRRAC)" funded by Harvard EHSCC and UPenn .

Study [1] is being prepared for publication and studies [2] and [3] have just been funded, with results in a year or two.

The above studies are just beginning, but preliminary information will be available in approximately one year;

--the EPA HF study; an interim progress report was issued in December 2012 http://www.epa.gov/hfstudy/pdfs/hf-report20121214.pdf ; the study is funded and due to completed in 2016; this study focuses on the potential pathways of exposure related to water;

PEER REVIEWED LITERATURE

Peer reviewed papers are the gold standard in medicine. The papers on the health impacts near gas drilling operations that are emerging include the work of our colleagues at Cornell, Michelle Bamberger and Robert Oswald, who documented several cases where chemicals associated with drilling were implicated in negative health outcomes in animals and people. http://www.psehealthyenergy.org/Impacts_of_Gas_Drilling_on_Human_and_Animal_Health

One of the several cases they describe was the death of 17 cows within one hour from direct exposure to hydraulic fracturing fluid. The final necropsy report listed the most likely cause of death as respiratory failure with circulatory collapse. The hydraulic fracturing fluid that they drank contained petroleum hydro-carbons plus other toxins.

Another case documented was the death of companion animals with gas operations nearby—and road-spreading of waste was implicated.

Two cases provided unplanned but inadvertent control experiments—another standard in research-- since herds of cows were kept in different pastures. The cows that drank contaminated water had a high death rate, and a high rate of stillborn and deformed calves.

In one of the homes, a child became ill with fatigue, confusion, abdominal and back pain. After several animals in the household had died, the doctor became suspicious of toxins and testing revealed arsenic in the child. The family then stopped drinking the water despite results which showed the well water was safe and he eventually recovered, having lost a year of school. In these cases, there were 25 wells within two miles of the homes, and there was also the aerated impoundment, and two compressor stations within a mile. While checking for other toxins in these two homes, random urine tests on family members revealed phenol, a metabolite of benzene; symptoms observed by families in both homes included extreme fatigue, headaches, nosebleeds, rashes, and sensory deficits (smell and hearing). Were it not for the deaths of the animals, the human health effects would not have been found.

Their study illustrates several plausible links between gas drilling and negative health effects.

Drs Bamberger and Oswald are the guest editors of an entire edition of a journal called New Solutions, and it is dedicated to impacts of gas drilling. All raise concerns whether gas drilling as it is currently done is safe. http://baywood.metapress.com/link.asp?id=k01404273056 (pre-publication, galley proofs can be found here).

Elaine Hill is documenting how proximity to gas wells affects birth weight, and she is finding that it does, and it is a negative impact which will likely cost the government healthcare dollars in the long run. http://ourhealthandenvironment.wordpress.com/2012/07/21/fracking-and-low-birth-weight-preliminary-evidence/

Medical colleagues in Utah are dealing with unprecedented levels of dangerous air pollution, estimating billions of dollars of additional healthcare costs due to exposure to ozone, PAHs, endocrine disruptors and other chemicals which will plague the population for generations. (personal communication, Utah Physicians for a Healthy Environment, wrote that they think the costs of air pollution in Utah, pop. 3 million, are already $10 to 12 Billion; and Dr Kirtley Jones comments on health impacts on babies http://environews.tv/dr-kirtly-jones-reveals-the-damage-caused-to-fetuses-and-young-children-by-elevated-air-pollution/)

Early results from an on-the-ground public health assessment from the Southwest Pennsylvania Environmental Health Project (SWPA-EHP) indicate that environmental contamination is occurring near natural gas drilling sites and is the likely cause of associated illnesses.

According to this assessment, in one small county of about 200,000 people, 27 people thought they were getting sick and went to a single rural health clinic and fracking was determined to be a plausible cause.

Since drilling has only been going on for six years in this area, it does not include chronic illnesses that can take years to manifest.

The 27 cases documented by the Southwest Pennsylvania Environmental Health Project team are not a surveyed sample of the region’s population, nor were they recruited to be part of a study. They are patients from a single rural clinic who came in seeking help. As such, these early figures could easily be the leading edge of a rising wave of human injury.

Mesothelioma from asbestos, thyroid cancer from radiation, mental retardation from lead poisoning, birth defects from the rubella virus — all these now-proven connections began with a handful of case studies that, looking back, were just the tip of an iceberg. We know that many of the chemicals released during drilling and fracking operations — including benzene — are likewise slow to exert their toxic effects. Detection of illness can lag by years or decades, as did the appearance of illnesses in construction workers and first responders from exposure to pollution in the 9/11 World Trade Center response and cleanup.

The early results from the Southwest Pennsylvania Environmental Health Project study implicate air contamination as the likely cause of three-quarters of the associated illnesses so documented. In some cases, significantly elevated levels of fracking-related air pollutants were found in the air inside of people’s homes. This is an unacceptable problem: breathing is mandatory and, while a drinking water source might be replaced, air cannot.

A minority of cases suffered from likely exposures to tainted water, but these low numbers are not reassuring. Water contamination often takes a while to appear. Well casings continue to fail as they age — up to 60 percent over 30 years — and, as they do, we expect health effects from waterborne contaminants to rise and spread to more communities.

Given that exposures and illness increase over time and given that many instances of contamination and illness related to fracking never come to light due to non-disclosure agreements with the industry, we cannot accurately quantify the extent of our problems with gas drilling. But Washington County shows that they are here, and we have every reason to expect that they are not yet fully visible and they are growing. http://concernedhealthny.org/category/press-releases/

www.concernedhealthny.org and www.psehealthyenergy.org list additional and updated peer-reviewed articles, reports and testimonies from health professionals, and please see more references at the end of this paper.

STRESSORS ON HEALTH FROM SHALE GAS EXTRACTION WHICH CANNOT BE ELIMINATED

--ABANDONED WELLS --

WELL CASING INTEGRITY –all wells will eventually leak since casings and cement are man-made and will not withstand decades of high-pressure and corrosive materials. Abandoned wells include ignored wells; it would be extremely costly to plug all of them, and the locations of many are unmapped.

--AIR and WATER CONTAMINATION --cannot be 100% contained with current use of triple casings; chemical leakage will follow the methane leaks which have been documented and occur with regularity.

FLARING –releases chemicals, creates particulates and causes symptoms (observed by health professionals); at issue are the unknown chemicals, exemptions, and the fact that the technology does not exist for alternatives.

DIESEL EXHAUST --from trucks, compressors, processing plants; no cumulative impacts have been considered, yet it is clear that there are health impacts from these emitters; modeling has shown that impacts may be experienced at six miles; diesel exhaust is now considered a definite canrcinogen.

WATER CONTAMINATION –residents have barium, arsenic, VOCs, methane, radionuclides and other toxins in their water wells claimed to be a result of drilling nearby, and which is denied by industry; residents whose blood results I have seen have these in their blood.

AIR POLLUTION --has been shown to be associated with neurodevelopmental disorders, lower IQ in babies born to mothers with polycyclic aromatic hydrocarbon exposure during pregnancy, and learning disorders in exposed children. (see references at end of paper).

The American Academy of Pediatrics notes that children are especially vulnerable because their lungs continue to grow and enlarge until about age 18. Plus children breathe faster and are closer to the ground. As they mature in the presence of ozone, alveolar production is reduced, and the result of chronic ozone exposure can be brittle lungs like those of an elderly adult.

And since the World Health Organization has now classified diesel exhaust as a definite carcinogen, it raises additional concerns for workers and other vulnerable groups exposed to diesel exhaust.

Silica is the sand that is used in hydraulic fracturing. It is mined in Minnesota and Wisconsin and is not regulated as a hazardous pollutant by the U.S. Environmental Protection Agency. NIOSH has identified exposure to crystalline silica during hydraulic fracturing as the most significant known health hazard to workers. It is also a hazard to the workers in the Midwest mining it and to the residents living nearby.

Inhalation of fine dusts of crystalline silica can cause silicosis which is an incurable lung disease. It's also been determined to be a lung carcinogen.

--ACCIDENTS—happen, even with best management practices and regulations.

--CHEMICALS –including both introduced and those from down-hole; related to DIESEL and AIR CONTAMINATION; federal exemptions limit information; observed symptoms include respiratory, cardiovascular and/or neurologic problems; interaction of chemicals with other chemicals and with naturally-occurring substances have not been studied (limited by NDAs and federal exemptions).

ENDOCRINE-DISRUPTING CHEMICALS (EDCs)–a large percentage (about 40% according to Dr Theo Colborn) are EDCs which impact children and the unborn disproportionately.

FOOD CHAIN CONTAMINATION –animals are sentinels; soil farming with gas well waste occurs with some regularity, as does road spreading.

The toxic chemicals are classified as secret, or proprietary, which hampers health studies, but we know it includes known or suspected carcinogens, mutagens, neurotoxins, hazardous air pollutants, and endocrine disruptors which have effects at very low doses.

COMMUNITY IMPACTS – Besides the environment, community well-being is another major determinant of health.

In areas where the drilling has occurred it has splintered the residents into the minority who benefit financially--like those who have leased large acreages, some businesses like motels and diners, those who get jobs in the industry, drug traffickers, and politicians who are given money for their campaigns. But those who lose are the majority—homeowners who have lost their water, the value of their homes and their health. The stress of not knowing if and when that loss will occur is also significant, and research provides evidence that such stress can negatively impact a person's health. People already under stress from an underlying illness, or poor socioeconomic status, or because they are simply very young or very old and therefore a vulnerable population, suffer environmental and societal impacts less well than people who are not so stressed.

There is also the potential loss of traditional, sustainable jobs, such as in tourism and farming which could be displaced when a high impact industry such as gas extraction moves into a region.

VULNERABLE POPULATIONS AND SOCIAL JUSTICE – this extractive industry not only impacts vulnerable populations in a disproportionate way, it also creates vulnerable groups, eg, sick workers, small-for-gestational-age babies, etc .

WORKER HEALTH -- these workers are part of the community and their ill-health taxes the family and the community, and eventually the state.

SILICA USE – highly toxic to workers and community where it is mined, stored and used.

ECONOMIC BUST –few years of prosperity for some (but there will be inequity), and then there will be a bust (documented).

--HUMAN ECOLOGY--

- Vulnerable populations are created but not protected
- Economics impact human health
- Food chain contamination will eventually impact humans
- Occupational safety --the on-the-job fatality rate of oil and gas workers is eight times higher than the rate for all U.S. workers, as reported by the Centers for Disease Control.

--NOISE POLLUTION --EU study links noise to CV and neurologic ill health http://www.euro.who.int/__data/assets/pdf_file/0008/136466/e94888.pdf

--PATHWAYS OF EXPOSURE exist but their identification is limited by non-disclosure agreements (NDAs) and federal exemptions, as well as limited funding for research;

- Source of contamination: Cement casing leaks >7% PA wells/abandoned wells
- Environmental media and transport mechanism: Soluble/volatile and particulate. slickwater. Drilling muds. Flowback/produced water/Waste
- Points of exposure
- Route of exposure
- Receptor population – human ecology

--RADIOACTIVITY -- high radon in indoor air, gas and in water from the Marcellus shale area already exists. http://pubs.usgs.gov/of/2009/1257/pdf/ofr20091257.pdf, http://pubs.usgs.gov/of/2012/1150/pdf/ofr2012-1150_report_508.pdf, http://pubs.usgs.gov/sir/2011/5135/pdf/sir2011-5135.pdf

A federal exemption to the Resource Conservation and Recovery Act allows anything that has come from down hole to be exempt from hazardous classification.

--STRESS (related to everything) – leads to depression and other mental health issues

--WASTE – NY is already receiving toxic waste from PA, and this process is inadequately controlled; there is no place to safely put the waste due to radioactivity, heavy metals, TDS, VOCs; road spreading and soil farming are unacceptable (animals have died).

For decades we have known the Marcellus shale to be more radioactive than other shales. The radioactive elements found in Marcellus shales include uranium, thorium, radium and also radon.

Radon is the leading cause of lung cancer among non-smokers and the second leading cause among smokers, and accounts for 21,000 lung cancer deaths per year on a nationwide basis, according to the EPA. Also from the EPA, we know that areas overlying the Marcellus shale have high indoor radon, on average, already, and will be at risk if exposed to radon additionally via delivered gas which we believe will be higher in radon than is safe. The only "safe" level of radon is "0 picoCuries/L". No environmental or health agency is tracking the radioactive exposure at the well site (radon and radium), in pipelines (radon, radium, lead, polonium) or at end use—people's homes (radon).

The press has exposed industry practices such as dangerous disposal of radioactive waste (NYTimes). A federal exemption to the Resource Conservation and Recovery Act allows anything that has come from down hole to be exempt from hazardous classification. So this waste, including radioactive drill cuttings and sludge, can be spread on roads, buried on site, released into streams or sent to town dumps or POTWs which can leach into drinking water. And there's the underground injection of toxins which then contaminate drinking water which Propublica has exposed.

EMERGING HEALTH STUDIES ARE VITAL

So why is gas drilling with HVHF proceeding when scientific evidence is pointing to such significant community and environmental hazards?

In 2005, Congress passed the Energy Policy Act, also known as the Halliburton loophole (Cheney retired from Halliburton in July 2000, when he was tapped by Bush for the vice-presidency) http://www.msnbc.msn.com/id/8870039/#.UMTpQoM8CSo

In effect, the 2005 Energy Policy Act exempted the oil and gas industry from key provisions of the most important environmental and public health laws, such as the SDWA, CAA, CWA, RCRA, NEPA, CERCLA aka Superfund, and others. The federal exemptions were passed seven years ago (Highlights of Oil and Gas Industry Exemptions From Federal Statutes http://www.citizenscampaign.org/PDFs/cce_hvhf_wp_final.pdf), and during that time the oil&gas industry has been minimally overseen. So we do not know the extent to which health or environmental impacts have occurred, though we know that people in close proximity to oil and gas exploration and production activities perceive that they have been negatively impacted.

Other reasons for the paucity of scientific information:

--Most of the peer-reviewed literature on health impacts has been published only in the last 1-2 years.

--Research funding has been limited.

--State regulations vary but so far have not included health literature, doctors and public health professionals. In fact, in Pennsylvania there is a gag order to be imposed on physicians if information to assist in the treatment of a patient is disclosed to that doctor, and Colorado seems to be following suit.

--We know that accidents happen and violations occur, despite the best regulations.

--Non-disclosure agreements hamper access to important information. http://www.post-gazette.com/stories/business/legal/washington-county-judge-orders-marcellus-shale-development-settlement-records-unsealed-680087/?print=1

Another obstacle has recently emerged in certain states, and that is limiting the information that doctors can share if they receive vital chemical information from industry in order to treat their patients. In Pennsylvania and Colorado, doctors are required to sign a non-disclosure agreement in exchange for life-saving information. http://www.motherjones.com/environment/2012/03/fracking-doctors-gag-pennsylvania and http://www.denverpost.com/environment/ci_22827696/colorado-docs-chafe-at-secrecy-oath-needed-access#ixzz2O658UecK

It has come to the point that non-governmental organizations are engaging in research: Earthworks just published a paper on a survey done in Pennsylvania which demonstrates negative health impacts close to wells. Amy Mall of NRDC has a list of hundreds of cases of water contamination; Damascus Citizens for Sustainability is doing baseline methane monitoring in select localities.

IMPACTED PEOPLE

People near gas drilling sites in Pennsylvania, Colorado, Texas and other states have had a rash of unexplained illnesses, sick and dying pets and livestock, contaminated drinking water, unacceptably high ozone in areas that were known previously for their pristine air quality, lost homes and shattered communities.

I have spoken with impacted families who have become ill since their air or drinking water became contaminated after a gas well was drilled near their home, or compressor stations erected nearby, and referred them for further evaluation in New York City's Mt Sinai Hospital, as well as to the Southwest Pennsylvania Environmental Health Project (SWPA-EHP) http://www.environmentalhealthproject.org/. these people have skin lesions, headaches and other neurological problems;

--there are those with breathing problems when gas wells are vented;

--and a pregnant woman who was having seizures, and was surrounded by gas wells;

--and the mother of a child with arsenic in his blood; that family was also dealing with water that had turned after drilling, and with dead and ill animals;

--and there are others that we know about, and the only advice to offer them is not to drink the water—but we can't advise people to stop breathing the air.

--I have also spoken with a woman in Erie Colorado whose family has had exacerbations of asthma and recently they've begun experiencing neurological problems; Erie CO has many gas wells and compressors http://www.denverpost.com/business/ci_20553795/colorado-join-studies-air-quality-around-oil-and .

--Last year I travelled to Paradise Road in Wyalusing, Bradford County to speak with a group of people who had leased and who already had contaminated water--many of the homes on Paradise Road had visible water buffaloes. Shockingly, these people had never spoken with a doctor about their water contamination and the possible health implications. The couple hosting this gathering was expecting a baby… A few months later we learned that the baby was born with a cardiac defect. Chance? Perhaps…but maybe not...and no public health, state or federal agency ever asked about the environmental history.

--Over the past week I have spoken with two families. These are their stories:

The first family was well, living modestly on family-owned land which sits in a valley, until 2008. The children were average to very good students, with excellent attendance records.

Although rural, this area was a coal mining region.

In 2005 an electric compressor was placed on the hill above their home, about 500-700 ft away.

In 2008 two gas compressors joined the first one on the hill. Also in 2008 five gas wells were spudded and completed on another hilltop, less than one-half mile away from the house, plus a glycol dehydrator and a sludge tank.

Around the end of 2008, and early 2009, the mother and grandmother began observing changes, subtle at first, in the children, as well as in themselves.

Over the course of the years since 2008/2009, there have been odor events noted numerous times. The odors have been chlorine-like, and at other times sweet-smelling. These occur almost every day. It may be preceded by a vapor mist, which appears to have tiny bubbles, that comes downhill from the compressors. On occasion there are what the family would characterize as extremely odorous events, where it is difficult to breathe. Significant health impacts occur right after such events.

One of the twin sons, who was an average student with perfect attendance, developed headaches, rashes and behavior changes, beginning in 2008/2009. These were minor at first, but have worsened. He began missing school and was more difficult to manage. In 2012 he began having involuntary movements that appeared tic-like, tremulousness on occasion, shaking hands and seemed to lack coordination. He had a neurological work –up and is under the care of a neurologist who prescribed an anti-seizure medication. He has recently been evaluated by the Individualized Education Program (IEP) team at school because of poor performance.

The other twin has had a similar course as his brother. He also developed abnormal movements a short while later than the first twin, and he is also being treated with the anti-seizure drug. After having been an honors student, he is also now undergoing an IEP evaluation. The twins currently weigh about 90 lbs, and have had very little, if any, weight gain in two years.

A 13 yo son suffers from severe headaches for which he is medicated, and he has lost days of school. Since last week he has also had abnormal movements and just had an EEG and he was also started on the anti-seizure meds. He is also very sensitive to noise; his room faces the compressors and therefore receives the most noise. When the compressors are running, which is most of the time, the family describes the noise as similar to ten trains. The blowdowns occur without notice.

An 18 yo daughter began having behavior problems and slowed speech at age 16. An evaluation by the neurologist included an EEG and MRI, and revealed that she had had a stroke.

A 20 yo daughter and not living in the house for the past year, but lives not far and visits, has had headaches, abnormal hand movements, leg pain and memory problems.

The mother was also previously healthy. Over the past few years she has had gastrointestinal problems (improved when she stopped drinking the water) and has lost about 50 lbs. In 2010 she noted a very strong chlorine-like smell which “took her breath away” and to which she was exposed for about 2 to 3 minutes. She felt ill immediately and shortly thereafter developed congestion, and blisters in her nose, on her neck, face and arms (exposed skin areas). About three months later, because she was pale and had continued blistering of the mucous membranes, particularly the nasal mucosa, she returned to the hospital. Following an evaluation, the health professionals recommended that the family evacuate the house and also a Hazmat team visit, but none appeared. The mother has also seen the neurologist for weakness, memory problems, trembling hands and a feeling described as “bugs crawling on the skin”. She has been diagnosed with polyneuropathy and is on medication.

The grandmother has hypertension and tachycardia, and is on medication for these conditions.

In 2010 the mother and grandmother both had bloodwork for environmental toxins. The grandmother had phenol, benzene, arsenic, and cadmium in her blood; the mother had phenol and benzene. The children were not tested.

All the family members have had rashes which appear occasionally, described as red, occasionally slightly raised. The family recalls one specific episode of these rashes in the children, in 2010 , following another chlorine odor event.

On July 3rd of this year there was a strong sweet-smelling odor event that was followed by diffuse red rashes in the boys who had been playing outside. One boy developed a boil in the groin which improved, in time, after two rounds of antibiotics, but recently another boil developed. The other boy developed a boil and cellulitis in the axilla this past week. They never had such infections.

Additional Environmental History:

GAS WELLS—there are five on the opposite hill which were fracked in 2008, during which time there were two frack ponds. In 2009 a neighbor whose house overlooked the ponds noticed that a creek that runs between his house and this family's house suddenly flooded and the water turned black in the creek. This creek is 15-20 ft from their yard.

PETS—There is a small dog owned by the grandmother who, whenever he had been outside, was seen licking his paws afterwards, and then he would vomit. The dog no longer wants to go outside, especially when the decking is moist from rain or what appears to be dew, but could be the vapors that come down the hill from the compressors (often noticed in the evenings), as they also cover the house with a moist film. The grandmother separately noticed that when she took the plant covers from her tomatoes, that covering, which often had some moisture on it, burned her hands.

The family has not been evaluated by any public health agency, although DEP takes spot air samples.

The second family works in the industry. The husband does construction work as a sub-contractor. He describes one episode where his crew were doing work and there was a blowback, a foggy material was released and covered the ground, and the accompanying fluid spraying his workers with a burning fluid. He had no idea what the material was, and they were not wearing any protective gear.

He has seen too many dead cows and deer not far from gas development areas, he says.

But the story is about his wife. About five years ago, the wife took a job painting glycol dehydrators, well heads, brine tanks and other infrastructure on working well sites and compressor stations. Immediately following one of the first jobs, as she started the drive home, she felt nauseated, developed a severe headache, a sore throat and by the time she got home she was covered in rash on all the exposed parts of her body. Eventually some of the red rash evolved into open sores. These came and went. The husband reports that she has the scars from these sores. The wife stopped going on these jobs after several of these episodes. Then, she started to have behavior changes —irritability and forgetfulness. She has now been diagnosed with dementia, and is in a doctor's care and being medicated for that.

About four years ago she developed an excoriated area on the top of her ear, which seemed never to completely heal. At this point, the top of her ear is gone, and two days ago the lesion was biopsied for cancer.

Her case has never been reported to any public health agency.

--The List of the Harmed has over a thousand "anecdotes". http://pennsylvaniaallianceforcleanwaterandair.wordpress.com/the-list/

Those of us who have been following this issue closely know of many cases of illness near gas drilling operations and most are called anecdotes because pathways of exposure have not been identified, which is when you don't have a link from the toxin to the illness. Those links are not yet proven because research on health impacts is just now emerging. http://www.ncbi.nlm.nih.gov/pmc/articles/PMC3339470/ . Also, doctors who are practitioners haven't been educated on environmental issues and do not routinely take an environmental history, which is necessary if a causal effect is ever to be established. As an end result and most importantly, the complaints of the patients are not investigated by those tasked with protecting public health. And, if patients complain directly to the companies, and the families receive compensation, the records of the transactions are often sealed through non-disclosure agreements.

Prominent scientists who have been at the forefront of both research and patient care recently wrote to the Albany Times Union.

In "*Assessing the risks of fracking",* Dr David Brown (SWPA-Environmental Health Project) points to several lessons learned http://www.timesunion.com/opinion/article/Assessing-the-risks-of-fracking-4342593.php .

"Beware impact of fracking" is a commentary urging caution from Dr Theo Colborn (The Endocrine Disruption Exchange), and Nadia Steinzor (Earthworks) http://www.timesunion.com/opinion/article/Beware-impact-of-fracking-4324911.php?cmpid=twitter .

Even without proving a direct relationship, in other words, a particular chemical (which is secret) caused this person's illness, we can attribute a person's illness to the gas development nearby by following these three guidelines:

•**Temporal relationship** – was the development of the symptom (or exacerbation of pre-existing symptom) after the onset of gas extraction activities
•**Plausible exposure** – is there an identifiable exposure source in proximity to the individual experiencing symptoms
•**Absence of a more likely explanation** – Symptoms were not attributed to gas extraction activities if an individual had an underlying medical condition that was as (or more) likely to have caused the symptom.

There are many such cases, and they fit the criteria of having been impacted by gas development nearby: **a temporal relationship, plausible exposure, and absence of a more likely explanation.** Studies implicate air contamination as the likely cause of three-quarters of the illnesses. Breathing is mandatory, and, while a drinking water source might be replaced, air cannot.

Having spent time speaking with these impacted people, I am convinced that the health of many of them living near gas wells, processing plants and compressors is deteriorating and that it is a result of gas drilling activities. These people were well before this industry moved in, and now they are not, and there is no other plausible reason for their illnesses. Given that exposures and illness increase over time and given that many instances of contamination and illness related to fracking never come to light due to non-disclosure agreements with the industry, I am afraid that this is the just beginning of a huge public health crisis. I believe that some have irreversible neurological problems already. I implore you not to create a generation of people who are industry's lab rats with governmental complicity--young people who would otherwise be happy and thriving and productive members of society, and instead will be on disability and dependent on the welfare system. They did not ask for this nor consent to experimentation.

REFERENCES:

HEALTH EFFECTS (general)

http://www.who.int/about/definition/en/print.html

http://baywood.metapress.com/media/e05d2179tjdjww5edyvm/contributions/6/6/1/4/661442p346j5387t.pdf

http://www.damascuscitizens.org/Teitelbaum-Report_R1.pdf and http://www.ccag.org.au/images/stories/pdfs/literature%20review%20witter%20et%20al%202008.pdf and http://63.134.196.109/documents/10sep28_Otsego2000EPACommentsFINAL.pdf

http://www.psehealthyenergy.org/Impacts_of_Gas_Drilling_on_Human_and_Animal_Health

http://www2.gnb.ca/content/dam/gnb/Departments/h-s/pdf/en/HealthyEnvironments/Recommendations_ShaleGasDevelopment.pdf

http://www.ncbi.nlm.nih.gov/pmc/articles/PMC3237379/

http://www.youtube.com/watch?v=KOPLKXuiZmI&playnext=1&list=PL26E430AAECBFF78F&feature=results_main

AIR

McKenzie LM, et al, Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources http://www.ncbi.nlm.nih.gov/pubmed/22444058

Colborn T, et al, An Exploratory Study of Air Quality near Natural Gas Operations

NOAA ozone study http://www.eenews.net/public/Landletter/2011/04/21/1

http://www.uphe.org/general-research/health-consequences-of-utahs-air-pollution

http://iopscience.iop.org/1748-9326/8/1/014017/pdf/1748-9326_8_1_014017.pdf

http://www.endocrinedisruption.com/files/HERA12-137NGAirQualityManuscriptforwebwithfigures.pdf and

http://www.ncbi.nlm.nih.gov/pubmed/22916444 and

http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf and

http://www.damascuscitizens.org/HEALTH-EPA_Comments_Eric_London_MD.pdf and

http://www.eeb.cornell.edu/howarth/GHG%20update%20for%20web%20--%20Jan%202011%20(2).pdf

http://s3.documentcloud.org/documents/29077/new-epa-data-subpart-w-tsdf.pdf and

http://www.star-telegram.com/2010/10/03/2516374/formaldehyde-from-gas-compressor.html

http://www.ars.usda.gov/Main/docs.htm?docid=12462

http://web.mit.edu/newsoffice/2007/ozone-1026.html

http://www.iom.edu/~/media/Files/Activity%20Files/Environment/EnvironmentalHealthRT/2012-Apr-30/Adgate.pdf

http://researchmatters.noaa.gov/news/Pages/utah.aspx

http://www.iom.edu/~/media/Files/Activity%20Files/Environment/EnvironmentalHealthRT/2012-Apr-30/Robinson.pdf

http://www.lung.org/assets/documents/publications/state-of-the-air/state-of-the-air-2011-report-embargoed.pdf

http://ccceh.hs.columbia.edu/pdf-papers/PereraCEBP2011.pdf

http://www.environment.ucla.edu/reportcard/article.asp?parentid=1700

http://www.epa.gov/airquality/oilandgas/pdfs/20120417finalrule.pdf

WATER

http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf and

http://www.nytimes.com/2011/02/01/business/energy-environment/01gas.html?src=me&ref=business and

http://www.earthworksaction.org/NM_GW_Contamination.cfm and

http://www.vanityfair.com/business/features/2010/06/fracking-in-pennsylvania-201006 and

http://www.fractracker.org/2010/09/water-well-contamination-studies.html and http://switchboard.nrdc.org/blogs/amall/incidents_where_hydraulic_frac.html

http://www.iom.edu/~/media/Files/Activity%20Files/Environment/EnvironmentalHealthRT/2012-Apr-30/Swackhamer.pdf

http://yosemite.epa.gov/opa/admpress.nsf/0/EF35BD26A80D6CE3852579600065C94E and

http://www.epa.gov/region8/superfund/wy/pavillion/EPA_ReportOnPavillion_Dec-8-2011.pdf

http://www.iom.edu/~/media/Files/Activity%20Files/Environment/EnvironmentalHealthRT/2012-Apr-30/Jackson.pdf

http://www.biology.duke.edu/jackson/pnas2011.html

Methane migration—2011 Duke study http://www.biology.duke.edu/jackson/pnas2011.html

Brine migration----2012 Duke and CalStatePolytech http://www.pnas.org/content/early/2012/07/03/1121181109.full.pdf

Amy Mall—NRDC 2011-12 http://switchboard.nrdc.org/blogs/amall/incidents_where_hydraulic_frac.html

Bamberger and Oswald—2012 New Solutions http://www.psehealthyenergy.org/Impacts_of_Gas_Drilling_on_Human_and_Animal_Health

CHEMICALS

Natural Gas Operations from a Public Health Perspective Theo Colborn, Carol Kwiatkowski, Kim Schultz, Human and Ecological Risk Assessment: An International Journal Vol. 17, Iss. 5, 2011

http://edrv.endojournals.org/content/early/2012/03/14/er.2011-1050.full.pdf#page=1&view=FitH

http://www.psehealthyenergy.org/Impacts_of_Gas_Drilling_on_Human_and_Animal_Health

http://www.dec.ny.gov/energy/58440.html (see Ch 5 here) and http://endocrinedisruption.com/files/NaturalGasManuscriptPDF09_13_10.pdf and http://democrats.energycommerce.house.gov/index.php?q=news/waxman-markey-and-degette-investigation-finds-continued-use-of-diesel-in-hydraulic-fracturing-f

http://endocrinedisruption.com/chemicals.multistate.php and

http://63.134.196.109/documents/RiskAssessmentNaturalGasExtraction.pdf and http://archive.durangoherald.com/asp-bin/article_generation.asp?article_type=news&article_path=/news/08/news080717_2.htm and

http://www.atsdr.cdc.gov/phs/phs.asp?id=345&tid=61 and

http://www.endocrinedisruption.com/files/cP02591Colborn20021022coalbedmethane2-BEcommments.pdf and

http://catskillcitizens.org/FOIL_products/UNIFOAM_MSDS.pdf and

http://www.who.int/ipcs/publications/cicad/cicad_10_revised.pdf

RADIOACTIVITY

http://www.epa.gov/osw/nonhaz/industrial/special/oil/oil-gas.pdf federal exemption

The International Atomic Energy Agency has recommendations regarding radioactivity at oil and gas mining sites http://www-pub.iaea.org/MTCD/publications/PDF/TCS-40_web.pdf.

http://www.grassrootsinfo.org/pdf/whitereport.pdf and

http://pubs.usgs.gov/fs/fs-0142-99/fs-0142-99.pdf and http://s3.amazonaws.com/propublica/assets/natural_gas/nysdoh_marcellus_concerns_090721.pdf and http://63.134.196.109/documents/10sep28_Otsego2000EPACommentsFINAL.pdf and

http://www.rwma.com/Marcellus%20Shale%20Report%205-18-2010.pdf and http://63.134.196.109/documents/10sep21_RadioactiveWastefromHorizontalHydrofracking.pdf and http://www.scientificamerican.com/article.cfm?id=marcellus-shale-natural-gas-drilling-radioactive-wastewater and http://www.nysacho.org/files/CEHD%20Gas%20Drilling%20Comments%20final%2012%2029%2009.pdf and http://www.nytimes.com/2011/02/27/us/27gas.html?_r=3&hp and

http://www.nytimes.com/interactive/2011/02/27/us/natural-gas-documents-1-intro.html?ref=us http://www.scientificamerican.com/article.cfm?id=wastewater-sediment-natural-gas-mckeesport-sewage and http://63.134.196.109/documents/10sep21_RadioactiveWastefromHorizontalHydrofracking.pdf

http://www.nap.edu/openbook.php?record_id=5499&page=R11

Radioactivity in the Environment, Volume 17, 2010

http://www.icrp.org/docs/Michael%20Cowie%20Developemetn%20of%20a%20NORM%20Management%20Strategy%20Oil%20and%20Gas%20.pdf

WORKER HEALTH

National Institute for Occupational Safety and Health (NIOSH),

http://www.cdc.gov/niosh/docket/review/docket213/ and http://www.cdc.gov/niosh/docket/review/docket213/pdfs/OilGasExtractionDraftAug2010.pdf

http://www.bls.gov/opub/cwc/sh20110712ar01p1.htm

http://wellservicingmagazine.com/hours-service-regulation-revealed HOS regulation and “oilfield exemption”

http://www.cdc.gov/mmwr/preview/mmwrhtml/mm5716a3.htm fatalities among gas field workers 2003-2006

http://www.cdc.gov/niosh/programs/oilgas/projects.html update on NIOSH research projects

http://www.nytimes.com/2012/05/15/us/for-oil-workers-deadliest-danger-is-driving.html?_r=2

http://www.cdc.gov/niosh/docket/review/docket213/pdfs/OilGasExtractionDraftAug2010.pdf

http://www.southernstudies.org/2012/05/institute-index-frackings-dangers-for-workers.html

http://www.iom.edu/~/media/Files/Activity%20Files/Environment/EnvironmentalHealthRT/2012-Apr-30/Esswein.pdf

http://blogs.cdc.gov/niosh-science-blog/2012/05/silica-fracking/ NIOSH

NIOSH Field Effort to Assess Chemical Exposures in Oil and Gas Extraction Workers

NOISE

http://www.euro.who.int/__data/assets/pdf_file/0008/136466/e94888.pdf

http://www.citidep.pt/papers/articles/alvesper.htm and

http://teeic.anl.gov/er/oilgas/impact/drilldev/index.cfm and

http://shaleshock.org/2009/01/noise-and-health/ and

http://www.fastcompany.com/1744151/air-pollution-causes-europeans-to-lose-16-million-years-of-healthy-living-annually-study and

COMMUNITY IMPACTS

http://www.damascuscitizensforsustainability.org/wp-content/uploads/2012/01/stateimpactpa-troy-community-hospital-report.pdf

http://www.sungazette.com/page/content.detail/id/576617/Housing-woes-worsen.html?nav=5011

http://www.nytimes.com/2011/12/02/us/drilling-down-fighting-over-oil-and-gas-well-leases.html?pagewanted=all and

http://www.earthworksaction.org/issues/detail/colorado_health_concerns

http://www.garfield-county.com/public-health/battlement-mesa-health-impact-assessment-ehms.aspx

http://www.iom.edu/~/media/Files/Activity%20Files/Environment/EnvironmentalHealthRT/2012-Apr-30/Witter.pdf http://www.iom.edu/~/media/Files/Activity%20Files/Environment/EnvironmentalHealthRT/2012-Apr-30/Kelsey.pdf http://forumonpublicpolicy.com/vol2011.no2/archivevol2011.no2/perry.pdf http://mediasite.cidde.pitt.edu/mediasite/SilverlightPlayer/Default.aspx?peid=689293c50f404f12b8c628b8f2285780 http://ehp03.niehs.nih.gov/article/info:doi/10.1289/ehp.0900612 and

http://www.countyhealthrankings.org/new-york

http://envirn.org/pg/pages/view/1334/harmful-environmental-exposures-and-vulnerable-populations

CLIMATE CHANGE

http://www.psehealthyenergy.org/Venting_and_leaking_of_methane_from_shale_gas_development__response_to_Cathles_et_al_

http://www.psehealthyenergy.org/Methane_and_the_Greenhouse-Gas_Footprint_of_Natural_Gas_from_Shale_Formations

http://www.postcarbon.org/reports/PCI-Hughes-NETL-Cornell-Comparison.pdf

http://thinkprogress.org/romm/2012/02/08/421588/high-methane-emissions-measured-over-gas-field-offset-climate-benefits-of-naturalgasquot/

NYS AAP on a moratorium, see http://gdacc.wordpress.com/medical-professionals-information/ and other medical organizations' statements Mt Sinai Children's Environmental Health Center comments to the EPA and

http://www.bassett.org/our-network/media-room/news/2011/bassett-statements-on-hydrofracking/ http://www.epa.gov/region02/spmm/pdf/Marcellus_dSGEIS_Comment_Letter_plus_Enclosure.pdf

http://gdacc.wordpress.com/2010/12/10/new-york-state-medical-societies-call-for-moratorium

Video from The Endocrine Disruption Exchange http://www.endocrinedisruption.com/chemicals.video.php

Study commissioned by the NYC DEP http://www.cwconline.org/news/final%20hazn%20sawyr%20report-on-drilling.pdf

HIA REFERENCES

http://www.iaia.org/

http://www.hiaconnect.edu.au/files/HIA_International_Best_Practice_Principles.pdf

Quigley, R., L. den Broeder, P. Furu, A. Bond, B. Cave and R. Bos 2006 *Health Impact Assessment International Best Practice Principles. Special Publication Series No. 5. Fargo, USA: International* Association for Impact Assessment.

http://www.euro.who.int/__data/assets/pdf_file/0003/98283/E90794.pdf

http://www.healthimpactproject.org/resources#presentations_webinars

http://www.cdc.gov/healthyplaces/hia.htm

Health Impact Assessment: Integrating Health into the NEPA Process, January 2011 Author: Aaron Wernham, M.D., M.S. Presented to: Transportation Resources Board, January 2011

http://www.apha.org/NR/rdonlyres/171AF5CD-070B-4F7C-A0CD-0CA3A3FB93DC/0/HIABenefitHlth.pdf Health in All Policies, from the APHA

http://www.ph.ucla.edu/hs/health-impact/

http://www.who.int/hia/en/

http://www.naccho.org/topics/environmental/landuseplanning/HIAresources.cfm

http://www.apho.org.uk/default.aspx?QN=P_HIA

http://www.dh.gov.uk/en/Publicationsandstatistics/Legislation/Healthassessment/DH_4093617

http://www.dh.gov.uk/prod_consum_dh/groups/dh_digitalassets/documents/digitalasset/dh_120110.pdf

Institute of Medicine Conference, The Health Impact Assessment of New Energy Sources: Shale Gas Extraction http://www.iom.edu/Activities/Environment/EnvironmentalHealthRT/2012-APR-30.aspx Please also see the accompanying videos

Legal Review Concerning the Use of Health Impact Assessments in Non-Health Sectors http://www.healthimpactproject.org/resources/body/Legal_Review_of_HIA_report.pdf

National Research Council of the National Academies of Science, Improving Health in the United States: The Role of Health Impact Assessment, National Academies Press, November 2011 http://www.nap.edu/chapterlist.php?record_id=13229&type=pdf_chapter&free=1

NAS brief review of HIA http://dels.nas.edu/resources/static-assets/materials-based-on-reports/reports-in-brief/Health-Impact-Assessment-Report-Brief-Final.pdf

http://www.blm.gov/ak/st/en/prog/planning/npra_general/ne_npra/northeast_npr-a_final.html

EIS/HIA

Wernham, A. Inupiat Health and Proposed Alaskan Oil Development: Results of the First Integrated HIA/EIS for Proposed Oil Development on Alaskas North Slope. EcoHealth 4:500-513 (2007).

Please see www.concernedhealthny.org and www.psehealthyenergy.org for updated peer-reviewed articles, reports and testimonies from health professionals.

Larysa Dyrszka MD
Lar917dy@gmail.com
845-583-4381
09/11/13

5. Global Warming Effects of Unconventional Shale Gas Development by Professor Anthony Ingraffea

Presenter – Mav Moorhead

Support for natural gas development appears to be based on the mistaken premise that natural gas is a “clean” fossil fuel, that it is “good” in our efforts to combat climate change. These are characterizations that shale gas cannot claim when fugitive methane emissions from development, transportation and use are taken into account.

Methane is a far more powerful greenhouse gas than carbon dioxide. For the first 20 years of its lifetime in the atmosphere, one pound of methane traps as much heat as at least 80 pounds of CO_2. Its potency declines until it is about 25 to 30 times more powerful than CO_2 over a hundred years. Although when burned gas emits half the CO_2 of coal, methane leakage eviscerates this advantage because of its greenhouse power. (Shindell et al., 2009)

And methane is leaking. At the downstream end of the methane life-cycle, recent measurements in Boston, Washington, DC, and New York City have revealed a shocking number of leaks in aging distribution pipelines and methane concentrations in the air in these major cities up to 5 times the natural background level (Phillips et al. 2013; Ackley and Payne, 2013). Recent field measurements led by scientists at the National Oceanic and Atmospheric Administration (NOAA) have found upstream/midstream only (not including transmission and distribution losses) emissions in a region of Colorado between 2.3 and 7 percent of production; upstream/midstream emissions only up to 9 percent in Utah; and upstream/midstream/downstream emissions up to 17 percent in the Los Angeles CA basin (Petron et al., 2012; Nature, 2013; Peischl et al. 2013).

These measurements validate the range predicted in the seminal paper on this topic published by scientists and engineers at Cornell

University in 2011 (Howarth et al. 2011; Howarth and Ingraffea, 2011; Howarth et al. 2012; Howarth et al., 2012). A subsequent 2011 study from the National Center for Atmospheric Research (NCAR) concluded that unless leaks can be kept below about 2%, gas lacks any climate advantage over coal (Wigley, 2011). A 2012 paper from the Environmental Defense Fund pegs this crossover rate at about only 3% (Alvarez et al., 2013). A recent study by the science group Climate Central shows that the alleged 50% climate advantage of natural gas is unlikely to be achieved for many decades, if at all (Larson, 2013).

Unfortunately, we don't have that long to address climate change—the next two decades are crucial. Shindell et al. (2012) note that the climate system is more immediately responsive to changes in methane (and black carbon) emissions than carbon dioxide emissions. They predict that unless emissions of methane and black carbon are reduced immediately, the Earth will warm to 1.5° C by 2030 and to 2.0° C by 2045 to 2050 whether or not carbon dioxide emissions are reduced. Reducing methane and black carbon emissions, even if carbon dioxide is not controlled, would significantly slow the rate of global warming and postpone reaching the 1.5° C and 2.0° C marks by 12 to 15 years. Controlling carbon dioxide as well as methane and black carbon emissions further slows the rate of global warming after 2045, through at least 2070. The life-cycle of shale gas produces all three of these climate change culprits: carbon dioxide, methane, and black carbon.

While it is possible to reduce fugitive emissions from shale gas development, the technologies to do so have not been embraced by operators because the costs are prohibitive from their view. For example, in 2012 the industry demanded a delay from the EPA until January 1, 2015 of the mandatory implementation of the simplest of these technologies: green completions. It is also certain that any efforts to adequately regulate the industry will be vigorously opposed by this well- resourced industry and its lobbyists.

The other unfounded assumption of some shale gas promoters is that natural gas is a bridge fuel to a cleaner low carbon economy.

Not only does the evidence show that shale gas development is more problematic than continued use of oil and even coal, certainly over the short term, the supposed bridge period, there is no scientific basis for assuming that curbing methane emissions will be easier than implementing the conservation, efficiency and renewable energy strategies that will reduce our reliance upon fossil fuels including natural gas.

We have renewable wind, water, solar and energy-efficiency technology options now to avoid the enormous risks of fracking for shale gas (Jacobson et al., 2013). We can scale these quickly and affordably, creating economic growth, jobs, and a truly clean energy future to address climate change. Political will is the missing ingredient. Meaningful carbon reduction is impossible while the fossil fuel industry has captured too much of our energy policies and regulatory agencies, plus intentionally distorted public debate. Policy-makers, including the President, need to listen more closely to the voices of independent scientists over the din of industry lobbyists.

Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. Science, **326**:716-718

NG. Phillips et al., Mapping urban pipeline leaks: Methane leaks across Boston.
Environmental Pollution,**173** (2013) 1-4.

Ackley R, Payne B, Report on a Preliminary Investigation of Ground-Level ambient Methane Levels in Manhattan, New York City, New York, 2013. available at:
http://www.damascuscitizensforsustainability.org/2013/03/manhattan-natural-gas-pipeline-emissions-2/

Pétron, G. et al. J. Geophys. Res. 117, D04304 (2012)

Peischl et al., 2013: Quantifying sources of methane using light alkanes in the Los Angeles basin, California, JGR/Atmos. doi: 10.1002/jrgd.50413

Nature 493, 12 (03 January 2013) doi:10.1038/493012a

Howarth RW, Santoro R, Ingraffea AR. 2011. Methane and the greenhouse gas footprint of natural gas from shale formations. Climatic Change Letters, doi: 10.1007/s10584-011-0061-5, 2011.

Howarth RW, Ingraffea AR. Should Fracking Stop? Yes, It's Too High Risk. Nature, **477**, 271-273, 2011.

RW Howarth, R Santoro, AR Ingraffea. Venting and leaking of methane from shale gas development: response to Cathles et al., Climatic Change (2012) 113:537-549, DOI 10.1007/s10584-012-0401-0.

Howarth RW et al., Methane Emissions from Natural Gas Systems, Background Paper Prepared for the National Climate Assessment, Reference number 2011-0003

Wigley T, Coal to gas: the influence of methane leakage. Climatic Change, 2012,
DOI 10.1007/s10584-011-0217-3.

Alvarez R, et al., Greater focus needed on methane leakage from natural gas infrastructure, www.pnas.org/cgi/doi/10.1073/pnas.1202407109

Larson E, Natural Gas & Climate Change, Climate Central, 2013. Available at:
http://assets.climatecentral.org/pdfs/NaturalGas-and-ClimateChange.pdf

Shindell D et al. (2012). Simultaneously mitigating near-term climate change and improving human health and food security. Science 335: 183–189.

Jacobson MZ, Howarth RW, Delucchi M, Scobie S, Barth J, Dvorak M, Klevze M, Katkhuda H, Miranda B, Chowdhury N, Jones R, Plano L, Ingraffea AR. Examining the feasibility of converting New York State's all-purpose energy infrastructure to one using wind, water, and sunlight. Energy Policy (2013), http://dx.doi.org/10.1016/j.enpol.2013.02.036i

September 11, 2013

DRBC Public Hearing Comments

In Dec of 2012, The AP reported that a USGS team based in Menlo Park, CA found that a quake in Colorado and a damaging 5.6 magnitude earthquake in Oklahoma were induced by underground disposal of fracking waste. A detailed report by Young Kim of The Lamont-Doherty Laboratory (published in the Journal of Geophysical Research) in concert with USGS concluded that the occurrence of over 100 earthquakes within a 14 month period near Youngstown, Ohio were also the result of fracking waste injection wells. Scientists concluded that 95 quakes in the Raton Basin between 2001 and 2011 were also the result of deep injection of oil and gas drilling waste. USGS scientists concluded that most quakes this past decade were located within 3 miles of an active wastewater injection well. USGS scientist Justin Rubinstein, co-author of the report said that "This is a societal risk you need to be considering. At the moment we're the only people who have done this work and our evidence is pretty conclusive."

The same thing is happening elsewhere in the US including Arkansas, West Virginia, Texas and Wyoming where there are injection wells. ProPublica reported that "Records from disparate corners of the US show that wells drilled to bury this waste deep beneath the ground have repeatedly leaked, sending dangerous chemicals and waste gurgling to the surface or on occasion, seeping into shallow aquifers that store a significant portion of the nation's drinking water." The waste is comprised of millions of gallons of water mixed with toxic, carcinogenic chemicals combined with “produced water” that comes to the surface during fracking operations. “Produced water” has high levels of BTEX chemicals, and salts such as chloride and bromides and heavy metals and is also radioactive.

Migration of fluids from wells have been documented to travel faster and farther than researchers thought possible. In a 2000 case that wasn't caused by injection but brought important lessons about how fluids could move underground, hydrogeologists concluded that bacteria-polluted water migrated horizontally underground for several thousand feet in just 26 hours, contaminating a water supply in Walkerton, Ontario and sickening thousands of residents.

Deep well injection takes place in 32 states from PA to CA. The energy industry has its own injection well category, Class 2, which includes disposal wells and wells in which fluids are injected to force out trapped gas and oil. All hydrofracked gas wells are injection wells. Class 2 is very lightly regulated, a problem that allows unsupervised injection operations - one of the contributing factors of the fatal contamination of 38-mile long Dunkard Creek.

Tom Myers, a hydrologist, drew on research showing that natural faults and fractures are more prevalent than commonly understood to create a model that predicts how chemicals might move in the Marcellus Shale. Myers new model said that chemicals could leak through natural cracks into aquifers tapped for drinking water in about 100 years, far more quickly than had been thought. In areas where there is hydrofracking or drilling, man-made faults and natural ones could intersect and chemicals could migrate to the surface in as little as a few years - or less. "It's out of sight, out of mind. Simply put, they are not impermeable, it's not a matter of if fluid will move through rock layers, but when." he said referring to injected waste and the rock layers.

Until recently injection wells were not considered suitable in the PA geology and wastewater from fracking has been shipped to the injection wells in Ohio (which are the subject of earthquakes). But a recent change in policy - certainly not geology, has paved the way for the installation of fracking wastewater wells in PA. That means that if PA regulations were to be implemented in the DRB there would be fracking and injection wells here in the basin.

The DRB is within a seismically active region that has a documented history of earthquakes. Fracking induced earthquakes and migration of toxic fluids as a result, in addition to the risks that earthquakes pose to potentially hundreds or thousands of gas wells is much too dangerous a risk and should cause this commission to ban fracking in this basin.

Joe Levine,
Damascus Citizens

Reference attachments

Testimony Submitted to the Delaware River Basin Commission. September 11, 2013
By Elisabeth N. Radow, Esq. enradow@radowlaw.com; www.radowlaw.com

My name is Elisabeth Radow. I am grateful for the opportunity to submit testimony to Executive Director Carol Collier on behalf of the Delaware River Basin Commission (DRBC). I am a lifelong New Yorker, the managing attorney of Radow Law PLLC and a mother. I chair the Committee on Energy Agriculture and the Environment for the League of Women Voters of New York. The League of Women Voters of New York, New Jersey, Pennsylvania and Delaware have submitted joint testimony to the DRBC previously. Today I submit testimony on my own behalf. My work has been sourced and cited in national publications such as the New York Times, Huffington Post and MORE Magazine and has been published in several law journals. My law practice includes real estate development, real estate finance and increasingly, the effects of gas drilling operations on property ownership.

The basis for my testimony today comes from my research identifying the impacts of unconventional shale gas drilling on property value, risk allocation between the gas drilling company and the homeowner and the increasing inability of homeowners to obtain and maintain a mortgage and homeowners insurance in the presence of gas drilling.

The majestic Delaware River provides drinking water to 15 million people. The responsibility of the DRBC as stewards of this water supply for so many Americans is an awesome one. What I wish to stress is that how the DRBC discharges that obligation will also profoundly and permanently affect the ability of all citizens living in the Delaware River Basin states to have a safe place to call home. Across America, in shale rich-states, property ownership is being revolutionized by the proliferation of the multi-step, heavy industrial drilling operations on the land surface and subsurface of private homes and farms.

Home represents a family's most valuable asset, financially, spiritually and otherwise. From a property value standpoint, think of home as a bundle of rights: the right to construct, obtain a mortgage loan, lease and sell the property; the right to clean running water, electricity, a roof over ones' head; a safe place to raise children, crops or cattle, or all of the above. Americans pay for these rights when we purchase our property, and expect these rights to continue until we sell. We want the property value to increase. So does the state. Our tax base depends upon it. Now there is mounting evidence that banks will not extend mortgage loans and insurance companies will not renew homeowners' insurance policies for homeowners with gas leases and in some cases their neighbors without gas leases. These trends have potentially grave implications for community vitality and personal wealth in areas with fracking and must be examined and clearly understood by policy makers such as the DRBC.

What about unconventional shale gas drilling is producing these threats to homeowner and community wealth and security? Up to now, home has represented the one place people have control of the destiny of their economic assets. Standard gas leases grab homeowner control of property use by giving the gas company the right to establish surface operations, create perpetual, unfunded, road and utility easements, and the right to store gas underground from any source. The standard leases do not require the gas company to fund or perform the maintenance, repair and ultimate restoration of the easements and other surface uses. So that expense stays with the property owner. They give the gas company the free right to sell the lease or take in investors without homeowner consent. This means the homeowner has no control over who comes onto their private property to drill, or the quality of the work they perform.

Gas drilling introduces hazardous activity and hazardous substances, practices which are expressly prohibited by standard mortgages. Consider that while the mortgage lender expects the home to retain its value for the 30 year life of the loan, a gas driller, and by extension its investors, on that very same property, cares more about extracting the most gas for the least expense and least regulation.

Publicly traded gas company 10-K's filed with the Securities and Exchange Commission characterize the drilling lifecycle as subject to many risks. The list of hazards includes: blow-outs, explosions, pipe failures and uncontrollable flows of natural gas, or well fluids. The same public disclosure documents report that the gas drillers are not fully insured for their operations and fail to state that they have available cash reserves to pay for uninsured casualties, property damage and environmental pollution resulting from their operations.

Well-water contamination can occur at one or more points in the drilling process, including from leaks, spills and cracked well casings and the inappropriate road spreading, disposal and treatment of the toxic, radioactive hydraulic fracturing waste. A recently released EPA power point presentation of its Dimock PA water analysis reflects an apparent nexus between gas drilling operations and contaminated water. http://desmogblog.com/2013/08/05/censored-epa-pennsylvania-fracking-water-contamination-presentation-published-first-time. As is currently happening, properties without potable water will lose substantial value and farms without potable water will fail causing personal economic catastrophe. If this impact continues, it could have major ripple effects on the tax base.

While water contamination from gas drilling operations is the most discussed and most obvious adverse impact to a home's use and value, structural damage to the residence represents another cause for concern. Gas drilling operations involve seismic testing which causes vibrations, moving earth, use of explosives, drilling wells and fracturing shale using extreme high pressure and deep well injection of the toxic waste, where permitted. For example, the Youngstown, Ohio region logged more than 100 earthquakes in 2011 which have been linked to deep well injection of hydraulic fracturing waste. http://www.nbcnews.com/science/fracking-practices-blame-ohio-earthquakes-8C11073601?ocid=msnhp&pos=4 According to the US Geological Survey, "the number of earthquakes has increased dramatically over the past few years within the central and eastern United States. More than 300 earthquakes above a magnitude 3.0 occurred in the three years from 2010-2012, compared with an average rate of 21 events per year observed from 1967-2000. USGS scientists have found that at some locations the increase in seismicity coincides with the injection of wastewater in deep disposal wells."
http://www.usgs.gov/blogs/features/usgs_top_story/man-made-earthquakes/

Any of these invasive gas drilling operations can cause a home's foundation to falter and walls to crack making the residence unsafe to inhabit. For example, recently, two couples in Johnson County, Texas filed a lawsuit for property damage allegedly resulting from fracking-related earthquakes.

While there is no government sponsored registry of gas drilling related impacts to homeowners, these accounts abound. Many are reflected on the FrackTracker Internet database. I am providing the link so the DRBC can review and confirm the mounting accounts. http://www.fractracker.org/2013/03/pacwas-list-of-the-harmed-now-mapped-by-fractracker/

Standard gas leases fail to mention insurance. Homeowners remain potentially liable for the activity that occurs on their property, if it is not effectively delegated to the gas company in the lease or effectively addressed by the gas driller. Homeowners insurance excludes from coverage industrial activity and leaves homeowners vulnerable to losing their insurance coverage. This was confirmed in a July 2012 press release by Nationwide Mutual Insurance Company stating that:

> Nationwide's personal and commercial lines insurance policies were not designed to provide coverage for any fracking-related risks.…. From an underwriting standpoint, we do not have a comfort level with the unique risks associated with the fracking process to provide coverage at a reasonable price. Insurance is a contract and it is designed to cover certain risks. Risks like natural gas and oil drilling are not part of our contracts, and this is common across the industry**.**
> (http://www.nationwide.com/newsroom/071312-FrackingStatement.jsp)**.**

This fact was reconfirmed in a March 2013 news report which stated: Fracking-related damage, insurance industry insiders say, is not covered under a standard homeowner's insurance policy. Neither is damage caused by floods, earthquakes or earth movement, which insurers call exclusions. "(Fracking is) deemed an exclusion in the same way earthquake or earth movement is," according to the Insurance Information Institute, a nonprofit institute funded by the insurance industry. According to State Farm Insurance, the insurance underwriter does not have a fracking endorsement for private residences. While State Farm does have earthquake, earth-movement and sinkhole endorsements available in most areas, the endorsement may not cover fracking related impacts. http://m.shalereporter.com/industry/article_2cbf4e02-4f96-52cb-9264e169b706b05a.html

In August 2013, Lebanon, New York's town supervisor Jim Goldstein disclosed in an open letter that a constituent had their homeowner's insurance renewal for their home and farm in Lebanon denied because there is a gas well on their property. Mr. Goldstein confirmed through the insurance agent, who writes a lot of policies in southern Madison County, that this is a new trend and will come up as property owners fill out renewal applications. The property owner reported no history of payment problems or incidents on the property**.**

90% of all mortgage loans are sold into the secondary mortgage market. The standard mortgage used in the secondary mortgage market prohibits the transfer of an interest in the real property (which includes entering into a gas lease) without lender consent; and the presence of hazardous materials and hazardous activity consistent with the practices characterized by unconventional gas drilling operations. People with mortgage loans who signed gas leases without lender consent violated their mortgage; yet, as long as the borrower pays the loan, the lender may not become aware of the default. However, a mortgaged residence without homeowner's insurance constitutes an incurable mortgage default. If the homeowner/borrower cannot obtain replacement coverage in the marketplace, he or she would have to pay the substantially more expensive "forced insurance" premiums arranged through the originating bank or loan servicer (which coverage inures only to the benefit of the bank, not the homeowner), or risk losing the mortgage loan altogether and face foreclosure.

What if a homeowner doesn't have a mortgage yet, but wants one? Because most loans are sold by the originating lender into the secondary mortgage market, mortgage loans are underwritten based upon guidelines issued by the secondary mortgage market. These guidelines have restrictions which could put the originating bank on the hook for buying back the loan if a homeowner allows gas drilling after obtaining a mortgage and the gas drilling results in well water contamination, structural damage or other property damage, or the home becomes uninsured. In recognition of the risks, some national banks are taking precautions when asked to loan on properties with gas leases; others are just saying "no" to residential mortgage loans with residential fracking. Because the property's conformity to secondary market standards will be questioned, an originating lender who elects to make a mortgage loan is more likely to keep the loan in its private loan portfolio and not sell it into the secondary mortgage market. With finite reserves, originating banks can make only a limited number of portfolio loans.

One national bank is taking charge of borrowers who sign a gas lease while also having an outstanding mortgage: Sovereign Bank, N.A., now requires borrowers to sign and record a mineral, oil and gas rights rider to the mortgage which stays in effect for the duration of the mortgage. It prohibits leasing the surface and subsurface of the property for minerals, oil or gas extraction; and requires the borrower to take affirmative steps to prevent renewal or expansion of rights under any existing lease or similar prior grant. The covenant restricting this use entitles the bank to bring the property back into conformity and requires the borrower to pay all bank and attorneys' fees incurred as a result.

Key Bank's Mortgage Group has lending guidelines which provide:

> No mortgages will be written on properties that have a gas well.
> Key Bank can deny a mortgage to homeowners whose properties are within 600 feet of a gas well.
> No mortgages will be written on properties with a gas lease. .
> Property owners with gas leases and gas companies can be held liable for damages.
> http://neogap.org/neogap/

In another case, JPMorgan Chase refused to amend the terms of an existing borrower's refinancing agreement to permit a gas lease with BP. Chase's spokeswoman stated: "It's becoming wide-spread across the industry. Servicers and lenders are becoming more unwilling to approve a loan on these properties," "At the end of the day, we may not even own the loan." http://www.vindy.com/news/2013/mar/10/banks-build-roadblocks-to-riches-from-dr/?print

If a person cannot obtain a mortgage loan or keep a mortgage loan because of the risks associated with gas drilling operations, the house will be difficult to hold onto or sell. Where does that leave the homeowner? Either vulnerable to foreclosure, trapped in the home or forced to abandon it. If current trends continue, homeowners living in gas drilling regions, even those who elect not to sign a gas lease but who are compelled through compulsory integration or forced pooling to join a spacing unit; or other people living in close proximity to homeowners with gas drilling on their property, may find themselves swept into the same net facing bankers and insurance underwriters electing not to loan or renew homeowners insurance because of the migrating risks, such as water contamination and seismic activity, associated unconventional gas drilling. What effect would this have on the home value of people who do not even support the gas drilling? Does the DRBC or a DRBC State open itself up to litigation for forcing a property owner against their will into a spacing unit if that homeowner is subsequently turned down for a mortgage loan or homeowners' insurance? How will the ripple effects of this affect the tax base?

New concerns regarding the ability to mortgage and insure a home are also arising out of the proliferation of retooled older pipelines and newer ones crisscrossing under residences throughout the Country. For example, on May 29, 2013 Exxon owned Pegasus pipeline burst open spilling at least hundreds of thousands of gallons of tar sands crude oil into the residential neighborhood of Mayflower, Arkansas requiring dozens of families to evacuate. In August, 2013 two unrelated pipeline explosions occurred in Illinois, one in Erie which required 80 families to temporarily evacuate their homes, another in Van Buren County which killed a man, destroyed his home and caused the temporary evacuation of 25 homes, affecting 35-40 people. What would such spills do to the Delaware River Basin and its residents? Time will tell whether mortgage lenders and insurance underwriters will revise their underwriting standards to exclude coverage for homes located in close proximity to high pressure pipelines.
http://www.bloomberg.com/news/print/2013-09-02/decades-of-ruptures-from-defect-show-perils-of-old-pipe.html
http://www.arktimes.com/arkansas/ArticleArchives?tag=Pegasus%20pipeline%7C%7CExxonMobil
http://thinkprogress.org/climate/2013/08/13/2457691/cornfield-explosion-in-western-illinois
http://thesouthern.com/news/local/natural-gas-caused-deadly-house-explosion/article_06a3d02e-06bc-11e3-969a-0019bb2963f4.

Because of the connection to water contamination from the multi-phase drilling and fracking process and the vulnerability of homes to structural damage, what will happen to the property investment of families living across the Delaware River Basin if the DRBC elects to proceed with drilling in this water rich region? Where will these people go if their property is harmed? Who will buy the affected homes? For what price? Again, what will happen to the tax base?

The assertion by the oil and gas industry that unconventional shale gas drilling using current technology can be performed safely lacks credibility. Industry public disclosure documents, risk assessment by the insurance industry and regular reports of property damage and environmental impacts affecting homes across the nation support a contrary conclusion. Indeed, the growing reluctance of the mortgage and insurance industries to handle fracking affected properties, a reluctance driven by the long tradition of objective calculation of risk in both of these industries, presents an irrefutable answer to the claims of the oil and gas industry that unconventional gas drilling can be performed safely.

I urge the Delaware River Basin Commission not to endorse unconventional gas drilling in light of the expensive, uninsured risks it poses to homeowners and the potential it has for inflicting enormous economic losses, potentially in the many millions of dollars on homeowners and communities in the Delaware River Basin. The oil and gas industry asks that we consider the benefits of unconventional shale gas drilling. I ask that you consider the costs, including the potential financial devastation of hundreds, if not thousands or more, of innocent homeowners and just say “No” to fracking. Thank you.

5. Global Warming Effects of Unconventional Shale Gas Development

Presenter – Mav Moorhead

Support for natural gas development appears to be based on the mistaken premise that natural gas is a "clean" fossil fuel, that it is "good" in our efforts to combat climate change. These are characterizations that shale gas cannot claim when fugitive methane emissions from development, transportation and use are taken into account.

Methane is a far more powerful greenhouse gas than carbon dioxide. For the first 20 years of its lifetime in the atmosphere, one pound of methane traps as much heat as at least 80 pounds of CO_2. Its potency declines until it is about 25 to 30 times more powerful than CO_2 over a hundred years. Although when burned gas emits half the CO_2 of coal, methane leakage eviscerates this advantage because of its greenhouse power. (Shindell et al., 2009)

And methane is leaking. At the downstream end of the methane life-cycle, recent measurements in Boston, Washington, DC, and New York City have revealed a shocking number of leaks in aging distribution pipelines and methane concentrations in the air in these major cities up to 5 times the natural background level (Phillips et al. 2013; Ackley and Payne, 2013). Recent field measurements led by scientists at the National Oceanic and Atmospheric Administration (NOAA) have found upstream/midstream only (not including transmission and distribution losses) emissions in a region of Colorado between 2.3 and 7 percent of production; upstream/midstream emissions only up to 9 percent in Utah; and upstream/midstream/downstream emissions up to 17 percent in the Los Angeles CA basin (Petron et al., 2012; Nature, 2013; Peischl et al. 2013).

These measurements validate the range predicted in the seminal paper on this topic published by scientists and engineers at Cornell University in 2011 (Howarth et al. 2011; Howarth and Ingraffea, 2011; Howarth et al. 2012; Howarth et al., 2012). A subsequent 2011 study from the National Center for Atmospheric Research (NCAR) concluded that unless leaks can be kept below about 2%, gas lacks any climate advantage over coal (Wigley, 2011). A 2012 paper from the Environmental Defense Fund pegs this crossover rate at about only 3% (Alvarez et al., 2013). A recent study by the science group Climate Central shows that the alleged 50%

climate advantage of natural gas is unlikely to be achieved for many decades, if at all (Larson, 2013).

Unfortunately, we don't have that long to address climate change—the next two decades are crucial. Shindell et al. (2012) note that the climate system is more immediately responsive to changes in methane (and black carbon) emissions than carbon dioxide emissions. They predict that unless emissions of methane and black carbon are reduced immediately, the Earth will warm to 1.5^{o} C by 2030 and to 2.0^{o} C by 2045 to 2050 whether or not carbon dioxide emissions are reduced. Reducing methane and black carbon emissions, even if carbon dioxide is not controlled, would significantly slow the rate of global warming and postpone reaching the 1.5^{o} C and 2.0^{o} C marks by 12 to 15 years. Controlling carbon dioxide as well as methane and black carbon emissions further slows the rate of global warming after 2045, through at least 2070. The life-cycle of shale gas produces all three of these climate change culprits: carbon dioxide, methane, and black carbon.

While it is possible to reduce fugitive emissions from shale gas development, the technologies to do so have not been embraced by operators because the costs are prohibitive from their view. For example, in 2012 the industry demanded a delay from the EPA until January 1, 2015 of the mandatory implementation of the simplest of these technologies: green completions. It is also certain that any efforts to adequately regulate the industry will be vigorously opposed by this well-resourced industry and its lobbyists.

The other unfounded assumption of some shale gas promoters is that natural gas is a bridge fuel to a cleaner low carbon economy. Not only does the evidence show that shale gas development is more problematic than continued use of oil and even coal, certainly over the short term, the supposed bridge period, there is no scientific basis for assuming that curbing methane emissions will be easier than implementing the conservation, efficiency and renewable energy strategies that will reduce our reliance upon fossil fuels including natural gas.

We have renewable wind, water, solar and energy-efficiency technology options now to avoid the enormous risks of fracking for shale gas (Jacobson et al., 2013). We can scale these quickly and affordably, creating economic growth, jobs, and a truly clean energy future to address climate change. Political will is the missing ingredient. Meaningful carbon reduction is impossible while the fossil fuel industry has captured too much of our energy policies and regulatory agencies, plus intentionally distorted public debate. Policy-makers, including the President, need to listen more closely to the voices of independent scientists over the din of industry lobbyists.

Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. *Science*, **326**:716–718

NG. Phillips et al., Mapping urban pipeline leaks: Methane leaks across Boston. *Environmental Pollution,***173** (2013) 1-4.

Ackley R, Payne B, Report on a Preliminary Investigation of Ground-Level ambient Methane Levels in Manhattan, New York City, New York, 2013. available at:
http://www.damascuscitizensforsustainability.org/2013/03/manhattan-natural-gas-pipeline-emissions-2/

Pétron, G. et al. *J. Geophys. Res*. 117, D04304 (2012)

Peischl et al., 2013: Quantifying sources of methane using light alkanes in the Los Angeles basin, California, *JGR/Atmos*. doi: 10.1002/jrgd.50413

Nature 493, 12 (03 January 2013) doi:10.1038/493012a

Howarth RW, Santoro R, Ingraffea AR. 2011. Methane and the greenhouse gas footprint of natural gas from shale formations. *Climatic Change Letters*, doi: 10.1007/s10584-011-0061-5, 2011.

Howarth RW, Ingraffea AR. Should Fracking Stop? Yes, It's Too High Risk. *Nature*, **477**, 271-273, 2011.

RW Howarth, R Santoro, AR Ingraffea. Venting and leaking of methane from shale gas development: response to Cathles et al., *Climatic Change* (2012) 113:537–549, DOI 10.1007/s10584-012-0401-0.

Howarth RW et al., Methane Emissions from Natural Gas Systems, Background Paper Prepared for the National Climate Assessment, Reference number 2011-0003

Wigley T, Coal to gas: the influence of methane leakage. *Climatic Change, 2012,* DOI 10.1007/s10584-011-0217-3.

Alvarez R, et al., Greater focus needed on methane leakage from natural gas infrastructure, www.pnas.org/cgi/doi/10.1073/pnas.1202407109

Larson E, Natural Gas & Climate Change, Climate Central, 2013. Available at: http://assets.climatecentral.org/pdfs/NaturalGas-and-ClimateChange.pdf

Shindell D et al. (2012). Simultaneously mitigating near-term climate change and improving human health and food security. Science 335: 183-189.

Jacobson MZ, Howarth RW, Delucchi M, Scobie S, Barth J, Dvorak M, Klevze M, Katkhuda H, Miranda B, Chowdhury N, Jones R, Plano L, Ingraffea AR. Examining the feasibility of converting New York State's all-purpose energy infrastructure to one using wind, water, and sunlight. *Energy Policy* (2013), http://dx.doi.org/10.1016/j.enpol.2013.02.036i

Please see ***The whole story-including the Extended Report, Press Release and media coverage:*** *http://www.damascuscitizensforsustainability.org/2013/03/manhattan-natural-gas-pipeline-emissions-2/*

PRESS RELEASE: **for immediate release** 3/25/13

Media: New Study Exposes How Natural Gas Isn't the Clean Fossil Fuel It's Hyped up to Be

Actual Methane Emissions Measured in Manhattan Showing No Advantage to Natural Gas: Two Reports

Report on a Preliminary Investigation of Ground-Level ambient Methane Levels in Manhattan, New York City, New York
Extended Report on Preliminary Investigation of Ground-Level Ambient Methane Levels in Manhattan, New York City, New York

Report on a Preliminary Investigation of Ground-Level Ambient Methane Levels in Manhattan, New York City, New York
[This is an initial report subject to revision. First revision 29 March 2013]

16 December 2012

Robert Ackley and Bryce F. Payne Jr. , PhD
Gas Safety, Inc. Southboro, Massachusetts

BACKGROUND

There are serious environmental concerns with the development of shale gas and the related new gas industry infrastructure, and recent investigations have raised concerns about the role of cities in assuring the public and environmental safety of natural gas use. In cities gas will be distributed and delivered through existing and new gas lines, almost all buried under city streets and sidewalks. In most U.S. cities the gas lines have been in place for decades. Consolidated Edison, Inc. (ConEd) in New York City, for example, has been installing gas lines underground since the early 1800s and now has a system of 4320 miles of gas pipe.[1] ConEd has installed pipes under almost every street or sidewalk in their service territory (except northern Westchester). The ConEd gas system in the 23-square mile service area in Manhattan delivers gas through 336,000 customer gas meters. All underground pipes, as in the ConEd gas system, are subject to stresses and strains of corrosion, and physical damage during excavation or due to natural forces. It follows that such extensive, complex and largely aged pipe systems will have maintenance requirements and will develop leaks and other problems that have to be

[1] http://www.coned.com/PublicIssues/PDF/GLRP1210c.pdf

managed to prevent explosion hazards and property damage, e.g. to urban trees, and to assure public and worker safety.

In addition to the more obvious concerns about safety, (such as explosions and wasted gas) there is an additional concern that arises from the fact that commercial natural gas is almost entirely comprised of methane. This naturally occurring gas is formed deep in the earth during the geological processes that form oil and coal, and near or at the earth's surface by biological processes, like decay of sewage, or in the gut of mammals. Until recently, CO2 has received most of the attention as a problematic greenhouse gas; yet now there is an increasing awareness of the role of methane, which has an unusual potency as a greenhouse gas. Depending on how it is calculated, methane is 20 to 100 times more potent as a greenhouse gas than carbon dioxide.[2] However, because burning natural gas generates less carbon dioxide than burning coal or oil, natural gas has been considered a cleaner energy source. **However, because methane is such a potent greenhouse gas, if only a small amount leaks into the atmosphere during extraction, transport and delivery of natural gas to the consumer, the smaller carbon footprint of natural gas burned as fuel grows quickly.** Recent estimates are that if more than 2% of natural gas produced at a well is lost to the atmosphere before it is burned by the consumer, then natural gas will no longer be a cleaner fuel than coal with respect to global warming.[3] How much urban gas distribution and delivery systems may be contributing to exceeding that 2% loss rate is only beginning to be understood.

To begin to better understand the role of NYC with regard to these and other concerns about natural gas safety and global climate concerns a group of private donors in NYC funded Damascus Citizens for Sustainability (DCS) to commission a preliminary investigation of natural gas leaks in parts of the Manhattan Borough. DCS engaged Gas Safety, Inc. (GSI) of Southboro, Massachusetts to perform the preliminary investigation.

METHOD

The investigation involved a road survey of ground level ambient air methane levels using a methane (natural gas) leak surveyor system comprised of a cavity ring-down spectrometer combined with a GPS system and computer control system. The leak surveyor was installed in an automobile with an air sampling line mounted over the rear

---

[2] Differences in the greenhouse potency of methane compared to carbon dioxide arise from differences in how long these two gases typically remain in the atmosphere. Once released into the air both methane and carbon dioxide are removed relatively slowly, but carbon dioxide disappears about ten times more slowly than methane. Consequently, if compared on a ten-year time frame the faster removed methane has a relatively higher effect (methane 100 times CO_2) than when compared over a one-hundred-year time frame during which the longer-lived carbon dioxide will have a stronger overall effect (methane 20 times CO_2). See Intergovernmental Panel on Climate Change (2007) IPCC fourth assessment report (AR4). Working Group 1, The Physical Science Basis. http://www.ipcc.ch/publications_and_data/ar4/wg1/en/contents.html, and Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. Science 326:716-718

[3] Robert W. Howarth , Renee Santoro and Anthony Ingraffea, 2011. Methane and the greenhouse-gas footprint of natural gas from shale formations -- A letter. Climatic Change. DOI 10.1007/s10584-011-0061-5

bumper to ride with the inlet facing down approximately 1 foot above the pavement surface, and the GPS antenna on the roof. The instrument measures and records methane levels in the air above the pavement with an accuracy of a few parts per billion (ppb) about 4 times per second. The onboard GPS system simultaneously records the location of the instrument as sampling occurs.

To confirm the reliability of the methane surveyor several leaks were confirmed by locating the actual points in the road surface from which methane was actually being released into the air. Methane levels just below the surface at the actual methane release points were too high to be measured using the spectrometer and were instead measured using a conventional combustible gas indicator.

RESULTS

The surveyor was driven over 160 miles of selected roads in Manhattan from 27-30 November and 9 December 2012 (see Images 1-5). Methane measurement functions were normal during the survey. However, in some areas in Manhattan tall buildings block GPS satellite signals. Consequently GPS data was intermittent, with deviations from actual driven paths apparent in the visualization of the data in the Google Earth images in this report. Loss of GPS signal caused the plotted survey course in the images to appear to occasionally randomly curve off roadways (see Images 1-5). Those random deviations are minor location errors in the plotted survey course, had no functional connection or impact on the methane data, and did not impact the reliability of the methane leak survey. The survey generated over 700,000 methane measurements, and associated numbers of time and location data points. Those data are presented visually in Images 1 through 6 in this report.

During the survey the periphery of the island was driven at different times. Also, the surveyor was intentionally left on during GSI travel from and to Southboro, MA. The data collected on the cross-country drives from and to Massachusetts provided reference methane levels for comparison to those measured in Manhattan (see Image 6 and DISCUSSION below). Methane levels measured along the upwind periphery of Manhattan were similar to those measured on the cross-country drives.

Images 1-5. Results for each day of the methane survey of ground level ambient air in Manhattan on 27-30 November and 9 December 2012. The height of the red line (curtain) indicates ambient air methane levels (in ppm) 1 foot above the road surface along the survey course. One or more peaks are labeled with the associated methane level (in ppm) to provide scale. The viewer should be aware of the perspective in the images, i.e., similarly sized peaks will appear smaller at visually more distant areas of Manhattan in the images.

Image 6. Preliminary gas leak survey of Manhattan 27-30 November 2012 and 9 December. This image provides a visual impression of the relative levels of methane in ambient air in Manhattan compared to levels on open country highways travelled to and from Manhattan. The height of the red line (curtain) indicates ambient air methane levels 1 foot above the road surface along the survey course. One or more peaks are labeled with the associated methane level (in ppm) to provide scale.

DISCUSSION

The survey indicated that natural gas leaks are occurring generally throughout the Manhattan Borough (see Images 1-5). This preliminary study was more intense in some southeastern and southern parts of Manhattan. Leaks appeared more common in those areas. A more thorough study would be necessary to definitively discriminate areas that may have more or larger leaks than other areas. The preliminary investigation results indicated hundreds to thousands of likely leaks in the surveyed parts of Manhattan.

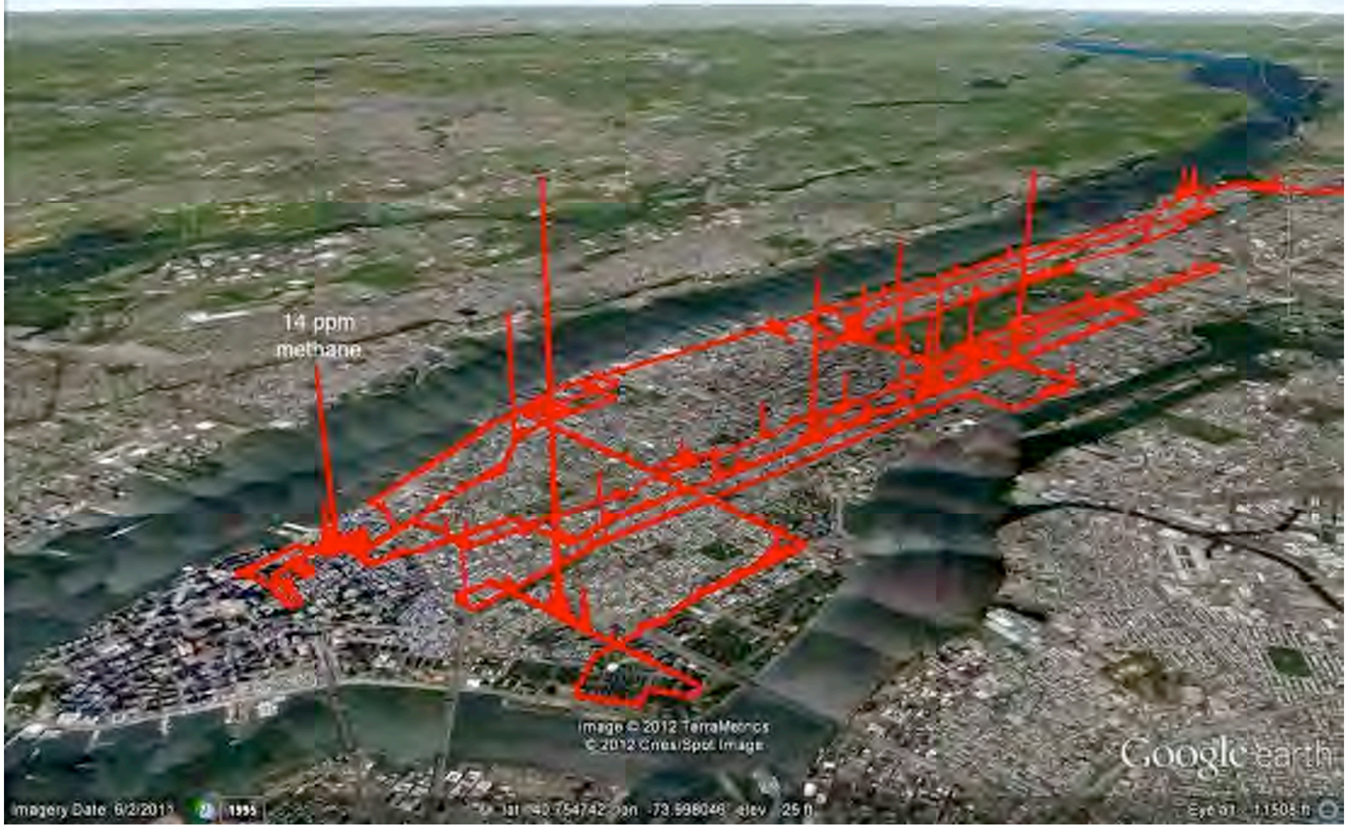
Six methane (natural gas) leaks were tested by inserting a gas probe approximately 6 inches through a valve box cover, pre-existing drill holes, or accessible manhole opening. All of these were likely Grade 2 leaks (in need of repair but not posing immediate danger of explosion) with combustible gas concentrations at the tested locations as follows: 0.35%, 15%, 55%, 55%, 67%, and 70%. Determining the exact location of a leak requires excavation of the probable leaking gas line until the exact location of the leak or leaks is determined. Such efforts were beyond the scope of this methane survey.

Image 6 was prepared from the survey data to provide a visualization of the potential relative importance of the methane leakage from the gas system in Manhattan on a regional atmospheric scale. Further work is needed to determine whether an approximate estimate of the amount of methane being released to the atmosphere can be developed from the data generated by this preliminary methane survey. For this initial report the following table presents a brief comparison of two randomly selected one-hour data sets for Manhattan and an open country drive. The methane measurements in Manhattan indicated many leaks (8.44% of all measurements were >2.5 ppm), some intense (measured levels up to 90 ppm), and almost no measurements at normal background methane levels (only 0.05% of the measurements were ≤2.0 ppm). In contrast, in the open country data, 86.37% of the measured methane levels were ≤2.0 ppm and only 0.03% in a range indicating substantial methane leaks or sources in the vicinity of the measurements.

Date-Time	1129-1959Z	1127-1514Z
Location	Manhattan	Open Country
Methane (ppm)		
Max	90.000	2.484
Mean	2.186	1.858
Min	1.897	1.787
Distribution of measured methane levels		
Total # measurements	13215	13101
% ≤ 2.0 ppm	0.050	86.370
% > 2.5 ppm	8.44	0.03

Work is planned for further analysis and interpretation of the data produced during this preliminary investigation. This report reveals the need and provides a foundation for additional work to better evaluate the apparently substantial amounts of methane being released into the atmosphere from pipeline leaks in New York City.

Image 1. Results of methane survey of parts of Manhattan on 27 November 2012



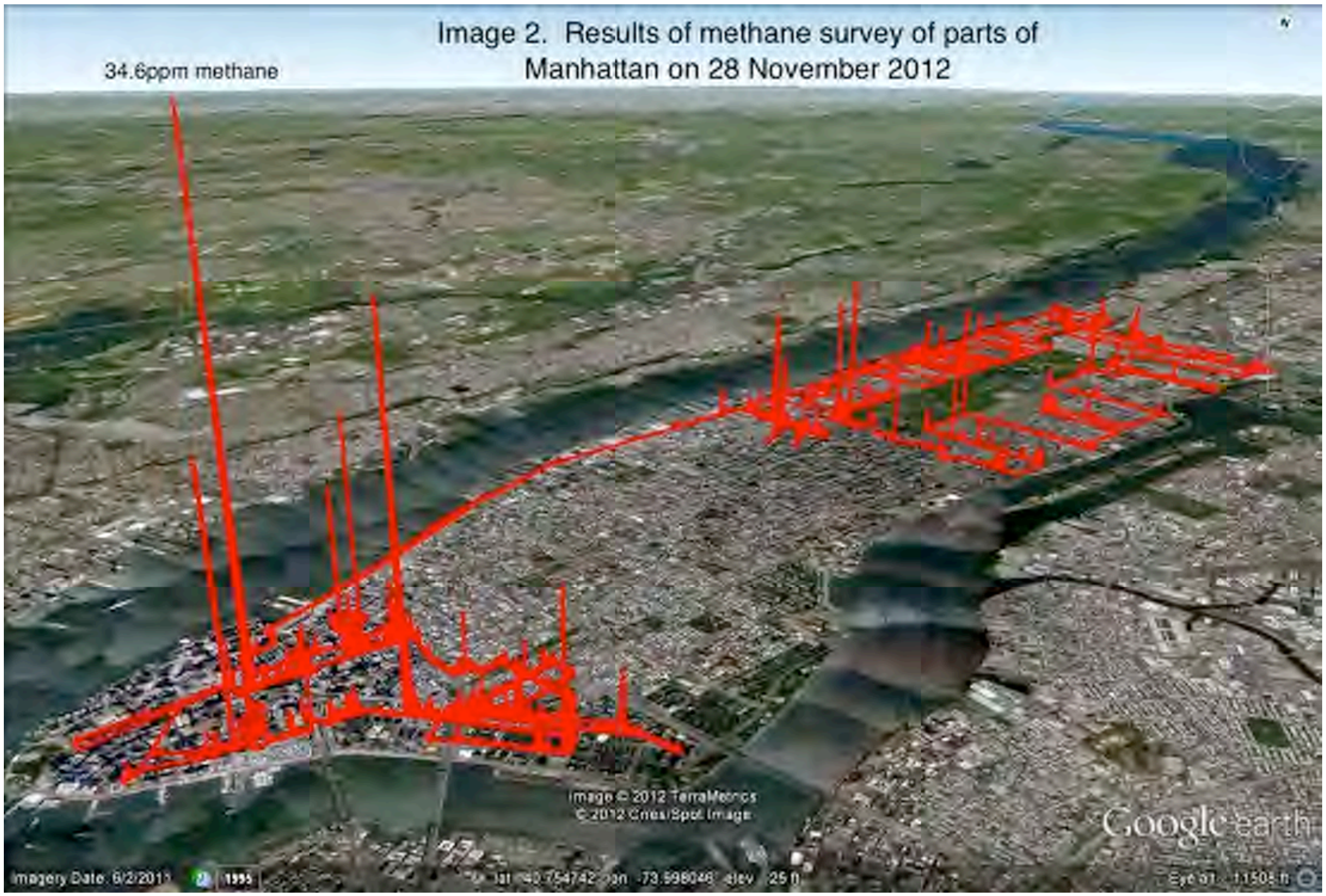


Image 2. Results of methane survey of parts of Manhattan on 28 November 2012

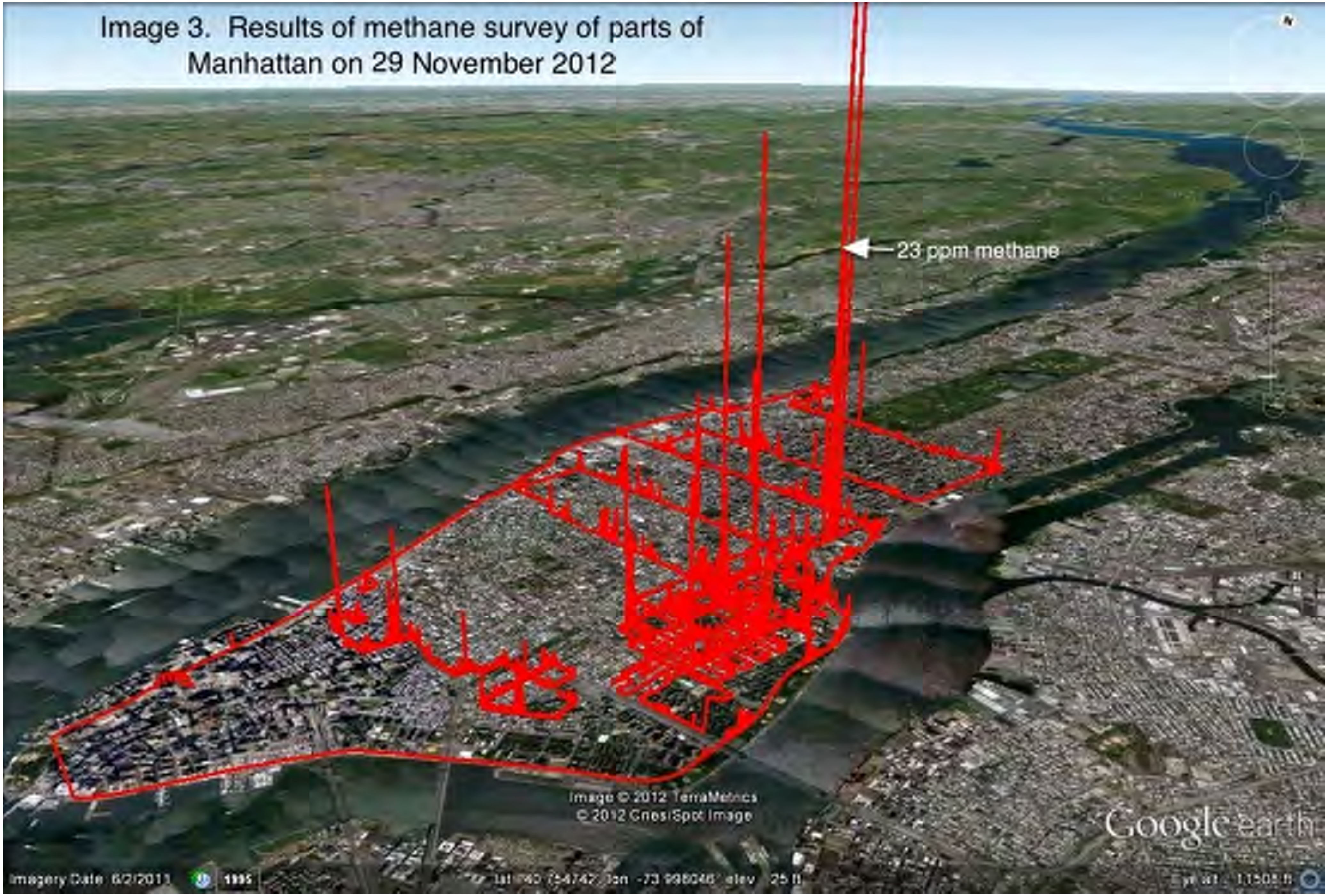


Image 3. Results of methane survey of parts of Manhattan on 29 November 2012

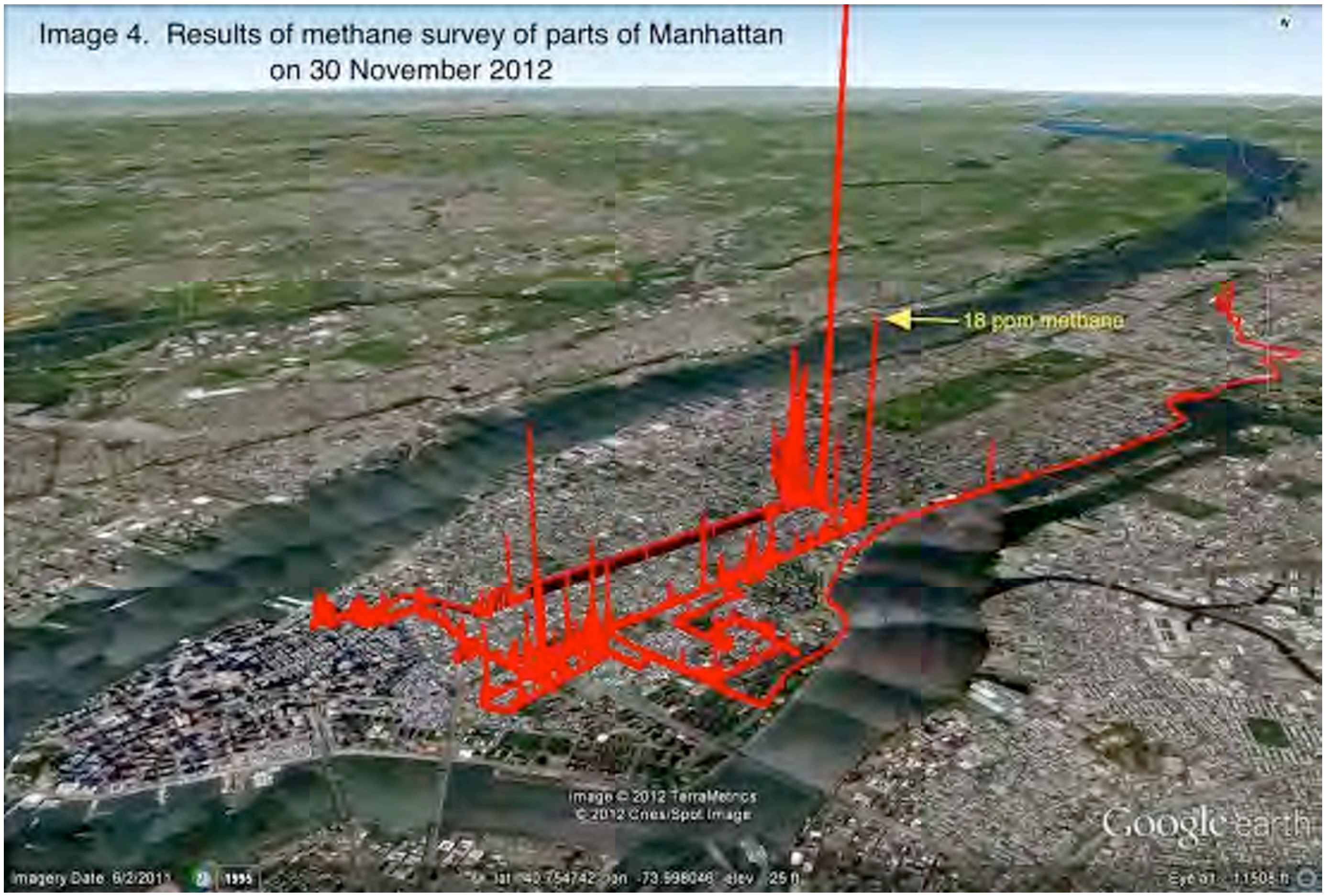


Image 4. Results of methane survey of parts of Manhattan on 30 November 2012

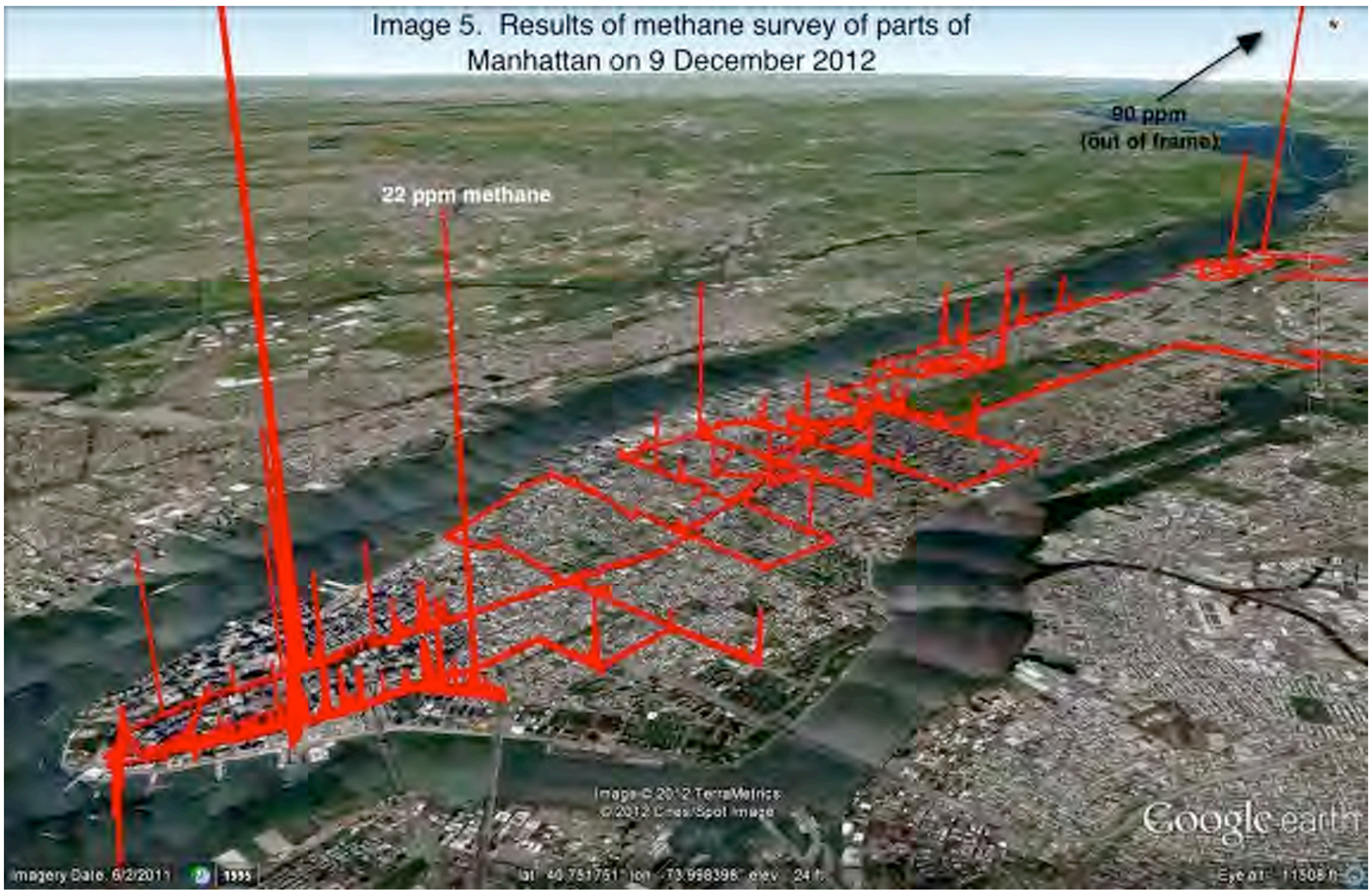
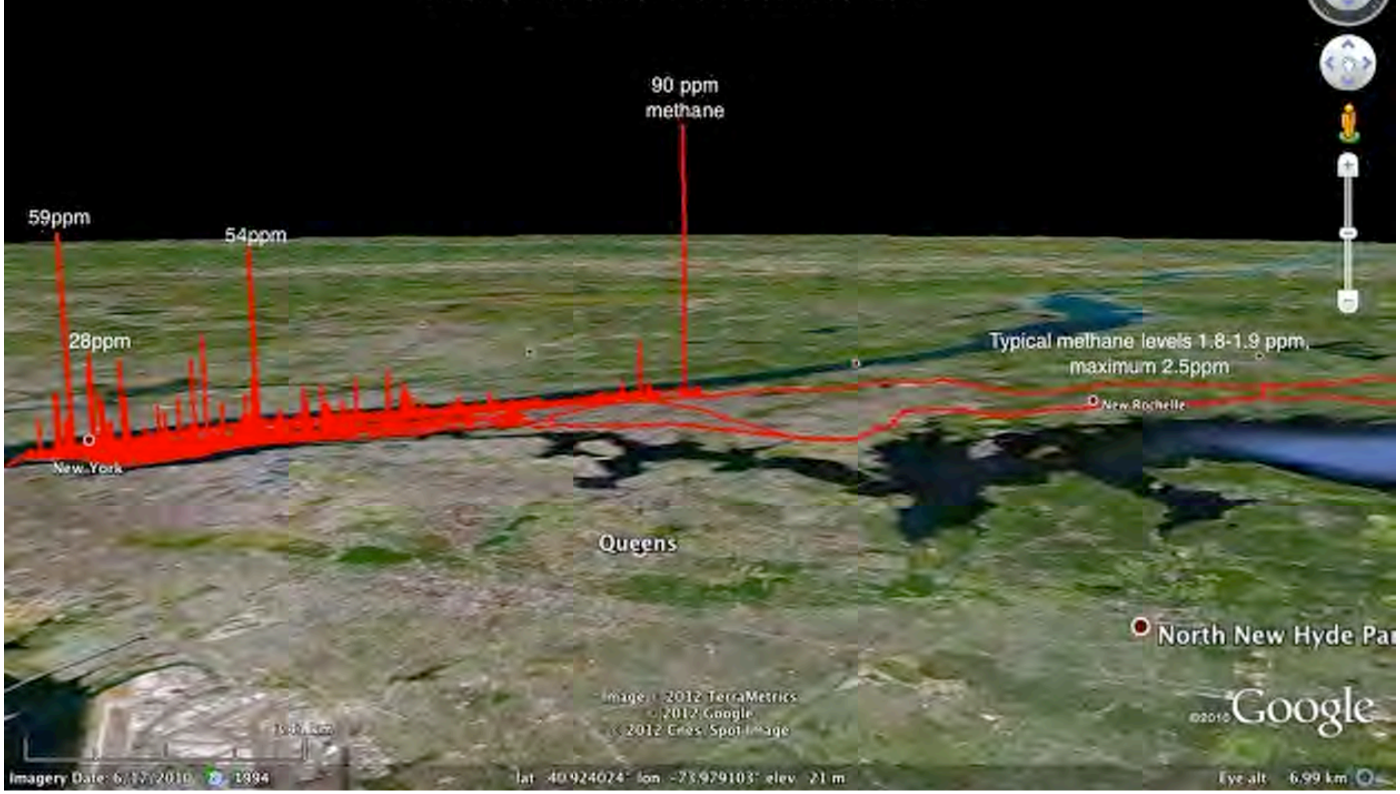


Image 5. Results of methane survey of parts of Manhattan on 9 December 2012

Image 6. Results of methane survey of parts of Manhattan and rural areas to the east on 27-30 November and 9 December 2012



Climatic Change (2012) 113:537–549
DOI 10.1007/s10584-012-0401-0

Venting and leaking of methane from shale gas development: response to Cathles et al.

Robert W. Howarth · Renee Santoro ·
Anthony Ingraffea

Received: 10 December 2011 / Accepted: 10 January 2012 / Published online: 1 February 2012

Abstract In April 2011, we published the first comprehensive analysis of greenhouse gas (GHG) emissions from shale gas obtained by hydraulic fracturing, with a focus on methane emissions. Our analysis was challenged by Cathles et al. (2012). Here, we respond to those criticisms. We stand by our approach and findings. The latest EPA estimate for methane emissions from shale gas falls within the range of our estimates but not those of Cathles et al. which are substantially lower. Cathles et al. believe the focus should be just on electricity generation, and the global warming potential of methane should be considered only on a 100-year time scale. Our analysis covered both electricity (30% of US usage) and heat generation (the largest usage), and we evaluated both 20- and 100-year integrated time frames for methane. Both time frames are important, but the decadal scale is critical, given the urgent need to avoid climate-system tipping points. Using all available information and the latest climate science, we conclude that for most uses, the GHG footprint of shale gas is greater than that of other fossil fuels on time scales of up to 100 years. When used to generate electricity, the shale-gas footprint is still significantly greater than that of coal at decadal time scales but is less at the century scale. We reiterate our conclusion from our April 2011 paper that shale gas is not a suitable bridge fuel for the 21st Century.

1 Introduction

Promoters view shale gas as a bridge fuel that allows continued reliance on fossil fuels while reducing greenhouse gas (GHG) emissions. Our April 2011 paper in *Climatic Change* challenged this view (Howarth et al. 2011). In the first comprehensive analysis of the GHG emissions from shale gas, we concluded that methane emissions lead to a large

Electronic supplementary material The online version of this article (doi:10.1007/s10584-012-0401-0) contains supplementary material, which is available to authorized users.

R. W. Howarth (✉) · R. Santoro
Department of Ecology & Evolutionary Biology, Cornell University, Ithaca, NY 14853, USA
e-mail: rwh2@cornell.edu

A. Ingraffea
School of Civil and Environmental Engineering, Cornell University, Ithaca, NY 14853, USA

GHG footprint, particularly at decadal time scales. Cathles et al. (2012) challenged our work. Here, we respond to the criticisms of Cathles et al. (2012), and show that most have little merit. Further, we compare and contrast our assumptions and approach with other studies and with new information made available since our paper was published. After carefully considering all of these, we stand by the analysis and conclusions we published in Howarth et al. (2011).

2 Methane emissions during entire life cycle for shale gas and conventional gas

Cathles et al. (2012) state our methane emissions are too high and are "at odds with previous studies." We strongly disagree. Table 1 compares our estimates for both conventional gas and shale gas (Howarth et al. 2011) with 9 other studies, including 7 that have only become available since our paper was published in April 2011, listed chronologically by time of publication. See Electronic Supplementary Materials for details on conversions and calculations. Prior to our study, published estimates existed only for conventional gas. As we discussed in Howarth et al. (2011), the estimate of Hayhoe et al. (2002) is very close to our mean value for conventional gas, while the estimate from Jamarillo et al. (2007) is lower and should probably be considered too low because of their reliance on emission factors from a 1996 EPA report (Harrison et al. 1996). Increasing evidence over the past 15 years has suggested the 1996 factors were low (Howarth et al. 2011). In November 2010, EPA (2010) released parts of their first re-assessment of the 1996 methane emission factors, increasing some emissions factors by orders of magnitude. EPA (2011a), released just after our paper was published in April, used these new factors to re-assess and update the U.S. national GHG inventory, leading to a 2-fold increase in total methane emissions from the natural gas industry.

Table 1 Comparison of published estimates for full life-cycle methane emissions from conventional gas and shale gas, expressed per unit of Lower Heating Value (gC MJ^{-1}). Studies are listed by chronology of publication date

	Conventional gas	Shale gas
Hayhoe et al. (2002)	0.57	*
Jamarillo et al. (2007)	0.15	*
Howarth et al. (2011)	0.26–0.96	0.55–1.2
EPA (2011a)	0.38	0.60+
Jiang et al. (2011)	*	0.30
Fulton et al.(2011)	0.38++	*
Hultman et al. (2011)	0.35	0.57
Skone et al. (2011)	0.27	0.37
Burnham et al. (2011)	0.39	0.29
Cathles et al. (2012)	0.14–0.36	0.14–0.36

See Electronic Supplemental Materials for details on conversions

* Estimates not provided in these reports

\+ Includes emissions from coal-bed methane, and therefore may under-estimate shale gas emissions

++ Based on average for all gas production in the US, not just conventional gas, and so somewhat over-estimates conventional gas emissions

The new estimate for methane emissions from conventional gas in the EPA (2011a) inventory, 0.38 g C MJ^{-1}, is within the range of our estimates: 0.26 to 0.96 g C MJ^{-1} (Table 1). As discussed below, we believe the new EPA estimate may still be too low, due to a low estimate for emissions during gas transmission, storage, and distribution. Several of the other recent estimates for conventional gas are very close to the new EPA estimate (Fulton et al. 2011; Hultman et al. 2011; Burnham et al. 2011). The Skone et al. (2011) value is 29% lower than the EPA estimate and is very similar to our lower-end number. Cathles et al. (2012) present a range of values, with their high end estimate of 0.36 g C MJ^{-1} being similar to the EPA estimate but their low end estimate (0.14 g C MJ^{-1}) far lower than any other estimate, except for the Jamarillo et al. (2007) estimate based on the old 1996 EPA emission factors.

For shale gas, the estimate derived from EPA (2011a) of 0.60 g C MJ^{-1} is within our estimated range of 0.55 to 1.2 g C MJ^{-1} (Table 1); as with conventional gas, we feel the EPA estimate may not adequately reflect methane emissions from transmission, storage, and distribution. Hultman et al. (2011) provide an estimate only slightly less than the EPA number. In contrast, several other studies present shale gas emission estimates that are 38% (Skone et al. 2011) to 50% lower (Jiang et al. 2011; Burnham et al. 2011) than the EPA estimate. The Cathles et al. (2012) emission estimates are 40% to 77% lower than the EPA values, and represent the lowest estimates given in any study.

In an analysis of a PowerPoint presentation by Skone that provided the basis for Skone et al. (2011), Hughes (2011a) concludes that a major difference between our work and that of Skone and colleagues was the estimated lifetime gas production from a well, an important factor since emissions are normalized to production. Hughes (2011a) suggests that Skone significantly overestimated this lifetime production, and thereby underestimated the emissions per unit of energy available from gas production (see Electronic Supplemental Materials). We agree, and believe this criticism also applies to Jiang et al. (2011). The lifetime production of shale-gas wells remains uncertain, since the shale-gas technology is so new (Howarth and Ingraffea 2011). Some industry sources estimate a 30-year lifetime, but the oldest shale-gas wells from high-volume hydraulic fracturing are only a decade old, and production of shale-gas wells falls off much more rapidly than for conventional gas wells. Further, increasing evidence suggests that shale-gas production often has been exaggerated (Berman 2010; Hughes 2011a, 2011b; Urbina 2011a, 2011b).

Our high-end methane estimates for both conventional gas and shale gas are substantially higher than EPA (2011a) (Table 1), due to higher emission estimates for gas storage, transmission, and distribution ("downstream" emissions). Note that our estimated range for emissions at the shale-gas wells ("upstream" emissions of 0.34 to 0.58 g C MJ^{-1}) agree very well with the EPA estimate (0.43 g C MJ^{-1}; see Electronic Supplementary Materials). While EPA has updated many emission factors for natural gas systems since 2010 (EPA 2010, 2011a, 2011b), they continue to rely on the 1996 EPA study for downstream emissions. Updates to this assumption currently are under consideration (EPA 2011a). In the meanwhile, we believe the EPA estimates are too low (Howarth et al. 2011). Note that the downstream emission estimates of Hultman et al. (2011) are similar to EPA (2011a), while those of Jiang et al. (2011) are 43% less, Skone et al. (2011) 38% less, and Burnham et al. (2011) 31% less (Electronic Supplemental Materials). One problem with the 1996 emission factors is that they were not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed emissions from model facilities run by companies that voluntarily participated (Kirchgessner et al. 1997). The average long-distance gas transmission pipeline in the U.S. is more than 50 years old, and many cities rely on gas distribution systems that are 80 to 100 years old, but these older systems were not part of the 1996 EPA assessment. Our range of estimates for methane emissions during gas storage, transmission, and distribution falls well within the range given by Hayhoe et al. (2002), and our mean estimate is virtually identical to their "best estimate" (Howarth et al. 2011). Nonetheless, we readily admit that these estimates are highly uncertain. There is an urgent need for better measurement of methane fluxes from all parts of the natural gas industry, but particularly during completion of unconventional wells and from storage, transmission, and distribution sectors (Howarth et al. 2011).

EPA proposed new regulations in October 2009 that would require regular reporting on GHG emissions, including methane, from natural gas systems (EPA 2011c). Chesapeake Energy Corporation, the American Gas Association, and others filed legal challenges to these regulations (Nelson 2011). Nonetheless, final implementation of the regulations seems likely. As of November 2011, EPA has extended the deadline for the first reporting to September 2012 (EPA 2011c). These regulations should help evaluate methane pollution, although actual measurements of venting and leakage rates will not be required, and the reporting requirement as proposed could be met using EPA emission factors. Field measurements across a range of well types, pipeline and storage systems, and geographic locations are important for better characterizing methane emissions.

3 How much methane is vented during completion of shale-gas wells?

During the weeks following hydraulic fracturing, frac-return liquids flow back to the surface, accompanied by large volumes of natural gas. We estimated substantial methane venting to the atmosphere at this time, leading to a higher GHG footprint for shale gas than for conventional gas (Howarth et al. 2011). Cathles et al. (2012) claim we are wrong and assert that methane emissions from shale-gas and conventional gas wells should be equivalent. They provide four arguments: 1) a physical argument that large flows of gas are not possible while frac fluids fill the well; 2) an assertion that venting of methane to the atmosphere would be unsafe; 3) a statement that we incorrectly used data on methane capture during flowback to estimate venting; and 4) an assertion that venting of methane is not in the economic interests of industry. We disagree with each point, and note our methane emission estimates during well completion and flowback are quite consistent with both those of EPA (2010, 2011a, b) and Hultman et al. (2011).

Cathles et al. state that gas venting during flowback is low, since the liquids in the well interfere with the free flow of gas, and imply that this condition continues until the well goes into production. While it is true that liquids can restrict gas flow early in the flow-back period, gas is freely vented in the latter stages. According to EPA (2011d), during well cleanup following hydraulic fracturing "backflow emissions are a result of free gas being produced by the well during well cleanup event, when the well also happens to be producing liquids (mostly water) and sand. The high rate backflow, with intermittent slugs of water and sand along with free gas, is typically directed to an impoundment or vessels until the well is fully cleaned up, where the free gas vents to the atmosphere while the water and sand remain in the impoundment or vessels." The methane emissions are "vented as the backflow enters the impoundment or vessels" (EPA 2011d). Initial flowback is 100% liquid, but this quickly becomes a two-phase flow of liquid and gas as backpressure within the fractures declines (Soliman & Hunt 1985; Willberg et al. 1998; Yang et al. 2010; EPA 2011a, d). The gas produced is not in solution, but rather is free-flowing with the liquid in this frothy mix. The gas cannot be put into production and sent to sales until flowback rates are sufficiently decreased to impose pipeline pressure.

Is it unsafe for industry to vent gas during flowback, as Cathles et al. assert? Perhaps, but venting appears to be common industry practice, and the latest estimates from EPA (2011b, page 3–12) are that 85% of flowback gas from unconventional wells is vented and less than 15% flared or captured. While visiting Cornell, a Shell engineer stated Shell never flares gas during well completion in its Pennsylvania Marcellus operations (Bill Langin, pers. comm.). Venting of flow-back methane is clearly not as unsafe as Cathles et al. (2012) believe, since methane has a density that is only 58% that of air and so would be expected to be extremely buoyant when vented. Under sufficiently high wind conditions, vented gas may be mixed and advected laterally rather than rising buoyantly, but we can envision no atmospheric conditions under which methane would sink into a layer over the ground. Buoyantly rising methane is clearly seen in Forward Looking Infra Red (FLIR) video of a Pennsylvania well during flowback (Fig. 1). Note that we are not using this video information to infer any information on the rate of venting, but simply to illustrate that venting occurred in the summer of 2011 in Pennsylvania and that the gas rose rapidly into the atmosphere. Despite the assertion by Cathles et al. that venting is illegal in Pennyslvania, the only legal restriction is that "excess gas encountered during drilling, completion or stimulation shall be flared, captured, or diverted away from the drilling rig in a manner than does not create a hazard to the public health or safety" (PA § 78.73. *General provision for well construction and operation*).

Cathles et al. state with regard to our paper: "The data they cite to support their contention that fugitive methane emissions from unconventional gas production is [sic] significantly greater than that from conventional gas production are actually estimates of gas emissions that were captured for sale. The authors implicitly assume that capture (or even flaring) is rare, and that the gas captured in the references they cite is normally vented directly into the atmosphere." We did indeed use data on captured gas as a surrogate for vented emissions, similar to such interpretation by EPA (2010). Although most flowback gas appears to be vented and not captured (EPA 2011b), we are aware of no data on the rate of venting, and industry apparently does not usually measure or estimate the gas that is vented during flowback. Our assumption (and that of EPA 2010) is that the rate of gas flow is the same during flowback, whether vented or captured. Most of the data we used were reported to the EPA as part of their "green completions" program, and they provide some of the very few publicly available quantitative estimates of methane flows at the time of flowback. Note that the estimates we published in Howarth et al. (2011) for emissions at the time of well completion for shale gas could be reduced by 15%, to account for the estimated average percentage of gas that is not vented but

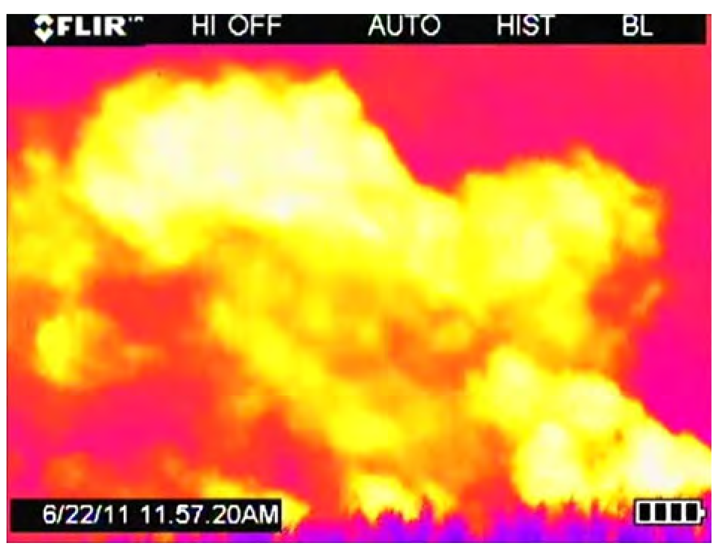


Fig. 1 Venting of natural gas into the atmosphere at the time of well completion and flowback following hydraulic fracturing of a well in Susquehanna County, PA, on June 22, 2011. Note that this gas is being vented, not flared or burned, and the color of the image is to enhance the IR image of this methane-tuned FLIR imagery. The full video of this event is available at http://www.psehealthyenergy.org/resources/view/198782. Video provided courtesy of Frank Finan

rather is flared or captured and sold (EPA 2011b). Given the other uncertainty in these estimates, though, our conclusions would remain the same.

Cathles et al. also assert that we used initial production rates for gas wells, and that in doing so over-estimated flowback venting. Our estimates of flowback emissions for the Barnett, Piceance, Uinta, and Denver-Jules basins were not based on initial production rates, but rather solely on industry-reported volumes of gas captured, assuming. We estimated emissions for the Haynesville basin as the median of data given in Eckhardt et al. (2009), who reported daily rates ranging from 400,000 m^3 (14 MMcf) to 960,000 m^3 (38 MMcf). We assumed a 10-day period for the latter part of the flowback in which gases freely flow, the mean for the other basin studies we used. The use of initial production rates applied to the latter portion of flowback duration as an estimate of venting is commonly accepted (Jiang et al. 2011; NYS DEC 2011).

Finally, Cathles et al. state that economic self-interest would make venting of gas unlikely. Rather, they assert industry would capture the gas and sell it to market. According to EPA (2011b), the break-even price at which the cost of capturing flowback gas equals the market value of the captured gas is slightly under $4 per thousand cubic feet. This is roughly the well-head price of gas over the past two years, suggesting that indeed industry would turn a profit by capturing the gas, albeit a small one. Nonetheless, EPA (2011b) states that industry is not commonly capturing the gas, probably because the rate of economic return on investment for doing so is much lower than the normal expectation for the industry. That is, industry is more likely to use their funds for more profitable ventures than capturing and selling vented gas (EPA 2011b). There also is substantial uncertainty in the cost of capturing the gas. At least for low-energy wells, a BP presentation put the cost of "green" cleanouts as 30% higher than for normal well completions (Smith 2008). The value of the captured gas would roughly pay for the process, according to BP, at the price of gas as of 2008, or approximately $6.50 per thousand cubic feet (EIA 2011a). At this cost, industry would lose money by capturing and selling gas not only at the current price of gas but also at the price forecast for the next 2 decades (EPA 2011b).

In July 2011, EPA (2011b, e) proposed new regulations to reduce emissions during flowback. The proposed regulation is aimed at reducing ozone and other local air pollution, but would also reduce methane emissions. EPA (2011b, e) estimates the regulation would reduce flowback methane emissions from shale gas wells by up to 95%, although gas capture would only be required for wells where collector pipelines are already in place, which is often not the case when new sites are developed. Nonetheless, this is a very important step, and if the regulation is adopted and can be adequately enforced, will reduce greatly the difference in emissions between shale gas and conventional gas in the U.S. We urge universal adoption of gas-capture policies.

To summarize, most studies conclude that methane emissions from shale gas are far higher than from conventional gas: approximately 40% higher, according to Skone et al. (2011) and using the mean values from Howarth et al. (2011), and approximately 60% higher using the estimates from EPA (2011a) and Hultman et al. (2011). Cathles et al. assertion that shale gas emissions are no higher seems implausible to us. The suggestion by Burnham et al. (2011) that shale gas methane emissions are less than for conventional gas seems even less plausible (see Electronic Supplementary Materials).

4 Time frame and global warming potential of methane

Methane is a far more powerful GHG than carbon dioxide, although the residence time for methane in the atmosphere is much shorter. Consequently, the time frame for comparing methane and carbon dioxide is critical. In Howarth et al. (2011), we equally presented two time frames, the 20 and 100 years integrated time after emission, using the global warming potential (GWP) approach. Note that GWPs for methane have only been estimated at time scales of 20, 100, and 500 years, and so GHG analyses that compare methane and carbon dioxide on other time scales require a more complicated atmospheric modeling approach, such as that used by Hayhoe et al. (2002) and Wigley (2011). The GWP approach we follow is quite commonly used in GHG lifecycle analyses, sometimes considering both 20-year and 100-year time frames as we did (Lelieveld et al. 2005; Hultman et al. 2011), but quite commonly using only the 100-year time frame (Jamarillo et al. 2007; Jiang et al. 2011; Fulton et al. 2011; Skone et al. 2011; Burnham et al. 2011). Cathles et al. state that a comparison based on the 20-year GWP is inappropriate, and criticize us for having done so. We very strongly disagree.

Considering methane's global-warming effects at the decadal time scale is critical (Fig. 2). Hansen et al. (2007) stressed the need for immediate control of methane to avoid critical tipping points in the Earth's climate system, particularly since methane release from permafrost becomes increasingly likely as global temperature exceeds 1.8°C above the

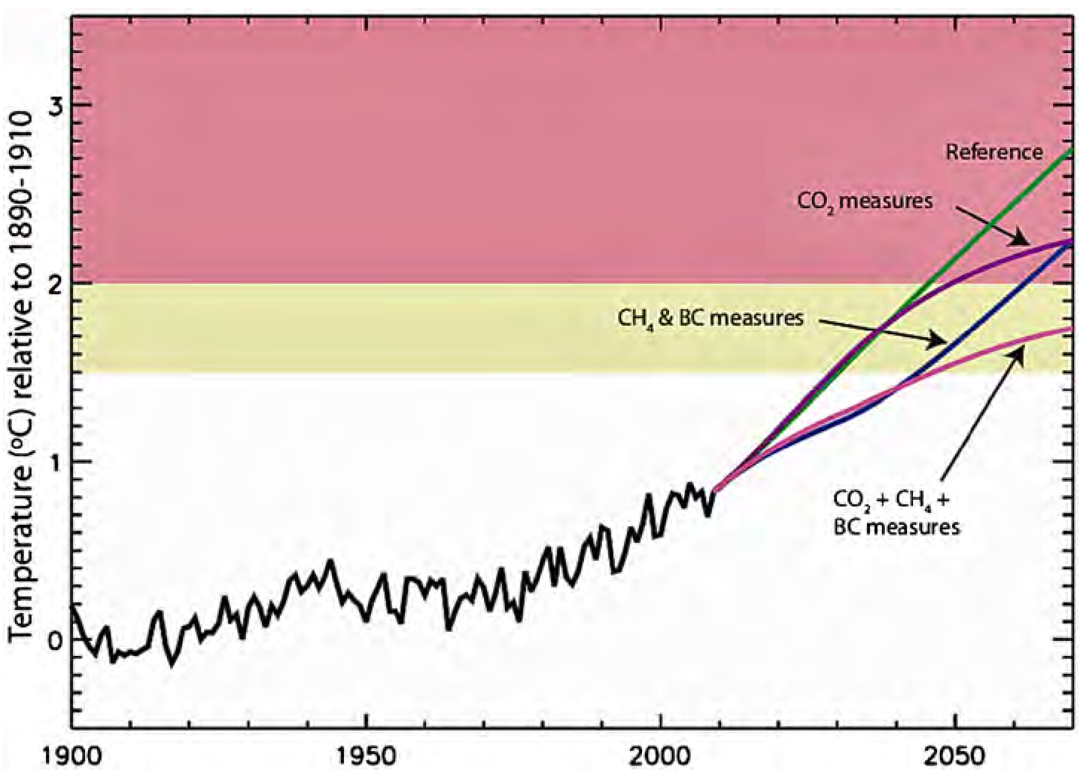


Fig. 2 Observed global mean temperature from 1900 to 2009 and projected future temperature under four scenarios, relative to the mean temperature from 1890–1910. The scenarios include the IPCC (2007) reference, reducing carbon dioxide emissions but not other greenhouse gases ("CO_2 measures"), controlling methane and black carbon emissions but not carbon dioxide ("CH_4 + BC measures"), and reducing emissions of carbon dioxide, methane, and black carbon ("$CO_2 + CH_4$ + BC measures"). An increase in the temperature to 1.5° to 2.0°C above the 1890–1910 baseline (illustrated by the yellow bar) poses high risk of passing a tipping point and moving the Earth into an alternate state for the climate system. The lower bound of this danger zone, 1.5° warming, is predicted to occur by 2030 unless stringent controls on methane and black carbon emissions are initiated immediately. Controlling methane and black carbon shows more immediate results than controlling carbon dioxide emissions, although controlling all greenhouse gas emissions is essential to keeping the planet in a safe operating space for humanity. Reprinted from UNEP/WMO (2011)

baseline average temperature between 1890 and 1910 (Hansen and Sato 2004; Hansen et al. 2007). This could lead to a rapidly accelerating positive feedback of further global warming (Zimov et al. 2006; Walter et al. 2007). Shindell et al. (2012) and a recent United Nations study both conclude that this 1.8°C threshold may be reached within 30 years unless societies take urgent action to reduce the emissions of methane and other short-lived greenhouse gases now (UNEP/WMO 2011). The reports predict that the lower bound for the danger zone for a temperature increase leading to climate tipping points – a 1.5°C increase – will occur within the next 18 years or even less if emissions of methane and other short-lived radiatively active substances such as black carbon are not better controlled, beginning immediately (Fig. 2) (Shindell et al. 2012; UNEP/WMO 2011).

In addition to different time frames, studies have used a variety of GWP values. We used values of 105 and 33 for the 20- and 100-year integrated time frames, respectively (Howarth et al. 2011), based on the latest information on methane interactions with other radiatively active materials in the atmosphere (Shindell et al. 2009). Surprisingly, EPA (2011a) uses a value of 21 based on IPCC (1995) rather than higher values from more recent science (IPCC 2007; Shindell et al. 2009). Jiang et al. (2011), Fulton et al. (2011), Skone et al. (2011), and Burnham et al. (2011) all used the 100-year GWP value of 25 from IPCC (2007), which underestimates methane's warming at the century time scale by 33% compared to the more recent GWP value of 33 from Shindell et al. (2009). We stand by our use of the higher GWP values published by Shindell et al. (2009), believing it appropriate to use the best and most recent science. While there are considerable uncertainties in GWP estimates, inclusion of the suppression of photosynthetic carbon uptake due to methane-induced ozone (Sitch et al. 2007) would further increase methane's GWP over all the values discussed here.

In Fig. 3, we present the importance of methane to the total GHG inventory for the US, considered at both the 20- and 100-year time periods, and using the Shindell et al. (2009) GWP values. Figure 3 uses the most recently available information on methane fluxes for the 2009 base year, reflecting the new methane emission factors and updates through July 2011 (EPA 2010; 2011a, b); see Electronic Supplemental Materials. Natural gas systems dominate the methane flux for the US, according to these EPA estimates, contributing 39% of the nation's total. And methane contributes 19% of the entire GHG inventory of the US at the century time scale and 44% at the 20-year scale, including all gases and all human activities. The methane emissions from natural gas systems make up 17% of the entire anthropogenic GHG inventory of the US, when viewed through the lens of the 20-year integrated time frame. If our high-end estimate for downstream methane emissions during gas storage, transmission, and distribution is correct (Howarth et al. 2011), the importance of methane from natural gas systems would be even greater.

5 Electricity vs. other uses

Howarth et al. (2011) focused on the GHG footprint of shale gas and other fuels normalized to heat from the fuels, following Lelieveld et al. (2005) for conventional gas. We noted that for electricity generation – as opposed to other uses of natural gas – the greater efficiency for gas shifts the comparison somewhat, towards the footprint of gas being less unfavorable. Nonetheless, we concluded shale gas has a larger GHG footprint than coal even when used to generate electricity, at the 20-year time horizon (Howarth et al. 2011). Hughes (2011b) further explored the use of shale gas for electricity generation, and supported our conclusion. Cathles et al. criticize us for not focusing exclusively on electricity.

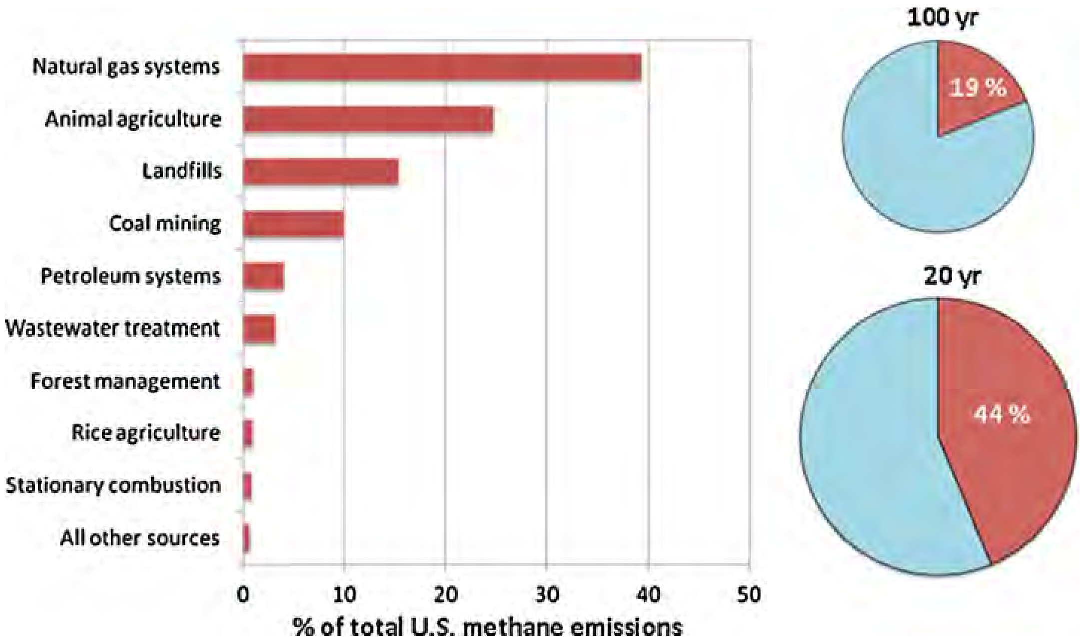


Fig. 3 Environmental Protection Agency estimates for human-controlled sources of methane emission from the U.S. in 2009 (bar graph) and percent contribution of methane to the entire greenhouse gas inventory for the U.S. (shown in red on the pie charts) for the 100-year and 20-year integrated time scales. The sizes of the pie charts are proportional to the total greenhouse gas emission for the U.S. in 2009. The methane emissions represent a greater portion of the warming potential when converted to equivalents of mass of carbon dioxide at the shorter time scale, which increases both the magnitude of the total warming potential and the percentage attributed to methane. Data are from EPA (2011a, b), as discussed in Electronic Supplemental Material, and reflect an increase over the April 2011 national inventory estimates due to new information on methane emissions from Marcellus shale gas and tight-sand gas production for 2009 (EPA 2011b). Animal agriculture estimate combines enteric fermentation with manure management. Coal mining combines active mines and abandoned mines. The time-frame comparisons are made using the most recent data on global warming potentials from Shindell et al. (2009)

We stand by our focus on GHG emissions normalized to heat content. Only 30% of natural gas in the U.S. is used to generate electricity, while most is used for heat for domestic, commercial, and industrial needs, and this pattern is predicted to hold over coming decades (EIA 2011b; Hughes 2011b). Globally, demand for heat is the largest use of energy, at 47% of use (International Energy Agency 2011). And natural gas is the largest source of heat globally, providing over half of all heat needs in developed countries (International Energy Agency 2011). While generating electricity from natural gas has some efficiency gains over using coal, we are aware of no such advantage for natural gas over other fossil fuels for providing heat.

Many view use of natural gas for transportation as an important part of an energy future. The “Natural Gas Act” (H.R.1380) introduced in Congress in 2011 with bipartisan support and the support of President Obama would provide tax subsidies to encourage long-distance trucks to switch from diesel to natural gas (Weiss and Boss 2011). And in Quebec, industry claims converting trucks from diesel to shale gas could reduce GHG emissions by 25 to 30% (Beaudine 2010). Our study suggests this claim is wrong and indicates shale gas has a larger GHG footprint than diesel oil, particularly over the 20-year time frame (Howarth et al. 2011). In fact, using natural gas for long-distance trucks may be worse than our analysis suggested, since it would likely depend on liquefied natural gas, LNG. GHG emissions from LNG are far higher than for non-liquified gas (Jamarillo et al. 2007). See Electronic Supplemental Materials for more information on future use of natural gas in the U.S.

6 Conclusions

We stand by our conclusions in Howarth et al. (2011) and see nothing in Cathles et al. and other reports since April 2011 that would fundamentally change our analyses. Our methane emission estimates compare well with EPA (2011a), although our high-end estimates for emissions from downstream sources (storage, transmission, distribution) are higher. Our estimates also agree well with earlier papers for conventional gas (Hayhoe et al. 2002; Lelieveld et al. 2005), including downstream emissions. Several other analyses published since April of 2011 have presented significantly lower emissions than EPA estimates for shale gas, including Cathles et al. but also Jiang et al. (2011), Skone et al. (2011), and Burnham et al. (2011). We believe these other estimates are too low, in part due to over-estimation of the lifetime production of shale-gas wells.

We reiterate that all methane emission estimates, including ours, are highly uncertain. As we concluded in Howarth et al. (2011), "the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas." The new GHG reporting requirements by EPA will provide better information, but much more is needed. Governments should encourage and fund independent measurements of methane venting and leakage. The paucity of such independent information is shocking, given the global significance of methane emissions and the potential scale of shale gas development.

We stress the importance of methane emissions on decadal time scales, and not focusing exclusively on the century scale. The need for controlling methane is simply too urgent, if society is to avoid tipping points in the planetary climate system (Hansen et al. 2007; UNEP/WMO 2011; Shindell et al. 2012). Our analysis shows shale gas to have a much larger GHG footprint than conventional natural gas, oil, or coal when used to generate heat and viewed over the time scale of 20 years (Howarth et al. 2011). This is true even using our low-end methane emission estimates, which are somewhat lower than the new EPA (2011a) values and comparable to those of Hultman et al. (2011). At this 20-year time scale, the emissions data from EPA (2011a, b) show methane makes up 44% of the entire GHG inventory for the U.S., and methane from natural gas systems make up 17% of the entire GHG inventory (39% of the methane component of the inventory).

We also stress the need to analyze the shale-gas GHG footprint for all major uses of natural gas, and not focus on the generation of electricity alone. Of the reports published since our study, only Hughes (2011b) seriously considered heat as well as electricity. Cathles et al. (2012), Jiang et al. (2011), Fulton et al. (2011), Hultman et al. (2011), Skone et al. (2011), and Wigley (2011) all focus just on the generation of electricity. We find this surprising, since only 30% of natural gas in the U.S. is used to generate electricity. Other uses such as transportation should not be undertaken without fully understanding the consequences on GHG emissions, and none of the electricity-based studies provide an adequate basis for such evaluation.

Can shale-gas methane emissions be reduced? Clearly yes, and proposed EPA regulations to require capture of gas at the time of well completions are an important step. Regulations are necessary to accomplish emission reductions, as economic considerations alone have not driven such reductions (EPA 2011b). And it may be extremely expensive to reduce leakage associated with aging infrastructure, particularly distribution pipelines in cities but also long-distance transmission pipelines, which are on average more than 50 years old in the U.S. Should society invest massive capital in such improvements for a bridge fuel that is to be used for only 20 to 30 years, or would the capital be better spent on constructing a smart electric grid and other technologies that move towards a truly green energy future?

We believe the preponderance of evidence indicates shale gas has a larger GHG footprint than conventional gas, considered over any time scale. The GHG footprint of shale gas also exceeds that of oil or coal when considered at decadal time scales, no matter how the gas is used (Howarth et al. 2011; Hughes 2011a, b; Wigley et al. 2011). Considered over the century scale, and when used to generate electricity, many studies conclude that shale gas has a smaller GHG footprint than coal (Wigley 2011; Hughes 2011b; Hultman et al. 2011), although some of these studies biased their result by using a low estimate for GWP and/or low estimates for methane emission (Jiang et al. 2011; Skone et al. 2011; Burnham et al. 2011). However, the GHG footprint of shale gas is similar to that of oil or coal at the century time scale, when used for other than electricity generation. We stand by the conclusion of Howarth et al. (2011): "The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming."

Acknowledgements We thank Terry Chapin, Chris Costello, Jon Foley, David Hughes, Amy Mall, Roxanne Marino, Nathan Phillips, and Drew Shindell for comments and advice. Funding was provided by the Park Foundation and endowments given by David. R. Atkinson and Dwight C. Baum to Cornell University. The authors have no financial conflict of interests.

References

Beaudine M (2010) In depth: shale gas exploration in Quebec. The Gazette, November 15, 2010

Berman A (2010) Shale gas—Abundance or mirage? Why the Marcellus shale will disappoint expectations. The Oil Drum, Drumbeat, October 29, 2010. http://www.theoildrum.com/node/7079

Burnham A, Han J, Clark CE, Wang M, Dunn JB, and Rivera IP (2011) Life-cycle greenhouse gas emissions of shale gas, natural gas, coal, and petroleum. Environ Sci Technol. doi:10.1021/es201942m

Cathles LM, Brown L, Taam M, Hunter A (2012) this volume

Eckhardt M, Knowles B, Maker E, Stork P (2009) IHS U.S Industry Highlights. (IHS) Houston TX. Feb-Mar 2009. http://www.gecionline.com/2009-prt-7-final-reviews

EIA (2011a) U.S. Natural Gas Wellhead Price (Dollars per Thousand Cubic Feet). U.S. Department of Energy, Energy Information Agency http://www.eia.gov/dnav/ng/hist/n9190us3m.htm

EIA (2011b) Annual Energy Outlook 2011. U.S. Department of Energy, Energy Information Agency (released April 2011)

EPA (2010) Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry. Background Technical Support Document. U.S. Environmental Protection Agency, Washington DC. http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf

EPA (2011a) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009. April 14, 2011. U.S. Environmental Protection Agency, Washington DC. http://epa.gov/climatechange/emissions/usinventoryreport.html

EPA (2011b) Regulatory Impact Analysis: Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Gas Industry. July 2011. U.S. Environmental Protection Agency, Office of Air and Radiation. Washington DC

EPA (2011c) Climate Change – Regulatory Initiatives. U.S. Environmental Protection Agency, Washington DC. http://www.epa.gov/climatechange/emissions/ghgrulemaking.html (downloaded Nov. 22, 2011)

EPA (2011d) Oil and natural gas sector: standards of performance for crude oil and natural gas production, transmission, and distribution. EPA-453/R-11-002. Prepared for U.S. EPA Office of Air Quality Planning and Standards by EC/R Incorporated. U.S. Environmental Protection Agency, Washington DC

EPA (2011e) Proposed Amendments to Air Regulations for the Oil and Gas Industry Fact Sheet. U.S. Environmental Protection Agency, Washington DC. http://www.epa.gov/airquality/oilandgas/pdfs/20110728factsheet.pdf

Fulton M, Mellquist N, Kitasei S, and Bluestein J (2011) Comparing greenhouse gas emissions from natural gas and coal. 25 Aug 2011. Worldwatch Institute/Deutsche Bank

Hansen J, Sato M (2004) Greenhouse gas growth rates. Proc Natl Acad Sci USA 101:16 109–16 114

Hansen J, Sato M, Kharecha P, Russell G, Lea DW, Siddall M (2007) Climate change and trace gases. Phil Trans R Soc A 365:1925–1954

Harrison MR, Shires TM, Wessels JK, Cowgill RM (1996) Methane emissions from the natural gas industry. Volume 1: executive summary. EPA-600/R-96-080a. U.S. Environmental Protection Agency, Office of Research and Development, Washington, DC

Hayhoe K, Kheshgi HS, Jain AK, Wuebbles DJ (2002) Substitution of natural gas for coal: climatic effects of utility sector emissions. Clim Chang 54:107–139

Howarth RW, Ingraffea A (2011) Should fracking stop? Yes, it is too high risk. Nature 477:271–273

Howarth RW, Santoro R, Ingraffea A (2011) Methane and the greenhouse gas footprint of natural gas from shale formations. Climatic Chang Lett. doi:10.1007/s10584-011-0061-5

Hughes D (2011a) Lifecycle greenhouse gas emissions from shale gas compared to coal: an analysis of two conflicting studies. Post Carbon Institute, Santa Rosa, http://www.postcarbon.org/reports/PCI-Hughes-NETL-Cornell-Comparison.pdf

Hughes D (2011b) Will Natural Gas Fuel America in the 21st Century? Post Carbon Institute, Santa Rosa, CA. http://www.postcarbon.org/report/331901-will-natural-gas-fuel-america-in

Hultman N, Rebois D, Scholten M, Ramig C (2011) The greenhouse impact of unconventional gas for electricity generation. Environ Res Lett 6:044008. doi:10.1088/1748-9326/6/4/044008

International Energy Agency (2011) Cogeneration and renewables: solutions for a low-carbon energy future. International Energy Agency, Paris

IPCC (1995) IPCC Second Assessment, Climate Change, 1995. http://www.ipcc.ch/pdf/climate-changes-1995/ipcc-2nd-assessment/2nd-assessment-en.pdf

IPCC (2007) IPCC Fourth Assessment Report (AR4), Working Group 1, The Physical Science Basis. http://www.ipcc.ch/publications_and_data/ar4/wg1/en/contents.html

Jamarillo P, Griffin WM, Mathews HS (2007) Comparative life-cycle air emissions of coal, domestic natural gas, LNG, and SNG for electricity generation. Environ Sci Technol 41:6290–6296

Jiang M, Griffin WM, Hendrickson C, Jaramillo P, vanBriesen J, Benkatesh A (2011) Life cycle greenhouse gas emissions of Marcellus shale gas. Environ Res Lett 6:034014. doi:10.1088/1748-9326/6/3/034014

Kirchgessner DA, Lott RA, Cowgill RM, Harrison MR, Shires TM (1997) Estimate of methane emissions from the US natural gas industry. Chemosphere 35:1365–1390

Lelieveld J, Lechtenbohmer S, Assonov SS, Brenninkmeijer CAM, Dinest C, Fischedick M, Hanke T (2005) Low methane leakage from gas pipelines. Nature 434:841–842

Nelson G (2011) Natural gas, electronics groups sue EPA. Energy Tribune. Feb. 2, 2011. http://www.energytribune.com/articles.cfm/6480/Natural-Gas-Electronics-Groups-Sue-EPA

NYS DEC (2011) SGEIS on the Oil, Gas and Solution Mining Regulatory Program: Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs. Revised draft, Sept 2011. New York State Dept. of Environmental Conservation, Albany, NY

Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. Science 326:716–718

Shindell D, Kuylenstierna JCI, Vignati E, van Dingenen R, Amann M, Klimont Z, Anenberg SC, Muller N, Janssens-Maenhout G, Raes F, Schwartz J, Faluvegi G, Pozzoli L, Kupiainen K, Höglund-Isaksson L, Emberson L, Streets D, Ramanathan V, Hicks K, Oanh NTK, Milly G, Williams M, Demkine V, Fowler D (2012) Simultaneously mitigating near-term climate change and improving human health and food security. Science 335:183–189. doi:10.1126/science.1210026

Sitch S, Cox PM, Collins WJ, Huntingford C (2007) Indirect radiative forcing of climate change through ozone effects on the land-carbon sink. Nature 448:791–794

Skone TJ, Littlefield J, Marriott J (2011) Life cycle greenhouse gas inventory of natural gas extraction, delivery and electricity production. Final report 24 Oct 2011 (DOE/NETL-2011/1522). U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA

Smith GR (2008) Reduced Emission (Green) Completion in Low Energy Reserves. BP America Production Company. 15th Annual Natural Gas STAR Implementation Workshop, San Antonio TX, Nov. 11–13, 2008. http://www.epa.gov/gasstar/workshops/annualimplementation/2008.html

Soliman MY Hunt JL (1985) Effect of fracturing fluid and its cleanup on well performance. SPE 14514. Presented paper. SPE Regional Meeting, Morgantown WV, 6–8 Nov 1985

UNEP/WMO (2011) Integrated assessment of black carbon and tropospheric ozone: summary for decision makers. United Nations Environment Programme and the World Meteorological Organization, Nairobi

Urbina I (2011a) Insiders sound an alarm amid a natural gas rush. New York Times, June 26, 2011. http://www.nytimes.com/2011/06/26/us/26gas.html?_r=1&ref=ianurbina

Urbina I (2011b) Behind veneer, doubts on natural gas. New York Times, June 26, 2011. http://www.nytimes.com/2011/06/27/us/27gas.html?ref=ianurbina

Walter KM, Smith LC, Chapin FS (2007) Methane bubbling from northern lakes: present and future contributions to the methane budget. Phil Trans R Soc A 365:1657–1676

Weis DJ, Boss S (2011) Conservatives Power Big Oil, Stall Cleaner Natural Gas Vehicles. Center for American Progress, June 6, 2011. http://www.americanprogress.org/issues/2011/06/nat_gas_statements.html

Wigley TML (2011) Coal to gas: the influence of methane leakage. Climatic Chang Lett. doi:10.1007/s10584-011-0217-3

Willberg DM, Steinsberger N, Hoover R, Card RJ, Queen J (1998) Optimization of fracture cleanup using flowback analysis. SPE 39920. Presented paper. SPE Rocky Mountain Regional/ Low-permeability Reservoirs Symposium and Exhibition, Denver CO, 5–8 April 1998

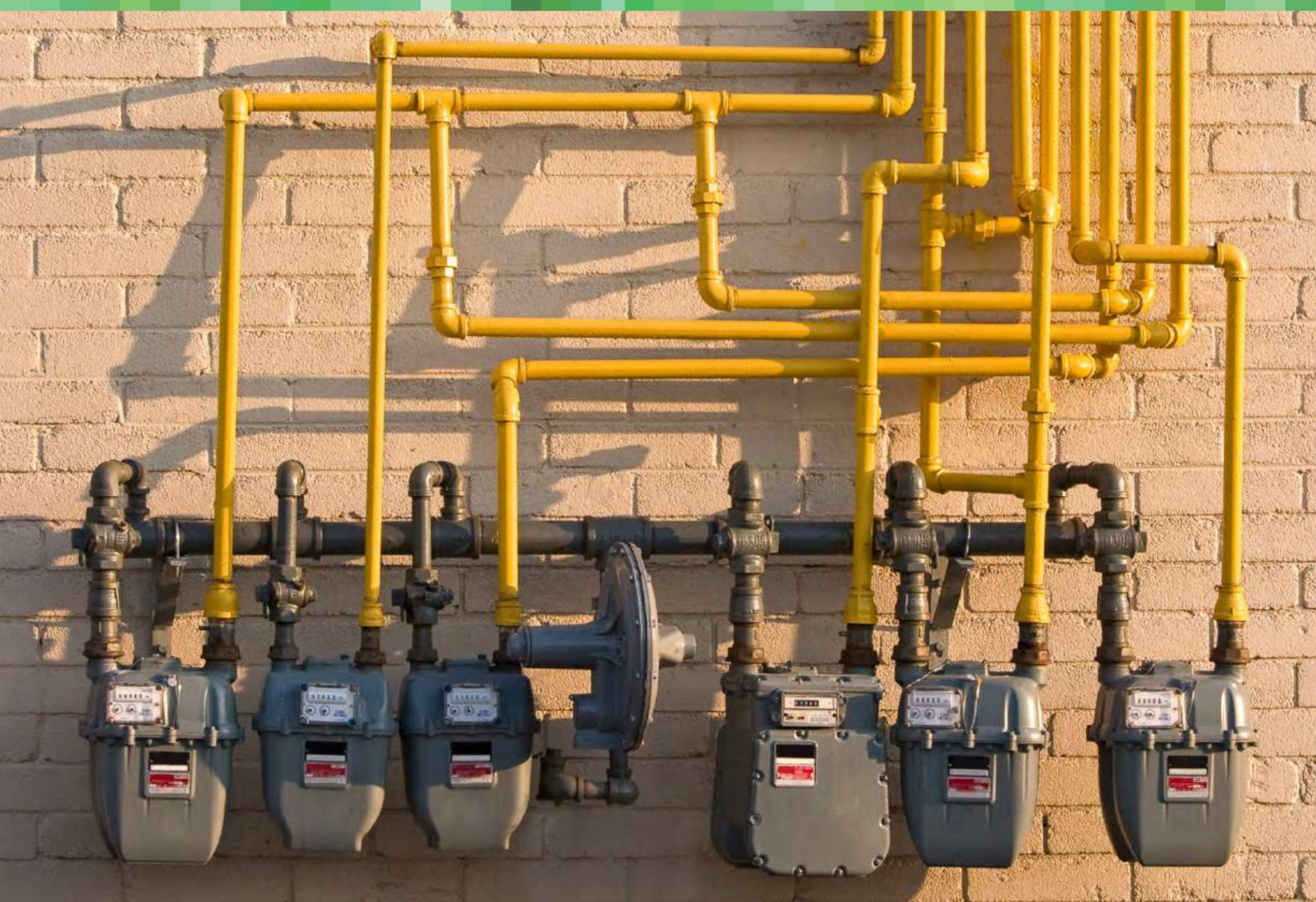
Yang JY, Holditch SA, McVay DA (2010) Modeling fracture-fluid cleanup in tight-gas wells. Paper SPE 119624, SPE Journal 15(3)

Zimov SA, Schuur EAG, Chapin FS (2006) Permafrost and the global carbon budget. Science 312:1612–1613

Natural Gas & Climate Change

Eric D. Larson, PhD

CLIMATE CENTRAL



Natural Gas & Climate Change

Eric D. Larson, PhD

Climate Central surveys and conducts scientific research on climate change and informs the public of key findings. Our scientists publish and our journalists report on climate science, energy, sea level rise, wildfires, drought, and related topics. Climate Central is not an advocacy organization. We do not lobby, and we do not support any specific legislation, policy or bill. Climate Central is a qualified 501(c)3 tax-exempt organization.

Climate Central scientists publish peer-reviewed research on climate science; energy; impacts such as sea level rise; climate attribution and more. Our work is not confined to scientific journals. We investigate and synthesize weather and climate data and science to equip local communities and media with the tools they need.

Princeton

One Palmer Square, Suite 330
Princeton, NJ 08542

Phone: +1 609 924-3800

Call Toll Free

+1 877 4-CLI-SCI (877 425-4724)

www.climatecentral.org

May 2013

Report Author

Eric D. Larson, PhD

Senior Scientist

Dr. Larson leads energy-related research at Climate Central while also being part of the research faculty at Princeton University in the Energy Systems Analysis Group of the Princeton Environmental Institute. His research interests include engineering, economic, and policy-related assessments of advanced clean-energy technologies and systems. He has published over 80 peer-reviewed articles and more than 200 papers in total. He has a Ph.D. in Mechanical Engineering from the University of Minnesota.

Contents

Key Findings

Knowing how much methane is leaking from the natural gas system is essential to determining the potential climate benefits of natural gas use. Climate Central's extensive review of the publicly available studies finds that a pervasive lack of measurements makes it nearly impossible to know with confidence what the average methane leak rate is for the U.S. as a whole. More measurements, more reliable data, and better understanding of industry practices are needed.

It has been widely reported that shifting from coal to gas in electricity generation will provide a 50 percent reduction in greenhouse gas emissions. In reality, the extent of reduced global warming impact depends largely on three factors:

1. The methane leak rate from the natural gas system;
2. How much time has passed after switching from coal to gas, because the potency of methane as a greenhouse gas is 102 times that of carbon dioxide (on a pound-for-pound basis) when first released into the atmosphere and decays to 72 times CO_2 over 20 years and to 25 times CO_2 over 100 years, and;
3. The rate at which coal electricity is replaced by gas electricity.

Climate Central has developed an interactive graphic incorporating all three factors. This makes it easy to visualize the greenhouse benefits of converting power generation from coal to natural gas for different assumptions of methane leak rates and coal-to-gas conversion rates while also considering methane's greenhouse potency over time.

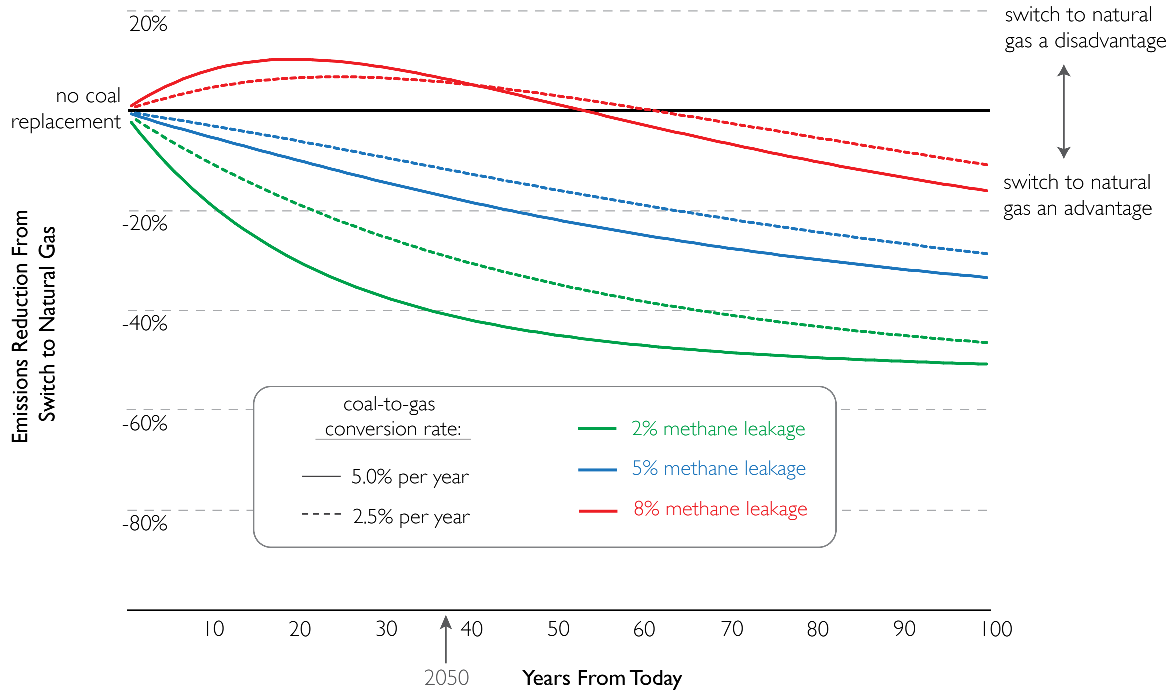
The EPA recently estimated methane leaks in the natural gas system at 1.5 percent. A 1.5 percent leak rate would achieve an immediate 50 percent reduction in greenhouse gas (GHG) emissions, at the individual power plant level. However, EPA's estimate contains significant uncertainty, and like all estimates available in the peer-reviewed literature, lacks sufficient real-world measurements to guide decision-making at the national level. Climate Central found that the ongoing shift from coal to gas in power generation in the U.S. is unlikely to provide the 50 percent reduction in GHG emissions typically attributed to it over the next three to four decades, unless gas leakage is maintained at the lowest estimated rates (1 to 1.5 percent) and the coal replacement rate is maintained at recent high levels (greater than 5 percent per year).

The climate benefits of natural gas are sensitive to small increases in leak rates. Assuming that natural gas replaces 2.5 percent of coal-fired power each year (the average over the past decade) even a relatively low overall leak rate of 2 percent would not achieve a 50 percent reduction in GHG emissions compared to the current fleet of coal-fired power plants, for over 100 years. If the leak rate were as high as 8 percent, there would be no climate benefit at all from switching to natural gas for more than 60 years.

To compute these estimates, we analyzed first the potential GHG benefits from replacing the electricity generated by a single coal power plant with electricity from natural gas instead. For an individual power plant, if the leak rate were 2 percent it would take 55 years to reach a 50 percent reduction in greenhouse impacts compared to continued coal use. If the leak rate is more than 6 percent of methane production, switching to natural gas provides zero global warming benefit for the first 5 years compared to continuing with coal. The switch achieves a modest 17 percent reduction in GHG emissions after 37 years (or by 2050, if the switch occurs in 2013). An 8 percent leak rate increases GHG emissions until 2050 compared with continued coal use, and produces only about 20 percent less climate pollution than continued coal use after 100 years of operation.

But unlike converting a single power plant from coal to natural gas, the U.S. cannot switch its entire fleet of coal-fired power plants to natural gas all at once. When substitution is analyzed across the entire fleet of coal-fired plants, the rate of adoption of natural gas is a critical factor in achieving greenhouse benefits. The rate of adoption is analyzed together with the powerful but declining potency of methane emissions over time. Each year, as a certain percentage

It will be Decades Before Switching to Natural Gas From Coal Power Brings a 50 Percent Reduction in Emissions



of coal plants are converted to natural gas, a new wave of highly potent methane leaks into the atmosphere and then decreases in potency over time.

When the rate of adoption is included, the GHG benefits of switching to natural gas can be even more elusive. With a 2 percent methane leak rate, and an average annual conversion rate of electricity from coal to gas of 2.5 percent (a rate that would be supportable with new gas production projected by the U.S. Department of Energy) the reductions would be 29 percent by 2050 and 16 percent by 2030. If methane leakage is 5 percent of production, by 2050 the U.S. would reduce the global warming impact of its fleet of coal fired power plants by 12 percent. By 2030, the reductions would be just 5 percent. With an 8 percent leak rate, GHG emissions would be greater than with coal for more than 50 years before a benefit begins to be realized.

What is the natural gas leak rate in the U.S.? There are large differences among published estimates of leakage from the natural gas supply system, from less than 1 percent of methane production to as much as 8 percent. At the basin level, studies have reported methane leak rates as high as 17 percent. The EPA's 2012 annual greenhouse gas emissions inventory estimate was 2.2 percent. Its 2013 inventory estimate made a large adjustment that reduced the estimate to 1.5 percent. The degree of methane leakage is uncertain, but it is likely to be reduced in the future since it also represents lost profits for gas companies. Nevertheless, our analysis indicates that the ongoing shift from coal to gas in power generation in the U.S. over the next three to four decades is unlikely to provide the 50 percent benefit that is typically attributed to such a shift.

Determining methane leakage is complicated by various uncertainties:

- Large variability and uncertainty in industry practices at wellheads, including:
    - Whether methane that accompanies flowback of hydraulic fracking fluid during completion of shale gas wells is captured for sale, flared, or vented at the wellhead. Industry practices appear to vary widely.

    - Liquids unloading, which must be done multiple times per year at most conventional gas wells and at some shale gas wells. Gas entrained with the liquids may be vented to the atmosphere. There have been relatively few measurements of vented gas volumes, and estimating an average amount of methane emitted per unloading is difficult due to intrinsic variations from well to well.

- Lack of sufficient production experience with shale gas wells:

    - There are orders of magnitude in variability of estimates of how much gas will ultimately be recovered from any given shale well. This makes it difficult to define an average lifetime production volume per well, which introduces uncertainty in estimating the percentage of gas leaked over the life of an average well.

    - The frequency with which a shale gas well must be re-fractured to maintain gas flow. This process, known as a well workover, can result in methane emissions. The quantity of emissions per workover is an additional uncertainty, as it depends on how workover gas flow is handled.

- The leak integrity of the large and diverse gas distribution infrastructure:

    - Leakage measurements are challenging due to the large extent of the distribution system, including more than a million miles of distribution mains, more than 60 million service line connections, and thousands of metering and regulating stations operating under varying gas pressures and other conditions.

    - Recent measurements of elevated methane concentrations in the air above streets in Boston, San Francisco and Los Angeles strongly suggest distribution system leakages. Additional measurements are needed to estimate leak rates based on such measurements.

Report in Brief

Natural gas use in the U.S. grew by 25 percent from 2007 to 2012. Within the power sector natural gas use grew from 30 percent to 36 percent of all gas use. Shale gas produced by hydraulic fracturing has grown especially rapidly, from close to zero a decade ago to about one-third of all gas today. Continued growth is projected, and shale gas could account for half of all gas in another two decades.

As gas production has grown, electricity generated using gas has grown, from less than 19 percent of all electricity in 2005 to more than 30 percent in 2012. During the same period coal electricity fell from 50 percent to 37 percent. Many associate the shift from coal to gas with significant reductions in U.S. greenhouse gas emissions from electricity because of the lower carbon content of natural gas compared to coal and the higher efficiency with which gas can be converted to electricity.

However, the main component of natural gas, methane, is a much stronger global warming gas than CO_2, and any methane leakage to the atmosphere from the natural gas supply system offsets some of the carbon benefit of a coal-to-gas shift. Here we review a wide set of studies that have been published and provide analysis to put the question of methane leakage in perspective: Depending on the rate of methane leakage, how much more climate friendly is natural gas than coal for electricity generation, and how does the rate at which gas is substituted for coal change that answer?

The two most recent official estimates of U.S. methane emissions from the natural gas supply system (published by the EPA) are that from 1.5 percent to 2.2 percent of methane extracted from the ground in 2010 leaked to the atmosphere, from well drilling and production, through gas processing, transmission, and final distribution to end users.

The range in the EPA's leakage estimates and our review of a large number of others' methane leakage estimates indicate significant uncertainty in the leakage rate. The largest uncertainties are for the production and distribution stages. Peer-reviewed studies, which have focused almost exclusively on assessing leakage rates in the first three stages (excluding distribution), have estimated average leakage for these three stages from less than 1 percent up to 4.5

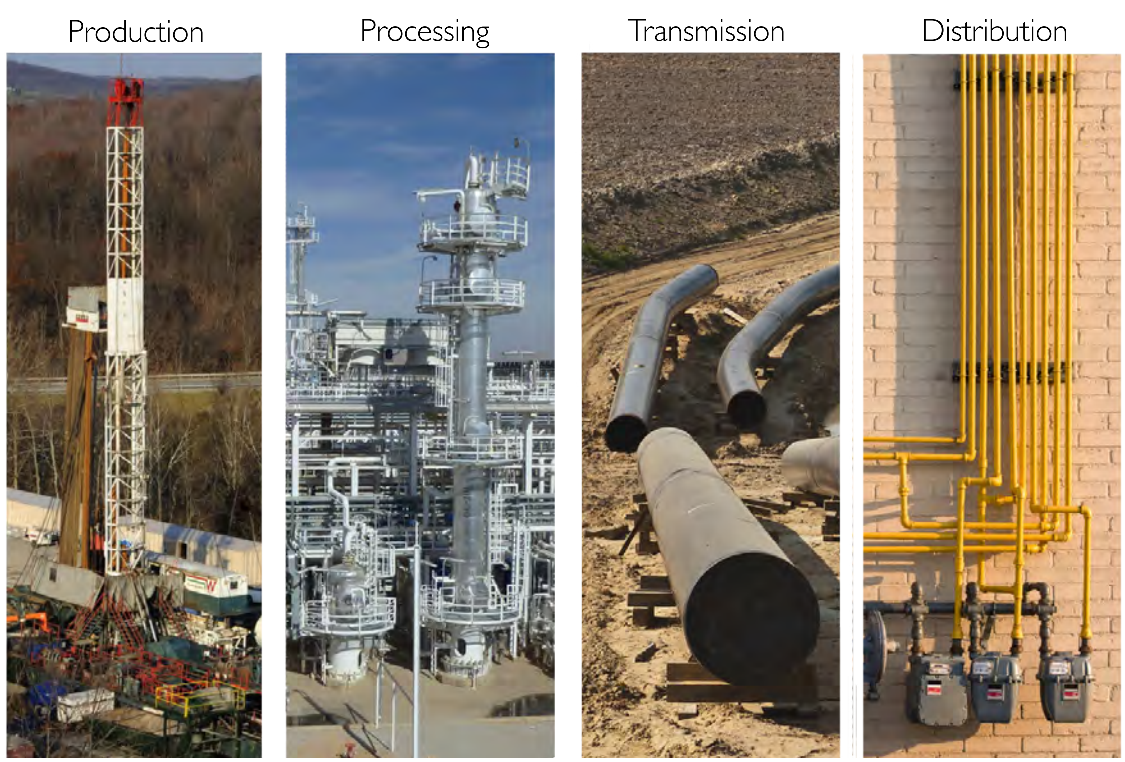


Figure 1. *The four stages of the U.S. natural gas supply system.*

percent of gas produced, with uncertainty bands extending this range on the high end up to as much as 7 percent. The production stage in most studies accounts for 60 to 85 percent or more of the total estimated leakage across the three stages.

The large uncertainties in leakage estimates arise from the sheer size and diversity of the gas supply system and a lack of sufficient measurements and other data for calculating leak rates.

Gas Production

There are more than half a million gas wells in the U.S., and an average of about 20,000 new wells have been drilled each year over the past several years.

During the production of gas from conventional wells (not hydraulically fractured wells), a significant leakage source is the periodic unloading of liquids that seep into and accumulate in a well over time. A typical gas well undergoes liquids unloading multiple times each year, and the gas that accompanies liquids to the surface when they are unloaded is vented, burned, or diverted to a pipeline. Burning converts methane to CO_2, a less potent greenhouse gas. Estimating the methane vented during liquids unloading requires estimating the number of liquid unloadings that occur each year and the amount of methane vented at each unloading. The EPA made significant revisions in its most recent inventory in estimates of both the number of wells using liquids unloading and the annual emissions from unloadings at such wells. The revisions resulted in a greater than 90 percent reduction in estimated liquids unloading emissions between EPA's 2012 and 2013 estimates. Such a large adjustment raises questions as to the uncertainties in such estimates. Having confidence in emissions estimates at the national level is challenging because of the large variations in liquids unloading requirements across wells, the differing industry practices for handling the gas streams that accompany liquids unloading, and the lack of measurements.

Average methane leakage rates for conventional gas production based on different studies in the literature range from 0.3 to 2.2 percent of gas produced. The large range reflects a lack of agreement among authors due in part to the poor quality and limited amount of publicly available data.

With shale gas, the largest emissions during production occur during well completion, the process of preparing the well for the start of marketed production. This includes drilling, hydraulic fracturing, and flow back of the fracturing fluid to the surface. In some cases, maintaining gas production requires periodic well re-fracturing, called a workover. Whether the gas that accompanies the flowback fluid to the surface is vented, burned, or captured for sale significantly affects the overall leakage rate. How flowback gas is handled at different wells is not well known, which further contributes to uncertainties in average estimates of well completion emissions.

An additional significant source of uncertainty in methane leakage during production is the amount of gas that a well will produce over its lifetime. This estimated ultimate recovery (EUR) is important because the one-time methane emissions that occur during well completion are allocated across the total expected production from the well to estimate the percentage of gas production that leaks. An appropriate average EUR to use in leakage estimates is difficult to know with confidence because few shale wells have yet operated for their full lifetime. Moreover, it is likely that EUR values for wells in different shale basins will vary by an order of magnitude or more, and wells within the same basin are expected to have variations in EUR of 2 or 3 orders-of-magnitude.

Beginning in 2013, all natural gas producers are required to report data to the EPA on their production practices, and these data are expected to help reduce some of the uncertainties around estimated leakage rates during gas production. In addition, beginning in August 2011, EPA regulations required that methane be either burned or captured during completion of hydraulically fractured wells. Starting in 2015, all hydraulically fractured wells will be required to use "green completion" technologies to capture the methane. The EPA estimates that methane leakage is reduced by 95 percent with a green completion compared with venting of the methane.

The average methane leakage rate for gas production from hydraulically fractured shale wells estimated in different studies ranges from 0.6 to 3.0 percent.

Gas Processing

An estimated 60 percent of gas coming out of wells in the U.S. contain CO_2 and other contaminants at unacceptably high levels for market sale, so this gas must first undergo processing. A gas processing plant is a collection of chemical reactors that strip contaminants, along with a series of electric and engine-driven compressors that move gas through the plants. Most of the methane leakage during gas processing is believed to come from compressor seals and from incomplete gas combustion in the engines. A major EPA-sponsored study published in 1996 reported measured leak rates from more than 100 different emission sources in the natural gas supply system. Measurements included compressors and engines at gas processing plants, on the basis of which representative daily leakage rates were determined. These are the basis for most of the EPA's gas processing emission estimates today. Additionally, when required, CO_2 that originated in the natural gas is separated from the gas during processing and vented to the atmosphere. This is not a methane emission, but contributes to the overall upstream greenhouse gas emissions footprint of natural gas.

Average methane leakage from gas processing is 0.1 to 0.3 percent of the methane produced, based on different studies. Because there is a well-documented number of gas processing facilities – one facility will handle gas from many wells – and because emission factors are based on measurements of compressor and engine leak rates (albeit measurements made nearly two decades ago), the level of confidence in estimates of gas processing methane leakage rates is relatively high. Moreover, based on EPA's estimates, gas processing accounts for the least methane leakage among the four stages in the natural gas supply system, so uncertainties in gas processing estimates are of less significance overall than uncertainties around leakage in other stages.

Gas Transmission

There are more than 300,000 miles of natural gas transmission pipelines in the U.S., some 400 storage reservoirs of varying types, more than 1400 pipeline-gas compressor stations, and thousands of inter-connections to bulk gas users (such as power plants) and distribution networks. Essentially all gas passes through the transmission system, and about half is delivered directly from a transmission line to large customers like power plants. Transmission pipelines are relatively well maintained, given the risks that poor maintenance entails. The EPA estimates that most methane emissions associated with transmission are due to leakage at compressors and from engines that drive compressors.

Most studies estimate that average methane leakage in gas transmission ranges from 0.2 to 0.5 percent of production. Because the number of compressors and engines in the transmission system are relatively well documented and because emission factors are based on leakage measurements (albeit made in the mid-1990s), the level of confidence in estimates of gas transmission leakage is relatively high. However, variations in leakage associated with the large seasonal movements of gas in and out of storage reservoirs was not considered when measurements were made, and this introduces some uncertainties.

Gas Distribution

About half of all gas leaving the transmission system passes through a distribution network before it reaches a residential, commercial, or small industrial user. Next to gas production, the uncertainties in methane leakage estimates are most significant for gas distribution. Aside from EPA estimates, there are few systematic studies of leakage in gas distribution. The uncertainties in estimating distribution leakage arise in part because of the large number and varying vintages of distribution mains (an estimated 1.2 million miles of pipes in the U.S.), the large number of service lines connecting distribution lines to users (more than 60 million), and the large number and variety of metering and pressure-regulating stations found at the interface of transmission and distribution systems and elsewhere within the distribution network.

The EPA's leakage estimates are based on measurements made in the 1996 study mentioned earlier, and nearly half of distribution system leakage is estimated to occur at metering/regulating stations. Leakage from distribution and service pipelines accounts for most of the rest. The EPA assumes there is no leakage on the customer side of gas meters, though at least one recent study has suggested this may not be the case.

More recent measurement-based studies help highlight some of the uncertainties with estimating distribution emissions. One study in Sao Paulo, Brazil, measured leakage rates from distribution mains made of cast iron, pipe material that leaks the most. Cast iron was the standard material for U.S. distribution mains in the 1950s, and there are an estimated 35,000 miles of cast-iron pipe still in everyday use in the U.S. The EPA assumes the annual leakage rate for a mile of cast-iron pipe is 78 times that for an equivalent pipe made of steel, a principal replacement pipe for cast iron. The Brazilian study, based on measurements at more than 900 pipe sections, estimated an annual leakage rate per mile at least three times that assumed by the EPA.

There have not been many assessments of total leakage in distribution systems other than that of the EPA, which estimates leakage of 0.3 percent of production. However, several recent studies have measured elevated methane concentrations above the streets of Boston, San Francisco, and Los Angeles. These concentration measurements cannot be converted into estimates of leak rates without additional companion measurements. Follow-up measurements are in progress. Given the poor quality of available data on methane leaks from the distribution system, such measurements will be essential in reducing the uncertainties in distribution leakage estimates.

Natural Gas System Leakage in Total and Implications for Electricity Generation

Electric power generation is the largest gas-consuming activity in the U.S. When considering natural gas electricity generation, leakage from the production, processing, and transmission stages are important to consider, since nearly all power plants receive gas directly from the transmission system. The EPA has estimated methane leakage across the production, processing, and transmission stages of the U.S. natural gas supply system to be 1.2 percent to 2 percent of production, but our review of other assessments finds leakage estimates ranging from less than 1 percent to 2.6 percent for conventional gas and from 1 percent to 4.5 percent for shale gas. When uncertainties in the individual estimates are included, the range extends to 3.8 percent for conventional gas and 7 percent for shale gas. Our review finds that additional leakage measurements are needed to better understand actual leakage rates.

Absent more certainty about methane leak rates, we can assess global warming impacts of different leak rates to identify important threshold leakage levels. For illustration, we consider gas-fired electricity generation, which has been increasing rapidly in recent years primarily at the expense of coal-fired generation. In 2012, 30 percent of all electricity was generated from gas. Many authors have suggested that displacing existing coal-fired generation with natural gas electricity provides a 50 percent reduction in global warming impact because of the lower carbon content of gas and the higher efficiency with which it can be used to generate electricity. But the claim of a 50 percent reduction ignores the global warming impact of methane leaks and the related fact that the potency of methane as a greenhouse gas is far higher than that of CO_2. On a pound-for-pound basis methane has a global warming potential about 100 times that of CO_2 initially, although over 20- or 100-year timeframes, this reduces to 72 or 25 times.

Taking into consideration the time-dependent global warming potential of methane relative to CO_2, we estimated the potential greenhouse benefits from replacing the electricity generated by a single coal power plant with electricity from natural gas instead. Our analysis indicates that if total methane leakage from the gas supply system were 4 percent of production, this substitution of gas-fired electricity for coal-fired electricity would result in only about a 25 percent climate benefit over the next decade, a 35 percent benefit over a 50-year horizon, and a 41 percent benefit over a century (i.e., less than the often cited 50 percent reduction). At higher methane leak rates, the benefits would be lower over the same time horizons. For a switch from coal to gas to provide any positive climate benefit over any time horizon, methane leakage needs to be 6 percent per year or less, and to achieve a 50 percent or better climate benefit over any time horizon leakage needs to be 1.5 percent or less. This analysis applies to a situation in which a coal plant retires and its electricity output is provided instead by a natural gas plant.

At the national level, one must also consider the rate at which coal plants are substituted by gas plants. Here we consider a scenario in which there is a steady substitution of coal electricity by gas-generated power at some average annual rate over time, assuming the total electricity supplied by gas plus coal remains constant. This has roughly been the situation in the U.S. over the past decade, when coal electricity generation decreased at an average rate of 2.4 percent per year, with generation from natural gas making up most of the reduction. (The rate of reduction in coal generation has been accelerating. It averaged 5.5 percent per year over the last 5 years, and 9.4 percent per year over the past 3 years.)

With a coal-to-gas shift, every year there is more gas-fired electricity produced than the previous year, and the methane leakage associated with each new increment of gas electricity has a warming potency that is initially very high and falls with time. When the global warming potential of each new annual pulse of methane is considered, the impact of shifting from coal to gas is less than for the one-time coal-to-gas conversion considered above.

For example, if existing coal electricity were substituted by gas at 5 percent per year, requiring 59 years to reach 95 percent coal replacement, then in 2050 – 37 years from today – the global warming impact (compared to continued coal use) would be lower by 17 or 41 percent, assuming methane leakage of 5 or 2 percent, respectively (Figure 2). If leakage were 8 percent there would be no global warming benefit from switching to gas for at least 50 years.

The 5 percent per year coal substitution rate assumed in the previous paragraph may be difficult to sustain with the gas supply levels the U.S. Department of Energy currently projects will be available over the next three decades. A more realistic coal substitution rate may be 2.5 percent per year, which will require 118 years to reach 95 percent coal replacement. At this rate, the reduction in global warming potential over the next 37 years relative to continued coal use would be only 12 or 29 percent for methane leakage of 5 or 2 percent, respectively (Figure 2). To achieve better than these levels would require other lower-carbon options, such as reduced electricity consumption and/or increased electricity supply from nuclear, wind, solar, or fossil fuel systems with CO_2 capture and storage to provide some of the substitution in lieu of gas.

This analysis considers no change in leakage rate or in the efficiencies of power generation over time. The benefit of a switch from coal to gas would obviously increase if leakage were reduced and/or natural gas power-generating efficiency increased over time.

In summary, the coal-to-gas transition rate, the changing potency of methane over time, and the methane leakage fraction all significantly affect future global warming. Knowing with greater certainty the level of methane leakage from the natural gas supply system would provide a better understanding of the actual global warming benefits being achieved by shifting from coal to gas.

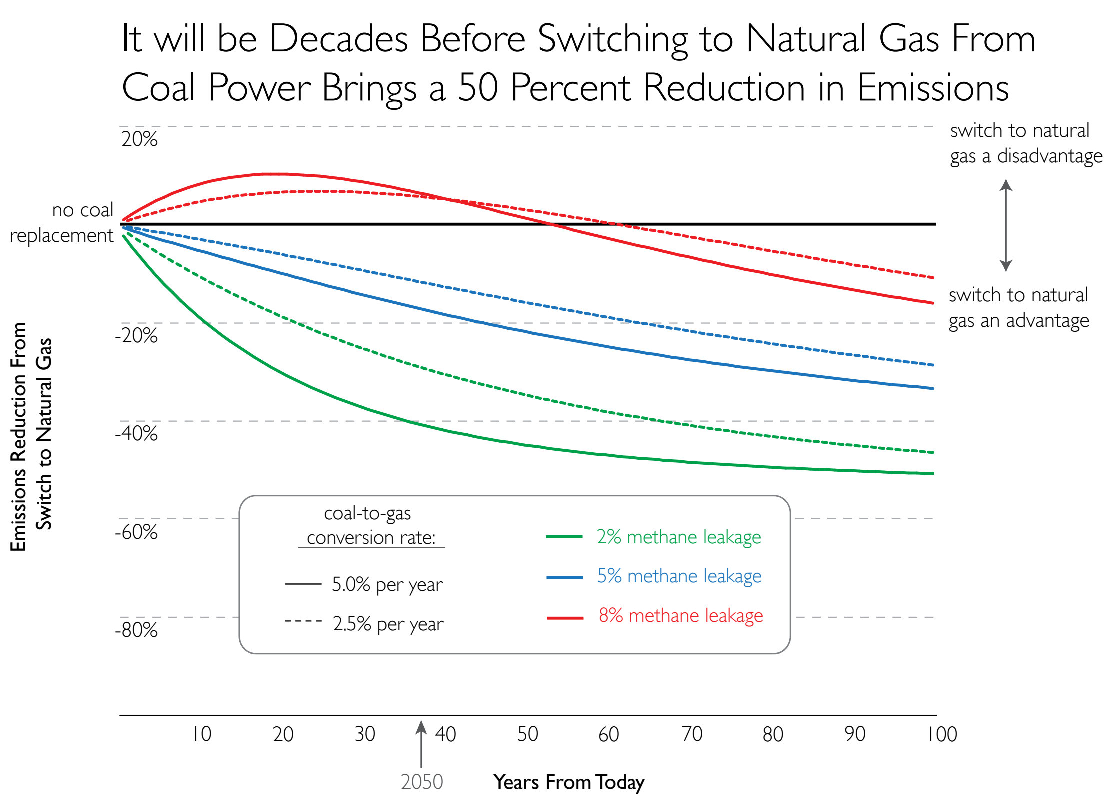


Figure 2. Impact on global warming of shifting existing coal generated electricity to natural gas over time relative to maintaining existing coal generation at current level. The impacts are calculated for two different annual coal-to-gas substitution rates and for three assumed methane leakage rates.

1. Introduction

Natural gas is the second most abundant fossil fuel behind coal, in both the U.S. and the world. At the rate it was used in 2011, the U.S. has an estimated (recoverable) 91-year supply of natural gas. Coal would last 140 years (Table 1). Oil, the most-used fossil fuel in the U.S., would last 36 years.

The estimates of the total amount of natural gas stored under the U.S. increased dramatically in the past decade with the discovery of new forms of unconventional gas, which refers broadly to gas residing in underground formations requiring more than a simple vertical well drilling to extract. Shale, sandstone, carbonate, and coal formations can all trap natural gas, but this gas doesn't flow easily to wells without additional "stimulation".[4] The production of shale gas, the most recently discovered unconventional gas, is growing rapidly as a consequence of new technology and know-how for horizontal drilling and hydraulic fracturing, or fracking.[a] (See Box 1.) An average of more than 2000 new wells per month were drilled from 2005 through 2010 (Figure 3), the majority of which were shale gas wells.

Shale gas accounted for 30 percent of all gas produced in the U.S. in 2011, a share that the U.S. Department of Energy expects will grow significantly in the decades ahead, along with total gas production (Figure 4). Gas prices in the U.S. fell significantly with the growth in shale gas and this has dramatically increased the use of gas for electric-power generation (Figure 5) at the expense of coal-fired power generation. Coal and natural gas provided 37 percent and 30 percent of U.S. electricity in 2012.[6] Only five years earlier, these shares were 49 percent for coal and 22 percent for gas.

Using natural gas in place of coal in electricity generation is widely thought to be an important way to reduce the amount of globe-warming CO_2 emitted into the atmosphere, because combustion of natural gas by itself produces much less CO_2 than the combustion of an energy-equivalent amount of coal (Figure 6, left), and natural gas can be converted much more efficiently into electricity than coal, resulting in an even larger difference between combustion-related emissions per kilowatt-hour of electricity generated (Figure 6, right).

When comparing only combustion emissions, natural gas has a clear greenhouse gas emissions advantage over coal. But emissions are also released during fossil fuel extraction and transportation (these are known as the upstream emissions) and these must also be considered to get an accurate picture of the full greenhouse emissions impact of natural gas compared to coal. The upstream plus combustion emissions when considered together are often called the lifecycle emissions.

Table 1. *Number of years that estimated recoverable resources of natural gas, petroleum, and coal would last if each are used at the rate that they were consumed in 2011.**

	Years left at 2011 rate of use	
	WORLD*	**U.S.****
Conventional Natural Gas	116	42
Unconventional Natural Gas	1021	49
Petroleum	171	36
Coal	2475	140

** Calculated as the average of estimated reserves plus resources from Rogner, et al[1], divided by total global use of gas, petroleum, or coal in 2011 from BP.[2] The consumption rates in 2011 were 122 exajoules for gas, 170 exajoules for oil, and 156 exajoules for coal. One exajoule is 10^{18} joules, or approximately 1 quadrillion BTU (one quad).*
*** Including Alaska. Calculated from resource estimates and consumption data of EIA.[3]*

[a] Horizontal drilling and hydraulic fracturing are also applied to produce gas from some tight sandstone and tight carbonate formations. A key distinction between the term tight gas and shale gas is that the latter is gas that formed and is stored in the shale formation, whereas the former formed external to the formation and migrated into it over time (millions of years).[4]

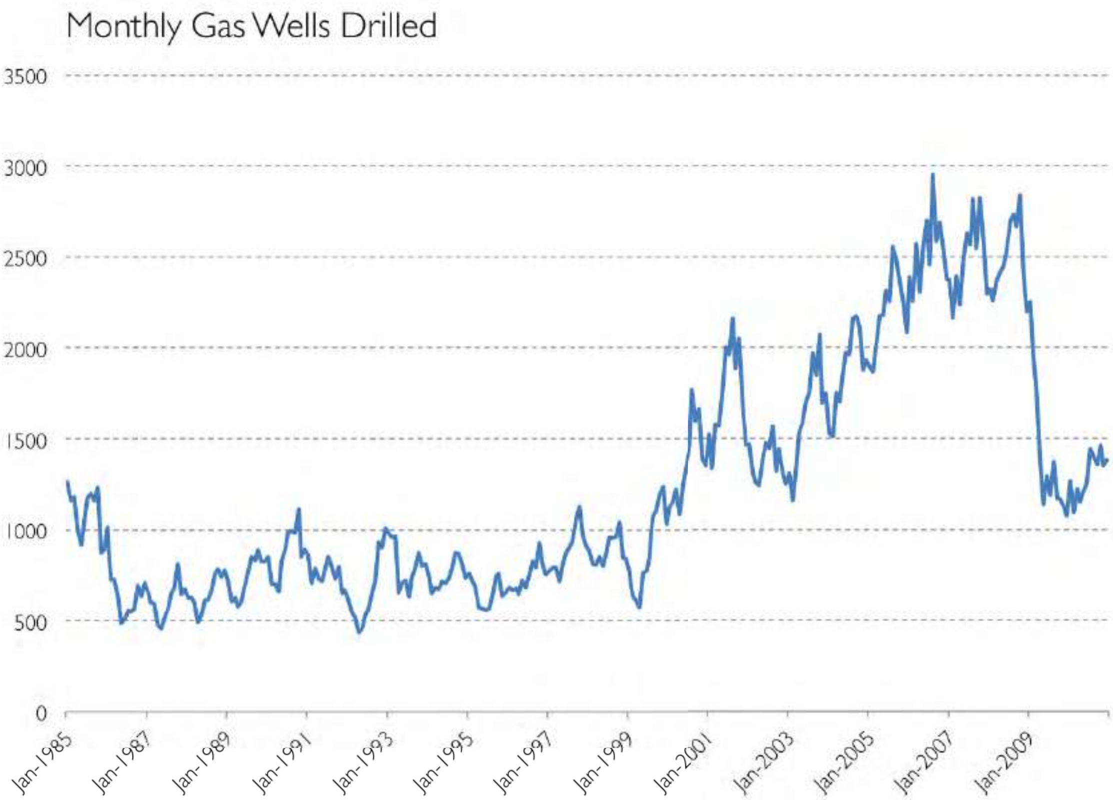


Figure 3. *Number of gas wells drilled per month in the U.S.* [5]

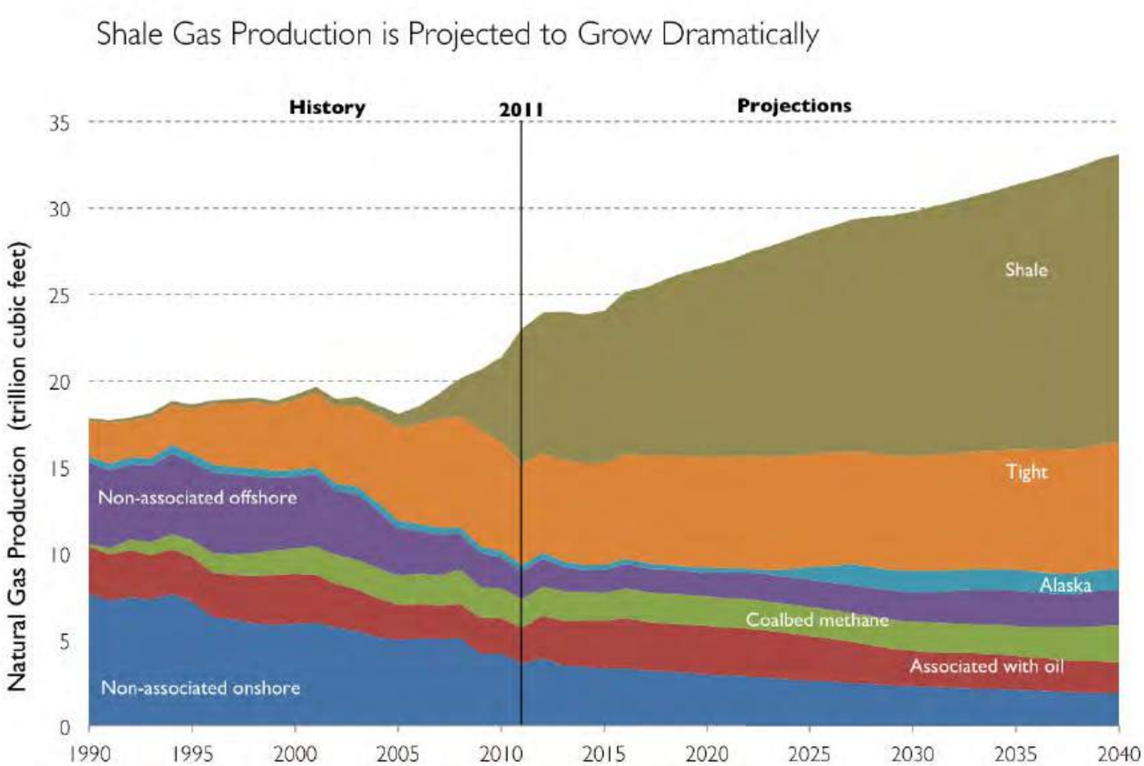


Figure 4. *Past and projected U.S. natural gas production (in trillion cubic feet per year). A trillion cubic feet of natural gas contains about one quadrillion BTU (quad), or equivalently about 1 exajoule (EJ) of energy. Source: EIA.* [7]

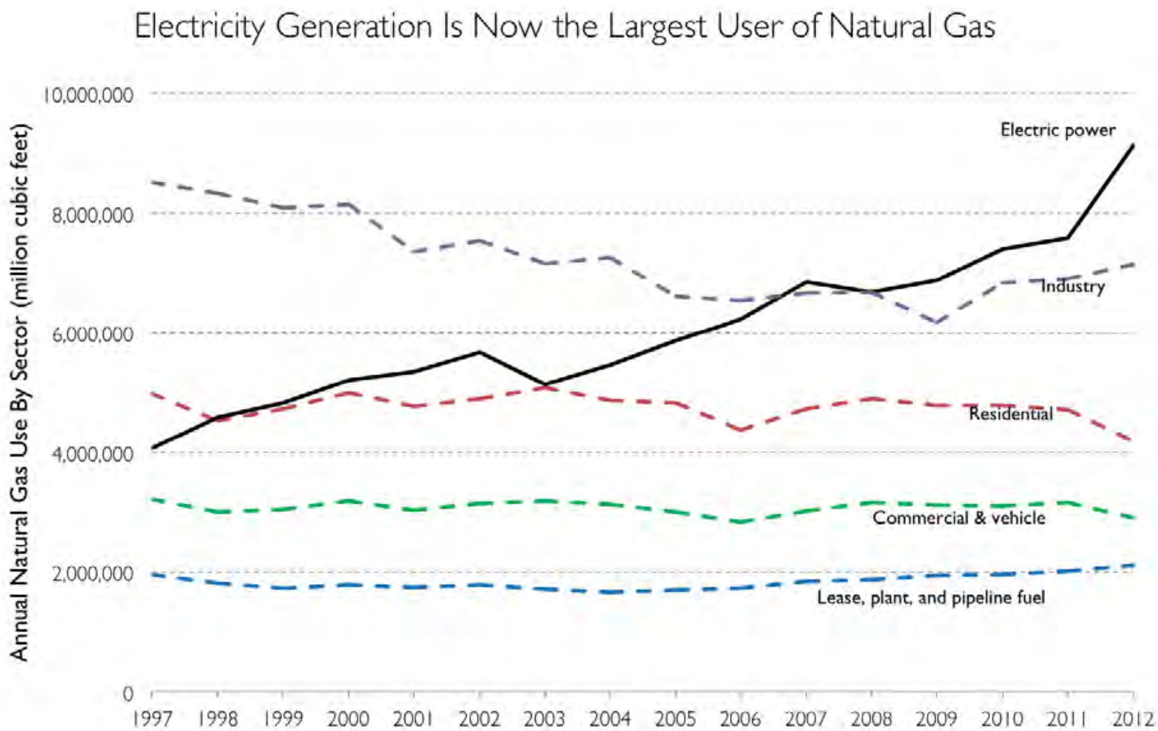


Figure 5. *Unlike other sectors, natural gas for electricity generation has been growing since around 1990 and is now the single largest user of natural gas. This graph shows gas use (in million cubic feet per year) by different sectors. Lease, plant, and pipeline fuel refers to natural gas consumed by equipment used to produce and deliver gas to users, such as natural gas engines that drive pipeline compressors. Source: EIA.*

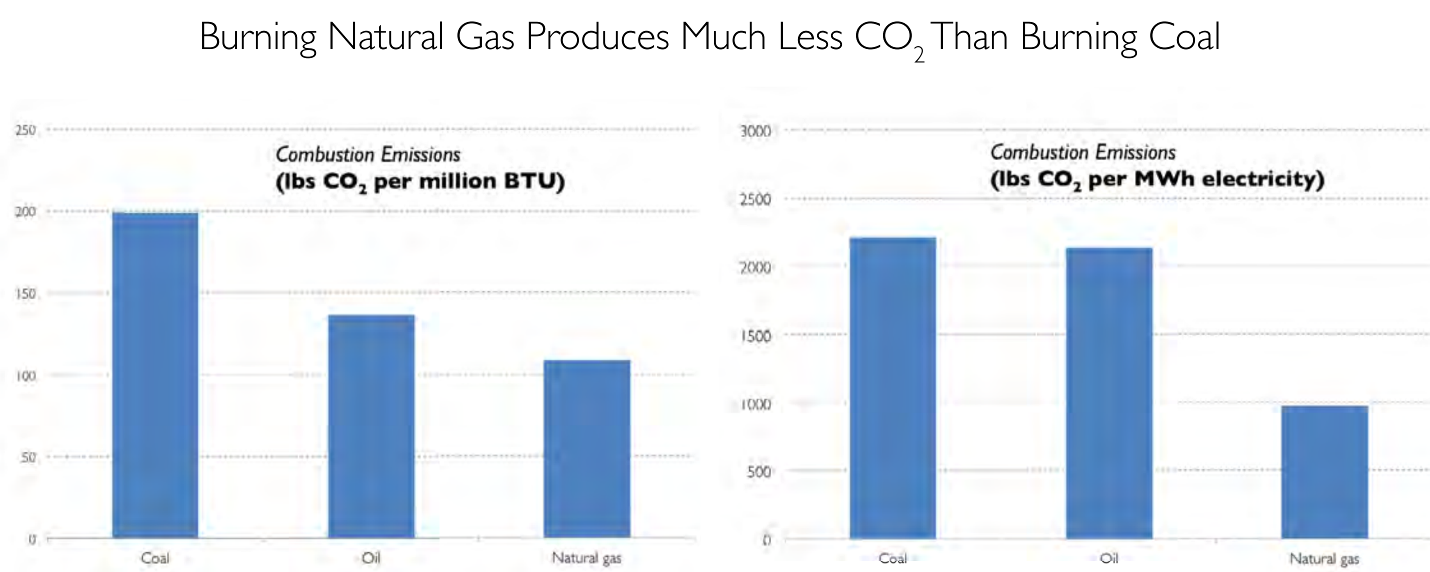


Figure 6. *Average emissions by fuel type from combustion of fossil fuels in the U.S. in 2011:*[7] *average emissions per million BTU (higher heating value) of fuel consumed (left) and average emissions per kWh of electricity generated (right).*

The recent and dramatic appearance of shale gas on the energy scene has raised questions about whether or not lifecycle greenhouse gas emissions for natural gas are as favorable as suggested by the simple comparison of combustion emissions alone. The main constituent of natural gas, methane (CH_4), is a much more powerful greenhouse gas than CO_2, so small leaks from the natural gas system can have outsized impacts on the overall lifecycle carbon footprint of natural gas. (See Box 2.)

In this report, we review what is known about methane leakage and other greenhouse gas emissions in the full lifecycle of natural gas, including shale gas. The natural gas supply system includes production of raw gas, processing of the raw gas to make it suitable for pipeline transport, transmission of gas in bulk by pipeline (often over long distances), and finally local distribution of the gas to users (Figure 7). The infrastructure is vast, with literally thousands of places where leaks of methane could occur. As of 2011, the U.S. natural gas system included more than half a million producing wells, several hundred gas processing facilities (Figure 8), hundreds of thousands of miles of gas transmission pipelines (Figure 9) and integrated storage reservoirs (Figure 10), more than a million miles of local distribution mains, and more than 60 million service pipe connections from distribution mains to users. The system delivered on average about 70 billion cubic feet of gas each day to users nationwide in 2012.

We discuss GHG emission estimates of the natural gas system made by the U.S. Environmental Production Agency (EPA), which annually produces official and detailed estimates of all U.S. greenhouse gas emissions. We then review other, non-EPA estimates, compare these with EPA's numbers, and highlight where the most significant uncertainties lie. We finish with an analysis that puts in perspective the significance of different methane leak rates for the global warming impact of natural gas substituting coal in electricity generation.

Each Stage in the Natural Gas Supply System is a Vast Infrastructure

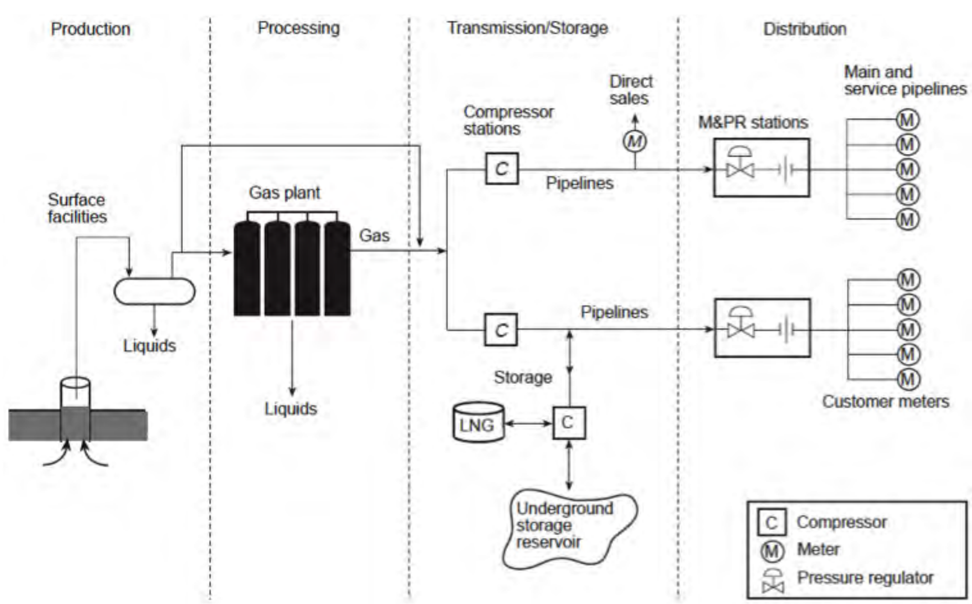


Figure 7. The U.S. natural gas supply system.[8]

There are Hundreds of Natural Gas Processing Plants in the Country

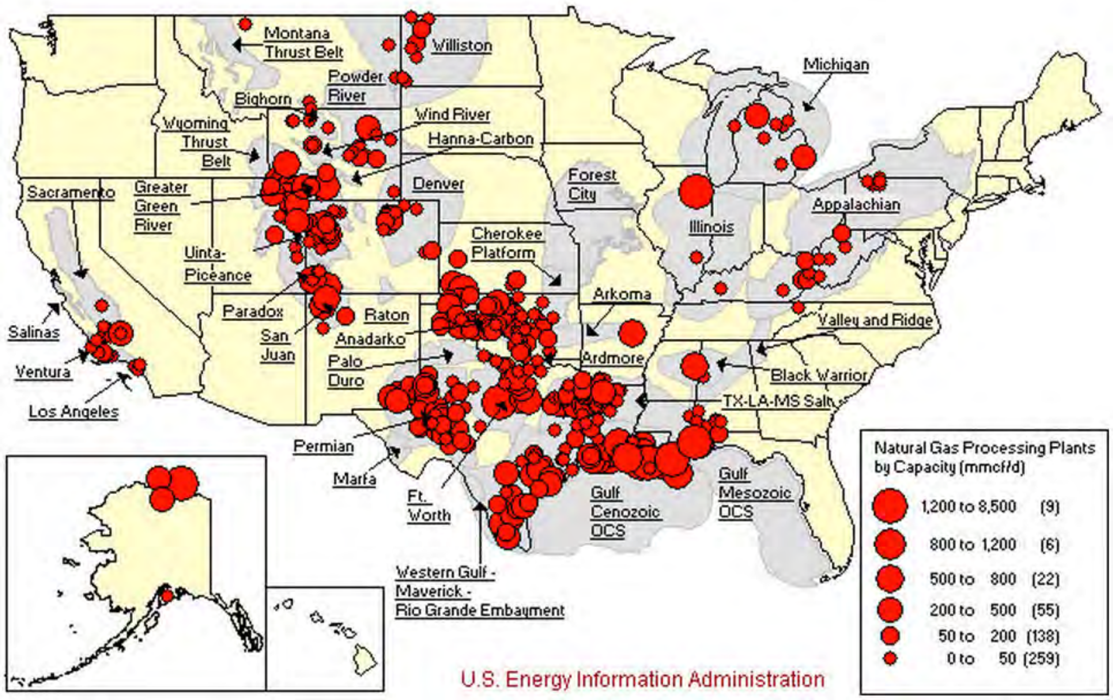


Figure 8. U.S. natural gas processing plants.[9]

Hundreds of Thousands of Miles of Gas Transmission Pipelines Cover the U.S.

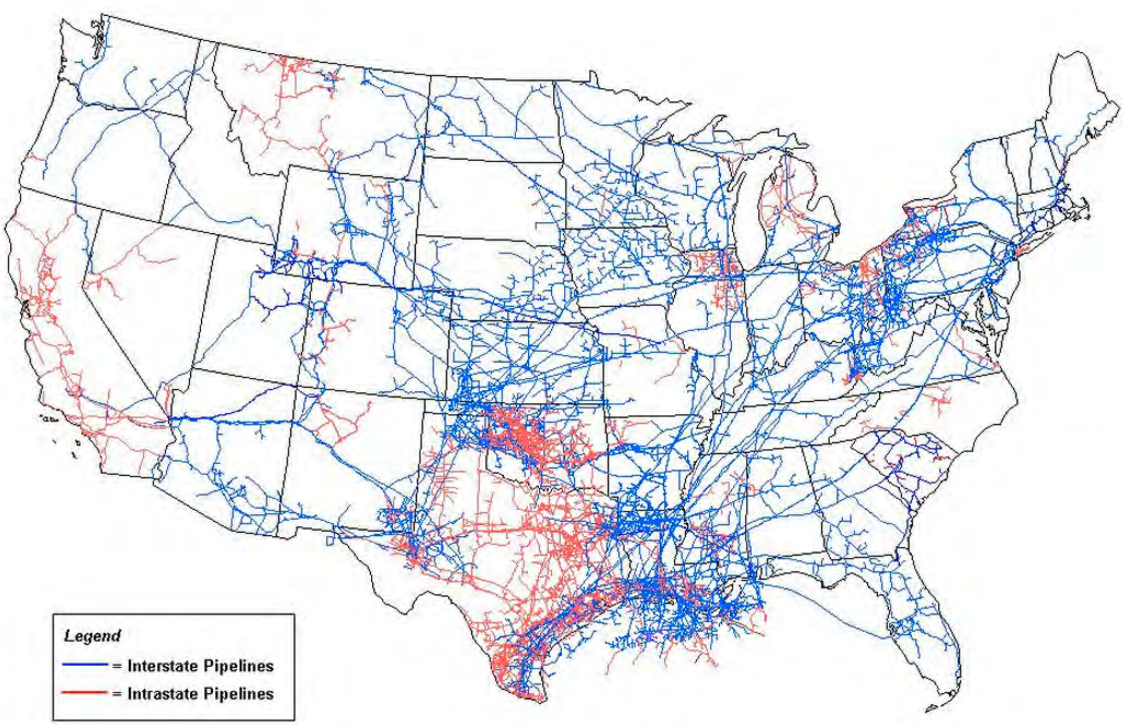
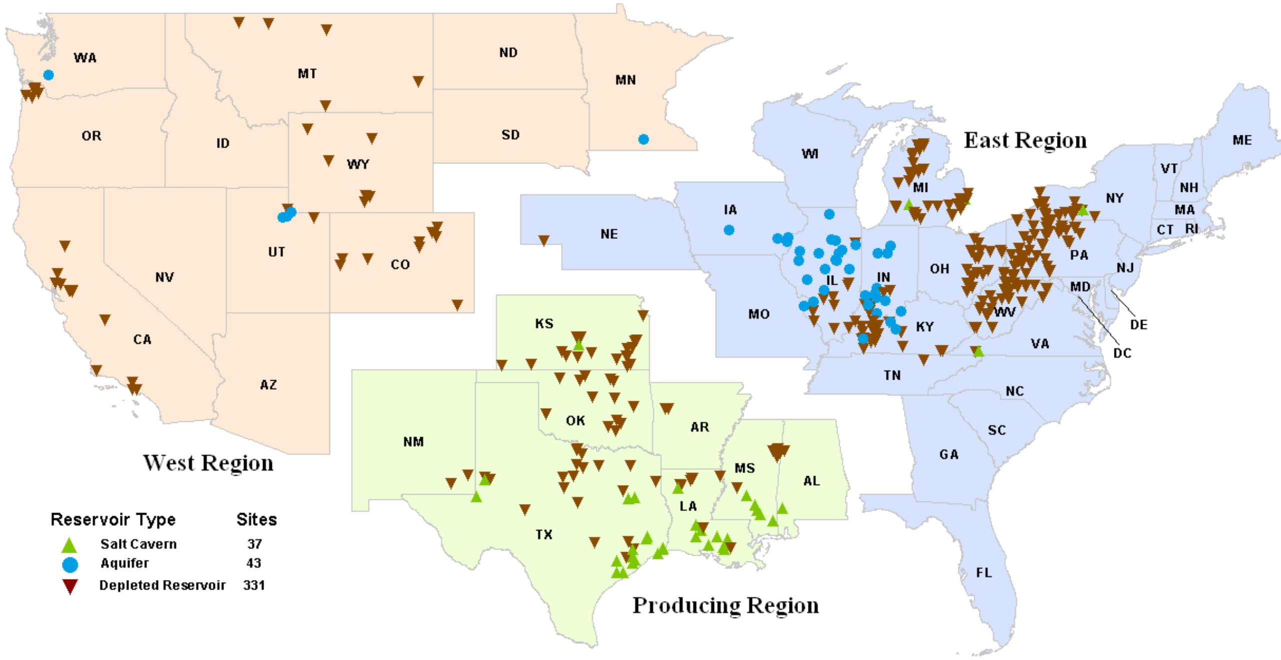


Figure 9. The U.S. natural gas transmission system (as of 2009).[10]

Natural Gas Storage Facilities Exist Across the Country

U.S. Lower 48 Underground Natural Gas Storage Facilities, by Type (December 31, 2010)



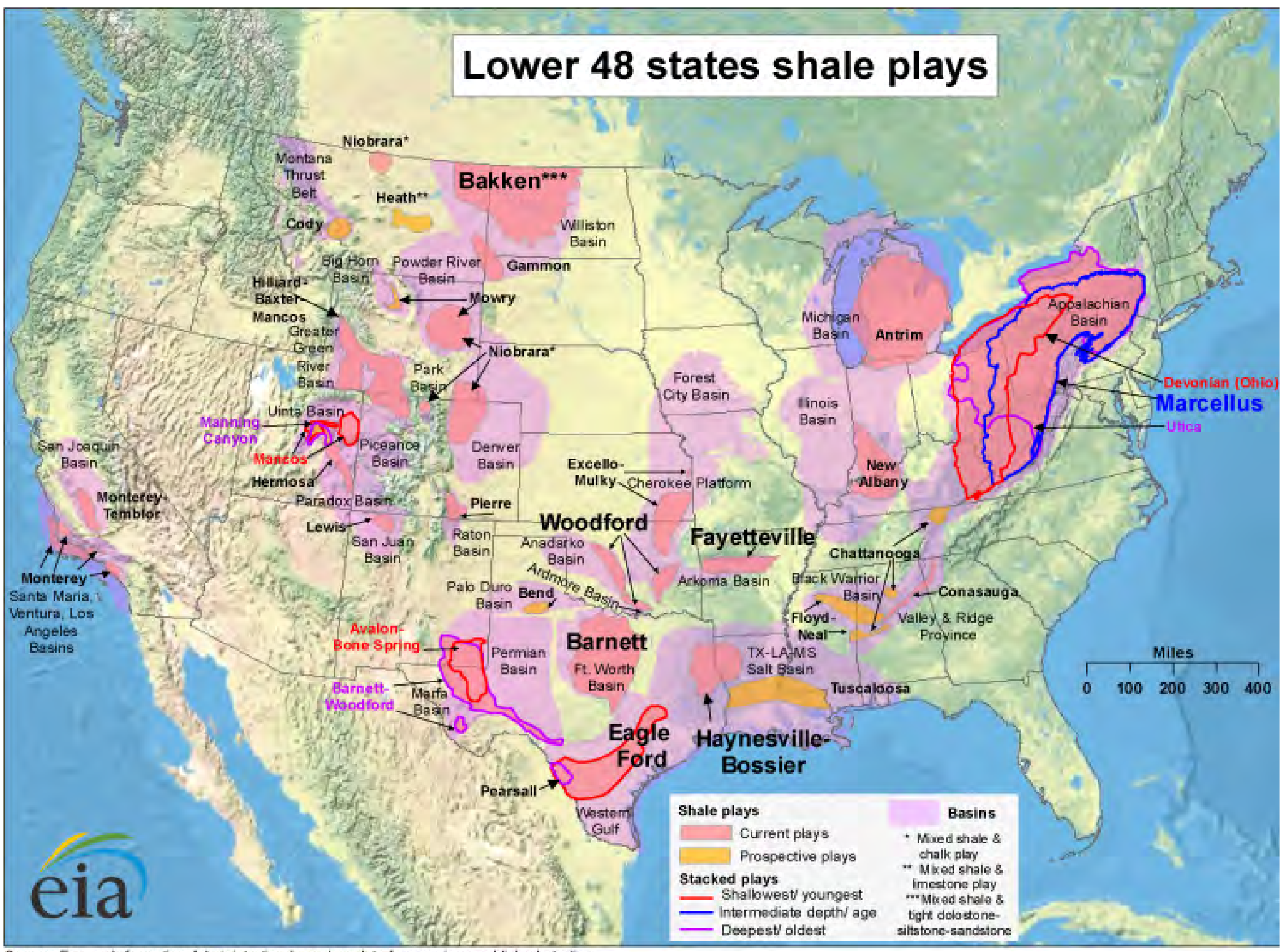
Note: Locations of storage facilities presented in the map are approximate. Some symbols representing storage facilities may overlap.
Source: U.S. Energy Information Administration, Form EIA-191A, "Annual Underground Gas Storage Report"

Figure 10. U.S. natural gas storage facilities. [11]

Box 1: Shale Gas

There are numerous gas-containing shale formations across the lower-48 states (Figure 11) and Alaska, with the largest shale gas reserves estimated to be in the Texas/Gulf Coast and Appalachian regions (Table 2). Alaska's resources are also large, but there are limited means in place today to transport this gas to users elsewhere. Shale gas production in the U.S. quadrupled between 2007 and 2011, with average annual growth of 44 percent. Seven states – Texas, Louisiana, Pennsylvania, Oklahoma, Arkansas, West Virginia and Colorado – accounted for about 90 percent of all shale gas production in 2011 (Figure 12).

Shale gas is formed by decomposition over millennia of organic (carbon-containing) plant and animal matter trapped in geologic sediment layers. Most shale formations are relatively thin and occur thousands of feet below the surface. Marcellus shales are typical, with thicknesses of 50 to 200 feet and occurring at depths of 4,000 to 8,500 feet.[4] The Antrium and New Albany formations (see Figure 11) are unusual in being thinner and shallower than most other U.S. shale deposits. Antrium and New Albany are also differentiated by the presence of water. This leads to the co-production of some water with shale gas from these formations, a complication not present for most wells in other shale formations (but a common occurrence for conventional (non-shale) gas wells – see discussion in Section 2.1 of liquids unloading).



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 11. Shale gas formations in the lower-48 states. [12]

Table 2. *Mean estimate by the U.S. Geological Survey of undiscovered technically recoverable shale gas resources by basin.* [13]

	Trillion cubic feet*
Gulf Coast	**124.896**
Haynesville Sabine	60.734
Eagle Ford	50.219
Maverick Basin Pearsall	8.817
Mid-Bossier Sabine	5.126
Appalachian Basin	**88.146**
Interior Marcelllus	81.374
Northwestern Ohio	2.654
Western Margin Marcellus	2.059
Devonian	1.294
Foldbelt Marcellus	0.765
Alaska North Slope	**40.589**
Shublick	38.405
Brookian	2.184
Permian Basin	**35.130**
Delaware-Pecos Basins Barnett	17.203
Delaware-Pecos Basins Woodford	15.105
Midland Basin Woodword-Barnett	2.822
Arkoma Basin	**26.670**
Woodford	10.678
Fayetteville-High Gamma Ray Depocenter	9.070
Fayetteville Western Arkansas	4.170
Chattanooga	1.617
Caney	1.135
Bend Arch-Forth Worth Basin	**26.229**
Greater Newark East Frac-Barrier	14.659
Extended Continuous Barnett	11.570
Andarko Basin	**22.823**
Woodford	15.973
Thirteen Finger Limestone-Atoka	6.850
Paradox Basin	**11.020**
Gothic, Chimney Rock, Hovenweep	6.490
Cane Creek	4.530
Michigan Basin (Devonian Antrim)	**7.475**
Illinois Basin (Devonian-Mississippian New Albany)	**3.792**
Denver Basin (Niobrara Chalk)	**0.984**
Total	**376.734**

* *One trillion cubic feet of gas contains about one quadrillion BTU (one quad).*

Seven States Accounted for 90 Percent of Shale Gas Production in 2011

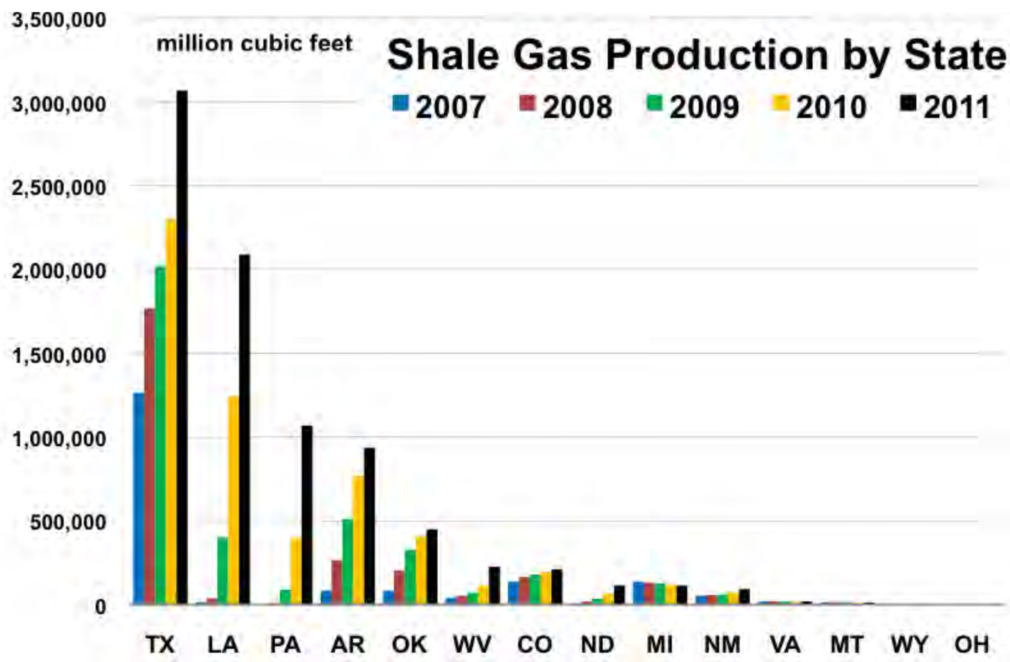


Figure 12. *Shale gas production in the U.S. has grown rapidly.* [14]

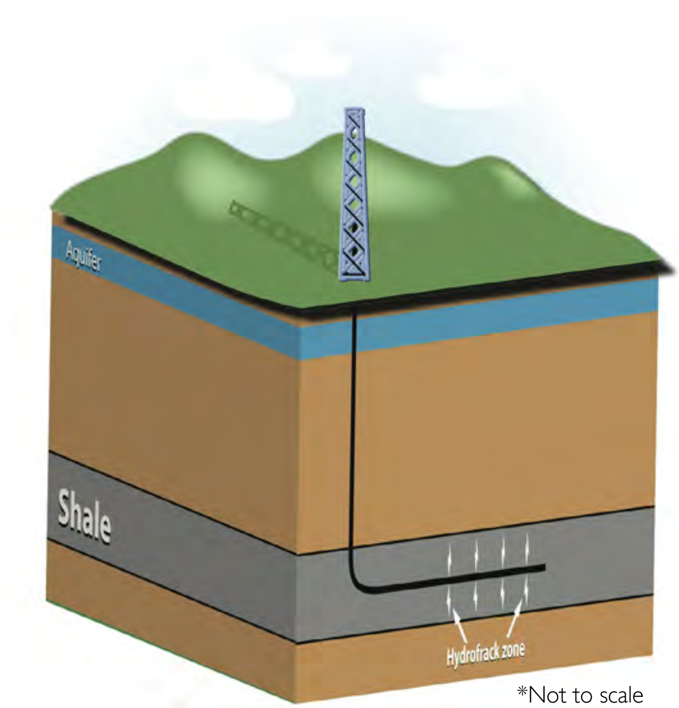


Figure 13. *Hydraulic fracturing combined with horizontal drilling allows accessing more of a thin shale formation.*

The existence of shale gas has been known for decades, but only with the development of hydraulic fracturing and horizontal drilling techniques in the mid-1990s did it become economically viable to produce. Hydraulic fracturing involves injecting a "fracking fluid" (water plus a "proppant" – typically sand – and small amounts of chemicals) at sufficiently high pressure into a well bore to crack the surrounding rock, creating fissures that can extend several hundred feet from the well bore. As the fluid flows back to the surface before the start of gas production, the proppant stays behind and keeps the fissures propped open allowing gas to escape to travel to the well bore.

"Fracking" was originally developed for use in vertically drilled wells, but shale gas production only began in earnest with the development of horizontal drilling, which when combined with fracking, enables access to much more of the volume of the thin, but laterally expansive shale formations (Figure 13). State-of-the art shale gas wells have horizontal holes extending 3000 feet or more from the vertical hole. Additionally, multiple horizontal holes are typically drilled from a single well pad, reducing overall drilling costs and enabling access to much more of a shale formation from a small area on the surface.

Box 2: The Global Warming Potential of Methane

Some molecules in the atmosphere allow solar energy to pass through to the earth's surface, but absorb energy radiated back from the earth and re-radiate that energy back to the surface, thereby making the earth's surface warmer than it would be without these "greenhouse gases" in the atmosphere. Two of the most important global warming molecules are carbon dioxide (CO_2) and methane (CH_4). Each has different global warming behavior and the term "Global Warming Potential" (GWP) is used to characterize their warming power. For convenience, the GWP of one pound (or kilogram) of CO_2 is defined to be equal to one, and GWP's of other gases are defined relative to the warming effect of CO_2.

The GWP of methane is determined by three factors: the warming properties of the methane molecule itself ("direct radiative forcing"), the warming resulting from interactions between methane and other molecules in the atmosphere ("indirect forcing"), and the effective lifetime of methane in the atmosphere. Considering the first two factors, the warming impact of one kilogram of methane is 102 times that of one kilogram of CO_2, according to the Intergovernmental Panel on Climate Change (IPCC). The third factor is relevant because the carbon in a molecule of methane emitted into the atmosphere will eventually react with oxygen and be converted to CO_2. The characteristic lifetime for methane molecules in the atmosphere is 12 years.[15] The lifetime for a CO_2 molecule in the atmosphere is far longer than this.

Because of the different lifetimes of CH_4 and CO_2, the GWP of CH_4 depends on the time period over which the impact is assessed. The longer the time after being emitted, the lower the GWP (Figure 14).

Thus, the timeframe used for any particular analysis is important. A shorter timeframe may be appropriate for evaluating GWP if the focus is on short-term warming effects or if the speed of potential climate change is of more interest than the eventual magnitude of change in the longer term. A longer horizon would be more appropriate when the interest is in changes that will be expressed more in the longer term, such as significant increase in sea level.

GWP values for methane that are considered the consensus of the climate science community are those published in the Assessment Reports of the Intergovernmental Panel on Climate Change (IPCC), Table 3. As understanding of the science of global warming has improved, the estimate of methane's GWP has increased. For example, the IPCC's Second Assessment Report and Third Assessment Report gave a 100-year GWP of 21 for methane, compared with 25 in the Fourth Assessment Report. More recent analysis has suggested that the GWP may be higher still,[16] but pending publication of the IPCC's Fifth Assessment Report (expected in 2013/2014), the scientific consensus GWP values are those in Table 3. Most analysts use the 100-year GWP to convert methane emissions into equivalent CO_2 emissions, since this is the time frame within which significant climate changes are expected to materialize, given current trends in emissions. Some analyses use a 20-year GWP, arguing that short-term effects are significant and demand significant near-term action to reduce emissions.[17] Alvarez et al.[18] suggest that varying time frames for assessing GWP may be useful. The utility of this approach is illustrated in Section 4 of this report.

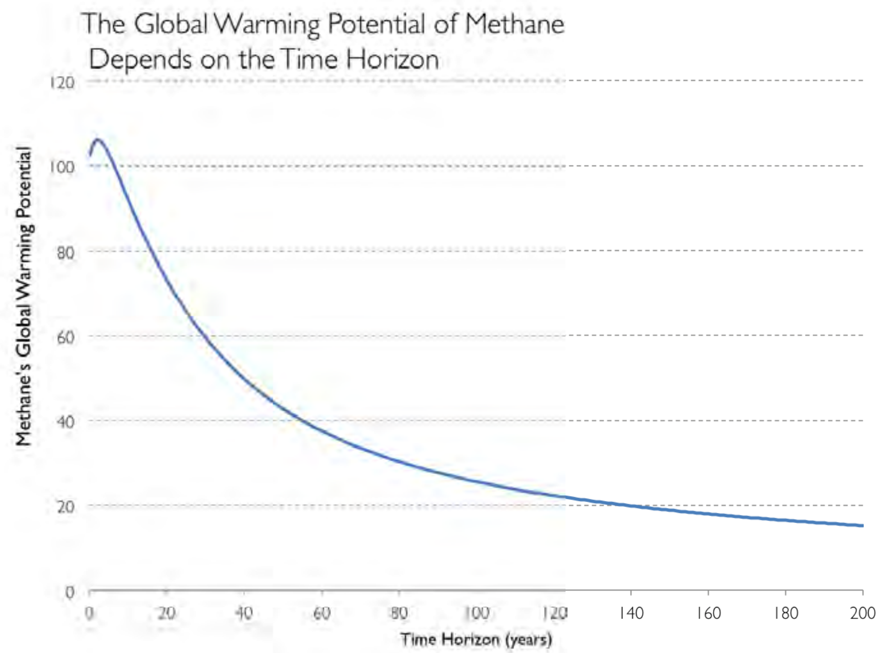


Figure 14. *The global warming potential (GWP) of methane relative to CO_2 for a pulse emission at time zero. This assumes a characteristic lifetime in the atmosphere of 12 years for methane and a lifetime for CO_2 as predicted by the Bern carbon cycle model.*[15] *(See Alvarez* et al.[18]*)*

Table 3. *The global warming potential for methane falls as the time horizon for its evaluation grows.*[15] *A 20-year GWP of 72 for methane means that 1 kilogram of methane gas in the atmosphere will cause the equivalent warming of 72 kilograms of CO_2 over a 20 year period. The GWP values here are consistent with those shown in Figure 14.*

	20-year GWP	100-year GWP	500-year GWP
GWP of CH_4 (methane)	72	25	7.6

2. EPA Estimates of GHG Emissions from the Natural Gas Supply System

Official estimates of U.S. greenhouse gas emissions since 1990 are published each year by the Environmental Protection Agency in its so-called Emissions Inventory[19]. The EPA recently released its 2013 inventory[20], reflecting estimates through 2011. Our discussion here also includes detail drawn from the 2012 inventory[21], reflecting estimates through 2010. We note key changes in methodology and results between the 2012 and 2013 inventories.

The EPA's estimate of total U.S. greenhouse gas (GHG) emissions in the 2012 inventory are shown in Figure 15 in terra-grams (Tg, or millions of metric tons) of CO_2 equivalent per year.[b] Nearly 80 percent of emissions are as CO_2 released from burning fossil fuels.

Methane leakage from the natural gas supply system also contributes[c]. In the 2012 inventory, EPA estimated that 10 percent of all GHG emissions in 2010 (in CO_2-equivalent terms) was methane, with leaks in the natural gas supply system accounting for one third of this, or 215 million metric tons of CO_2-equivalent (Figure 16). These methane emissions from the natural gas supply system correspond to 2.2 percent of methane extracted from the ground (as natural gas) in the U.S. in 2010[d]. The EPA adjusted this estimate significantly downward (to 144 million metric tons of CO_2-equivalent in 2010) in its 2013 inventory, corresponding to an estimated methane leakage rate in 2010 of 1.5 percent. This large adjustment from one EPA inventory to the next hints at the uncertainties involved in estimating the national methane leakage rate.

The EPA develops its emission estimates using a wide variety of data sources and by applying a multitude of assumptions. (See Box 3). EPA's estimated methane emissions in 2010 from the natural gas system are summarized in Table 4, as reported in the 2012 and 2013 inventories.

Methane was an Estimated 10 Percent of U.S. Greenhouse Gas Emissions in 2010

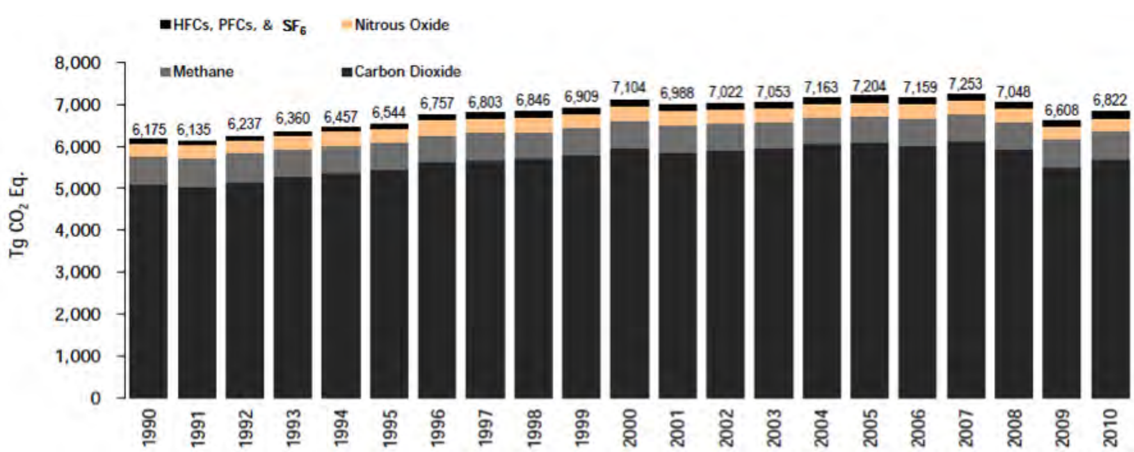


Figure 15. *U.S. greenhouse gas emissions as estimated by the Environmental Protection Agency.*[21]

[b] The EPA inventories use 100-year global warming potentials (GWPs) for non-CO_2 gases taken from the *Third Assessment Report* (1996) of the Intergovernmental Panel on Climate Change (IPCC), not from the most recent (2007) IPCC Assessment. The methane GWP value used by EPA in this inventory is 21. See Box 2 for discussion of GWP.

[c] Some naturally-occurring underground CO_2 is also vented to the atmosphere in the course of producing, processing, and transporting natural gas. EPA estimates these are much less one-tenth of one percent of the CO_2-equivalent emissions of methane.[23]

[d] U.S. natural gas consumption in 2010 was 24.1 trillion standard cubic feet according to the U.S. Energy Information Administration. Assuming the methane fraction in this gas was 93.4 percent, the value assumed by EPA in its emissions inventory,[23] and taking into account the fact that one standard cubic foot (scf) of methane contains 20.23 grams (or 20.23 metric tons per million scf), the total methane consumed (as natural gas) was 455 million metric tons. Considering a GWP of 21 for methane (as the EPA does), this is 9,556 million metric tons of CO_2-equivalent. The ratio of 215 (Table 4) to 9,556 gives a leakage estimate of 2.25 percent of methane consumed. The leakage as a fraction of methane extracted from the ground is $L = 1 - \frac{1}{(1+x)}$ where x is the leakage expressed as a fraction of methane consumption. For $x = 0.0225$, or $L = 0.0220$, or 2.2%.

Leaks in the Natural Gas System are Estimated to be One Third of Methane Emissions

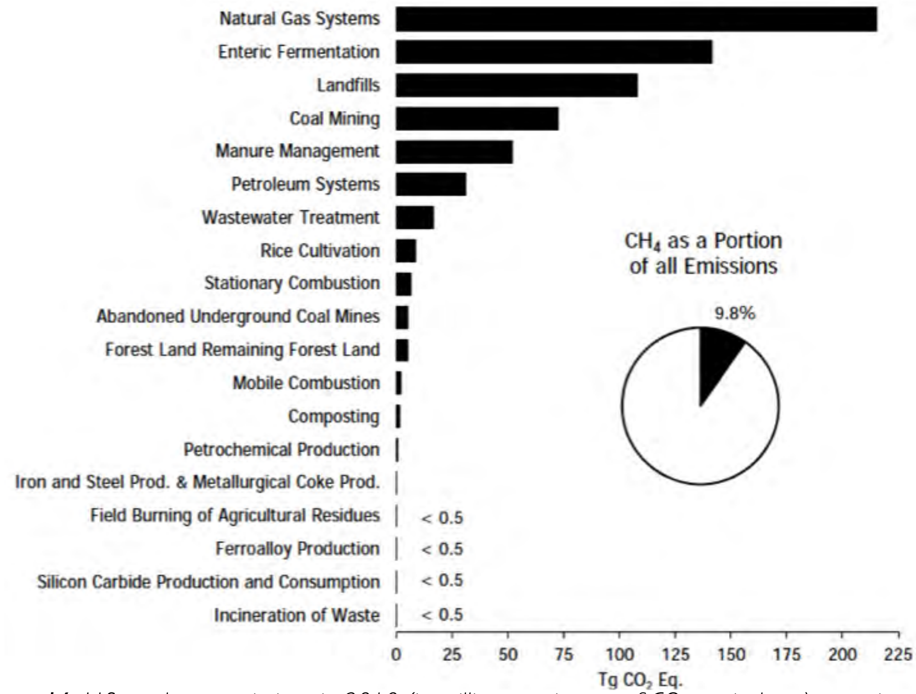


Figure 16. *U.S. methane emissions in 2010 (in million metric tons of CO_2 equivalents) as estimated by the Environmental Protection Agency.*[21]

Table 4. *EPA estimates of methane emissions in 2010 from the natural gas system in units of million metric tons of CO_2-equivalent (for a methane GWP of 21). Figures are from the 2012*[22] *inventory and the 2013 inventory.*[20]

	2012 Inventory	**2013 Inventory**
	million metric tons of CO_2-equivalent	
Natural Gas Production	**126.0**	**57.2**
Liquids unloading	85.7	5.4
Pneumatic device vents	12.8	
Gas engines	5.6	
Shallow water gas platforms	5.6	
Completions and workovers with hydraulic fracturing	3.8	16.7
Other production sources	12.5	
Natural Gas Processing	**17.1**	**16.5**
Reciprocating compressors	8.3	
Centrifugal compressors (wet seals)	4.9	
Gas engines	3.5	
Other processing sources	0.3	
Natural Gas Transmission and Storage	**43.8**	**41.6**
Centrifugal compressors (wet seals) (transmission)	15.7	
Reciprocating compressors (transmission)	12.8	
Engines (transmission)	4.7	
Reciprocating compressors (storage)	3.7	
Liquefied natural gas (LNG) systems	1.9	
Other transmission and storage sources	5.0	
Natural Gas Distribution	**28.5**	**28.3**
Meter/regulator (at city gates)	12.5	
Leaks from main distribution pipelines	9.3	
Leaks from service pipelines connected mains and users' meters	4.3	
Other distribution sources	2.4	
Total Natural Gas System (excluding end-use combustion)	**215.4**	**143.6**

Box 3: EPA's Methodologies for Estimating Methane Leakage from the Natural Gas Supply System

EPA arrives at most of the numbers in Table 4 using a "bottom-up" approach, which refers to estimating the emissions for a piece of equipment or process in the natural gas system as the product of an "emissions factor" and the estimated number of times this activity is repeated across the country each year. This is done for many different activities and the results are added up.[23] As an example, for reciprocating compressors used at gas processing plants (see Table 4), EPA estimated (for the 2012 inventory) that the total number of compressors was 5,028 in 2010 and that on average each compressor had an emission factor (leakage of natural gas to the atmosphere) of 15,205 cubic feet per day. Actual emissions per day will vary from one compressor to another[24], but the objective of the EPA inventory is to estimate emissions at a national level so an average emission factor is adopted. Multiplying the activity level (e.g., number of compressors) by the emission factor, by 365 days per year, and by the assumed methane fraction in the natural gas (which varies by region in the production and processing steps) gives the total annual estimated cubic feet of methane leaked from reciprocating compressors at gas processing plants in 2010. The EPA converts cubic feet per year to grams per year for purposes of reporting in the inventory. (A standard cubic foot of methane contains 20.2 grams.)

Many of EPA's emission factors were developed from a large measurement-based study of the natural gas system done in the mid-1990s.[25] Some of the factors have been updated since then.

For some activities, EPA adjusts its emissions estimates to account for various factors that lead to lower estimated emissions than when using default emission factors. For example, industry partners in EPA's Natural Gas STAR Program[26] use various technologies to lower emissions. In its 2012 inventory, EPA adjusted its national estimate of emissions to account for reductions by the STAR Program partners. As another example, some state regulations require the use of certain technologies to avoid venting of methane in parts of the natural gas system. The EPA adjusts

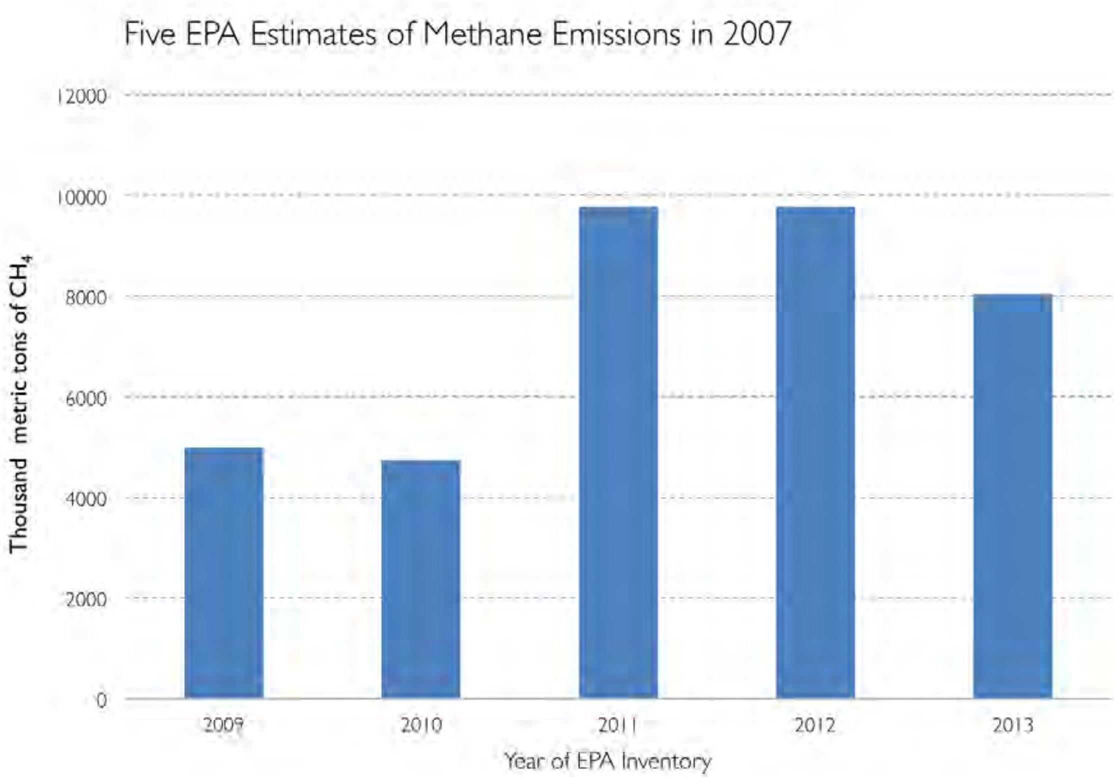


Figure 17. *Methane emissions from the natural gas supply system for 2007, as estimated in five different EPA Emission Inventories. Differences in data sources and methodologies account for the differences in estimated emissions.* [27]

its national estimates to account for the reduced emissions that are assumed to have been achieved in such states. For example, some states require gas wells created by hydraulic fracturing to use technology that eliminates venting of methane during well drilling and fracturing. In its 2012 inventory the EPA cites the example of Wyoming as having such regulations.[23] For its 2012 inventory, EPA estimated that in 2010 approximately 51 percent of all gas wells that were hydraulically fractured in the U.S. were in Wyoming. Accordingly, the 2012 inventory assumes that 51 percent of the estimated total number of hydraulically fractured gas wells in the U.S. had essentially no emissions associated with hydraulic fracturing. The 2013 inventory includes major changes in these assumptions, contributing to a significant increase in estimated emissions associated with hydraulically fractured wells (Table 4).

Completing the emissions inventory involves a massive effort on EPA's part, but is not without uncertainties. To help address these, EPA is continually evaluating and modifying its sources and assumptions in an effort to improve the accuracy of its estimates. When modifications are introduced into the estimation methodology, emissions estimates for all prior years (back to 1990) are revised to maintain a consistent set of estimates over time. These modifications sometimes result in large revisions in prior estimates. This is illustrated in Figure 17, which shows estimates of emissions from the natural gas system for a single year (2007) as made in five successive inventories. In its 2011 inventory, EPA made major adjustments in its data and methodologies from the prior year, resulting in a doubling in the estimate of methane emissions. No changes were made in the methodology for the inventory published in 2012, but changes in the 2013 inventory then resulted in a drop in emissions of nearly 20 percent.

2.1 Gas Production

Among the four stages that constitute the natural gas supply system (Figure 7), the production phase contributes the largest fraction of emissions in EPA's inventory (Table 4). It is also the stage for which the largest changes were made from the 2012 inventory to the 2013 inventory. Within the production phase, "liquids unloading" was the largest contributor in the 2012 inventory, but shrank by more than 90 percent in the 2013 inventory (Table 4). The category "completions and workovers with hydraulic fracturing" was the smallest contributor to production emissions in the 2012 inventory, but was more than quadrupled into the largest contributor in the 2013 inventory.

Liquids unloading refers to the removal of fluids (largely water) that accumulate in the well bore over time at a gas producing well. The fluids must be removed to maintain gas flow, and during this process, methane entrained with the fluids can be released to the atmosphere. Conventional gas wells tend to require more liquids unloading than shale gas wells due to differences in underground geology. From the 2012 to 2013 inventory EPA adjusted many of the assumptions used to estimate liquids unloading, including both the number of wells that use liquids unloading and the amount of methane emitted per unloading. Important considerations in the latter include the number of times each year that the average well is unloaded, the average volume of gas that is entrained with the liquids upon unloading (which varies by region), and the extent to which the entrained gas is captured for flaring (burning)[e] or for sale.[28]

A shale gas operation in Greene County, PA. (Nov 2010). Credit: Mark Schmerling via FracTracker.org.

[e] One pound of methane vented to the atmosphere has a GWP of 25, considering a 100-yr time horizon (see Box 2). If instead the 1 lb of methane were burned, 2.75 lbs of CO_2 would be produced. This amount of CO_2 has a GWP of 2.75. In this comparison, flaring methane instead of venting it reduces the global warming impact of the emission by a factor of 9.

Well completion refers to the process of finishing the creating of a shale gas well (including hydraulic fracturing) such that it can begin producing saleable gas. A workover is the re-fracturing of a shale gas well to maintain its productivity at an acceptable level. Different wells require different numbers of workovers during their producing life, with some wells not requiring any workovers. With hydraulic fracturing, before gas can flow freely to the surface, there is a fracking fluid flowback period (typically lasting several days) during which a substantial portion of the injected fluid returns to the surface, bringing some amount of gas with it. During the flowback period, if gas that surfaces with the returning fluid is not captured (for flaring or for sale) methane is released to the atmosphere. In the 2013 inventory, well completion and workover emissions more than quadrupled from the 2012 inventory primarily because of an increase in the estimate of the number of wells that were hydraulically fractured and a decrease in the assumed percentage of wells using "green completions" – technology that is employed at some wells to eliminate most well-completion emissions.

2.2 Gas Processing

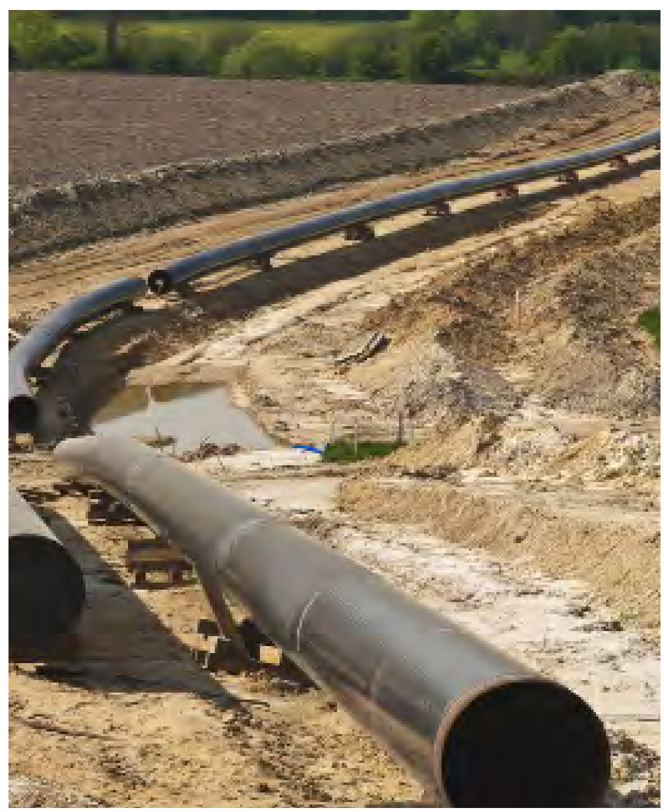
About 60 percent of all natural gas withdrawn from the ground in the U.S. each year undergoes processing[f] to make it suitable for entry into the gas transmission system.[29] Processing is estimated to account for the smallest contribution to methane emissions among the four stages of the natural gas system (Table 4).

Natural gas processing plant

Some 97 percent of methane emissions estimated to occur during gas processing are the result of leaks from compressors and gas-fired engines. (Gas-fired engines are used to drive reciprocating compressors. Incomplete combustion of gas in engines results in methane emissions.) The EPA estimates emissions based on the number of compressors and engines in use and an emissions factor (scf methane per day) for each. The 1990s EPA-sponsored study mentioned earlier[25] determined the emission factors and the number of compressors and engines operating in 1992. EPA's inventories for subsequent years use the same emission factors, and the number of compressors and engines is estimated by scaling the 1992 counts of these by the ratio of gas produced in the inventory year to the gas produced in 1992.

2.3 Gas Transmission and Storage

The natural gas pipeline transmission system in the U.S. includes more than 305,000 miles of pipe, some 400 storage reservoirs, over 1400 compressor stations (Figure 18) each usually with multiple compressors, and thousands of inter-connections to bulk gas users (such as power plants) and to distribution pipeline



Natural gas transmisison lines

[f] Processing typically removes "condensates" (water and hydrocarbon liquids), "acid gases" (H_2S, CO_2, and others), and sometimes nitrogen. On average the volume of gas after processing is 7 percent or 8 percent less than before processing.

Compression Stations Exist Throughout the Natural Gas Transmission System

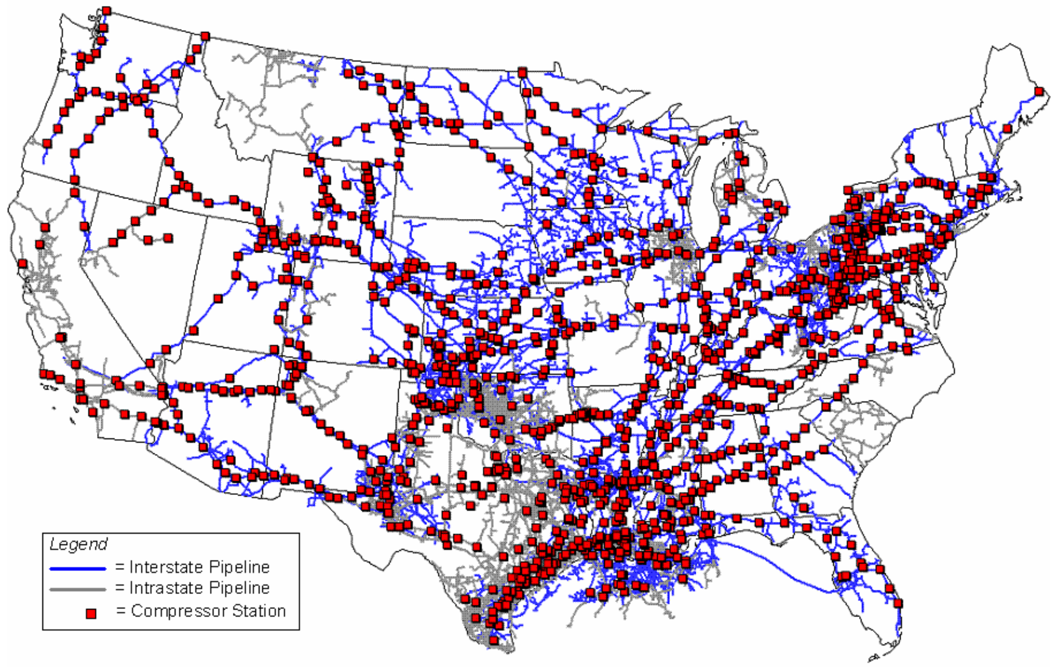
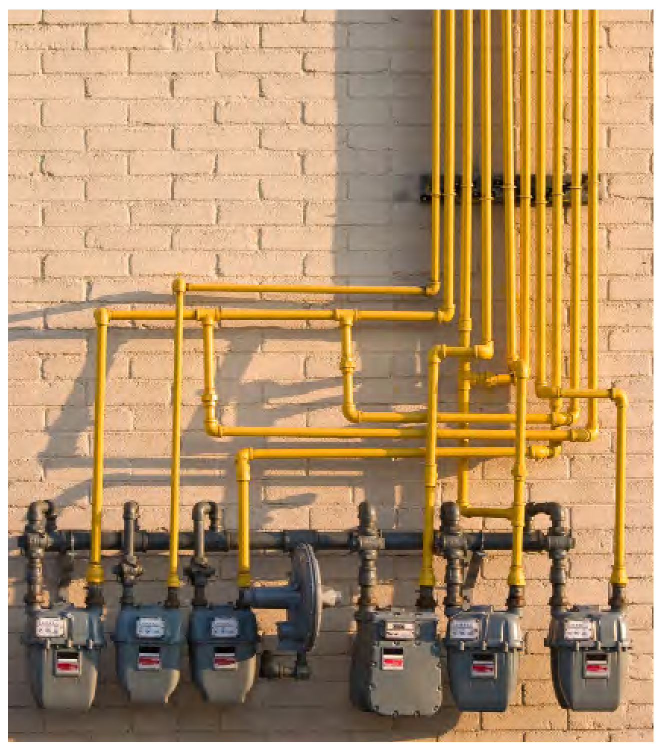


Figure 18. There are more than 1400 compressor stations in the U.S. natural gas transmission pipeline system. [30]

systems. The EPA estimates that most emissions from the transmission and storage stage come from compressors and engines, with only a small contribution from pipeline leakage (Table 4). Emissions are estimated using emission factors (e.g., scf/mile/yr for pipeline leaks or scf/day for compressor leaks), pipeline mileage, and equipment counts based largely on measurements made in the 1990s.[25] Variations in leakage associated with the large seasonal movements of gas in and out of storage reservoirs were not considered when measurements were made, and this may introduce some uncertainty.

2.4 Gas Distribution

More than 1,500 companies manage the distribution of natural gas to about 70 million customers.[31] The EPA's estimate of methane emissions from gas distribution are for local pipeline distribution systems (an estimated 1.2 million miles of pipe) that are fed by the main transmission pipelines and through which the majority of customers receive their gas. (This excludes most electric power plants and about half of large industrial customers, which are connected directly to a main transmission pipeline and account for perhaps half of all gas used.[g]) A gas-distribution system includes stations where gas is metered and pressure-regulated



Natural gas meters in the distribution system.

[g] In 2012, 36 percent of all gas used for energy was used in electric power generation and 33 percent was used in industry. Assuming all of the gas used for electric power and half of the gas used by industry was delivered via transmission pipelines, then approximately half of all gas used in the U.S. was delivered to users via transmission pipeline.

as it is transferred from a transmission line into a distribution network. It also includes the distribution pipelines, "services" (the pipe connecting a customer to a distribution main), and customer meters. The EPA estimates there are more than 63 million service connections in total, and it assumes no leakage occurs after the customer meter.

In the EPA 2012 inventory, the most significant leakage of methane is at the metering/regulating stations (Table 4). The EPA differentiates ten different station types according to function (metering and/or regulating) and the pressure of gas they each handle, and assigns a different emissions factor to each (ranging from 0.09 to 179.8 scf per station per year, based on measurements made in the 1990s[25]). The emissions factor for each type of station is multiplied by the estimated number of that type of station in operation in that year.

Leakage from distribution and service pipelines account for most of the rest of the estimated methane emissions from the distribution system. This leakage is calculated according to pipe type – cast iron, unprotected steel, protected steel, plastic, and copper – using a different emission factor for each type (in scf per mile per year) and service line (in scf per service per year). In the EPA inventory, cast-iron and unprotected steel pipes are assumed to have high leak rates, based on measurements made in the 1990s (Table 5)[h]. The inventory also estimates the number of miles of each type of pipe in the distribution system and the number of each type of service connection to customers based on data from the Pipeline and Hazardous Materials Safety Association (PHMSA)[32].

Table 5. Pipeline methane emission factors and pipeline mileage in EPA's 2013 inventory.[20]

	Annual Leak Rate (scf/mile)	**Miles of Pipe**
Distribution mains		
Cast iron	239,000	33,586
Unprotected Steel	110,000	64,092
Plastic	9,910	645,102
Protected steel	3,070	488,265
Transmission pipelines	**566**	**304,606**

[h] Protected steel refers to carbon steel pipes equipped with a special material coating or with cathodic protection to limit corrosion that can lead to leakage. (Cathodic protection involves the use of electrochemistry principles.) The use of cast iron and unprotected steel pipes, which are susceptible to corrosion, is declining. Nevertheless, there are still an estimated 100,000 miles of distribution pipe made of cast iron or unprotected steel and more than 4.2 million unprotected steel service lines still in use.[23]

3. Other Estimates of GHG Emissions from the Natural Gas Supply System

When the EPA made relatively large methodology adjustments in its 2011 inventory (Figure 17), they included a provision to separately calculate emissions from the production of shale gas and conventional gas. This adjustment, together with the growing importance of shale gas in the U.S. supply (Box 1), led others to develop greenhouse gas emission estimates for natural gas. Many technical reports[33-42] and peer-reviewed journal papers[17,43-51] have appeared, with emissions estimates varying from one to the next.

All of the published analyses have been made using methodologies similar to the bottom-up approach used in the EPA inventory calculations, but each study varies in its input assumptions. Because of the diversity of natural gas basin geologies, the many steps involved in the natural gas system, the variety of technologies and industry practices used, and, perhaps most importantly, the lack of measured emissions data, a large number of assumptions must be made to estimate overall emissions. As a consequence, different authors come to different conclusions about the magnitude of upstream GHG emissions. For example, some conclude that upstream emissions per unit energy for shale gas are higher than for conventional gas[17,46] and others conclude the opposite.[33,43,49] Many of the authors rely on the same two information sources for many of their input assumptions,[52,53] leaving just a few key assumptions mainly responsible for differences among results.

Table 6. *Estimates of upstream methane and CO_2 emissions for conventional gas and shale gas, with comparison to EPA estimates for the natural gas supply system as a whole.* (Emissions from gas distribution are not included here.)*

UPSTREAM EMISSIONS	**Jiang[47]**		**NETL[33]**		**Hultman[46]**	**Stephenson[48]**		**Burnham[43]**		**Howarth[17]**		**Best[49]**		**EPA**
Methane, $kgCO_2e$/GJ(LHV)	Conv	Shale	Conv	Shale	Shale	Conv	Shale	Conv	Shale	Conv	Shale	Conv	Shale	All
Well pad construction		0.1	0.2	0.1								0.16	0.16	
Well drilling		0.2				0.3	0.3	1.6	1.0		1.5	0.23	0.2	
Hydraulic fracturing water		0.3					0.3						0.26	
Chemicals for hydraulic fracturing		0.1											0.07	
Well completion		1.0		1.3	4.7	0.4	1.6		0.8		8.6	0.18	1.2	
Fugitive well emissions	3.4	3.4	1.8	1.8	2.1	0.9	0.9	3.6	3.6	5.0	5.0	2.70	2.70	
Workovers				4.6	4.7				1.5				1.20	
Liquids unloading	2.5		6.6					5.9		0.6		3.80		
Production emissions	5.9	5.1	8.6	7.8	11.5	1.6	3.1	11.1	6.9	5.6	15.1	7.1	5.8	6.8
Processing emissions	1.5	1.5	1.2	1.2	0.6	0.5	0.5	0.8	0.8	0.4	0.4	1.8	1.8	0.9
Transmission emissions	1.9	1.9	2.3	2.3	1.8	1.7	1.7	0.9	0.9	6.8	6.8	1.9	1.9	2.4
Total upstream methane emissions	**9.3**	**8.5**	**12.1**	**11.3**	**13.9**	**3.8**	**5.3**	**12.8**	**8.6**	**12.8**	**22.3**	**10.8**	**9.5**	**10.0**
Carbon dioxide, $kgCO_2$/GJ(LHV)														
Flaring	0.4	0.4	1.8	2.0				0.4	0.4			0.6	0.6	
Lease/plant energy	3.7	3.7				2.8	2.8	4.3	4.1	4.1	4.1	3.2	3.2	
Vented at processing plant	1.0	1.0	0.2	0.2				0.8	0.8			1.2	1.2	
Transmission compressor fuel	0.4	0.4	0.4	0.4		0.2	0.2	0.3	0.3	0.6	0.6	0.4	0.4	
Total upstream CO_2 emissions	**5.5**	**5.5**	**2.4**	**2.6**		**3.0**	**3.0**	**5.8**	**5.6**	**4.7**	**4.7**	**5.4**	**5.4**	**4.6**
TOTAL UPSTREAM, $kgCO_2e$/GJ(LHV)	**14.8**	**14.0**	**14.5**	**13.9**	**13.9**	**6.8**	**8.3**	**18.6**	**14.2**	**17.5**	**27.0**	**16.2**	**14.9**	**14.6**

** Methane leakage has been converted to $kgCO_2e$ using a GWP of 25. Numbers in all but the EPA column are taken from Table SI-5 in the supplemental information for the paper by Weber and Clavin.[49] Numbers in the EPA column are my estimates based on the 2012 inventory (Table 4, but adjusted to GWP of 25) and total 2010 U.S. natural gas end-use consumption for energy.[54] CO_2 emissions in the EPA column include estimates from the EPA 2012 inventory[23] plus emissions from complete combustion of lease and plant fuel in 2010 that I have estimated based on EIA data.[55]*

3.1 Leakage During Gas Production, Processing, and Transmission

A careful analysis by Weber and Clavin[49] encapsulates well the diversity of estimates of upstream emissions that have been published relating to the gas production, processing, and transmission stages. They analyzed in detail the assumptions made in six different studies and took care to normalize estimates from each study to eliminate differences arising from inconsistent assumptions between studies, such as different values for methane GWP, methane fraction in natural gas, and other variables. Weber and Clavin excluded distribution emissions estimates from their comparisons.

Table 6 shows their normalized estimates in units of grams of CO_2-equivalent per megajoule of lower heating value (MJ_{LHV}) natural gas energy,[i] assuming a methane GWP of 25. "Best" refers to what Weber and Clavin consider their best estimate based on their analysis, including a Monte Carlo uncertainty analysis, of all of the studies. For comparison, I have added estimates of emissions based on the EPA 2012 inventory (year 2010 values, adjusted for a methane GWP of 25).

Figure 19, taken from Weber and Clavin, graphs numbers from Table 6, and shows estimated uncertainty ranges.[j] For shale gas five of the seven estimates are similar (13.9 to 14.9 gCO_2e/MJ_{LHV}), with estimates based on Howarth[17] and Stephenson[48] being markedly higher and lower, respectively. Uncertainty ranges in most cases overlap each other. For conventional gas, the estimates based on Burnham and Stephenson represent the highest and lowest estimates, with the others falling in the range 14.5 to 17.5 gCO_2e/MJ_{LHV}.

As seen from Table 6, the largest upstream CO_2 emissions are due to combustion of natural gas used for energy in processing and transmission stages (lease and plant fuel plus transmission compressor fuel). The numbers in Table 6 suggest that the global warming impact of upstream CO_2 emissions accounts for about one third of the combined impact of CO_2 plus methane,

Estimates of Upstream Emissions in the Natural Gas System Vary Widely

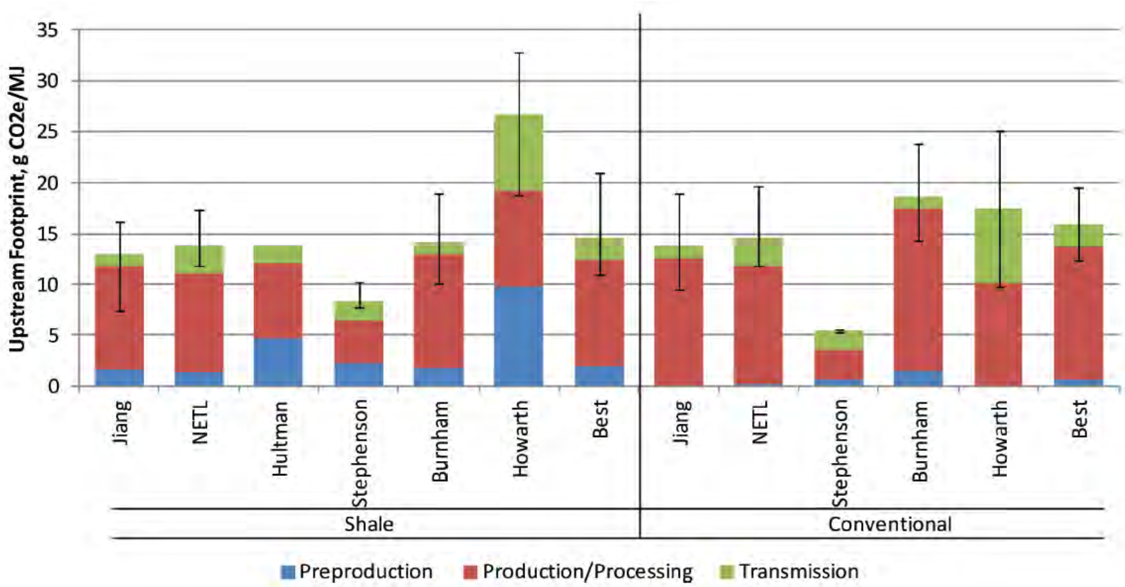


Figure 19. *A diversity of estimates exist in the literature for GHG emissions associated with natural gas production, processing, and delivery. This graph, from Weber and Clavin[49] (and consistent with numbers in Table 6, but using different sub-groupings) shows upstream emissions in units of grams of CO_2e/MJ_{LHV} of natural gas, excluding emissions associated with natural gas distribution. Ranges of uncertainty are also indicated. "Best" refers to Weber and Clavin's own estimates.*

[i] The energy content of a fuel can be expressed on the basis of its lower heating value (LHV) or its higher heating value (HHV). The difference between the LHV and HHV of a fuel depends on the amount of hydrogen it contains. The heating value of a fuel is determined by burning it completely under standardized conditions and measuring the amount of heat released. Complete combustion means that all carbon in the fuel is converted to CO_2 and all hydrogen is converted to water vapor (H_2O). The heat released as a result of these oxidation processes represents the LHV of the fuel. If the water vapor in the combustion products is condensed, additional heat is released and the sum of this and the LHV represents the HHV of the fuel. For fuels with low hydrogen content, like coal, relatively little water vapor forms during combustion, so the difference between LHV and HHV is not especially large. The high hydrogen content of methane, CH_4, means the difference between LHV and HHV is more significant. Delivered natural gas, which is mostly methane, has an HHV that is about 11 percent higher than its LHV.

[j] Category groupings in Figure 19 are different from those in Table 6, but overall totals are the same.

a not insignificant fraction. However, this is based on assuming a methane GWP of 25 (100-year time frame). Were a higher GWP value (shorter time frame) to be considered, methane would have a higher impact, and the impact of CO_2 would be correspondingly reduced.[k]

Leaving aside the upstream CO_2 emissions for the moment, it is possible to remove the complication introduced by the choice of GWP value by expressing the methane emissions in physical terms as a percent of total methane extracted from the ground. This total methane leakage during production, processing, and transmission, as estimated in the various studies, ranges from an average of under 1 percent to 2.6 percent for conventional gas and from 1 percent to 4.5 percent for shale gas (Table 7). The EPA 2012 inventory estimate corresponds to a leakage of 2 percent (which increases to 2.2 percent if leakage from the distribution system is included). The methane leak rates corresponding to the lower and upper ends of the uncertainty ranges for the "Best" case in Figure 19 are 0.9 percent to 3.4 percent for conventional gas and 0.7 percent to 3.8 percent for shale gas. The uncertainty range for shale gas in the highest emissions case (Howarth) corresponds to leakage of 3.3 percent to 7.0 percent[l] (not shown in Table 7). Notably, the lower bound of this range is nearly as high as the upper end of the uncertainty ranges for any of the other shale gas results shown in Figure 19. (Howarth's range for conventional gas is 1.6 percent to 3.8 percent.)

Some perspective on the estimates in Table 7 is provided by O'Sullivan and Paltsev,[50] who estimate leakage during completion (including hydraulic fracturing) of shale gas wells in the same shale basins (Barnett and Haynesville) as considered by Howarth.[m] O'Sullivan and Paltsev drew on gas production data for 1785 shale gas wells that were completed in 2010 in the Barnett formation and 509 in the Haynesville formation. They estimated well completion emissions by assuming that for each well the "flowback" of hydraulic fracking fluid (see Section 2.1) occurs over a 9 day period and that the amount of gas brought to the surface with the fluid during this period rises linearly from zero at start to a maximum at the end of the period equal to the peak gas production rate reported for the well. They further assume that current field practice for gas handling is represented by an assumption that, on average, 70 percent of the flowback gas is captured for sale, 15 percent is flared at the wellhead (converted to CO_2), and 15 percent is vented without flaring. They acknowledge the uncertainties in this latter assumption, stating that "significant opaqueness surrounds real world gas handling practices in the field, and what proportion of gas produced during well completions is subject to which handling techniques." Their estimate of average per-well emissions in the Barnett formation is 7 times less than the estimate of Howarth *et al.*,[17] who assume that all flowback gas is vented. For the Haynesville formation, the difference between the estimates in the two studies is a factor of 30.

*Table 7. Upstream methane leakage (excluding leakage in distribution systems) as a percentage of methane production for the studies shown in Table 6 and Figure 19.**

	Jiang		NETL		Hultman	Stephenson		Burnham		Howarth		Best		EPA
	Conv	Shale	Conv	Shale	Shale	Conv	Shale	Conv	Shale	Conv	Shale	Conv	Shale	All
	Methane leakage (percentage of methane production)													
Production	1.2	1.0	1.7	1.5	2.2	0.3	0.6	2.2	1.3	1.1	3.0	1.4	1.1	1.37
Processing	0.3	0.3	0.2	0.2	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.4	0.4	0.19
Transmission	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.2	0.2	1.4	1.4	0.4	0.4	0.48
TOTAL	**1.9**	**1.7**	**2.4**	**2.2**	**2.7**	**0.7**	**1.0**	**2.5**	**1.7**	**2.6**	**4.5**	**2.1**	**1.9**	**2.02**

** Based on Table 6 and (for all but the EPA numbers) energy contents of produced gas per kg of contained methane reported by Weber and Clavin:[49] Jiang (50 $MJ_{LHV}/kgCH_4$), NETL (48.8), Hultman (48.2), Stephenson (47.3), Burnham (48.6), Howarth (50.0), and Best (48.8). The EPA estimate assumes a gas energy content of 51.5 $MJ_{LHV}/kgCH_4$ for consistency with EPA numbers in Table 6.*

[k] For example, with GWP = 72 (20-year time frame), CO_2 emissions would be less than 15 percent of total CO_2-equivalent emissions in most cases.
[l] The paper by Howarth, *et al.*[17] gives total estimated system leakage fractions (including leakage in distribution), of 3.6 percent to 7.9 percent. I have estimated the range for distribution leakage, based on discussion in that paper, to be 0.35 percent to 0.9 percent and removed this from the original Howarth *et al.* estimates to provide a consistent figure for comparison with the others' results.
[m] O'Sullivan and Paltsev also made estimates for wells in the Fayetteville, Marcellus, and Woodford formations.

Table 8. Comparison of estimates for methane leakage during completion of shale gas wells in two different formations.

	O'Sullivan[50] kgCH_4 per well completion	Howarth[17](as quoted by O'Sullivan[50]) kgCH_4 per well completion
Barnett formation	35.1	252
Haynesville formation	151.3	4638

O'Sullivan and Paltsev report an estimate of total methane emissions from all U.S. shale well completions in 2010 of 216,000 metric tons of methane. EPA's estimate for 2010 using its 2012 inventory methodology was close to this value (181,000 tons), but using the methodology reported in its 2013 inventory, the emissions are more than triple this value (795,000 tons). (See Table 4.) Thus, there continues to be significant uncertainty about what average well completion emissions are.

Uncertainties may be reduced in the future when a new EPA rule takes effect starting in 2015. The rule requires all new hydraulically fractured shale gas wells to use commercially-established "green completion" technologies to capture, rather than vent or flare, methane. The EPA estimates that 95 percent or more of the methane that might otherwise be vented or flared during well completion will be captured for sale. Wyoming and Colorado already require green completions on all shale wells.

The new EPA rule is significant because there is general agreement that methane leakage in the gas production phase is among the most significant leakages in the entire natural gas system, a conclusion supported by some recent measurements of the concentrations of methane in the air above gas wells,[56,57,58] including a reported leakage rate of 9 percent from oil and gas production and processing operations in the Uinta Basin of Utah,[59] and 17 percent of production in the Los Angeles Basin.[60] Such estimates, based on "top-down" measurements, involve large uncertainties, but draw attention to the need for more and better measurements that can help reduce the uncertainty of estimated leakage from natural gas production. Some such measurements are underway.[61]

Well completion emissions are only one of several important leakage components in gas production. In Weber and Clavin's review, they identified six assumptions that contribute most significantly to variations in overall estimates from one study to another: *i)* the number of workovers per shale-gas well, *ii)* the well completion and workover emissions factor, *iii)* the liquids unloading emissions factor (for conventional gas wells), *iv)* the rate of fugitive emissions at the wellhead, *v)* the fugitive emissions during gas processing, *vi)* and the EUR.

The last of these requires some explanation. Emissions that occur only once over the lifetime of a well (e.g., well completion emissions) or only a limited number of times (e.g, liquids unloading) are converted into an estimate of emissions per unit of gas produced by dividing the estimated emission by the total gas production from the well over its full lifetime – the well's estimated ultimate recovery (EUR). Because the shale gas industry is still young, there is a limited production history with wells on which to base EUR estimates. O'Sullivan and Paltsev[50] have noted that there is "appreciable uncertainty regarding the level of ultimate recovery that can be expected from shale wells." The challenge of determining what EUR to use to accurately represent leakage per unit of gas production is compounded by the large and inherent variability in EUR across different wells. Mean EUR values estimated by the U.S. Geological Survey[62] for wells in different shale formations (based on decline-curve analysis using a limited amount of monthly production data), vary by a factor of 60 from largest to smallest. Within a given formation, the maximum estimated EUR can be up to 1,000 times larger than the estimated minimum EUR. In Weber and Clavin's "Best" estimate in Figure 19, the uncertainty range in emissions results in part from assumed average EUR values from a low of 0.5 to a high of 5.3 billion cubic feet per well. (The authors state that an EUR of 2 bcf is the "most likely" value.) This order-of-magnitude range in EUR highlights the (significant) uncertainty introduced in using EUR to estimate leakage fractions.

3.2 Leakage from Gas Distribution Systems

Studies reviewed in the previous section were concerned primarily with gas leakage in connection with power generation. Leakage from gas distribution systems was excluded in those studies because most gas-fired power plants receive gas directly from the gas transmission system. But gas used in residential and commercial buildings and smaller industrial facilities – about half of all gas used – passes through the distribution system before reaching a user. The EPA 2012 inventory estimates that leaks in the distribution system account for 13 percent of all upstream methane leakage (Table 4), or less than 0.3 percent of methane produced. But the sheer size and diversity of the gas distribution infrastructure – over a million miles of varying-vintage distribution mains, more than 60 million service pipelines connecting the mains to users, the large number of metering and pressure-regulating stations found at the interface of transmission and distribution systems and elsewhere – and the limited number of leakage measurements that have been made suggest that there could be large uncertainties in the EPA estimate.

One study[63] in Sao Paulo, Brazil, which measured leakage from cast-iron distribution mains, highlights the uncertainties. In the 1950s, cast-iron was the standard material used for distribution mains in the U.S. Sao Paulo has a cast-iron distribution network comparable to or younger than the U.S. cast-iron network. Much of the cast iron in the U.S. has been replaced with less-leaky steel or plastic in recent decades, but there are still an estimated 35,000 miles of cast-iron pipe still in everyday use in the U.S. When cast-iron pipes leak it is typically at the joints where 12-foot long pipe sections are fitted together in "bell and spigot" arrangements. The jute fiber that was routinely used as the sealant dries out over time, leading to leakage. There are about 15 million such joints in the U.S. distribution system today. Comgas, the natural gas utility in Sao Paulo, measured leak rates in over 900 pipe sections in their network. Based on these measurements, they conservatively estimated an average annual leak rate of 803,548 scf per mile of pipe, more than triple the emission factor used in the 2012 EPA inventory (Table 5).[n] In some 15 percent of the Comgas measurements, emissions were two million scf per mile or higher.

New "top-down" measurement approaches are being pursued to try to improve estimates of leakage from the distribution system. These involve measuring methane concentrations in the air above a defined region and analyzing these in conjunction with wind patterns and other variables to try to estimate what leakage originated from the natural gas system. Recent measurements have identified elevated methane concentrations above urban streets in Boston,[64] San Francisco,[65] and Los Angeles.[66] Work is ongoing in acquiring more measurements to help estimate associated leak rates.[61,65]

4. Natural Gas vs. Coal in Electricity Generation

The growing use of natural gas for power generation in place of coal makes it particularly important to understand methane leakage and its global warming implications. This issue has been discussed by others[17,33,43,46,47,49] with varying conclusions due in large part to different methane leakage rate assumptions (as discussed in Section 3.1). In the absence of greater certainty about actual methane leakage rates, it is especially informative to understand the prospective global warming impact of different overall leakage rates when natural gas electricity displaces coal electricity.

Figure 20 shows total lifecycle greenhouse gas emissions associated with natural gas (independent of end use) per unit of energy for different assumed total system leakage rates. The red portion of each bar

[n] Comgas subsequently implemented an effort to place plastic inserts in their cast-iron distribution mains to reduce leakage. The extent to which such leak mitigation measures have been applied in the U.S. is difficult to determine. Some U.S. gas utilities utilize pipe-crawling CISBOTs (cast-iron joint sealing robot) that add sealant to jute-packed joints by self-navigating through distribution mains, thereby reducing the need for more costly excavation to repair or replace pipes.[65,63]

Even Small Methane Leaks Can Have a Large Global Warming Impact in the Short Term

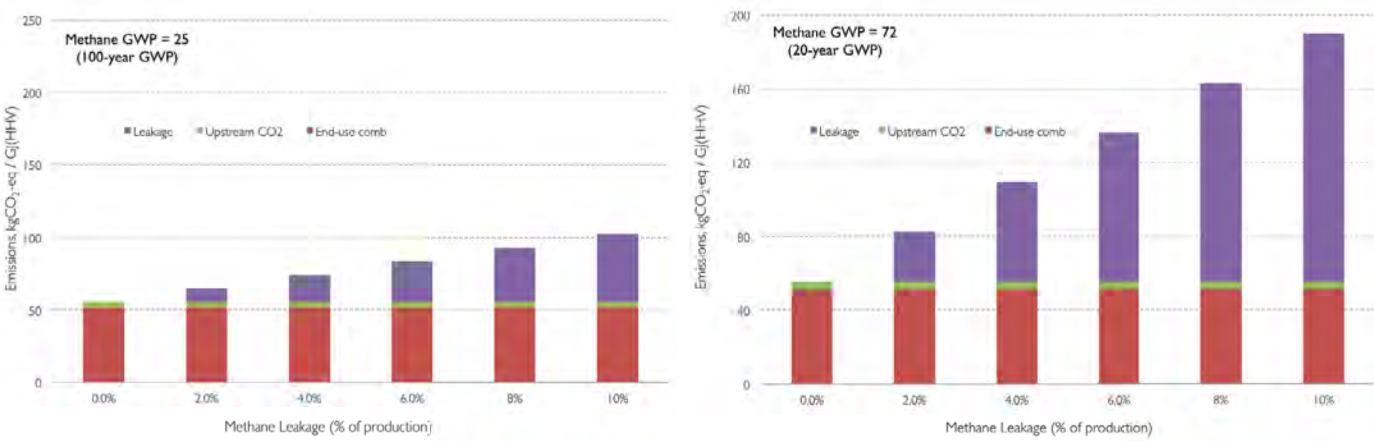


Figure 20. *Estimates of greenhouse gas emissions from natural gas production, processing, delivery, and end-use for different assumed rates of upstream methane leakage.*

represents end-use combustion emissions.[o] Purple is the contribution from methane leakage corresponding to leakage fractions on the x-axis.[p] Green represents the comparatively small direct "upstream" CO_2 emissions. (The latter result from combustion of natural gas used as fuel at gas processing plants and in the gas transmission system and from CO_2 that originated underground and was removed from the natural gas during gas processing.[q])

The left and right graphs include the same physical emissions, but represent these using 100-year and 20-year GWPs for methane, respectively. When there is leakage the choice of time horizon affects the global warming impact estimate tremendously, since the GWP for a 20-year time horizon is nearly triple the GWP for a 100 year horizon (Table 3).

As a point of reference, the EPA's 2012 inventory estimate of GHG emissions from the natural gas system is approximated by the 2 percent leakage case in the left panel (100-yr GWP). Also, as a reminder, other leakage estimates discussed in Section 3.1 ranged from 1 percent to 7 percent (excluding any gas distribution leakage).

With 2 percent leakage and a 100-yr GWP (left-panel), emissions of CO_2 from end-use combustion dominate total emissions. Methane leakage contributes only about 15 percent to the total global warming impact. Only if methane leakage is at the high end in this graph (10 percent leakage) does the global warming impact of leakage approach the level of combustion emissions. When a 20-year GWP is considered instead (right panel), leakage of only 4 percent is sufficient to cause a global warming impact equal to that from gas combustion alone. With 10 percent leakage, the impact of methane leakage is triple the impact from combustion alone.

Going a step further, we can calculate emissions per kilowatt-hour of electricity from natural gas and compare this with those for coal electricity. As noted earlier, natural gas contains much less carbon per unit of energy than coal and can be converted more efficiently into electricity. Power plant efficiencies for both coal and gas are well known. A representative efficiency for a modern natural gas combined cycle power plant is 50 percent (higher heating value basis).[67] Representative efficiencies for plants using pulverized bituminous coal are 31 percent for a "sub-critical" plant[68] and 36

[o] Assuming complete combustion of natural gas containing 14 kg of carbon per GJ_{HHV}. This corresponds to an assumed natural gas composition by volume of 97.01percent methane, 1.76 percent ethane, 0.47 percent nitrogen, 0.38 percent CO_2, 0.26 percent propane, and 0.11 percent n-butane and an elemental composition by weight of 74.0 percent C, 24.4 percent H, 0.8 percent N, and 0.7 percent O. The average molecular weight is 16.57 g/mol, and the LHV and HHV are 47.76 MJ/kg and 52.97 MJ/kg, respectively.

[p] The methane leakage (in $kgCO_2e/GJ_{HHV}$) as a function of the percentage of production leaked is calculated, using the natural gas characteristics in footnote o, as follows: $\frac{kgCO_2e}{GJ_{HHV}} = GWP * \frac{\%\ leaked}{100} * 14 \frac{kgC}{GJ_{HHV}} * \frac{16gCH_4}{molC} * \frac{1molC}{12gC}$

[q] Upstream CO_2 emissions include those reported by the EPA for the natural gas system[23] plus emissions from combustion of "lease and plant fuel" (which EPA excludes from its inventory for the natural gas system to avoid double counting). Lease and plant fuel emissions are estimated by assuming complete combustion of lease and plant fuel energy used in 2010 as reported by the Energy Information Administration.[54]

With Methane Leakage Natural Gas Power Generation Can Have a Similar or Higher Global Warming Impact as Coal Power Generation

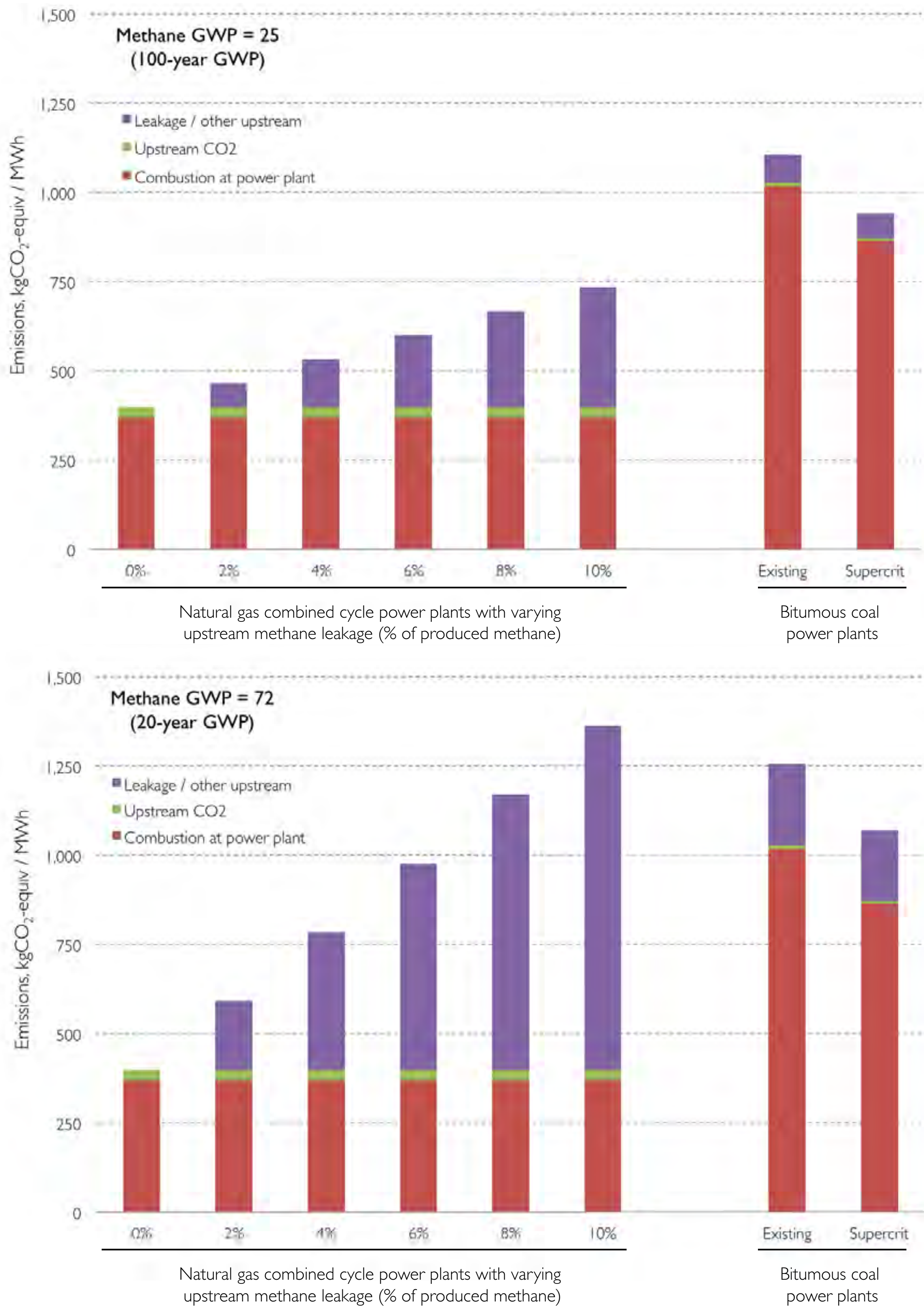


Figure 21. *Estimates of greenhouse gas emissions from electricity production from natural gas for different assumed rates of upstream methane leakage and from bituminous coal for typical existing coal plants and for a more efficient variant.*[r]

[r] Based on emissions shown in Figure 20 and power plant fuel consumption of 7172 GJ_{HHV}/kWh a natural gas combined cycle (corresponding to 50.2 percent efficiency),[67] 11736 GJ_{HHV}/kWh (30.7 percent efficiency) for an existing subcritical coal-fired power plant[67] and 10019 GJ_{HHV}/kWh for a supercritical coal plant (35.9 percent efficiency)[68] Upstream CO_2 emissions for the subcritical and supercritical coal plants are 8.34 kg/MWh and 7.48 kg/MWh, respectively, and upstream methane emissions are 3.20 $kgCH_4$/MWh and 2.76 $kgCH_4$/MWh, respectively.[68,69]

percent for a "super-critical" plant.[69] (Most existing coal power plants use sub-critical steam pressures. Newer plants use super-critical pressures.)

With these efficiencies, Figure 21 shows our estimates of GHG emissions per kWh of electricity generated from natural gas (with different methane leakage rates) and from bituminous coal, assuming methane GWP time horizons of 100 years (top panel) and 20 years (bottom panel). These calculations include estimates of the "upstream" emissions associated with coal electricity, including estimated methane emissions that accompany mining of bituminous coal.[68,69]

With the 100-yr time horizon (top panel), the GHG emissions for a kwh of electricity from a natural gas plant are half the emissions from a kwh from an existing coal plant if methane leakage is under about 5 percent. Even with leakage as high as 10 percent, the natural gas kwh still has a lower global warming impact than the coal kwh – about one-third less.

In contrast, when the 20-yr time horizon is considered (bottom panel), leakage must be limited to about 2 percent for the natural gas kwh to have half the global warming impact of an existing coal plant's kwh. If leakage is about 8 percent, the natural gas kwh is no better for the climate than the kwh from an existing coal plant.

The comparisons in Figure 21 do not address the question of what is the "correct" GWP value to use in comparing the global warming impact of electricity from gas and coal. Alvarez *et al.*[18] have proposed a method for assessing the climate impact of a switch from one technology to another (such as coal to gas electricity generation) that involves more than one type of greenhouse gas emission, for example methane and CO_2. They define a technology warming potential (TWP) that represents the ratio of the time-dependent global warming potential of technology "A" divided by the time-dependent global warming potential of technology "B" that it replaces. By explicitly including the different atmospheric lifetimes of methane and CO_2, this method yields a ratio, for any time horizon of interest, that represents the relative global warming potential of switching from technology

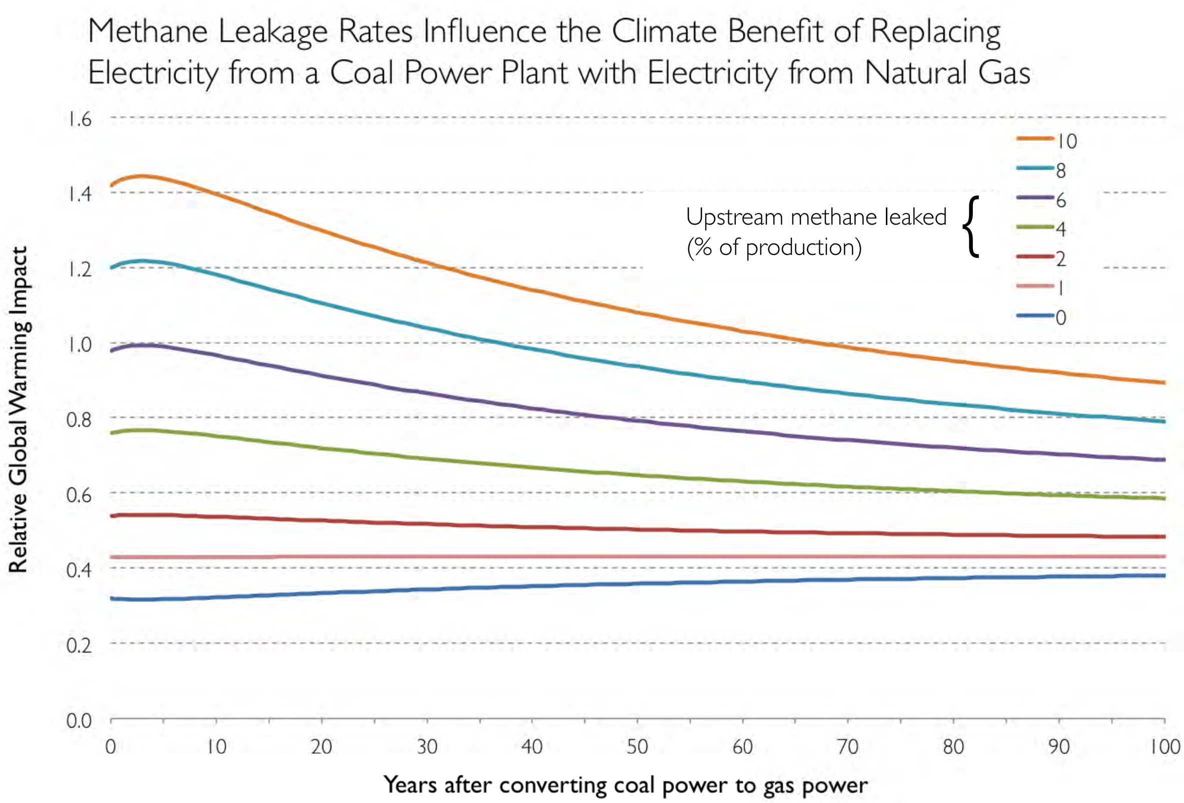


Figure 22. Global warming impact of shifting electricity generation from a coal power plant to a natural gas power plant in year zero and continuing that generation from gas each year thereafter, assuming different methane leakage rates in the natural gas system. Natural gas is friendlier for the climate for values less than 1.0. [s]

[s] Assumed heat rates for electricity generation are 7172 kJ_{HHV}/kWh (6798 BTU/kWh) for NGCC and 10550 kJ_{HHV}/kWh (10000 BTU/kWh) for existing coal plants. Upstream emissions for coal are as described for subcritical coal in footnote r.

"A" to technology "B". The ratio varies with the time horizon due to the different atmospheric lifetimes of methane and CO_2. A ratio less than one at a particular point in time after a switch is made from "A" to "B" means that technology "A" has a lower global warming potential than technology "B" over that time frame.

Combining the TWP methodology of Alvarez *et al.* with our leakage assumptions, Figure 22 shows the global warming impact of replacing the electricity from a coal-fired power plant with natural gas electricity and then maintaining that natural gas generation for every subsequent year thereafter. Results are shown for different assumed total methane leakage rates expressed as a fraction of gas produced. For a time-frame of interest (x-axis), if the corresponding value on the y-axis is less than one, then the switch from coal to gas produces some level of climate benefit relative to maintaining electricity generation using coal. For example, if the y-axis value is 0.5 at some point in time, NGCC electricity has half as much global warming potential as coal over that time period.

Many authors have suggested that switching from coal to gas electricity halves the global warming impact of electricity generation. Figure 22 indicates that this is true if methane leakage is about 1.5 percent of production. If leakage were as high as 6 percent, the switch to gas would still be better for the climate than coal over any time period considered, although barely so in the earlier years after the switch. If leakage were 8 percent, switching from coal to gas would require 37 years before any climate benefit is achieved. With 10 percent leakage it takes 67 years. At these higher leak rates, a 50 percent climate benefit would not be realized for well over a century.

Figure 22 represents the impact of shifting one power plant worth of electricity generation from coal to gas. An important follow-on question is what woud be the global warming impact of shifting over time the whole fleet of coal power plants to gas. To provide some context in answering the question, it is helpful to know that the average rate at which coal electricity generation decreased over the decade from 2002 to 2012 in the U.S. was 2.4 percent per year. The annual percentage rate of reduction has been rising in recent years (Table 9). The decreased generation from coal has been predominantly replaced by increased generation from natural gas. (The combined electricity generation from gas plus coal grew an average of less than half of one percent per year during the past decade, Table 9.)

We extend the method presented by Alvarez *et al.* to analyze shifting of the whole coal fleet to gas over time. We assume an average annual percentage reduction in electricity generated from coal and a corresponding increase in electricity generated from gas,[t] with total electricity production from coal plus gas remaining the same each year.[u] If we assume a methane leakage rate of 2 percent of production, then Figure 23 shows the prospective global warming impact of switching from coal to natural gas electricity at different annual rates (compared to not replacing any coal electricity). With a 10 percent per year switching rate, it would take 29 years to replace 95 percent of coal generation. For the other cases, 95 percent coal replacement would be reached in 39 years (7.5 percent per year), 59 years (5 percent per year), 118 years (2.5 percent per year), or more than 200 years (1 percent per year).

As full replacement of coal is approached, the impact on global warming reaches a limiting value. Over a long enough time horizon, all of the cases will approach the same relative impact level of around 0.5 (for an assumed 2 percent leakage) but, importantly, this impact level is reached more slowly when coal replacement occurs more slowly. The slower the approach to the 0.5 level, the more rapid the rate of warming. Considering an often-used target year of 2050, 37 years from today, we see that the higher replacement rates (5, 7.5, and 10 percent per year) each achieves 40 percent or more reduction in global warming potential – approaching the maximum level reachable in the longer term. At the 2.5 percent per year replacement rate (roughly the average actual rate over the past decade), only a 29 percent reduction in warming potential is achieved by 2050.

---

[t] For a constant annual percentage conversion of coal electricity to gas electricity, the fraction of original coal electricity converted to gas each year is $[r * (1 - r)^{(t-1)}]$ where r is the annual percentage reduction in coal electricity and t is the number of years from the start of the conversion process. (Conversion begins in year $t = 1$.)

[u] The Technology Warming Potential (TWP) defined by Alvarez *et al.*[18] (Equation 2 in their paper, with $L/L_{ref} = 1$) is used here to calculate the reduction in Global Warming Potential from substituting a unit amount of coal-generated electricity with gas-generated electricity in a given year and continuing to produce that unit amount of electricity from gas in subsequent years. (Figure 22 shows the result of this calculation.) When the amount of electricity made from natural gas is not constant every year but increases year to year (as coal electricity generation decrseases year to year) the climate impact of each new annual increment of gas electricity is assessed using the TWP. Then, the climate impact of the electricity generated from coal and gas in total in any year is the sum of climate impacts caused that year by each new increment of gas-generated electricity added from the start of the counting period up to that year plus the impact of the reduced amount of coal-generated electricity being produced in that year. Mathematically, the climate impact in total from the start of a shift from coal to gas over some number of years, N, is calculated as: $\int_{t=1}^{N}[r(1-r)^{(t-1)} * TWP(N+1-t)]dt + \{1 - \int_{t=1}^{N}[r(1-r)^{(t-1)}]dt\}$ where r is the annual percentage reduction in coal electricity and $TWP(N + 1 - t)$ is given by Equation 2 in Alvarez *et al.*

Table 9. U.S. coal and natural gas electricity generation 2002-2012 (left)[6] and annual percentage reduction in coal electricity generation when averaged over different time periods (right).

	Electricity Generated (1000 MWh per year)		
	Coal	Natural Gas	Coal + Gas
2002	1,933,130	691,006	2,624,136
2003	1,973,737	649,908	2,623,645
2004	1,978,301	710,100	2,688,401
2005	2,012,873	760,960	2,773,833
2006	1,990,511	816,441	2,806,952
2007	2,016,456	896,590	2,913,046
2008	1,985,801	882,981	2,868,782
2009	1,755,904	920,979	2,676,883
2010	1,847,290	987,697	2,834,987
2011	1,733,430	1,013,689	2,747,119
2012	1,517,203	1,230,708	2,747,911

Time Period	Average Annual Reduction in Coal Electricity
2002 - 2012	2.4 percent
2003 - 2012	2.9 percent
2004 - 2012	3.3 percent
2005 - 2012	4.0 percent
2006 - 2012	4.4 percent
2007 - 2012	5.5 percent
2008 - 2012	6.5 percent
2009 - 2012	4.8 percent
2010 - 2012	9.4 percent
2011 -2012	12.5 percent
-	-

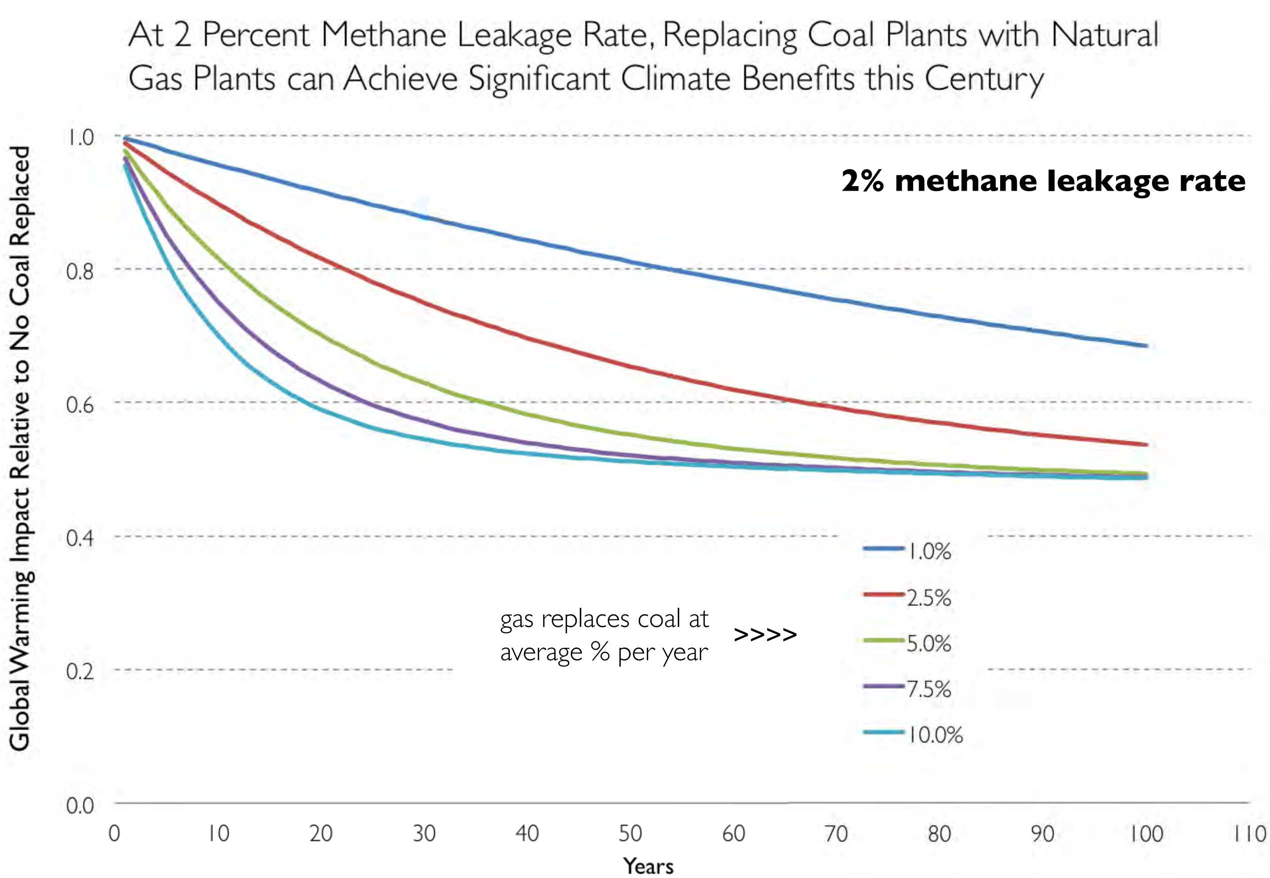


Figure 23. Relative global warming impact of natural gas combined cycle power replacing existing coal-fired power generation at different annual rates. In all cases the assumed methane leakage is 2 percent of production.

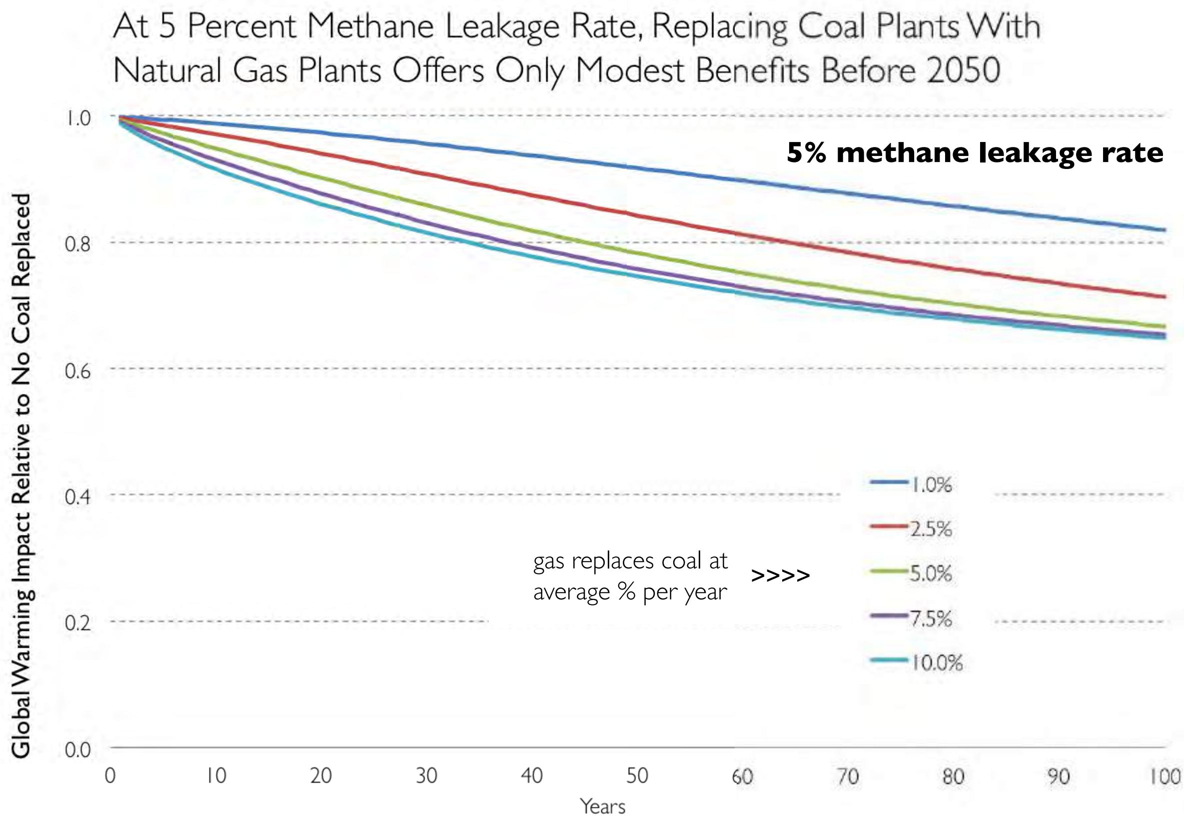


Figure 24. *Relative global warming impact of natural gas combined cycle power replacing existing coal-fired power generation at different annual rates. In all cases the assumed methane leakage is 5 percent of production.*

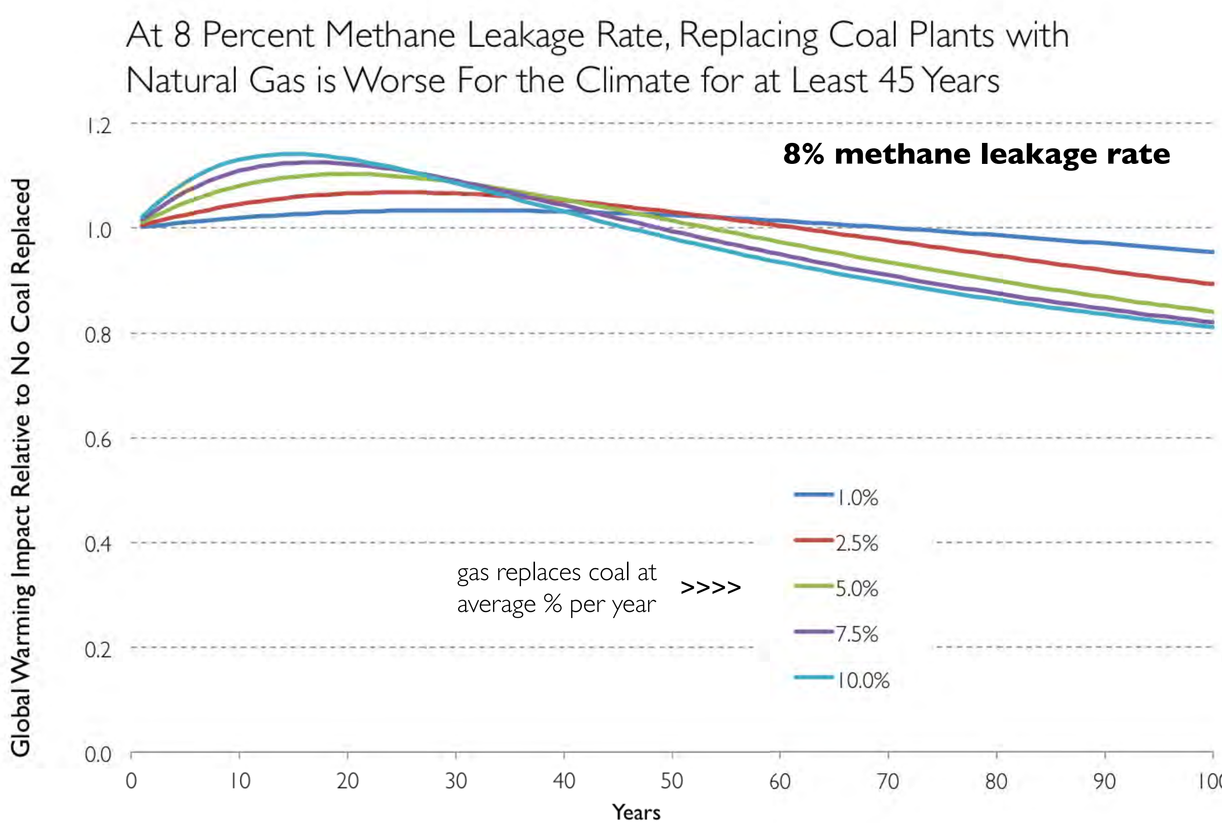


Figure 25. *Relative global warming impact of natural gas combined cycle power replacing existing coal-fired power generation at different annual rates. In all cases the assumed methane leakage is 8 percent of production.*

The same analysis can be carried out for a different assumed methane leakage rate. Figure 24 shows results for 5 percent leakage. Because of the higher methane leakage, the impact of switching from coal to gas is not as substantial as with lower leakage. In fact, by 2050, even the highest coal replacement rate of 10 percent/year achieves only about a 20 percent reduction in warming potential. The 2.5 percent replacement rate achieves only a 12 percent reduction compared with no coal-to-gas conversion.

As expected based on Figure 22, if leakage exceeds 6 percent, there would initially be negative impacts of switching from coal to gas nationally. With 8 percent leakage, a global warming benefit of switching from coal to gas is reached only after 45 years or more (Figure 25).

Finally, the different coal-to-gas substitution rates in Figure 23 and Figure 24 would have different gas supply requirements. If we consider 2013 as year 1 in these graphs, then the amount of additional gas supplies required in the U.S. to sustain the different rates of coal-to-gas substitution are as shown in Figure 26. Shown for comparison are the Energy Information Administration (EIA) projections of new gas supplies (for all end-uses of gas). New gas supplies could be higher than EIA projects, but the higher coal substitution rates (5 to 10

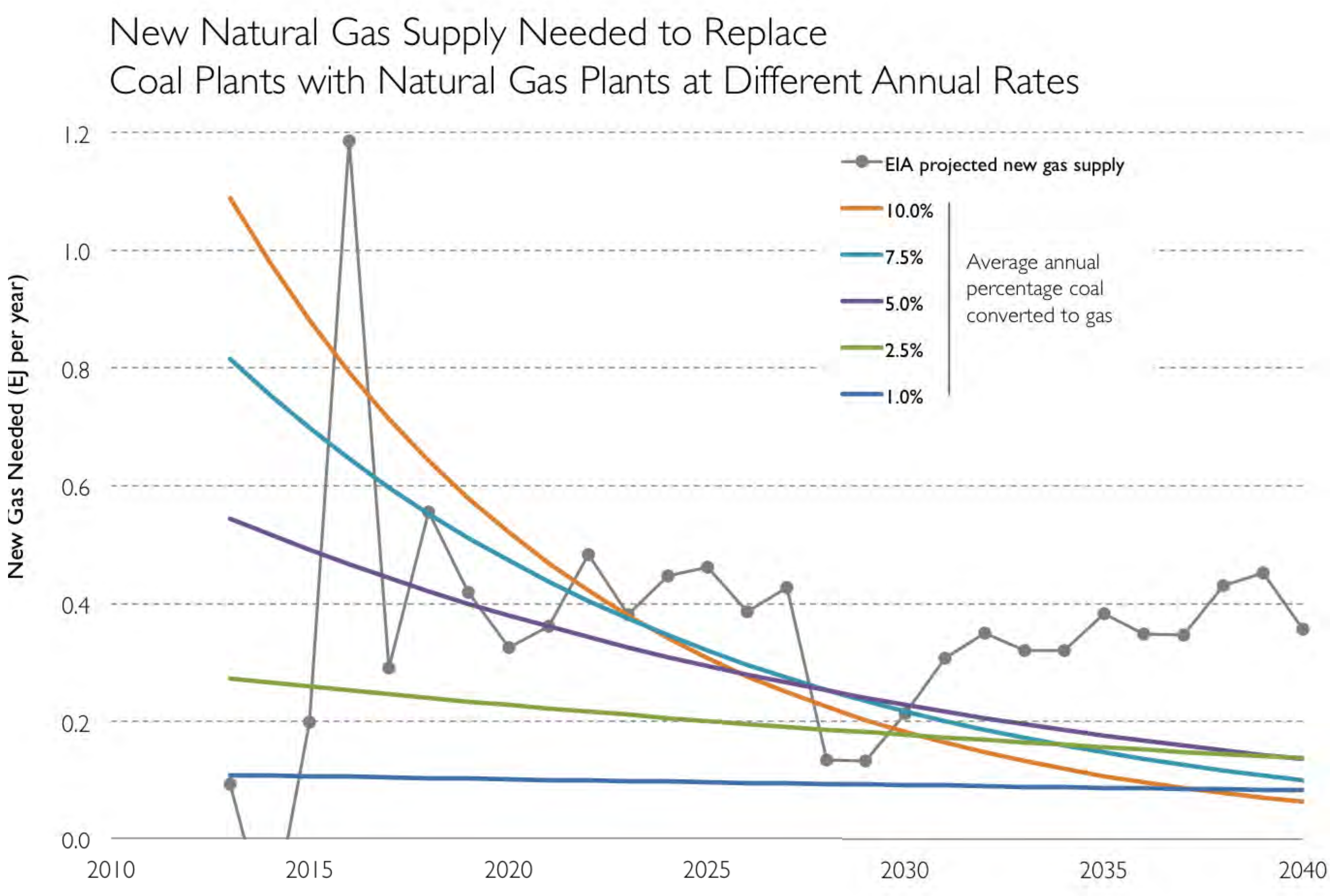


Figure 26. Additional gas required each year (compared to preceding year) under different scenarios. The solid lines represent the new gas required for electricity generation to replace coal-fired generation in the U.S. at the annual percentage rates indicated. (Coal-fired generation in 2012 was 1517 TWh. Gas generation that replaces coal is assumed to require 7,172 kJ of gas per kWh generated, corresponding to a heat rate of 6,798 BTU/kWh.) The black line is the new gas supply (for all gas uses) projected by the Energy Information Administration in its 2013 Annual Energy Outlook (Early Release) Reference Scenario[7] (There are approximately 1.1 EJ per trillion cubic feet (TCF) of gas.)

percent/year) would be difficult to achieve in the early years with the gas supply levels currently projected by the EIA, considering demands for gas from users other than electric power plants are also projected by EIA to grow during the projection period. In this context, the 2.5 percent per year rate may be an achievable average coal-to-gas shifting rate over the next several decades. In that case, the achievable reduction in global warming impact from substituting gas for coal out to 2050 would be 12 percent to 29 percent, considering methane leakage of 2 percent to 5 percent (Figure 23 and Figure 24). To achieve better than this would require other lower-carbon options, such as reduced electricity consumption and/or increased electricity supply from nuclear, wind, solar, or fossil fuel systems with CO_2 capture and storage to provide some of the substitution in lieu of gas over this time frame.

This analysis considered no change in leakage rate or in the efficiencies of power generation over time. The benefit of a switch from coal to gas would obviously increase if leakage were reduced and/or natural gas power generating efficiency increased over time.

References

(1) Rogner, H. (Convening Lead Author), *et al*. (2012), "Energy Resources and Potentials," chapter 7 in *The Global Energy Assessment*, Johansson, *et al*. (eds.), Cambridge University Press.

(2) BP (2012). Statistical Review of World Energy, http://www.bp.com/sectionbodycopy.do?categoryId=7500&contentId=7068481

(3) U.S. Energy Information Administration (2012). *Annual Energy Review*, U.S. Dept. of Energy, September, http://www.eia.gov/totalenergy/data/annual/index.cfm#consumption

(4) Ground Water Protection Council and ALL Consulting (2009). *Modern Shale Gas Technology Development in the United States: A Primer,* National Energy Technology Laboratory, April.

(5) U.S. Energy Information Administration, U.S. Natural Gas Develeopment Wells Drilled (count), U.S. Department of Energy, 2012, http://tonto.eia.gov/dnav/ng/hist/e_ertwg_xwcd_nus_cm.htm

(6) U.S. Energy Information Administration, Electric Power Monthly, U.S. Department of Energy, February 2013, http://www.eia.gov/electricity/monthly/pdf/epm.pdf

(7) Energy Information Administration (2012). *Annual Energy Outlook 2013, Early Release*, U.S. Dept. of Energy, December, http://www.eia.gov/forecasts/aeo/er/index.cfm

(8) Harrison, M.R., Shires, T.M., Wessels, J.K., and Cowgill, R.M. (1997). "Methane Emissions from the Natural Gas Industry," Project Summary, EPA/600/SR-96/080, EPA, June.

(9) U.S. Energy Information Administration, http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngpps2009/.

(10) U.S. Energy Information Administration, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/ngpipelines_map.html.

(11) U.S. Energy Information Administration, http://www.eia.gov/cfapps/ngqs/images/storage_2010.png.

(12) U.S. Energy Information Administration, http://www.eia.gov/analysis/studies/usshalegas/images/shalemap-lg.png

(13) U.S. Geological Survey (August 2012). http://certmapper.cr.usgs.gov/data/noga00/natl/tabular/2012/Summary_12_Cont_Gas.pdf

(14) U.S. Energy Information Administration (2013). *Natural Gas Annual*, http://www.eia.gov/naturalgas/annual/.

(15) Forster, P., V. Ramaswamy, P. Artaxo, T. Berntsen, R. Betts, D.W. Fahey, J. Haywood, J. Lean, D.C. Lowe, G. Myhre, J. Nganga, R. Prinn, G. Raga, M. Schulz and R. Van Dorland (2007). "Changes in Atmospheric Constituents and in Radiative Forcing". In: *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

(16) Shindell, D.T., G. Faluvegi, D.M. Koch, G.A. Schmidt, N. Unger, and S.E. Bauer (2009). "Improved Attribution of Climate Forcing to Emissions," *Science*, 326(30 Oct): 716-718.

(17) Howarth, R.W., R. Santoro, and A. Ingraffea (2011). "Methane and the greenhouse-gas footprint of natural gas from shale formations: a letter," *Climatic Change,* 106:679–690.

(18) Alvarez, R.A., S.W. Pacala, J.J. Winebrake, W.L. Chameides, and S.P. Hamburg (2012). "Greater focus needed on methane leakage from natural gas infrastructure," *PNAS*, 109(17): 6435-6440. See also the online supporting information accompanying the article.

(19) http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

(20) EPA (2013). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011, Environmental Protection Agency, Washington, DC, April 12. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf

(21) EPA (2012). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010*, 430-R-12-001, Environmental Protection Agency, Washington, DC, April.

(22) Taken from presentations by EPA staff at the "Stakeholder Workshop on Natural Gas in the Inventory of U.S. Greenhouse Gas Emissions and Sinks," September 13, 2012. http://www.epa.gov/climatechange/ghgemissions/Sept2012stakeholderworkshop.html

(23) EPA (2012). "Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems," Section 3.4 of Annex 3 of the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010, 430-R-12-001, Environmental Protection Agency, Washington, DC, April. http://www.epa.gov/climatechange/ghgemissions/Sept2012stakeholderworkshop.html

(24) Innovative Environmental Solutions (2009). "Field Measurement Program to Improve Uncertainties for Key Greenhouse Gas Emission Factors for Distribution Sources," Project No. 20497, Gas Technology Institute, Des Plaines, IL, Nov. 2009.

(25) EPA/GRI (1996). *Methane Emissions from the Natural Gas Industry*. Harrison, M., T. Shires, J. Wessels, and R. Cowgill (eds.), 15 volumes, Radian International LLC for National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC. EPA-600/R-96-080a. Available at EPA website: http://www.epa.gov/gasstar/tools/related.html.

(26) EPA, Gas Star Program: http://www.epa.gov/gasstar/.

(27) Numbers are from tables in Annex 3 of the EPA GHG Emissions Inventories published in 2009, 2010, 2011, 2012, and the 2013 inventory.

(28) Waltzer, S. (2012). "Liquids Unloading," presentation at the 'Stakeholder Workshop on Natural Gas in the Inventory of U.S. Greenhouse Gas Emissions and Sinks,' U.S. Environmental Protection Agency, 13 Sept, Wash. D.C.

(29) U.S. Energy Information Administration, http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

(30) http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/compressorMap.html

(31) U.S. Energy Information Administration (2008). "Distribution of Natural Gas: The Final Step in the Transmission Process," June. http://www.eia.gov/FTPROOT/features/ldc2008.pdf

(32) Pipeline and Hazardous Materials Safety Association, U.S. Department of Transportation. http://www.phmsa.dot.gov/

(33) Skone, T.J., J. Littlefield, and J. Marriot, "Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production," DOE/NETL-2011/1522, National Energy Technology Laboratory, October.

(34) Broderick, J., Anderson, K., Wood, R., Gilbert, P., Sharmina, M., Footitt, A., Glynn, S., and Nicholls, F. (2011). "Shale gas: an updated assessment of environmental and climate change impacts," The Tyndall Centre, University of Manchester, UK, November.

(35) Clark, C., A. Burnham, C. Harto, and R. Horner (2012). "Hydraulic Fracturing and Shale Gas Production: Technology, Impacts, and Policy," Argonne National Laboratory, September 10.

(36) Forster, D. and J. Perks (2012). "Climate impact of potential shale gas production in the EU," Report to the European Commission DG CLIMA, July 30.

(37) Howarth, R., D. Shindell, R. Santoro, A. Ingraffea, N. Phillips, and A. Townsend-Small (2012), "Methane Emissions from Natural Gas Systems," Background paper prepared for the National Climate Assessment, Reference number 2011-0003, February.

(38) Ritter, K. (API), A. Emmert, M. Lev-On, and T. Shires (2012), "Understanding Greenhouse Gas Emissions from Unconventional Natural Gas Production," 20th International Emissions Inventory Conference, August, Tampa, FL.

(39) Santoro, R.L., R.H. Howarth, and A.R. Ingraffea (2011). "Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development," A Technical Report from the Agriculture, Energy, & Environment Program at Cornell University, June.

(40) Hughes, J.D. (2011). "Lifecycle Greenhouse Gas Emissions from Shale Gas Compared to Coal: An Analysis of Two Conflicting Studies," Post-Carbon Institute, July.

(41) Fulton, M., Mellquist, N., Kitasei, S., and Bluestein, J. (2011). "Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal," Deutsche Bank Group Climate Change Advisors, August 25.

(42) Lechtenböhmer, S., Altmann, M., Capito, S., Matra, Z., Weindrorf, W., and Zittel, W. (2011). "Impacts of Shale Gas and Shale Oil Extraction on the Environment and on Human Health," IP/A/ENVI/ST/2011-07, prepared for the European Parliament's Committee on Environment, Public Health and Food Safety, June.

(43) Burnham, A., J. Han, C.E. Clark, M. Wang, J.B. Dunn, and I. Palou-Rivera (2012). "Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum," *Environmental Science and Technology*, 46, 619–627.

(44) Cathles III, L.M., L. Brown, and M. Taam, and A. Hunter (2012). "A commentary on 'The greenhouse-gas footprint of natural gas in shale formations' by R.W. Howarth, R. Santoro, and Anthony Ingraffea," *Climatic Change*, 113:525–535.

(45) Howarth, R.W., R. Santoro, and A. Ingraffea (2012). "Venting and leaking of methane from shale gas development: response to Cathles et al.," *Climatic Change*, 113:537-549.

(46) Hultman, N., D. Rebois, M. Scholten, and C. Ramig (2011). "The greenhouse impact of unconventional gas for electricity generation," *Environmental Research Letters*, Vol. 6.

(47) Jiang, M., W.M. Griffin, C. Hendrickson, P. Jaramillo, J. Van Briesen, and A. Venkatesh (2011). "Life cycle greenhouse gas emissions of Marcellus shale gas," *Environmental Research Letters*, Vol. 6.

(48) Stephenson, T., J.E. Valle, and X. Riera-Palou (2011), "Modeling the Relative GHG Emissions of Conventional and Shale Gas Production," *Environmental Science and Technology*, 45: 10757–10764.

(49)Weber, C.L. and C. Clavin (2012). "Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications," *Environmental Science and Technology*, 46: 5688-5695.

(50) O'Sullivan, F. and Paltsev, S. (2012). "Shale gas production: potential versus actual greenhouse gas emissions," *Environmental Research Letters*, Vol. 7.

(51) Laurenzi, I.J. and Jersey, G.R. (2013). "Life Cycle Greenhouse Gas Emissions and Freshwater Consumption of Marcellus Shale Gas," *Environmental Science and Technology,* published online, 2 April.

(52) EPA, (2010). Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technical Support Document, Environmental Protection Agency, Washington, DC.

(53) API (2009). Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry, American Petroleum Institute, Washington, DC.

(54) U.S. Energy Information Administration, http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

(55) U.S. Energy Information Administration, http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

(56) Caulton, D., Shepson, P., Cambaliza, M., Sparks, J., Santoro, R., Sweeney, C., Davis, K., Lauvaus, T., Howarth, R., Stirm, B., Sarmiento, D. and Belmecheri, S. (2012). "Quantifying Methane Emissions from Shale Gas Wells in Pennsylvania," A21J-03, Annual Meeting of the American Geophysical Union, San Francisco, December.

(57) Karion, A., Sweeney, C., Petron, G., Frost, G., Trainer, M., Brewer, A., Hardesty, R., Conley, S., Wolter, S., Newberger, T., Kofler, J., and Tans, P. (2012). "Estimate of methane emissions from oil and gas operations in the Uintah Basin using airborne measurements and Lidar wind data," A21J-01, Annual Meeting of the American Geophysical Union, San Francisco, December.

(58) Petron, G., et al. (2012). "Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study," J*ournal of Geophysical Research*, 117(D04304).

(59) Tollefson, J. (2013). "Methane leaks erode green credentials of natural gas," *Nature* 493(7430), January 2.

(60) Peischl, J., Ryerson, T.B., Brioude, J., Aikin, K.C., Andrews, A.E., Atlas, E., Blake, D., Daube, B.C., de Gouw, J.A., Dlugokencky, E., Frost, G.J., Gentner, D.R., Gilman, J.B., Goldstein, A.H., Harley, R.A., Holloway, J.S., Kofler, J., Kuster, W.C., Lang, P.M., Novelli, P.C., Santoni, G.W., Trainer, M., Wofsy, S.C., and Parrish, D.D. (2013). "Quantifying sources of methane using light alkanes in the Los Angeles basin, California, J*ournal of Geophysical Research: Atmospheres*, DOI: 10.1002/jgrd.50413 (accepted online) 17 April.

(61) Hamburg, S., "Measuring fugitive methane emissions from fracking," Ecowatch, January 4, 2013. http://ecowatch.org/2013/fugitive-methane-emissions-fracking/

(62) Oil and Gas Assessment Team (2012). "Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States," Open-File Report 2012-1118, U.S. Geological Survey, Washington, DC.

(63) Bylin, C., L. Cassab, A. Cazarini, D. Ori, D. Robinson, and D. Sechler (2009). "New Measurement Data has Implications for Quantifying Natural Gas Losses from Cast Iron Distribution Mains," *Pipeline and Gas Journal*, 236(9): Sept.

(64) Phillips, N.G., R. Ackley, E.R. Crosson, A. Down, L.R. Hutyra, M. Brondfield, J.D. Karr, K. Zhao, and R.B. Jackson (2013). "Mapping urban pipeline leaks: Methane leaks across Boston," *Environmental Pollution*, 173: 1-4.

(65) McKenna, P. (2011). "Methane leaks foil clean gas future," *New Scientist*, 9 July.

(66) Wennberg., P.O., Mui, W., Wunch, D., Kort, E.A., Blake, D.R., Atlas, E.L., Santoni, G.W., Wofsy, S.C., Diskin, G.S., Jeong, S., and Fisher, M.L. (2012). "On the Sources of Methane to the Los Angeles Atmosphere," *Environmental Science and Technology*, 46: 9282-9289.

(67) National Energy Technology Laboratory (2010). Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, (Revision 2), DOE/NETL-2010/1397, NETL, November.

(68) Skone, T. and James, R. (2010). Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant, DOE/NETL-403-110809, National Energy Technology Laboratory, September 30.

(69) Skone, T. and James, R. (2010). Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant, DOE/NETL-403-110609, National Energy Technology Laboratory, September 30.

This page intentionally blank

CLIMATE CENTRAL

Princeton

One Palmer Square, Suite 330
Princeton, NJ 08542

Phone: +1 609 924-3800

Call Toll Free

+1 877 4-CLI-SCI (877 425-4724)

www.climatecentral.org

Methane Emissions from Natural Gas Systems

Background Paper Prepared for the National Climate Assessment
Reference number 2011-0003

Robert Howarth (Cornell University), Drew Shindell (NASA Goddard Space Institute), Renee Santoro (Cornell University), Anthony Ingraffea (Cornell University), Nathan Phillips (Boston University), and Amy Townsend-Small (University of Cincinnati)

February 25, 2012

The past few years have seen major changes both in our understanding of the importance of methane as a driver of global climate change and in the importance of natural gas systems as a source of atmospheric methane. Here, we summarize the current state of knowledge, relying on peer-reviewed literature.

Methane is the second largest contributor to human-caused global warming after carbon dioxide. Hansen and Sato (2004) and Hansen et al. (2007) suggested that a warming of the Earth to 1.8° C above the 1890-1910 baseline may trigger a large and rapid increase in the release of methane from the arctic due to melting of permafrost. While there is a wide range in both the magnitude and timing of projected carbon release from thawing permafrost in the literature (e.g. Schaefer et al., 2011), warming consistently leads to greater release. This release will therefore in turn cause a positive feedback of accelerated global warming (Zimov et al. 2006).

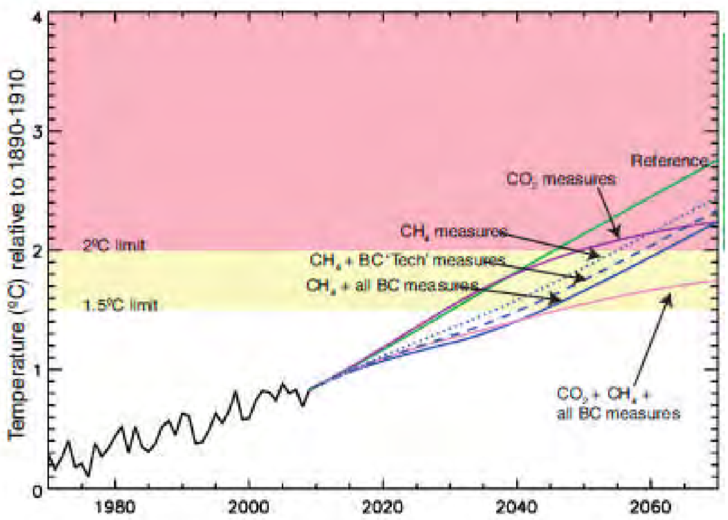


Fig. 1. Observed global mean temperature from 1900 to 2009 and projected future temperature under various scenarios of controlling methane + black carbon (BC) and carbon dioxide, alone and in combination. An increase to 1.5° to 2.0 ° C above the 1890-1910 baseline (illustrated by the yellow bar) poses high risk of passing a tipping point and moving the Earth into an alternate state for the climate system. Reprinted from Shindell et al. (2012).

Shindell et al. (2012) noted that the climate system is more immediately responsive to changes in methane (and black carbon) emissions than carbon dioxide emissions (Fig. 1). They predicted that unless emissions of methane and black carbon are reduced immediately, the Earth will warm to 1.5° C by 2030 and to 2.0° C by 2045 to 2050 whether or not carbon dioxide emissions are reduced. Reducing methane and black carbon emissions, even if carbon dioxide is not controlled, would significantly slow the rate of global warming and postpone reaching the 1.5° C and 2.0° C marks by 12 to 15 years. Controlling carbon dioxide as well as methane and black carbon emissions further slows the rate of global warming after 2045, through at least 2070.

Natural gas systems are the single largest source of anthropogenic methane emissions in the United States (Fig. 2), representing almost 40% of the total flux according to the most recent estimates from the U.S. Environmental Protection Agency (EPA) as compiled by Howarth et al. (2012). Note that through the summer of 2010, the EPA used emission factors from a 1996 study to estimate the contribution of natural gas systems to the U.S. greenhouse gas (GHG) inventory. Increasing evidence over the past 16 years has indicated these emission factors were probably too low, and in November 2010 EPA began to release updated factors. The estimates for natural gas systems in Fig. 2 are based on these updated emission factors and information released through 2011 in two additional EPA reports, as presented in Howarth et al. (2012). Note that the use of these new methane emission factors resulted in a doubling in the estimate of methane emissions from the natural gas industry. Note also that, to date, EPA has only increased emission factors for "upstream" and "midstream" portions of the natural gas industry (leaks and emissions at the well site and in processing gas). Factors for "downstream" emissions (storage systems and transmission and distribution pipelines) are still from the 1996 report, although EPA is considering also modifying these (Howarth et al. 2012).

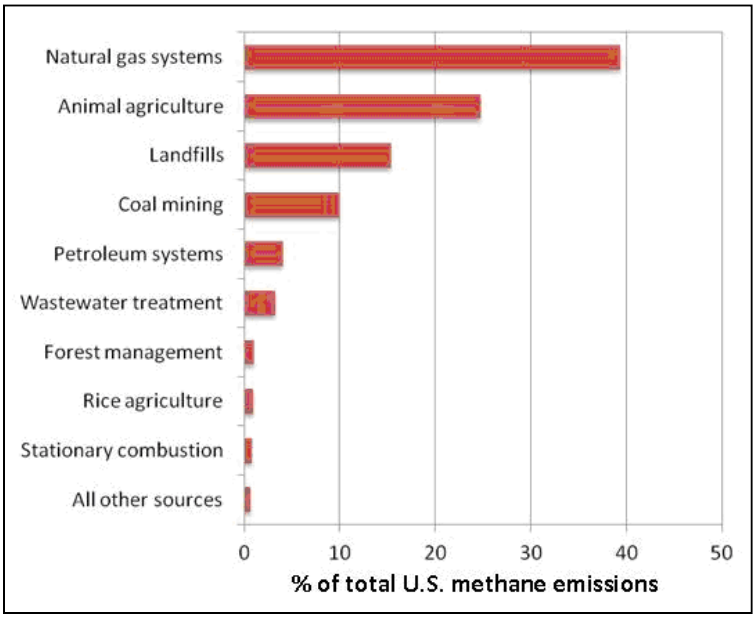


Fig. 2. Human-controlled sources of atmospheric methane from the United States for 2009, based on emission estimates from the U.S. Environmental Protection Agency in 2011. Reprinted from Howarth et al. (2012).

The natural-gas-system emissions in Fig. 2 are based on an average emission of 2.6% of the methane produced from natural gas wells over their production lifetime, with 1.7% from upstream and midstream emissions (for the national mix of conventional and unconventional gas in 2009) and 0.9% from downstream emissions (Howarth et al. 2012). As discussed below, these methane emission estimates from natural gas systems are based on limited data and remain uncertain.

Recent estimates in the peer-reviewed literature for downstream emissions of methane from natural gas systems range from 0.07% to 10% of the methane produced over the lifetime of a well (Table 1). It is important to note that only Lelieveld et al. (2005) presented actual data on emissions, in their case leakage from high-pressure transmission pipelines. Other estimates are based on emission factors from the 1996 EPA study, on emission factors from a more recent report from the American Petroleum Institute, or on reports of "lost and unaccounted for gas" to governmental agencies, leading to high uncertainty. Lelieveld et al. reported a leakage rate from high-pressure transmission pipelines of 0.4% to 1.6%, with a "best estimate" of 0.7%; they used the 1996 EPA emission factors to estimate emissions from storage and distribution systems, yielding an estimate for total downstream emissions of 1.4% (or twice their measured value for just transmission). Howarth et al. (2011) took the "best estimate" of 1.4% from Lelieveld et al. (2005) as their low-end estimate, arguing that the 1996 EPA emission factors were probably low. For their high-end estimate, Howarth et

Table 1. Estimates of methane emission from downstream emissions (transmission pipelines and storage and distribution systems) expressed as the percentage of methane produced over the lifecycle of a well. Studies are listed chronologically by date of publication. Modified from Howarth et al. (2012).

Hayhoe et al. (2002)	2.5 %	("best estimate;" range = 0.2% – 10%)
Lelieveld et al. (2005)	1.4 %	("best estimate;" range = 1.0% – 2.5%)
Howarth et al. (2011)	2.5 %	(mean; range = 1.4% – 3.6%)
EPA (2011)*	0.9 %	
Jiang et al. (2011)	0.4 %	
Hultman et al. (2011)	0.9 %	
Ventakesh et al. (2011)	0.4 %	
Burnham et al. (2011)	0.6 %	
Stephenson et al. (2011)	0.07 %	
Cathles et al. (2012)	0.7 %	

* The EPA (2011) estimate is as calculated in Howarth et al. (2012), using national emissions from EPA reports and national gas production data from US Department of Energy reports.

al. (2011) used data on "missing and unaccounted for gas" from Texas. Their mean estimate of 2.5% is identical to the "best estimate" from Hayhoe et al.

(2002). The estimates of Jiang et al. (2011), Hultman et al. (2011), Ventakesh et al. (2011), Burnham et al. (2011), and Cathles et al. (2012) are all based on various permutations of the 1996 EPA emission factors, factors that were developed before the measurements of Lelieveld et al. (2005). The "best estimate" of measured emissions from transmission pipelines of 0.7% by Lelieveld et al. (2005) is similar to or greater than the estimates for all downstream emissions (including storage and distribution) from these studies that used the 1996 EPA emission factors. The estimate of Stephenson et al. (2011) includes only transmission pipelines, is based on emission factors reported by the American Petroleum Institute in 2009 (which in turn are derived from the EPA 1996 emission factors), and is far lower than any other estimate. Comparisons of predicted and observed methane concentrations in Los Angeles have indicated that emissions factors for leakage from natural gas systems may be underestimated (Wunch et al. 2009; Hsu et al. 2010). A new study using stable isotopic and radiocarbon signatures of methane confirms that emission from natural gas systems is likely the dominant source of methane in Los Angeles (Townsend-Small et al. 2012).

Most recent estimates for upstream emissions (those that occur during well completion and production at the well site) and midstream emissions (those that occur during gas processing) for conventional natural

Table 2. Conventional natural gas, estimates of methane emissions from upstream (at the well site) plus midstream (at gas processing plants), expressed as the percentage of methane produced over the lifecycle of a well. Studies are listed chronologically by date of publication. Modified from Howarth et al. (2012).

Hayhoe et al. (2002)	1.2 %	("best estimate")
Howarth et al. (2011)	1.4 %	(mean; range = 0.2% to 2.4%)
EPA (2011)*	1.6 %	
Hultman et al. (2011)	1.3 %	
Venkatesh et al. (2011)	1.8 %	
Burnham et al. (2011)	2.0 %	
Stephenson et al. (2011)	0.4 %	
Cathles et al. (2012)	0.9 %	

* The EPA (2011) estimate is as calculated in Howarth et al. (2012), using national emissions from EPA reports and national gas production data from US Department of Energy reports.

gas cluster fairly closely to the new EPA estimate of 1.6% (Table 2). The mean estimate from Howarth et al. (2011) is 1.4%; the Howarth et al. (2011) low-end value of 0.2% is an estimate of what is possible using best technologies, while 2.4% reflects emissions using poor technologies. Other estimates range from 0.4% to 2.0% (Table 2). As for the downstream emissions, the lowest number (0.4%) comes from Stephenson et al. (2011).

Table 3. Unconventional gas (shale gas and gas from tight sands), estimates of methane emissions from upstream (at the well site) plus midstream (at gas processing plants), expressed as the percentage of methane produced over the lifecycle of a well. Studies are listed chronologically by date of publication. Modified from Howarth et al. (2012).

Howarth et al. (2011)	3.3 %	(mean; range = 2.2% to 4.3%)
EPA (2011)*	3.0 %	
Jiang et al. (2011)	2.0 %	
Hultman et al. (2011)	2.8 %	
Burnham et al. (2011)	1.3 %	
Stephenson et al. (2011)	0.6 %	
Cathles et al. (2012)	0.9 %	
Petron et al. (2012)	4.0 %	("best estimate;" range = 2.3 to 7.7%)

* The EPA (2011) estimate is as calculated in Howarth et al. (2012), using national emissions from EPA reports and national gas production data from US Department of Energy reports.

Estimates for upstream plus midstream methane emissions from unconventional gas (obtained from shales and tight-sands) vary from 0.6% to 4.0% for mean or "best" estimates (Table 3). The US EPA 2011 data indicate an estimated loss of 3.0% for upstream plus midstream emissions from unconventional gas (Howarth et al. 2012).

With the exception of the estimate by Petron et al. (2012), all of these upstream emissions for unconventional gas are based on sparse and poorly documented data (Howarth et al. 2011, 2012). The study by Petron et al. (2012) measured fluxes from an unconventional gas field – at the landscape scale – over the course of a year, and is a robust estimate. Although it represents only one field (the Piceance tight-sands basin in Colorado), emissions during the flowback period following hydraulic fracturing for unconventional gas are similar in this basin to other unconventional gas basins for which data are available (Howarth et al. 2011).

The Petron et al. (2012) study should be repeated in other unconventional gas fields, but it nonetheless suggests that most of the estimates in Table 3 are likely to be too low.

The methane emissions during flowback of fracking fluids, which occur during a 1-2 week period following hydraulic fracturing, are the major difference in emissions between unconventional and conventional gas. Flowback emissions are estimated as 1.9% of the lifetime production of an unconventional gas well according to Howarth et al. (2011), although the data of Petron et al. (2012) suggest the flux may in fact be greater. Flowback does not occur when a conventional gas well is completed, and the methane emissions at the time of well completion are far less (Howarth et al. 2011, 2012). Howarth et al. (2012), which was published before the Petron et al. (2012) study was released, concluded that shale gas emissions are 40% to 60% greater than emissions from conventional natural gas, when both upstream and downstream emissions are considered.

The US Department of Energy predicts that the major use of shale gas over the next 23 years will be to replace conventional reserves of natural gas as these become depleted. To the extent that methane emissions associated with shale gas and other unconventional gas are greater than for conventional gas, this will increase the methane emissions from the US from the natural gas industry beyond those indicated in Fig. 2. An increase of 40% to 60% in methane emissions is likely, based on the majority of studies summarized in Howarth et al. (2012), possibly more in light of the new field-based measurements by Petron et al. (2012). Note further that to the extent the US EPA is underestimating emissions from downstream sources (storage, transmission, and distribution), methane emissions from natural gas systems may already be substantially greater than shown in Fig. 2.

Global warming potentials provide a relatively simple approach for comparing the influence of methane and carbon dioxide on climate change. In the national GHG inventory, the US EPA uses a global warming potential of 21 over an integrated 100-year time frame, based on the 1995 report from the Intergovernmental Panel on Climate Change (IPCC) and the Kyoto protocol. However, the latest IPCC Assessment from 2007 used a value of 25, while more recent research that better accounts for the interaction of methane with other radiatively active materials in the atmosphere suggests a mean value for the global warming potential of 33 for the 100-year integrated time frame (Shindell et al. 2009). Using this value and the methane emission estimates based on EPA data shown in Fig. 2, Howarth et al. (2012) calculated that methane contributes 19% of the entire GHG inventory of the U.S., including carbon dioxide and all other gases from all human activities. The methane from natural gas systems alone contributes over 7% of the entire GHG inventory of the U.S. Note that the variation in the global warming potential estimates between 21 and 33 is substantially less than the variation among the methane emission estimates.

The global warming potentials of 21, 25 and 33 are all for an integrated 100-year time frame following emission of methane to the atmosphere. The choice of 100 years is arbitrary, and one can also consider the global warming potentials at longer or shorter time scales. To date, estimates have typically been provided at time scales of 20 years and 500 years, in addition to the 100-year time frame. An emphasis on the 20-year time frame in addition to the widely-used 100-year timeframe is important, given the urgency of reducing methane emissions and the evidence that if measures are not taken to rapidly reduce the rate of warming, the Earth will continue to warm so quickly that risk of dangerous consequences will grow markedly. We may reach critical tipping points in the climate system, on the time scale of 18 to 38 years (Figure 1).

For the 20-year time frame, Shindell et al. (2009) provide a mean estimate of 105 for the global warming potential. Using this value, Howarth et al. (2012) calculated that methane contributes 44% of the entire GHG inventory of the U.S., including carbon dioxide and all other gases from all human activities. Hence while methane is only causing about 1/5 of the century-scale warming due to US emissions, it is responsible for nearly half the warming impact of current US emissions over the next 20 years. At this time scale, the methane emissions from natural gas systems contribute 17% of the entire GHG inventory of the U.S., for all gases from all sources. We repeat that these estimates may be low, and that the gradual replacement of conventional natural gas by shale gas is predicted to increase these methane fluxes by 40% to 60% or more (Howarth et al. 2012).

References Cited:

Burnham A, Han J, Clark CE, Wang M, Dunn JB, and Rivera IP (2011). Life-cycle greenhouse gas emissions of shale gas, natural gas, coal, and petroleum. *Environ. Sci. Technol*., doi:10.1021/es201942m

Cathles LM, Brown L, Taam M, and Hunter A (2012). A commentary on "The greenhouse-gas footprint of natural gas in shale formations" by R.W. Howarth, R. Santoro, and Anthony Ingraffea. *Climatic Change*, doi: 10.1007/s10584-011-0333-0.

Hansen J, and Sato M (2004). Greenhouse gas growth rates. *Proc. Natl Acad. Sci. USA* 101: 16 109 –16 114.

Hansen J, Sato M, Kharecha P, Russell G, Lea DW, and Siddall M. (2007). Climate change and trace gases. *Phil. Trans. R. Soc. A* 365: 1925–1954.

Hayhoe K, Kheshgi HS, Jain AK, Wuebbles DJ (2002). Substitution of natural gas for coal: Climatic effects of utility sector emissions. *Climatic Change* 54: 107-139.

Howarth RW, Santoro R, and Ingraffea A (2011). Methane and the greenhouse gas footprint of natural gas from shale formations. *Climatic Change Letters*, doi: 10.1007/s10584-011-0061-5

Howarth RW, Santoro R, and Ingraffea A (2012). Venting and leakage of methane from shale gas development: Reply to Cathles et al. *Climatic Change,* doi:10.1007/s10584-012-0401-0

Hsu, YK, van Curen T, Park S, Jakober C, Herner J, FitzGibbon M, Blake DR, and

Parrish DD (2010). Methane emissions inventory verification in southern California, *Atmos. Environ.* 44: 1-7, doi:10.1016/j.atmosenv.2009.10.002.

Hultman N, Rebois D, Scholten M, and Ramig C (2011). The greenhouse impact of unconventional gas for electricity generation. *Environ. Res. Lett.* 6: 044008, doi:10.1088/1748-9326/6/4/044008

Jiang M., Griffin WM, Hendrickson C, Jaramillo P, van Briesen, J and Benkatesh A (2011). Life cycle greenhouse gas emissions of Marcellus shale gas. *Environ. Res. Lett.* 6: 034014, doi:10.1088/1748-9326/6/3/034014

Lelieveld J, Lechtenbohmer S, Assonov SS, Brenninkmeijer CAM, Dinest C, Fischedick M, and Hanke T (2005). Low methane leakage from gas pipelines. *Nature* 434: 841-842.

Petron G, Frost G, Miller BT, Hirsch AI, Montzka SA, Karion A, Trainer M, Sweeney C, Andrews AE, Miller L, Kofler J, Bar-Ilan A, Dlgokencky EJ, Patrick L, Moor CT, Ryerson TB, Siso C, Kolodzev W, Lang PM, Conway T, Novelli P, Masarie K, Hall B, Guenthere D, Kitzis D, Miller J, Welsh D, Wolfe D, Neff W., and Tans P. (2012). Hydrocarbon Emissions Characterization in the Colorado Front Range – A Pilot Study. *Journal of Geophysical Research*, in press, doi:10.1029/2011JD016360.

Schaefer K, Zhang T, Bruhwiler L, and Barrett A. (2011). Amount and timing of permafrost carbon release in response to climate warming. *Tellus* 63: 165-180. doi: 10.1111/j.1600-0889.2011.00527.x

Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, and Bauer SE (2009). Improved attribution of climate forcing to emissions. *Science* 326: 716-718.

Shindell D, and others (2012). Simultaneously mitigating near-term climate change and improving human health and food security. *Science* 335: 183-189.

Stephenson T, Valle JE, Riera-Palou X (2011). Modeling the Relative GHG Emissions of Conventional and Shale Gas Production. *Environ. Sci. Tech.* 45: 10757–10764.

Townsend-Small A, Tyler SC, Pataki DE, Xu X, and Christensen LE (2012). Isotopic measurements of atmospheric methane in Los Angeles, California, USA reveal the influence of "fugitive" fossil fuel emissions. *Journal of Geophysical Research*, in press, doi: 10.1029/2011JD016826.

Venkatesh A, Jamarillo P, Griffin WM, and Matthews HS (2011). Uncertainty in life cycle greenhouse gas emissions from United States natural gas end-uses and its effect on policy. *Environ. Sci. Tech.* 45: 8182-8189.

Wunch D, Wennberg PO, Toon GC, Keppel-Aleks G, and Yavin YG (2009). Emissions of greenhouse gases from a North American megacity. *Geophysical Research Letters* 36: L15810, doi:10.1029/2009GL039825.

Zimov SA, Schuur EAG, and Chapin FS (2006). Permafrost and the global carbon budget. *Science* 312: 1612–1613.

Climatic Change
DOI 10.1007/s10584-011-0061-5

LETTER

Methane and the greenhouse-gas footprint of natural gas from shale formations

A letter

Robert W. Howarth · Renee Santoro · Anthony Ingraffea

Received: 12 November 2010 / Accepted: 13 March 2011

Abstract We evaluate the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.

Keywords Methane · Greenhouse gases · Global warming · Natural gas · Shale gas · Unconventional gas · Fugitive emissions · Lifecycle analysis · LCA · Bridge fuel · Transitional fuel · Global warming potential · GWP

Electronic supplementary material The online version of this article (doi:10.1007/s10584-011-0061-5) contains supplementary material, which is available to authorized users.

R. W. Howarth (✉) · R. Santoro
Department of Ecology and Evolutionary Biology, Cornell University, Ithaca, NY 14853, USA
e-mail: rwh2@cornell.edu

A. Ingraffea
School of Civil and Environmental Engineering, Cornell University, Ithaca, NY 14853, USA

Many view natural gas as a transitional fuel, allowing continued dependence on fossil fuels yet reducing greenhouse gas (GHG) emissions compared to oil or coal over coming decades (Pacala and Socolow 2004). Development of "unconventional" gas dispersed in shale is part of this vision, as the potential resource may be large, and in many regions conventional reserves are becoming depleted (Wood et al. 2011). Domestic production in the U.S. was predominantly from conventional reservoirs through the 1990s, but by 2009 U.S. unconventional production exceeded that of conventional gas. The Department of Energy predicts that by 2035 total domestic production will grow by 20%, with unconventional gas providing 75% of the total (EIA 2010a). The greatest growth is predicted for shale gas, increasing from 16% of total production in 2009 to an expected 45% in 2035.

Although natural gas is promoted as a bridge fuel over the coming few decades, in part because of its presumed benefit for global warming compared to other fossil fuels, very little is known about the GHG footprint of unconventional gas. Here, we define the GHG footprint as the total GHG emissions from developing and using the gas, expressed as equivalents of carbon dioxide, per unit of energy obtained during combustion. The GHG footprint of shale gas has received little study or scrutiny, although many have voiced concern. The National Research Council (2009) noted emissions from shale-gas extraction may be greater than from conventional gas. The Council of Scientific Society Presidents (2010) wrote to President Obama, warning that some potential energy bridges such as shale gas have received insufficient analysis and may aggravate rather than mitigate global warming. And in late 2010, the U.S. Environmental Protection Agency issued a report concluding that fugitive emissions of methane from unconventional gas may be far greater than for conventional gas (EPA 2010).

Fugitive emissions of methane are of particular concern. Methane is the major component of natural gas and a powerful greenhouse gas. As such, small leakages are important. Recent modeling indicates methane has an even greater global warming potential than previously believed, when the indirect effects of methane on atmospheric aerosols are considered (Shindell et al. 2009). The global methane budget is poorly constrained, with multiple sources and sinks all having large uncertainties. The radiocarbon content of atmospheric methane suggests fossil fuels may be a far larger source of atmospheric methane than generally thought (Lassey et al. 2007).

The GHG footprint of shale gas consists of the direct emissions of CO_2 from end-use consumption, indirect emissions of CO_2 from fossil fuels used to extract, develop, and transport the gas, and methane fugitive emissions and venting. Despite the high level of industrial activity involved in developing shale gas, the indirect emissions of CO_2 are relatively small compared to those from the direct combustion of the fuel: 1 to 1.5 g C MJ^{-1} (Santoro et al. 2011) vs 15 g C MJ^{-1} for direct emissions (Hayhoe et al. 2002). Indirect emissions from shale gas are estimated to be only 0.04 to 0.45 g C MJ^{-1} greater than those for conventional gas (Wood et al. 2011). Thus, for both conventional and shale gas, the GHG footprint is dominated by the direct CO_2 emissions and fugitive methane emissions. Here we present estimates for methane emissions as contributors to the GHG footprint of shale gas compared to conventional gas.

Our analysis uses the most recently available data, relying particularly on a technical background document on GHG emissions from the oil and gas industry (EPA 2010) and materials discussed in that report, and a report on natural gas losses on federal lands from the General Accountability Office (GAO 2010). The

EPA (2010) report is the first update on emission factors by the agency since 1996 (Harrison et al. 1996). The earlier report served as the basis for the national GHG inventory for the past decade. However, that study was not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed facilities of companies that voluntarily participated (Kirchgessner et al. 1997). The new EPA (2010) report notes that the 1996 "study was conducted at a time when methane emissions were not a significant concern in the discussion about GHG emissions" and that emission factors from the 1996 report "are outdated and potentially understated for some emissions sources." Indeed, emission factors presented in EPA (2010) are much higher, by orders of magnitude for some sources.

1 Fugitive methane emissions during well completion

Shale gas is extracted by high-volume hydraulic fracturing. Large volumes of water are forced under pressure into the shale to fracture and re-fracture the rock to boost gas flow. A significant amount of this water returns to the surface as flow-back within the first few days to weeks after injection and is accompanied by large quantities of methane (EPA 2010). The amount of methane is far more than could be dissolved in the flow-back fluids, reflecting a mixture of fracture-return fluids and methane gas. We have compiled data from 2 shale gas formations and 3 tight-sand gas formations in the U.S. Between 0.6% and 3.2% of the life-time production of gas from wells is emitted as methane during the flow-back period (Table 1). We include tight-sand formations since flow-back emissions and the patterns of gas production over time are similar to those for shale (EPA 2010). Note that the rate of methane emitted during flow-back (column B in Table 1) correlates well to the initial production rate for the well following completion (column C in Table 1). Although the data are limited, the variation across the basins seems reasonable: the highest methane emissions during flow-back were in the Haynesville, where initial pressures and initial production were very high, and the lowest emissions were in the Uinta, where the flow-back period was the shortest and initial production following well completion was low. However, we note that the data used in Table 1 are not well documented, with many values based on PowerPoint slides from EPA-sponsored workshops. For this paper, we therefore choose to represent gas losses from flow-back fluids as the mean value from Table 1: 1.6%.

More methane is emitted during "drill-out," the stage in developing unconventional gas in which the plugs set to separate fracturing stages are drilled out to release gas for production. EPA (2007) estimates drill-out emissions at 142×10^3 to 425×10^3 m^3 per well. Using the mean drill-out emissions estimate of 280×10^3 m^3 (EPA 2007) and the mean life-time gas production for the 5 formations in Table 1 (85×10^6 m^3), we estimate that 0.33% of the total life-time production of wells is emitted as methane during the drill-out stage. If we instead use the average life-time production for a larger set of data on 12 formations (Wood et al. 2011), 45×10^6 m^3, we estimate a percentage emission of 0.62%. More effort is needed to determine drill-out emissions on individual formation. Meanwhile, in this paper we use the conservative estimate of 0.33% for drill-out emissions.

Combining losses associated with flow-back fluids (1.6%) and drill out (0.33%), we estimate that 1.9% of the total production of gas from an unconventional shale-gas

Table 1 Methane emissions during the flow-back period following hydraulic fracturing, initial gas production rates following well completion, life-time gas production of wells, and the methane emitted during flow-back expressed as a percentage of the life-time production for five unconventional wells in the United States

	(A) Methane emitted during flow-back (10^3 m^3)[a]	(B) Methane emitted per day during flow-back (10^3 m^3 day^{-1})[b]	(C) Initial gas production at well completion (10^3 m^3 day^{-1})[c]	(D) Life-time production of well (10^6 m^3)[d]	(E) Methane emitted during flow-back as % of life-time production[e]
Haynesville (Louisiana, shale)	6,800	680	640	210	3.2
Barnett (Texas, shale)	370	41	37	35	1.1
Piceance (Colorado, tight sand)	710	79	57	55	1.3
Uinta (Utah, tight sand)	255	51	42	40	0.6
Den-Jules (Colorado, tight sand)	140	12	11	?	?

Flow-back is the return of hydraulic fracturing fluids to the surface immediately after fracturing and before well completion. For these wells, the flow-back period ranged from 5 to 12 days

[a]Haynesville: average from Eckhardt et al. (2009); Piceance: EPA (2007); Barnett: EPA (2004); Uinta: Samuels (2010); Denver-Julesburg: Bracken (2008)

[b]Calculated by dividing the total methane emitted during flow-back (column A) by the duration of flow-back. Flow-back durations were 9 days for Barnett (EPA 2004), 8 days for Piceance (EPA 2007), 5 days for Uinta (Samuels 2010), and 12 days for Denver-Julesburg (Bracken 2008); median value of 10 days for flow-back was assumed for Haynesville

[c]Haynesville: http://shale.typepad.com/haynesvilleshale/2009/07/chesapeake-energy-haynesville-shale-decline-curve.html1/7/2011 and http://oilshalegas.com/haynesvilleshalestocks.html; Barnett: http://oilshalegas.com/barnettshale.html; Piceance: Kruuskraa (2004) and Henke (2010); Uinta: http://www.epmag.com/archives/newsComments/6242.htm; Denver-Julesburg: http://www.businesswire.com/news/home/20100924005169/en/Synergy-Resources-Corporation-Reports-Initial-Production-Rates

[d]Based on averages for these basins. Haynesville: http://shale.typepad.com/haynesvilleshale/decline-curve/); Barnett: http://www.aapg.org/explorer/2002/07jul/barnett_shale.cfm and Wood et al. (2011); Piceance: Kruuskraa (2004); Uinta: http://www.epmag.com/archives/newsComments/6242.htm

[e]Calculated by dividing column (A) by column (D)

Table 2 Fugitive methane emissions associated with development of natural gas from conventional wells and from shale formations (expressed as the percentage of methane produced over the lifecycle of a well)

	Conventional gas	Shale gas
Emissions during well completion	0.01%	1.9%
Routine venting and equipment leaks at well site	0.3 to 1.9%	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%	0 to 0.26%
Emissions during gas processing	0 to 0.19%	0 to 0.19%
Emissions during transport, storage, and distribution	1.4 to 3.6%	1.4 to 3.6%
Total emissions	1.7 to 6.0%	3.6 to 7.9%

See text for derivation of estimates and supporting information

well is emitted as methane during well completion (Table 2). Again, this estimate is uncertain but conservative.

Emissions are far lower for conventional natural gas wells during completion, since conventional wells have no flow-back and no drill out. An average of 1.04×10^3 m^3 of methane is released per well completed for conventional gas (EPA 2010), corresponding to 1.32×10^3 m^3 natural gas (assuming 78.8% methane content of the gas). In 2007, 19,819 conventional wells were completed in the US (EPA 2010), so we estimate a total national emission of 26×10^6 m^3 natural gas. The total national production of onshore conventional gas in 2007 was 384×10^9 m^3 (EIA 2010b). Therefore, we estimate the average fugitive emissions at well completion for conventional gas as 0.01% of the life-time production of a well (Table 2), three orders of magnitude less than for shale gas.

2 Routine venting and equipment leaks

After completion, some fugitive emissions continue at the well site over its lifetime. A typical well has 55 to 150 connections to equipment such as heaters, meters, dehydrators, compressors, and vapor-recovery apparatus. Many of these potentially leak, and many pressure relief valves are designed to purposefully vent gas. Emissions from pneumatic pumps and dehydrators are a major part of the leakage (GAO 2010). Once a well is completed and connected to a pipeline, the same technologies are used for both conventional and shale gas; we assume that these post-completion fugitive emissions are the same for shale and conventional gas. GAO (2010) concluded that 0.3% to 1.9% of the life-time production of a well is lost due to routine venting and equipment leaks (Table 2). Previous studies have estimated routine well-site fugitive emissions as approximately 0.5% or less (Hayhoe et al. 2002; Armendariz 2009) and 0.95% (Shires et al. 2009). Note that none of these estimates include accidents or emergency vents. Data on emissions during emergencies are not available and have never, as far as we can determine, been used in any estimate of emissions from natural gas production. Thus, our estimate of 0.3% to 1.9% leakage is conservative. As we discuss below, the 0.3% reflects use of best available technology.

Additional venting occurs during “liquid unloading.” Conventional wells frequently require multiple liquid-unloading events as they mature to mitigate water intrusion as reservoir pressure drops. Though not as common, some unconventional wells may also require unloading. Empirical data from 4 gas basins indicate that 0.02

to 0.26% of total life-time production of a well is vented as methane during liquid unloading (GAO 2010). Since not all wells require unloading, we set the range at 0 to 0.26% (Table 2).

3 Processing losses

Some natural gas, whether conventional or from shale, is of sufficient quality to be "pipeline ready" without further processing. Other gas contains sufficient amounts of heavy hydrocarbons and impurities such as sulfur gases to require removal through processing before the gas is piped. Note that the quality of gas can vary even within a formation. For example, gas from the Marcellus shale in northeastern Pennsylvania needs little or no processing, while gas from southwestern Pennsylvania must be processed (NYDEC 2009). Some methane is emitted during this processing. The default EPA facility-level fugitive emission factor for gas processing indicates a loss of 0.19% of production (Shires et al. 2009). We therefore give a range of 0% (i.e. no processing, for wells that produce "pipeline ready" gas) to 0.19% of gas produced as our estimate of processing losses (Table 2). Actual measurements of processing plant emissions in Canada showed fourfold greater leakage than standard emission factors of the sort used by Shires et al. (2009) would indicate (Chambers 2004), so again, our estimates are very conservative.

4 Transport, storage, and distribution losses

Further fugitive emissions occur during transport, storage, and distribution of natural gas. Direct measurements of leakage from transmission are limited, but two studies give similar leakage rates in both the U.S. (as part of the 1996 EPA emission factor study; mean value of 0.53%; Harrison et al. 1996; Kirchgessner et al. 1997) and in Russia (0.7% mean estimate, with a range of 0.4% to 1.6%; Lelieveld et al. 2005). Direct estimates of distribution losses are even more limited, but the 1996 EPA study estimates losses at 0.35% of production (Harrison et al. 1996; Kirchgessner et al. 1997). Lelieveld et al. (2005) used the 1996 emission factors for natural gas storage and distribution together with their transmission estimates to suggest an overall average loss rate of 1.4% (range of 1.0% to 2.5%). We use this 1.4% leakage as the likely lower limit (Table 2). As noted above, the EPA 1996 emission estimates are based on limited data, and Revkin and Krauss (2009) reported "government scientists and industry officials caution that the real figure is almost certainly higher." Furthermore, the IPCC (2007) cautions that these "bottom-up" approaches for methane inventories often underestimate fluxes.

Another way to estimate pipeline leakage is to examine "lost and unaccounted for gas," e.g. the difference between the measured volume of gas at the wellhead and that actually purchased and used by consumers. At the global scale, this method has estimated pipeline leakage at 2.5% to 10% (Crutzen 1987; Cicerone and Oremland 1988; Hayhoe et al. 2002), although the higher value reflects poorly maintained pipelines in Russia during the Soviet collapse, and leakages in Russia are now far less (Lelieveld et al. 2005; Reshetnikov et al. 2000). Kirchgessner et al. (1997) argue against this approach, stating it is "subject to numerous errors including gas theft, variations in temperature and pressure, billing cycle differences, and meter inaccuracies." With the exception of theft, however, errors should be randomly distributed and should not bias the leakage estimate high or low. Few recent data on lost and unaccounted gas are publicly available, but statewide data for Texas averaged 2.3% in 2000 and 4.9% in 2007 (Percival 2010). In 2007, the State of Texas passed new legislation to regulate lost and unaccounted for gas; the legislation originally proposed a 5% hard cap which was dropped in the face of industry opposition (Liu 2008; Percival 2010). We take the mean of the 2000 and 2007 Texas data for missing and unaccounted gas (3.6%) as the upper limit of downstream losses (Table 2), assuming that the higher value for 2007 and lower value for 2000 may potentially reflect random variation in billing cycle differences. We believe this is a conservative upper limit, particularly given the industry resistance to a 5% hard cap.

Our conservative estimate of 1.4% to 3.6% leakage of gas during transmission, storage, and distribution is remarkably similar to the 2.5% "best estimate" used by Hayhoe et al. (2002). They considered the possible range as 0.2% and 10%.

5 Contribution of methane emissions to the GHG footprints of shale gas and conventional gas

Summing all estimated losses, we calculate that during the life cycle of an average shale-gas well, 3.6 to 7.9% of the total production of the well is emitted to the atmosphere as methane (Table 2). This is at least 30% more and perhaps more than twice as great as the life-cycle methane emissions we estimate for conventional gas, 1.7% to 6%. Methane is a far more potent GHG than is CO_2, but methane also has a tenfold shorter residence time in the atmosphere, so its effect on global warming attenuates more rapidly (IPCC 2007). Consequently, to compare the global warming potential of methane and CO_2 requires a specific time horizon. We follow Lelieveld et al. (2005) and present analyses for both 20-year and 100-year time horizons. Though the 100-year horizon is commonly used, we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades (IPCC 2007). We use recently modeled values for the global warming potential of methane compared to CO_2: 105 and 33 on a mass-to-mass basis for 20 and 100 years, respectively, with an uncertainty of plus or minus 23% (Shindell et al. 2009). These are somewhat higher than those presented in the 4th assessment report of the IPCC (2007), but better account for the interaction of methane with aerosols. Note that carbon-trading markets use a lower global-warming potential yet of only 21 on the 100-year horizon, but this is based on the 2nd IPCC (1995) assessment, which is clearly out of date on this topic. See Electronic Supplemental Materials for the methodology for calculating the effect of methane on GHG in terms of CO_2 equivalents.

Methane dominates the GHG footprint for shale gas on the 20-year time horizon, contributing 1.4- to 3-times more than does direct CO_2 emission (Fig. 1a). At this time scale, the GHG footprint for shale gas is 22% to 43% greater than that for conventional gas. When viewed at a time 100 years after the emissions, methane emissions still contribute significantly to the GHG footprints, but the effect is diminished by the relatively short residence time of methane in the atmosphere. On this time frame, the GHG footprint for shale gas is 14% to 19% greater than that for conventional gas (Fig. 1b).

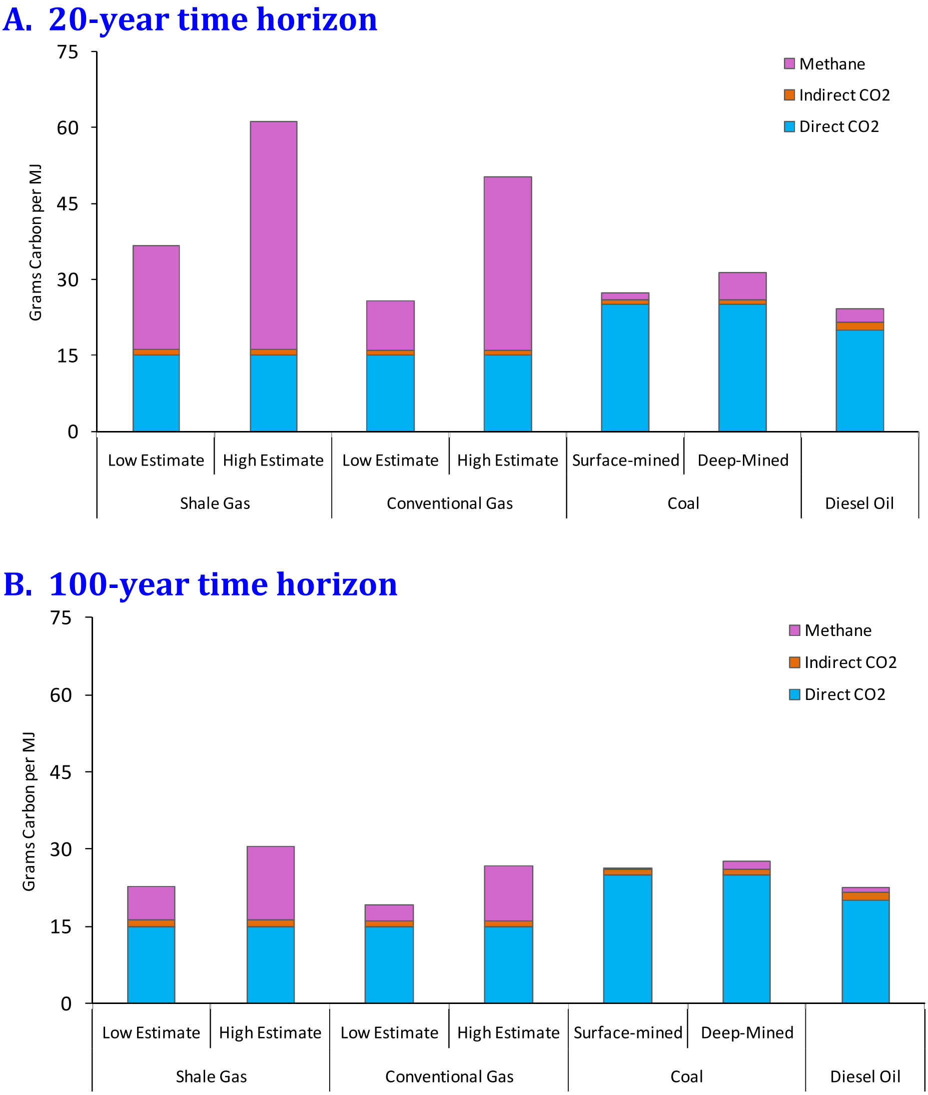


Fig. 1 Comparison of greenhouse gas emissions from shale gas with low and high estimates of fugitive methane emissions, conventional natural gas with low and high estimates of fugitive methane emissions, surface-mined coal, deep-mined coal, and diesel oil. **a** is for a 20-year time horizon, and **b** is for a 100-year time horizon. Estimates include direct emissions of CO_2 during combustion (*blue bars*), indirect emissions of CO_2 necessary to develop and use the energy source (*red bars*), and fugitive emissions of methane, converted to equivalent value of CO_2 as described in the text (*pink bars*). Emissions are normalized to the quantity of energy released at the time of combustion. The conversion of methane to CO_2 equivalents is based on global warming potentials from Shindell et al. (2009) that include both direct and indirect influences of methane on aerosols. Mean values from Shindell et al. (2009) are used here. Shindell et al. (2009) present an uncertainty in these mean values of plus or minus 23%, which is not included in this figure

6 Shale gas versus other fossil fuels

Considering the 20-year horizon, the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion (Fig. 1a; see Electronic Supplemental Materials for derivation of the estimates for diesel oil and coal). Over the 100-year frame, the GHG footprint is comparable to that for coal: the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions (Fig. 1b). For the 20 year horizon, the GHG footprint of shale gas is at least 50% greater than for oil, and perhaps 2.5-times greater. At the 100-year time scale, the footprint for shale gas is similar to or 35% greater than for oil.

We know of no other estimates for the GHG footprint of shale gas in the peer-reviewed literature. However, we can compare our estimates for conventional gas with three previous peer-reviewed studies on the GHG emissions of conventional natural gas and coal: Hayhoe et al. (2002), Lelieveld et al. (2005), and Jamarillo et al. (2007). All concluded that GHG emissions for conventional gas are less than for coal, when considering the contribution of methane over 100 years. In contrast, our analysis indicates that conventional gas has little or no advantage over coal even over the 100-year time period (Fig. 1b). Our estimates for conventional-gas methane emissions are in the range of those in Hayhoe et al. (2002) but are higher than those in Lelieveld et al. (2005) and Jamarillo et al. (2007) who used 1996 EPA emission factors now known to be too low (EPA 2010). To evaluate the effect of methane, all three of these studies also used global warming potentials now believed to be too low (Shindell et al. 2009). Still, Hayhoe et al. (2002) concluded that under many of the scenarios evaluated, a switch from coal to conventional natural gas could aggravate global warming on time scales of up to several decades. Even with the lower global warming potential value, Lelieveld et al. (2005) concluded that natural gas has a greater GHG footprint than oil if methane emissions exceeded 3.1% and worse than coal if the emissions exceeded 5.6% on the 20-year time scale. They used a methane global warming potential value for methane from IPCC (1995) that is only 57% of the new value from Shindell et al. (2009), suggesting that in fact methane emissions of only 2% to 3% make the GHG footprint of conventional gas worse than oil and coal. Our estimates for fugitive shale-gas emissions are 3.6 to 7.9%.

Our analysis does not consider the efficiency of final use. If fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation (see Electronic Supplemental Materials). However, this does not greatly affect our overall conclusion: the GHG footprint of shale gas approaches or exceeds coal even when used to generate electricity (Table in Electronic Supplemental Materials). Further, shale-gas is promoted for other uses, including as a heating and transportation fuel, where there is little evidence that efficiencies are superior to diesel oil.

7 Can methane emissions be reduced?

The EPA estimates that 'green' technologies can reduce gas-industry methane emissions by 40% (GAO 2010). For instance, liquid-unloading emissions can be greatly reduced with plunger lifts (EPA 2006; GAO 2010); industry reports a 99% venting reduction in the San Juan basin with the use of smart-automated plunger lifts (GAO 2010). Use of flash-tank separators or vapor recovery units can reduce dehydrator emissions by 90% (Fernandez et al. 2005). Note, however, that our lower range of estimates for 3 out of the 5 sources as shown in Table 2 already reflect the use of best technology: 0.3% lower-end estimate for routine venting and leaks at well sites (GAO 2010), 0% lower-end estimate for emissions during liquid unloading, and 0% during processing.

Methane emissions during the flow-back period in theory can be reduced by up to 90% through Reduced Emission Completions technologies, or REC (EPA 2010). However, REC technologies require that pipelines to the well are in place prior to completion, which is not always possible in emerging development areas. In any event, these technologies are currently not in wide use (EPA 2010).

If emissions during transmission, storage, and distribution are at the high end of our estimate (3.6%; Table 2), these could probably be reduced through use of better storage tanks and compressors and through improved monitoring for leaks. Industry has shown little interest in making the investments needed to reduce these emission sources, however (Percival 2010).

Better regulation can help push industry towards reduced emissions. In reconciling a wide range of emissions, the GAO (2010) noted that lower emissions in the Piceance basin in Colorado relative to the Uinta basin in Utah are largely due to a higher use of low-bleed pneumatics in the former due to stricter state regulations.

8 Conclusions and implications

The GHG footprint of shale gas is significantly larger than that from conventional gas, due to methane emissions with flow-back fluids and from drill out of wells during well completion. Routine production and downstream methane emissions are also large, but are the same for conventional and shale gas. Our estimates for these routine and downstream methane emission sources are within the range of those reported by most other peer-reviewed publications inventories (Hayhoe et al. 2002; Lelieveld et al. 2005). Despite this broad agreement, the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas.

The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming. We do not intend that our study be used to justify the continued use of either oil or coal, but rather to demonstrate that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming.

Finally, we note that carbon-trading markets at present under-value the greenhouse warming consequences of methane, by focusing on a 100-year time horizon and by using out-of-date global warming potentials for methane. This should be corrected, and the full GHG footprint of unconventional gas should be used in planning for alternative energy futures that adequately consider global climate change.

Acknowledgements Preparation of this paper was supported by a grant from the Park Foundation and by an endowment funds of the David R. Atkinson Professorship in Ecology & Environmental Biology at Cornell University. We thank R. Alvarez, C. Arnold, P. Artaxo, A. Chambers, D. Farnham, P. Jamarillo, N. Mahowald, R. Marino, R. McCoy, J. Northrup, S. Porder, M. Robertson, B. Sell, D. Shrag, L. Spaeth, and D. Strahan for information, encouragement, advice, and feedback on our analysis and manuscript. We thank M. Hayn for assistance with the figures. Two anonymous reviewers and Michael Oppenheimer provided very useful comments on an earlier version of this paper.

References

Armendariz A (2009) Emissions from natural gas production in the Barnett shale area and opportunities for cost-effective improvements. Report prepared for Environmental Defense Fund, Austin TX

Bracken K (2008) Reduced emission completions in DJ basin and natural buttes. Presentation given at EPA/GasSTAR Producers Technology Transfer Workshop. Rock Springs Wyoming, 1 May 2008. http://www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/rocksprings5.pdf

Chambers AK (2004) Optical measurement technology for fugitive emissions from upstream oil and gas facilities. Report prepared for Petroleum Technology Alliance Canada by Carbon and Energy Management, Alberta Research Council, Edmonton, Alberta

Cicerone RJ, Oremland R (1988) Biogeochemical aspects of atmospheric methane. Global Biogeochem. Cycles 2:299–327

Council of Scientific Society Presidents (2010) Letter from the council to President Obama and senior administration officials, dated May 4, 2010. Council of Scientific Society Presidents, 1155 16th Avenue NW, Washington, DC 20036. Available at http://www.eeb.cornell.edu/howarth/CCSP%20letter%20on%20energy%20&%20environment.pdf

Crutzen PJ (1987) Role of the tropics in atmospheric chemistry. In: Dickinson R (ed) Geophysiology of Amazonia. Wiley, NY, pp 107–129

Eckhardt M, Knowles B, Maker E, Stork P (2009) IHS U.S. Industry Highlights. (IHS) Houston, TX, Feb–Mar 2009. http://www.gecionline.com/2009-prt-7-final-reviews

EIA (2010a) Annual energy outlook 2011 early release overview. DOE/EIA-0383ER(2011). Energy Information Agency, U.S. Department of Energy. http://www.eia.gov/forecasts/aeo/pdf/0383er(2011).pdf. Accessed 3 January 2011

EIA (2010b) Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm

EPA (2004) Green completions. Natural Gas STAR Producer's Technology Transfer Workshop, 21 September 2004. http://epa.gov/gasstar/workshops/techtransfer/2004/houston-02.html

EPA (2006) Lessons learned: options for reducing methane emissions from pneumatic devices in the natural gas industry. U.S. EPA/ Gas STAR. http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf

EPA (2007) Reducing methane emissions during completion operations. Natural Gas STAR Producer's Technology Transfer Workshop, 11 September 2007. http://epa.gov/gasstar/documents/workshops/glenwood-2007/04_recs.pdf

EPA (2010) Greenhouse gas emissions reporting from the petroleum and natural gas industry. Background Technical Support Document. http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf. Accessed 3 January 2011

Fernandez R, Petrusak R, Robinson D, Zavadil D (2005) Cost-Effective methane emissions reductions for small and midsize natural gas producers. Reprinted from the June 2005 issue of Journal of Petroleum Technology. http://www.icfi.com/Markets/Environment/doc_files/methane-emissions.pdf

GAO (2010) 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 U.S. General Accountability Office Washington DC. http://www.gao.gov/new.items/d1134.pdf

Harrison MR, Shires TM, Wessels JK, Cowgill RM (1996) Methane emissions from the natural gas industry. Executive summary, vol 1. EPA-600/R-96-080a. U.S. Environmental Protection Agency, Office of Research and Development, Washington, DC
Hayhoe K, Kheshgi HS, Jain AK, Wuebbles DJ (2002) Substitution of natural gas for coal: climatic effects of utility sector emissions. Climatic Change 54:107–139
Henke D (2010) Encana, USA division overview. Encana Natural Gas, investors presentation. http://www.encana.com/investors/presentations/investorday/pdfs/usa-division-overview.pdf
Intergovernmental Panel on Climate Change (1995) IPCC second assessment. Climate Change, 1995. http://www.ipcc.ch/pdf/climate-changes-1995/ipcc-2nd-assessment/2nd-assessment-en.pdf
Intergovernmental Panel on Climate Change (2007) IPCC fourth assessment report (AR4). Working Group 1, The Physical Science Basis. http://www.ipcc.ch/publications_and_data/ar4/wg1/en/contents.html
Jamarillo P, Griffin WM, Mathews HS (2007) Comparative life-cycle air emissions of coal, domestic natural gas, LNG, and SNG for electricity generation. Environ Sci Technol 41:6290–6296
Kirchgessner DA, Lott RA, Cowgill RM, Harrison MR, Shires TM (1997) Estimate of methane emissions from the US natural gas industry. Chemosphere 35: 1365–1390
Kruuskraa VA (2004) Tight gas sands development—How to dramatically improve recovery efficiency. GasTIPS, Winter 2004. http://media.godashboard.com/gti/4ReportsPubs/4_7GasTips/Winter04/TightGasSandsDEvelopment-HowToDramaticallyImproveRecoveryEfficiency.pdf
Lassey KR, Lowe DC, Smith AM (2007) The atmospheric cycling of radiomethane and the “fossil fraction” of the methane source. Atmos Chem Phys 7:2141–2149
Lelieveld J, Lechtenbohmer S, Assonov SS, Brenninkmeijer CAM, Dinest C, Fischedick M, Hanke T (2005) Low methane leakage from gas pipelines. Nature 434:841–842
Liu AE (2008) Overview: pipeline accounting and leak detection by mass balance, theory and hardware implementation. Quantum Dynamics, Woodland Hills. Available at http://www.pstrust.org/library/docs/massbalance_ld.pdf
National Research Council (2009) Hidden costs of energy: unpriced consequences of energy production and use. National Academy of Sciences Press, Washington
New York Department of Environmental Conservation (2009) Draft supplemental generic environmental impact statement on the oil, gas and solution mining regulatory program. http://www.dec.ny.gov/energy/58440.html
Nisbet EG, Manning MR, Lowry D, Lassey KR (2000) Methane and the framework convention on climate change, A61F-10, Eos Trans. AGU 81(48), Fall Meet. Suppl
Pacala S, Socolow R (2004) Stablization wedges: solving the climate problem for the next 50 years with current technologies. Science 305:968–972
Percival P (2010) Update on “lost and unaccounted for” natural gas in Texas. Basin Oil and Gas. Issue 32. http://fwbog.com/index.php?page=article&article=248
Reshetnikov AI, Paramonova NN, Shashkov AA (2000) An evaluation of historical methane emissions from the Soviet gas industry. JGR 105:3517–3529
Revkin A, Krauss C (2009) By degrees: curbing emissions by sealing gas leaks. New York Times, 14 October 2009. Available at http://www.nytimes.com/2009/10/15/business/energy-environment/15degrees.html
Samuels J (2010) Emission reduction strategies in the greater natural buttes. Anadarko Petroleum Corporation. EPA Gas STAR, Producers Technology Transfer Workshop Vernal, Utah, 23 March 2010. http://www.epa.gov/gasstar/documents/workshops/vernal-2010/03_anadarko.pdf
Santoro R, Howarth RW, Ingraffea T (2011) Life cycle greenhouse gas emissions inventory of Marcellus shale gas. Technical report of the Agriculture, Energy, & Environment Program, Cornell University, Ithaca, NY. To be archived and made available on-line
Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. Science 326:716–718
Shires TM, Loughran, CJ, Jones S, Hopkins E (2009) Compendium of greenhouse gas emissions methodologies for the oil and natural gas industry. Prepared by URS Corporation for the American Petroleum Institute (API). API, Washington DC
Wood R, Gilbert P, Sharmina M, Anderson K, Fottitt A, Glynn S, Nicholls F (2011) Shale gas: a provisional assessment of climate change and environmental impacts. Tyndall Center, University of Manchester, Manchester, England. http://www.tyndall.ac.uk/sites/default/files/tyndall-coop_shale_gas_report_final.pdf

COMMENT

D. ACKER/BLOOMBERG VIA GETTY

A drilling operation in Bradford County, Pennsylvania: one of the many places where shale rocks are fractured to release oil and gas.

Should fracking stop?

Extracting gas from shale increases the availability of this resource, but the health and environmental risks may be too high.

POINT

Yes, it's too high risk

Natural gas extracted from shale comes at too great a cost to the environment, say Robert W. Howarth *and* Anthony Ingraffea.

Natural gas from shale is widely promoted as clean compared with oil and coal, a 'win–win' fuel that can lessen emissions while still supplying abundant fossil energy over coming decades until a switch to renewable energy sources is made. But shale gas isn't clean, and shouldn't be used as a bridge fuel.

Shale rock formations can contain vast amounts of natural gas (which is mostly methane). Until quite recently, most of PAGE 272 ▶

COUNTERPOINT

No, it's too valuable

Fracking is crucial to global economic stability; the economic benefits outweigh the environmental risks, says Terry Engelder.

After a career in geological research on one of the world's largest gas supplies, I am a born-again 'cornucopian'. I believe that there is enough domestic gas to meet our needs for the foreseeable future thanks to technological advances in hydraulic fracturing. According to IHS, a business-information company in Douglas County, Colorado, the estimated recoverable gas from US shale source rocks using fracking is about 42 trillion cubic metres, almost PAGE 274 ▶

POINT: FRACKING: TOO HIGH RISK ▶ this gas was not economically obtainable, because shale is far less permeable than the rock formations exploited for conventional gas. Over the past decade or so, two new technologies have combined to allow extraction of shale gas: 'high-volume, slick-water hydraulic fracturing' (also known as 'fracking'), in which high-pressure water with additives is used to increase fissures in the rock; and precision drilling of wells that can follow the contour of a shale layer closely for 3 kilometres or more at depths of more than 2 kilometres (see 'Fracking for fuel'). Industry first experimented with these two technologies in Texas about 15 years ago. Significant shale-gas production in other states, including Arkansas, Pennsylvania and Louisiana, began only in 2007–09. Outside North America, only a handful of shale-gas wells have been drilled.

Industry sources claim that they have used fracking to produce more than 1 million oil and natural gas wells since the late 1940s. However, less than 2% of the well fractures since the 1940s have used the high-volume technology necessary to get gas from shale, almost all of these in the past ten years. This approach is far bigger and riskier than the conventional fracking of earlier years. An average of 20 million litres of water are forced under pressure into each well, combined with large volumes of sand or other materials to help keep the fissures open, and 200,000 litres of acids, biocides, scale inhibitors, friction reducers and surfactants. The fracking of a conventional well uses at most 1–2% of the volume of water used to extract shale gas[1].

Many of the fracking additives are toxic, carcinogenic or mutagenic. Many are kept secret. In the United States, such secrecy has been abetted by the 2005 'Halliburton loophole' (named after an energy company headquartered in Houston, Texas), which exempts fracking from many of the nation's major federal environmental-protection laws, including the Safe Drinking Water Act. In a 2-hectare site, up to 16 wells can be drilled, cumulatively servicing an area of up to 1.5 square kilometres, and using 300 million litres or more of water and additives. Around one-fifth of the fracking fluid flows back up the well to the surface in the first two weeks, with more continuing to flow out over the lifetime of the well. Fracking also extracts natural salts, heavy metals, hydrocarbons and radioactive materials from the shale, posing risks to ecosystems and public health when these return to the surface. This flowback is collected in open pits or large tanks until treated, recycled or disposed of.

Because shale-gas development is so new, scientific information on the environmental costs is scarce. Only this year have studies begun to appear in peer-reviewed journals, and these give reason for pause. We call for a moratorium on shale-gas development to allow for better study of the cumulative risks to water quality, air quality and global climate. Only with such comprehensive knowledge can appropriate regulatory frameworks be developed.

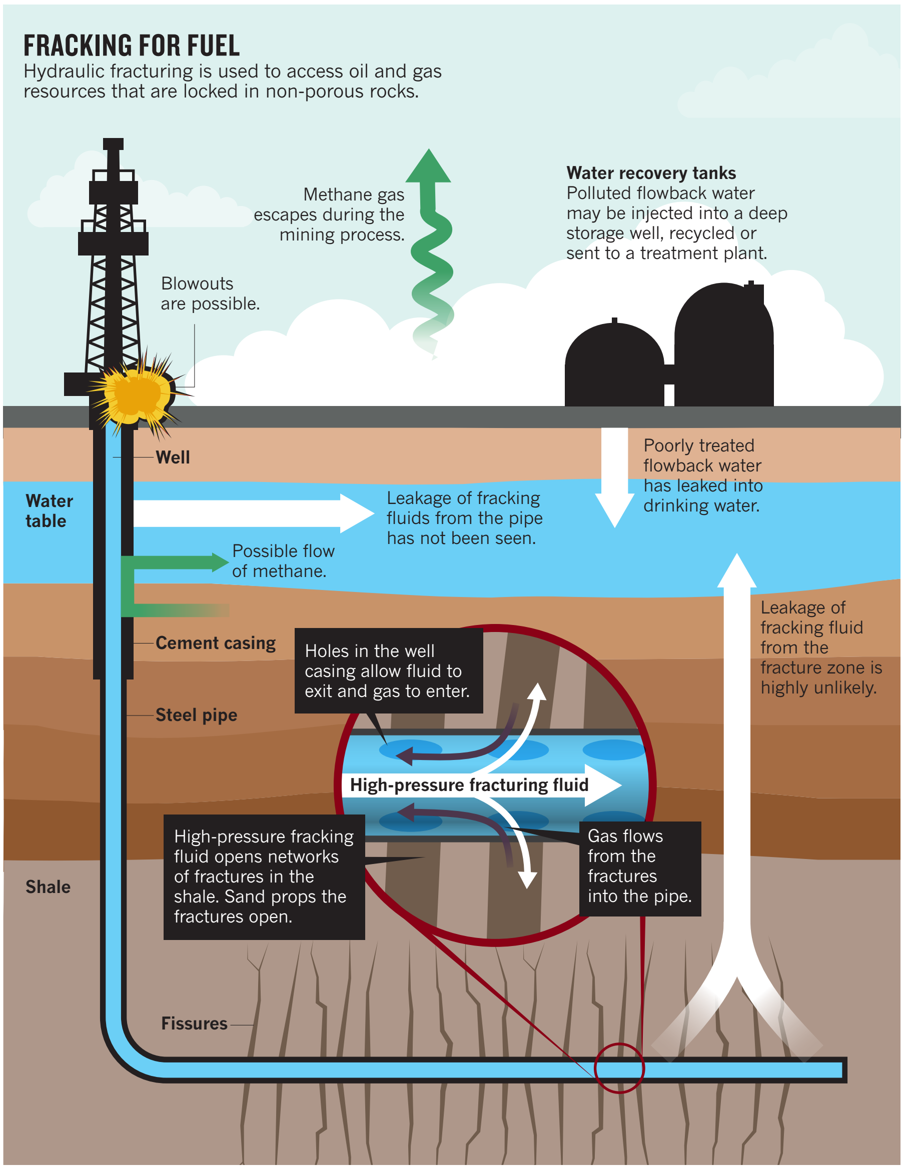
We have analysed the well-to-consumer lifecycle greenhouse-gas footprint of shale gas when used for heat generation (its main use), compared with conventional gas and other fossil fuels — the first estimate in the peer-reviewed literature[2]. Methane is a major component of this footprint, and we estimate that 3.6–7.9% of the lifetime production of a shale gas well (compared with 1.7–6% for conventional gas wells) is vented or leaked to the atmosphere from the well head, pipelines and storage facilities. In addition, carbon dioxide is released both directly through the burning of the gas for heat, and to a lesser extent indirectly through the process of developing the resource.

Methane is a potent greenhouse gas, so even small emissions matter. Over a 20-year time period, the greenhouse-gas footprint of shale gas is worse than that for coal or oil (see 'A daunting climate footprint'). The influence of methane is lessened over longer time scales, because methane does not stay in the atmosphere as long as carbon dioxide. Still, over 100 years, the footprint of shale gas remains comparable to that of oil or coal.

When used to produce electricity rather than heat, the greater efficiency of gas plants compared with coal plants slightly lessens the footprint of shale gas[3]. Even then, the total greenhouse-gas footprint from shale gas exceed those of coal at timescales of less than about 50 years.

Methane venting and leakage can be decreased by upgrading old pipelines and storage systems, and by applying better technology for capturing gas in the 2-week flowback period after fracking. But current economic incentives are not sufficient to drive such improvements; stringent regulation will be required. In July, the US Environmental Protection Agency released a draft rule that would push industry to reduce at least some methane emissions, in part focusing on post-fracking flowback. Nonetheless, our analysis[2] indicates that the greenhouse-gas footprint of shale gas is likely to remain large.

Another peer-reviewed study looked at



private water wells near fracking sites[4]. It found that about 75% of wells sampled within 1 kilometre of gas drilling in the Marcellus shale in Pennsylvania were contaminated with methane from the deep shale formations. Isotopic fingerprinting of the methane indicated that deep shale was the source of contamination, rather than biologically derived methane, which was present at much lower concentrations in water wells at greater distances from gas wells. The study found no fracking fluids in any of the drinking-water wells examined. This is good news, because these fluids contain hazardous materials, and methane itself is not toxic. However, methane poses a high risk of explosion at the levels found, and it suggests a potential for other gaseous substances in the shale to migrate with the methane and contaminate water wells over time.

Have fracking-return fluids contaminated drinking water? Yes, although the evidence is not as strong as for methane contamination, and none of the data has yet appeared in the peer-reviewed literature (although a series of articles in *The New York Times* documents the problem, for example go.nature.com/58hxot and go.nature.com/58koj3). Contamination can happen through blowouts, surface spills from storage facilities, or improper disposal of fracking fluids. In Texas, flowback fluids are disposed of through deep injection into abandoned gas or oil wells. But such wells are not available everywhere. In New York and Pennsylvania, some of the waste is treated in municipal sewage plants that weren't designed to handle these toxic and radioactive wastes. Subsequently, there has been contamination of tributaries of the Ohio River with barium, strontium and bromides from municipal wastewater treatment plants receiving fracking wastes[5]. This contamination apparently led to the formation of dangerous brominated hydrocarbons in municipal drinking-water supplies that relied on these surface waters, owing to interaction of the contaminants with organic matter during the chlorination process.

Shale-gas development — which uses huge diesel pumps to inject the water — also creates local air pollution, often at dangerous levels. Volatile hydrocarbons such as benzene (which occurs naturally in shale, and is a commonly used fracking additive) are one major concern. The state of Texas reports benzene concentrations in air in the Barnett shale area that sometimes exceed acute toxicity standards[6], and although the concentrations observed in the Marcellus shale area in Pennsylvania are lower[7] (with only 2,349 wells drilled at the time these air contaminants were reported, out of an expected total of 100,000), they are high enough to pose a risk of cancer from chronic exposure[8]. Emissions from drills, compressors, trucks and other machinery can lead to very high levels of ground-level ozone, as documented in parts of Colorado that had not experienced severe air pollution before shale-gas development[9].

"Have fracking-return fluids contaminated drinking water? Yes."

UNPROFITABLE PROGRESS

The argument for continuing shale-gas exploitation often hinges on the presumed gigantic size of the resource. But this may be exaggerated. The Energy Information Administration of the US Department of Energy estimates that 45% of US gas supply will come from shale gas by 2035 (with the vast majority of this replacing conventional gas, which has a lower greenhouse-gas footprint). Other gas industry observers are even more bullish. However, David Hughes, a geoscientist with more than 30 years experience with the Canadian Geological Survey, concludes in his report for the Post Carbon Institute, a non-profit group headquartered in Santa Rosa, California, that forecasts are likely to be overstated, perhaps greatly so[3]. Last month, the US Geological Survey released a new estimate of the amount of gas in the Marcellus shale formation (the largest shale-gas formation in the United States), concluding that the Department of Energy has over-estimated the resource by some five-fold[10].

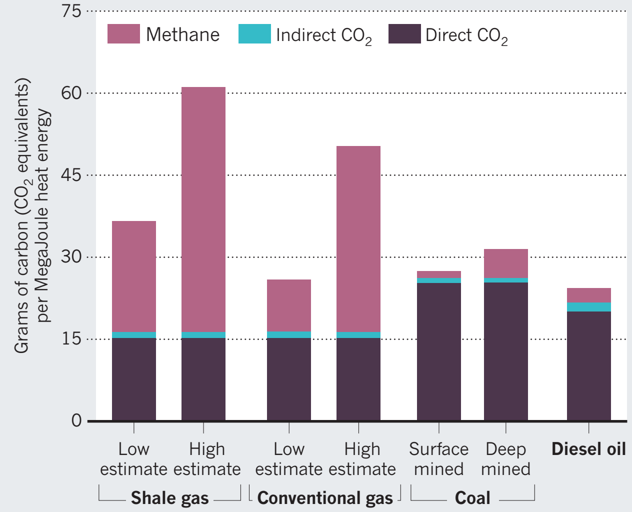
Shale gas may not be profitable at current prices, in part because production rates for shale-gas wells decline far more quickly than for conventional wells. Although very large resources undoubtedly exist in shale reservoirs, an unprecedented rate of well drilling and fracking would be required to meet the Department of Energy's projections, which might not be economic[3]. If so, the recent enthusiasm over shale gas could soon collapse, like the dot-com bubble.

Meanwhile, shale gas competes for investment with green energy technologies, slowing their development and distracting politicians and the public from developing a long-term sustainable energy policy.

With time, perhaps engineers can develop more appropriate ways to handle fracking-fluid return wastes, and perhaps the technology can be made more sustainable and less polluting in other ways. Meanwhile, the gas should remain safely in the shale, while society uses energy more efficiently and develops renewable energy sources more aggressively. ■

A DAUNTING CLIMATE FOOTPRINT

Over 20 years, shale gas is likely to have a greater greenhouse effect than conventional gas or other fossil fuels.



SOURCE: REF. 2

Robert W. Howarth *is in the Department of Ecology and Evolutionary Biology, Cornell University, Ithaca, New York, New York 14853, USA.* **Anthony Ingraffea** *is in the School of Civil and Environmental Engineering at Cornell University, Ithaca, New York, New York 14853, USA.*
e-mail: rwh2@cornell.edu

1. New York State Department of Environmental Conservation *Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program (Sept. 2011)*; available at: http://go.nature.com/yzponk
2. Howarth, R. W., Santoro, R. & Ingraffea, A. *Clim. Change* **106,** 679–690 (2011).
3. Hughes, D. *Will Natural Gas Fuel America in the 21st Century?* (Post Carbon Institute, 2011); available at: http://go.nature.com/gkboqm
4. Osborn, S. G., Vengosh, A., Warner, N. R. & Jackson, R. B. *Proc. Natl Acad. Sci. USA* **108,** 8172–8176 (2011).
5. Volz, C. D. *et al. Contaminant Characterization of Effluent from Pennsylvania Brine Treatment Inc., Josephine Facility Being Released into Blacklick Creek, Indiana County, Pennsylvania* (2011); available at: http://go.nature.com/5otd59
6. Texas Commission on Environmental Quality. *Barnett Shale Formation Area Monitoring Projects* (2010); available at: http://go.nature.com/v7k4re
7. Pennsylvania Department of Environmental Protection. *Northeastern Pennsylvania Marcellus Shale Short-Term Ambient Air Sampling Report* (2011); available at: http://go.nature.com/tjscnt
8. Talbott, E. O. *et al. Environ. Res.* **111,** 597–602 (2011).
9. Colorado Department of Public Health and Environment. *Public Health Implications of Ambient Air Exposures as Measured in Rural and Urban Oil & Gas Development Areas — an Analysis of 2008 Air Sampling Data* (2010); available at: http://go.nature.com/5tttna
10. Coleman, J. L. *et al. Assessment of Undiscovered Oil and Gas Resources of the Devonian Marcellus Shale of the Appalachian Basin Province, 2011.* US Geological Survey Fact Sheet 2011–3092 (2011); available at http://go.nature.com/8kejhm

COUNTERPOINT: FRACKING: TOO VALUABLE ▶ equal to the total conventional gas discovered in the United States over the past 150 years, and equivalent to about 65 times the current US annual consumption. During the past three years, about 50 billion barrels of additional recoverable oil have been found in shale oil deposits — more than 20% of the total conventional recoverable US oil resource. These 'tight' oil resources, which also require fracking to access, could generate 3 million barrels a day by 2020, offsetting one-third of current oil imports. International data aren't as well known, but the effect of fracking on global energy production will be huge (see 'Global gas reserves').

Global warming is a serious issue that fracking-related gas production can help to alleviate. In a world in which productivity is closely linked to energy expenditure, fracking will be vital to global economic stability until renewable or nuclear energy carry more of the workload. But these technologies face persistent problems of intermittency and lack of power density or waste disposal. Mankind's inexorable march towards 9 billion people will require a broad portfolio of energy resources, which can be gained only with breakthroughs such as fracking. Such breakthroughs should be promoted by policy that benefits the economy yet reduces overall greenhouse-gas emissions. Replacing coal with natural gas in power plants, for example, reduces the plants' greenhouse emissions by up to 50% (ref. 1).

At present, fracking accounts for 50% of locally produced natural gas (see 'US natural-gas production set to explode') and 33% of local petroleum. The gas industry in America accounts for US$385 billion in direct economic activity and nearly 3 million jobs. Because gas wells have notoriously steep production declines, stable supplies depend on a steady rate of new well completions. A moratorium on new wells would have an immediate and harsh effect on the US economy that would trigger a global ripple.

Global warming aside, there is no compelling environmental reason to ban hydraulic fracturing. There are environmental risks, but these can be managed through existing, and rapidly improving, technologies and regulations. It might be nice to have moratoria after each breakthrough to study the consequences (including the disposal of old batteries or radioactive waste), but because energy expenditure and economic health are so closely linked, global moratoria are not practical.

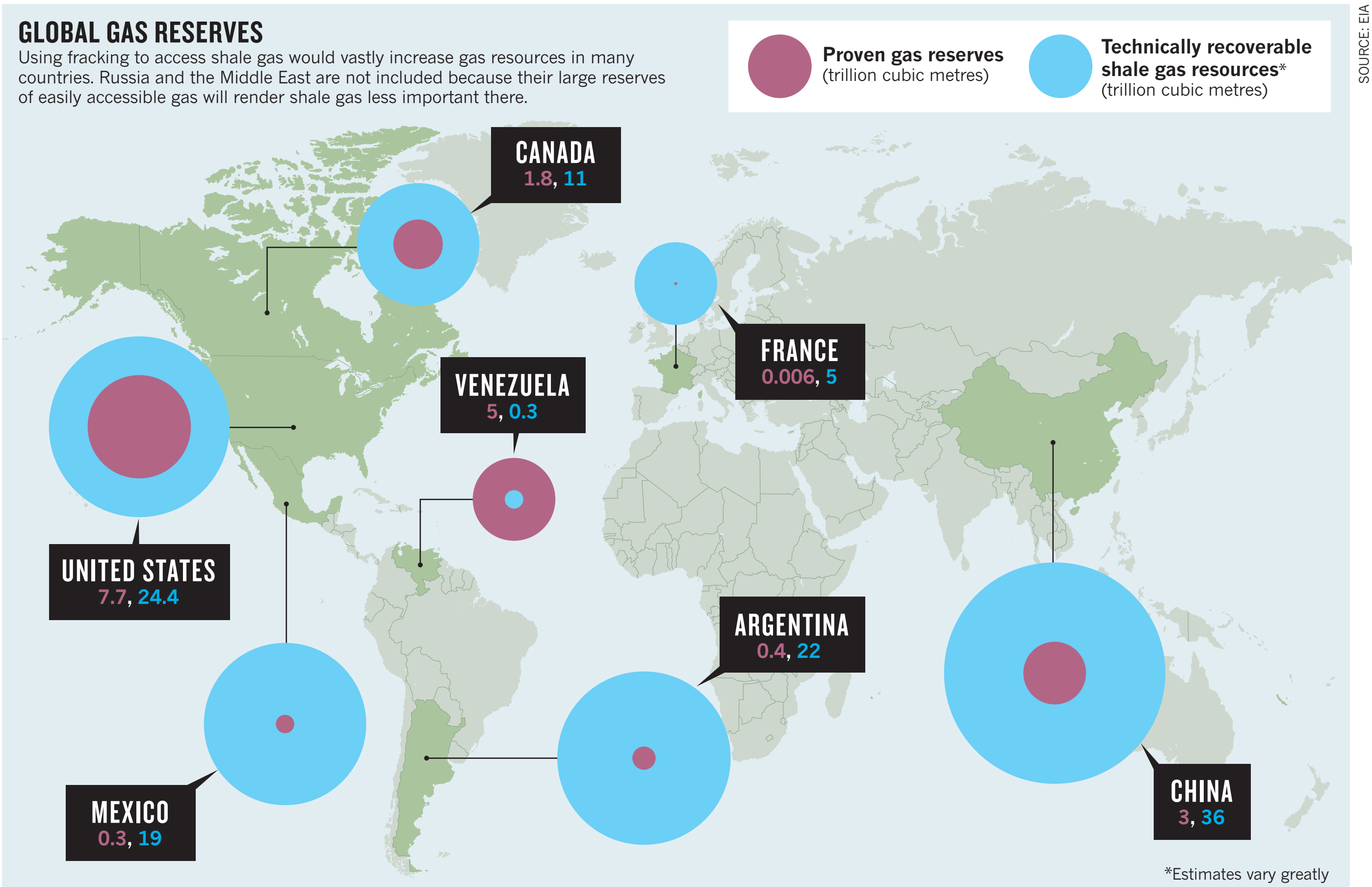
The gains in employment, economics and national security, combined with the potential to reduce global greenhouse-gas emissions if natural gas is managed properly, make a compelling case.

NO NEED FOR PANIC

I grew up with the sights, sounds and smells of the Bradford oil fields in New York state. My parents' small farm was over a small oil pool, with fumes from unplugged wells in the air and small oil seeps coating still waters. Before college, I worked these oil fields as a roustabout, mainly cleaning pipes and casings. Like me, most people living in such areas are not opposed to drilling, it seems. In my experience, such as during the recent hearings for the Pennsylvania Governor's Marcellus Shale Advisory Commission, activists from non-drilling regions outnumber those from drilling regions by approximately two to one.

Modern, massive hydraulic fracturing is very different from that used decades ago. Larger pads are required to accommodate larger drill rigs, pumps and water supplies. People usually infer from this that modern techniques have a greater impact on the environment. This isn't necessarily true. Although more water is used per well, there are far fewer wells per unit area. In the Bradford oil fields in the 1950s, a 640-acre parcel of land might have held more than 100 wells, requiring some 18 kilometres of roads, and with a lattice of surface pipelines. During the Marcellus development today, that same parcel of land is served by a single pad of five acres, with a 0.8-kilometre right-of-way for roads and pipelines.

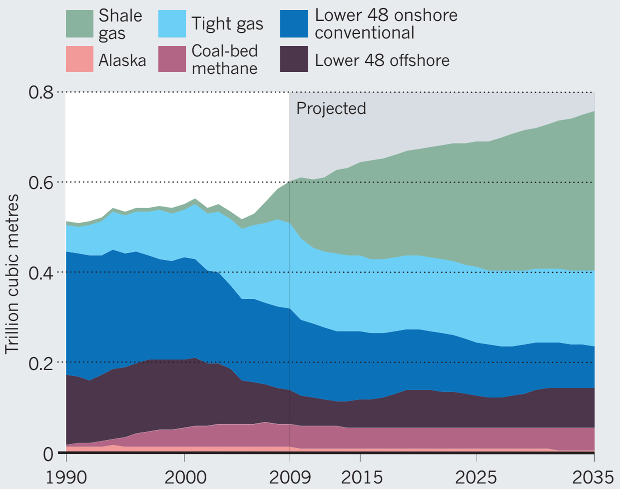
Although 'fracking' has emerged as a scare term in the press,



SOURCE: US EIA *ANNUAL ENERGY OUTLOOK 2011*

US NATURAL-GAS PRODUCTION SET TO EXPLODE

Shale-gas output already matches production from offshore wells in the lower 48 states (mainland US states excluding Alaska). Gas (shale and tight) extracted by fracking is set to overtake all other sources.



hydraulic fracturing is not so strange or frightening. The process happens naturally: high-pressure magma, water, petroleum and gases deep inside Earth can crack rock, helping to drive plate tectonics, rock metamorphism and the recycling of carbon dioxide between the mantle and the atmosphere.

Oil and gas have their origins in muds rich with organic matter in low-oxygen water bodies. Over millions of years, some of these deposits were buried and 'cooked' in the deep Earth, turning the organic matter into fossil fuel and the mud to shale rocks. In many areas, natural hydraulic fracturing allowed a large portion of oil and gas to escape from the dense, impermeable shale and migrate into neighbouring, more porous rocks. Some of this fossil fuel was trapped by cap rock, creating the conventional reserves that mankind has long tapped. The groundwater above areas that host such conventional deposits naturally contains methane, thanks to natural hydraulic fracturing of the rock and the upward seeping of gas into the water table over long time periods.

More than 96% of all oil and gas has been released from its original source rocks; industrial hydraulic fracturing aims to mimic nature to access the rest. As in nature, industrial fracking can be done with a wide variety of gases and liquids. Nitrogen can be used to open cracks in the shale, for example. But this is inefficient, because of the energy lost by natural decompression of the nitrogen gas. Water is more efficient, because very little energy is wasted in decompression. Sand is added to prop open the cracks, and compounds such as surface-tension reducers are added to improve gas recovery.

UNDER CONTROL

Two main environmental concerns are water use and water contamination. Millions of gallons of water are required to stimulate a well. In Pennsylvania, high rainfall means that water is abundant, and regulations ensure that operators stockpile rainwater during the wet season to use during drier months (thus the injection of massive volumes of water in the Bradford oil fields for secondary recovery of oil, once the well pressure has fallen, flew under the radar of environmentalists for half a century). Obtaining adequate water for industrial fracking in dry regions such as the Middle East and western China is a local concern, but is no reason for a global moratorium.

Press reports often repeat strident concerns about the chemicals added to fracking fluids. But many of these compounds are relatively benign. One commonly used additive is similar to simethicone, which is also used in antacids to reduce surface tension and turn small bubbles in the stomach into larger ones that can move along more easily. Many of the industrial additives are common in household products. Material safety data sheets for these additives are required by US regulation. Industry discloses additives on a website called FracFocus.org, run by state regulators.

Some people have expressed worries that fracking fluids might migrate more than 2 kilometres upwards from the cracked shale into groundwater. The Ground Water Protection Council, a non-profit national association of state groundwater and underground-injection control agencies headquartered in Oklahoma City, has found no instance in which injected fluid contaminated groundwater from below[2]. This makes sense: water cannot flow this distance uphill in timescales that matter. This is the premise by which deep disposal wells, used to hold toxic waste worldwide, are considered safe. During gas production, the pressure of methane is reduced: this promotes downward, not upward flow of these fluids.

Gas shale contains a number of materials that are carried back up the pipe to the surface in flowback water, including salts of barium and radioactive isotopes, that might be harmful in concentrated form. According to a recent *New York Times* analysis, these elements can be above the US Environmental Protection Agency's sanctioned background concentrations in some flowback tanks. Industry is moving towards complete recycling of these fluids so this should be of less concern to the public. However, production water will continue to flow to the surface in modest volumes throughout the life of a well; this water needs to be, and currently is, treated to ensure safe disposal.

The real risk of water contamination comes from these flowback fluids leaking into streams or seeping down into groundwater after reaching the surface. This can be caused by leaky wellheads, holding tanks or blowouts. Wellheads are made sufficiently safe to prevent this eventuality; holding tanks can be made secure; and blowouts, while problematic, are like all accidents caused by human error — an unpredictable risk with which society lives.

> ***"With hydraulic fracturing, as in many cases, fear levels exceed the evidence."***

Although methane coming up to the surface within the steel well pipe cannot escape into the surrounding rocks or groundwater, it is possible that the cement seal between the well and the bedrock might allow methane from shallow sandstone layers (rather than the reservoir deep below) to seep up into groundwater. Methane is a tasteless and odourless component of groundwater that can be consumed without ill effect when dissolved. It is not a poison. Long before gas-shale drilling, regulators warned that enclosed spaces, such as houses, should be properly ventilated in areas with naturally occurring methane in groundwater.

An alarm has been sounded too about the effect of escaped methane on global warming. The good news is that methane has a very short half-life in the atmosphere: carbon dioxide emitted during the building of the first Sumerian cities is still affecting our climate, whereas escaped methane from the fracturing of the Barnett shale in 1997 is more than half gone. Industry can and should take steps to reduce air emissions, by capturing or flaring methane and converting motors and compressors from diesel to natural gas.

Risk perception is ultimately subjective: facts are all too easily combined with emotional responses. With hydraulic fracturing, as in many cases, fear levels exceed the evidence. ■

Terry Engelder *is in the department of geosciences at Pennsylvania State University, University Park, Pennsylvania 16802, USA.*
e-mail: jte2@psu.edu

1. Jiang, M. *Environ. Res. Lett.* **6,** 034014 (2011).
2. Statement of Scot Kell, on behalf of the Ground Water Protection Council, to the House Commitiee on Natural Resources Subcommitee on Energy and Mineral Resources (4 June 2009); available at: http://go.nature.com/5jl2bp

The author declares competing financial interests: details accompany this article online at go.nature.com/pjenyw.

Energy Policy 57 (2013) 585–601

Contents lists available at SciVerse ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Examining the feasibility of converting New York State's all-purpose energy infrastructure to one using wind, water, and sunlight

Mark Z. Jacobson [a,*], Robert W. Howarth [b], Mark A. Delucchi [c], Stan R. Scobie [d], Jannette M. Barth [e], Michael J. Dvorak [a], Megan Klevze [a], Hind Katkhuda [a], Brian Miranda [a], Navid A. Chowdhury [a], Rick Jones [a], Larsen Plano [a], Anthony R. Ingraffea [f]

[a] *Atmosphere/Energy Program, Department of Civil and Environmental Engineering, Stanford University, Stanford, CA 94305, USA*
[b] *Department of Ecology and Evolutionary Biology, Cornell University Ithaca, NY 14853, USA*
[c] *Institute of Transportation Studies, U.C. Davis, Davis, CA 95616, USA*
[d] *PSE Healthy Energy, NY, USA*
[e] *Pepacton Institute LLC, USA*
[f] *School of Civil and Environmental Engineering, Cornell University, Ithaca, NY 14853, USA*

HIGHLIGHTS

- ► New York State's all-purpose energy can be derived from wind, water, and sunlight.
- ► The conversion reduces NYS end-use power demand by ~37%.
- ► The plan creates more jobs than lost since most energy will be from in state.
- ► The plan creates long-term energy price stability since fuel costs will be zero.
- ► The plan decreases air pollution deaths 4000/yr ($33 billion/yr or 3% of NYS GDP).

ARTICLE INFO

Article history:
Received 14 September 2012
Accepted 18 February 2013
Available online 13 March 2013

Keywords:
Renewable energy
Air pollution
Global warming

ABSTRACT

This study analyzes a plan to convert New York State's (NYS's) all-purpose (for electricity, transportation, heating/cooling, and industry) energy infrastructure to one derived entirely from wind, water, and sunlight (WWS) generating electricity and electrolytic hydrogen. Under the plan, NYS's 2030 all-purpose end-use power would be provided by 10% onshore wind (4020 5-MW turbines), 40% offshore wind (12,700 5-MW turbines), 10% concentrated solar (387 100-MW plants), 10% solar-PV plants (828 50-MW plants), 6% residential rooftop PV (~5 million 5-kW systems), 12% commercial/government rooftop PV (~500,000 100-kW systems), 5% geothermal (36 100-MW plants), 0.5% wave (1910 0.75-MW devices), 1% tidal (2600 1-MW turbines), and 5.5% hydroelectric (6.6 1300-MW plants, of which 89% exist). The conversion would reduce NYS's end-use power demand ~37% and stabilize energy prices since fuel costs would be zero. It would create more jobs than lost because nearly all NYS energy would now be produced in-state. NYS air pollution mortality and its costs would decline by ~4000 (1200–7600) deaths/yr, and $33 (10–76) billion/yr (3% of 2010 NYS GDP), respectively, alone repaying the 271 GW installed power needed within ~17 years, before accounting for electricity sales. NYS's own emission decreases would reduce 2050 U.S. climate costs by ~$3.2 billion/yr.

1. Introduction

This is a study to examine the technical and economic feasibility of and propose policies for converting New York State's (NYS's) energy infrastructure in all sectors to one powered by wind, water, and sunlight (WWS). The plan is a localized microcosm of that developed for the world and U.S. by Jacobson and Delucchi (2009, 2011) and Delucchi and Jacobson (2011). Recently, other plans involving different levels of energy conversion for some or multiple energy sectors have been developed at national or continental scales (e.g., Alliance for Climate Protection, 2009; Parsons-Brinckerhoff, 2009; Kemp and Wexler, 2010; Price-Waterhouse-Coopers, 2010; Beyond Zero Emissions, 2010; European Climate Foundation (ECF), 2010; European Renewable Energy Council (EREC), 2010; World Wildlife Fund, 2011).

Limited plans are currently in place in New York City (PlaNYC, 2011) and NYS (Power, 2011) to help the city and state, respectively, provide predictable and sustainable energy, improve the

* Corresponding author. Tel.: +1 650 723 6836.
E-mail address: Jacobson@stanford.edu (M.Z. Jacobson).

0301-4215/$ - see front matter © 2013 Elsevier Ltd. All rights reserved.
http://dx.doi.org/10.1016/j.enpol.2013.02.036

quality of life, and reduce climate-relevant emissions. NYS also has a renewable portfolio standard requiring 30% of its electric power to come from renewable sources by 2015 (NYSERDA (New York State Energy Research and Development Authority), 2012). Although current plans for NYS and other states, countries, and continents are visionary and important, the plan here goes further by proposing a long-term sustainable energy infrastructure that supplies *all* energy from wind, water, and solar power, and provides the largest possible reductions in air pollution, water pollution, and global warming impacts. This study represents the first effort to develop a plan for an individual state to provide 100% of its all-purpose energy from WWS and to calculate the number of WWS energy devices, land and ocean areas, jobs, and policies needed for such an infrastructure. It also provides new calculations of air pollution mortality and morbidity impacts and costs in NYS based on multiple years of high-resolution air quality data.

In brief, the plan requires or results in the following changes:

(1) Replace fossil-fuel electric power generators with wind turbines, solar photovoltaic (PV) plants and rooftop systems, concentrated solar power (CSP) plants, solar hot water heater systems, geothermal power plants, a few additional hydroelectric power plants, and a small number of wave and tidal devices.
(2) Replace all fossil-fuel combustion for transportation, heating and cooling, and industrial processes with electricity, hydrogen fuel cells, and a limited amount of hydrogen combustion. Battery-electric vehicles (BEVs), hydrogen fuel cell vehicles (HFCVs), and BEV–HFCV hybrids sold in NYS will replace all combustion-based passenger vehicles, trucks, buses, non-road machines, and locomotives sold in the state. Long-distance trucks will be primarily BEV-HFCV hybrids and HFCVs. Ships built in NYS will similarly run on hydrogen fuel cells and electricity. Today, hydrogen-fuel-cell ships, tractors, forklifts, buses, passenger vehicles, and trucks already exist, and electric vehicles, ferries, and non-road machinery also exist. Electricity-powered air- and ground-source heat pumps, heat exchangers, and backup electric resistance heaters will replace natural gas and oil for home heating and air conditioning. Air- and ground-source heat pump water heaters powered by electricity and solar hot water preheaters will provide hot water for homes. High-temperatures for industrial processes will be obtained with electricity and hydrogen combustion. Petroleum products may still be used for lubrication and plastics as necessary, but such products will be produced using WWS power for process energy.
(3) Reduce energy demand beyond the reductions described under (2) through energy efficiency measures. Such measures include retrofitting residential, commercial, institutional, and government buildings with better insulation, improving the energy-out/energy-in efficiency of end uses with more efficient lighting and the use of heat-exchange and filtration systems; increasing public transit and telecommuting, designing future city infrastructure to facilitate greater use of clean-energy transport; and designing new buildings to use solar energy with more daylighting, solar hot water heating, seasonal energy storage, and improved passive solar heating in winter and cooling in summer.
(4) Boost economic activity by implementing the measures above. Increase jobs in the manufacturing and installation industries and in the development of new and more efficient technologies. Reduce social costs by reducing health-related mortality and morbidity and reducing environmental damage to lakes, streams, rivers, forests, buildings, and statues resulting from air and water pollution. Reduce social costs by slowing the increase in global warming and its impacts on coastlines, agriculture, fishing, heat stress, severe weather, and air pollution (which otherwise increases with increasing temperatures). Reduce long-term macroeconomic costs by eliminating exposure to future rises in fossil fuel prices.
(5) The plan anticipates that the fraction of new electric power generators as WWS will increase starting today such that, by 2020, all new generators will be WWS generators. Existing conventional generators will be phased out over time, but by no later than 2050. Similarly, BEVs and HFCVs should be nearly the only new vehicles types sold in NYS by 2020. The growth of electric vehicles will be accompanied by a growth of electric charging stations in residences, commercial parking spaces, service stations, and highway rest stops.
(6) All new heating and cooling technologies installed by 2020 should be WWS technologies and existing technologies should be replaced over time, but by no later than 2050.
(7) To ensure reliability of the electric power grids, several methods should be used to match renewable energy supply with demand and to smooth out the variability of WWS resources. These include (A) combining geographically-dispersed WWS resources as a bundled set of resources rather than as separate resources and using hydroelectric power to fill remaining gaps; (B) using demand-response grid management to shift times of demand to match better with the timing of WWS power supply; (C) oversizing WWS peak generation capacity to minimize the times when available WWS power is less than demand and to provide power to produce heat for air and water and hydrogen for transportation and heating when WWS power exceeds demand; (D) integrating weather forecasts into system operation to reduce reserve requirements; (E) storing energy in thermal storage media, batteries or other storage media at the site of generation or use; and (F) storing energy in electric-vehicle batteries for later extraction (vehicle-to-grid).

2. How the technologies were chosen

The WWS energy technologies chosen for the NYS plan exist and were ranked the highest among several proposed energy options for addressing pollution and public health, global warming, and energy security (Jacobson, 2009). That analysis used a combination of 11 criteria (carbon-dioxide equivalent emissions, air-pollution mortality and morbidity, resource abundance, footprint on the ground, spacing required, water consumption, effects on wildlife, thermal pollution, water chemical pollution/radioactive waste, energy supply disruption, and normal operating reliability) to evaluate each technology.

Mined natural gas and liquid biofuels are excluded from the NYS plan for the reasons given below. Jacobson and Delucchi (2011) explain why nuclear power and coal with carbon capture are also excluded.

2.1. Why not natural gas?

Natural gas is excluded for several reasons. The mining, transport, and use of conventional natural gas for electric power results in at least 60–80 times more carbon-equivalent emissions and air pollution mortality per unit electric power generated than does wind energy over a 100-year time frame. Over the 10–30 year time frame, natural gas is a greater warming agent relative to all WWS technologies and a danger to the Arctic sea ice due to its leaked methane and black carbon-flaring emissions (discussed more below). Natural gas mining, transport, and use also produce carbon monoxide, ammonia, nitrogen oxides, and organic gases.

Natural gas mining degrades land, roads, and highways and produces water pollution.

The main argument for increasing the use of natural gas has been that it is a ‘‘bridge fuel’’ between coal and renewable energy because of the belief that natural gas causes less global warming per unit electric power generated than coal. Although natural gas emits less carbon dioxide per unit electric power than coal, two factors cause natural gas to increase global warming relative to coal: higher methane emissions and less sulfur dioxide emissions per unit energy than coal.

Although significant uncertainty still exists, several studies have shown that, without considering sulfur dioxide emissions from coal, natural gas results in either similar or greater global warming-relevant-emissions than coal, particularly on the 20-year time scale (Howarth et al., 2011, 2012a, 2012b; Howarth and Ingraffea, 2011; Wigley, 2011; Myhrvold and Caldeira, 2012). The most efficient use of natural gas is for electricity, since the efficiency of electricity generation with natural gas is greater than with coal. Yet even with optimistic assumptions, Myhrvold and Caldeira (2012) demonstrated that the rapid conversion of coal to natural gas electricity plants would “do little to diminish the climate impacts” of fossil fuels over the first half of the 21st Century. Recent estimates of methane radiative forcing (Shindell et al., 2009) and leakage (Howarth et al., 2012b; Pétron et al., 2012) suggest a higher greenhouse-gas footprint of the natural gas systems than that estimated by Myhrvold and Caldeira (2012). Moreover, conventional natural gas resources are becoming increasingly depleted and replaced by unconventional gas such as from shale formations, which have larger methane emissions and therefore a larger greenhouse gas footprint than do conventional sources (Howarth et al., 2011, 2012b; Hughes, 2011).

Currently, most natural gas in the U.S. and NYS is not used to generate electricity but rather for domestic and commercial heating and for industrial process energy. For these uses, natural gas offers no efficiency advantage over oil or coal, and has a larger greenhouse gas footprint than these other fossil fuels, particularly over the next several decades, even while neglecting the climate impact of sulfur dioxide emissions (Howarth et al., 2011, 2012a, 2012b). The reason is that natural gas systems emit far more methane per unit energy produced than do other fossil fuels (Howarth et al., 2011), and methane has a global warming potential that is 72–105 times greater than carbon dioxide over an integrated 20-year period after emission and 25–33 times greater over a century period (Intergovernmental Panel on Climate Change (IPCC), 2007; Shindell et al., 2009). As discussed below, the 20-year time frame is critical.

When used as a transportation fuel, the methane plus carbon dioxide footprint of natural gas is greater than for oil, since the efficiency of natural gas is less than that of oil as a transportation fuel (Alvarez et al., 2012). When methane emissions due to venting of fuel tanks and losses during refueling are accounted for, the warming potential of natural gas over oil rises further.

When sulfur dioxide emissions from coal are considered, the greater air-pollution health effects of coal become apparent, but so do the lower global warming impacts of coal versus natural gas, indicating that both fuels are problematic. Coal combustion emits significant sulfur dioxide and nitrogen oxides, most of which convert to sulfate and nitrate aerosol particles, respectively. Natural gas also emits nitrogen oxides, but not much sulfur dioxide. Sulfate and nitrate aerosol particles cause direct air pollution health damage, but they are ‘‘cooling particles’’ with respect to climate because they reflect sunlight and increase cloud reflectivity. Thus, although the increase in sulfate aerosol from coal increases coal’s air-pollution mortality relative to natural gas, it also decreases coal’s warming relative to natural gas because sulfate offsets a significant portion of coal’s CO_2-based global warming over a 100-year time frame (Streets et al., 2001; Carmichael et al., 2002). Coal also emits ‘‘warming particles’’ called soot, but pulverized coal in the U.S. results in little soot. Using conservative assumptions about sulfate cooling, Wigley (2011) found that electricity production from natural gas causes more warming than coal over 50–150 years when coal sulfur dioxide is accounted for. The low estimate of 50 years was derived from an unrealistic assumption of zero leaked methane emissions.

Thus, natural gas is not a near-term ‘‘low’’ greenhouse-gas alternative, in absolute terms or relative to coal. Moreover, it does not provide a unique or special path to renewable energy, and as a result, it is not bridge fuel and is not a useful component of a sustainable energy plan.

Rather than use natural gas in the short term, we propose to move to a WWS-power system immediately, on a worldwide scale, because the Arctic sea ice may disappear in 20–30 years unless global warming is abated (e.g., Pappas, 2012). Reducing sea ice uncovers the low-albedo Arctic Ocean surface, accelerating global warming in a positive feedback. Above a certain temperature, a tipping point is expected to occur, accelerating the loss to complete elimination (Winton, 2006). Once the ice is gone, regenerating it may be difficult because the Arctic Ocean will reach a new stable equilibrium (Winton, 2006).

The only potential method of saving the Arctic sea ice is to eliminate emissions of short-lived global warming agents, including methane (from natural gas leakage and anaerobic respiration) and particulate black carbon (from natural gas flaring and diesel, jet fuel, kerosene burning, and biofuel burning). The 21-country Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants recognized the importance of reducing methane and black carbon emissions for this purpose (UNEP (United Nations Environmental Program), 2012). Black carbon controls for this reason have also been recognized by the European Parliament (Resolution B7–0474/2011, September 14, 2011). Jacobson (2010a) and Shindell et al. (2012) quantified the potential benefit of reducing black carbon and methane, respectively, on Arctic ice.

Instead of reducing these problems, natural gas mining, flaring, transport, and production increase methane and black carbon, posing a danger to the Arctic sea ice on the time scale of 10–30 years. Methane emissions from the natural-gas system and nitrogen-oxide emissions from natural-gas combustion also contribute to the global buildup of tropospheric ozone resulting in additional respiratory illness and mortality.

2.2. Why not liquid biofuels?

This study also excludes the future use of liquid biofuels for transportation and heating. In addition to their creating more air pollution than gasoline for transportation, their tank-to-wheel efficiency of combustion is 1/4th to 1/5th the plug-to-wheel efficiency of electricity for transportation. This tends to make the energy cost-per-distance much higher for biofuel vehicles than electric vehicles. In addition, the land required to power a fleet of flex-fuel vehicles on corn or cellulosic ethanol is about 30 times the spacing area and a million times the footprint area on the ground required for wind turbines to power an equivalent fleet of electric vehicles (Jacobson, 2009).

Liquid biofuels are partially renewable with respect to carbon since they remove carbon dioxide from the air during photosynthetic growth. However, liquid biofuels require energy to grow and, in some cases (e.g., corn for ethanol) fertilize crops, irrigate crops (although not in NYS), distill the fuel (in the case of ethanol), transport crops to energy production plants, and transport the liquid fuel to its end use locations. For transportation, the resulting environmental costs of liquid biofuels are high, particularly for air and water quality (Delucchi, 2010), and greenhouse gas emissions are at best only slightly less than from using fossil fuels, and may be far worse when indirect land-use changes due to using land for fuel instead of food are fully considered (Searchinger et al., 2008). Moreover, carbon emissions from an advanced biofuel, cellulosic ethanol for flex-fuel vehicles, are about 125 times those from wind energy powering electric vehicles without considering indirect land use changes (Jacobson, 2009) and higher if indirect land use changes are accounted for (Searchinger et al., 2008). For these reasons alone, reviews by international agencies have recommended against the use of liquid biofuels for transportation (Bringezu et al., 2009; Howarth and Bringezu, 2009).

Ethanol combustion, regardless of the source, increases average air pollution mortality relative to gasoline due to the aldehyde and unburned ethanol emissions from ethanol fuel combustion (Jacobson, 2009; Anderson, 2009), and the effect increases at low temperature (Ginnebaugh et al., 2010, 2012). Ethanol and biodiesel fuel also increase air pollution from their upstream production more than do gasoline or diesel fuel, respectively (Delucchi, 2006). By contrast, electric and hydrogen fuel cell vehicles eliminate nearly all such pollution (Jacobson et al., 2005).

Much less analysis of the impacts of liquid biofuels for heating has been done than for transportation, but the fundamental issues remain the same. Namely, liquid biofuels for heating produce air pollution because they are combusted; require energy to grow, produce, and transport thus result in more emissions, and require much more land than solar power for the same energy output.

2.3. Temporary role of solid biofuels

The NYS plan allows for the temporary heating use of certain solid biofuels, such as wood pellets, energy crops grown on unused farmland, and agricultural waste and of biogas extracted from landfills and derived from anaerobic digestion of organic wastes. The use of such solid biofuels and biogas will be phased out by 2030–2050.

Solid biofuels combusted for cogeneration of electric power and heat are more efficient than liquid biofuels for transportation and are widely used in this way across northern Europe (Campbell et al., 2009; Howarth and Bringezu, 2009; Bringezu et al., 2009). Much of NYS is rural, with large expanses of old abandoned agricultural land, much of it now second-growth forest. Such land can produce large quantities of biomass. For example, the 8-county (Broome, Chemung, Chenango, Delaware, Schulyer, Steuben, Tioga, and Tompkins) Southern Tier economic development region of NYS is estimated to be able to produce 1.9 million dry tons annually of biomass for energy, with half of this coming from wood-chip harvest and the rest from dedicated energy crops such as switchgrass or willow (Woodbury et al., 2010). This is equivalent to 3 tons per year for every resident of this area, more than enough to alone supply all domestic heating needs.

Using biomass for heat allows farmers and forest owners to produce an energy crop on land that would not otherwise be used and to make use of low-value wood, increasing economic productivity and producing agricultural and forestry jobs. However, solid biomass should be used carefully so as not to over-harvest forestlands or use high-quality agricultural land. The scale of use is important as well, as moving and processing solid biomass takes substantial energy and carbon; the biomass should be used near the point of harvest to reduce this energy cost and the resulting environmental pollution. Using landfill biogas allows methane that would otherwise escape to the air to be used for energy. Similarly, converting organic waste to biogas allows the use of material for energy that would be processed biologically and released to the air in any case.

For two reasons, the use of solid biofuels and biogas in our plan is only temporary. First, biomass or biogas for energy requires much more land than solar power producing the same electricity and heat. For example, the growth of switchgrass for electric power requires about 115 times more land area than the use of solar PV to provide the same electric power based on biomass data from Kansas Energy Report (2011). If biomass combustion is used for both electricity and heat, switchgrass still requires 70 times more land area than does solar PV. Thus, one acre of land growing switchgrass for electricity produces 1/70th to 1/115th the usable energy of the same land with PV on it. Since electricity can run (a) air-source heat pumps very efficiently, (b) electric-resistance backup heating to produce heat, and (c) electrolyzers to produce hydrogen that can be used safely for home and building heat (KeelyNet, 2009), the use of solar PV for electricity and electricity-derived heat is more efficient than is the use of biomass for the same purpose in terms of land use and reducing air pollution,

Second, the use of solid biofuels or biogas for electricity and heat is still a combustion process, resulting in similar air pollution health and mortality impacts as fossil fuel combustion. Because solid biofuels for energy would be grown and processed in NYS, NYS "upstream" air pollution emissions from such processing will likely increase compared with current fossil fuel upstream emissions, most of which occur out of state (Woodbury et al., 2010). Because feedstock will be transported primarily by truck, road congestion, erosion, and pollution emissions will also likely increase (Woodbury et al., 2010). For these reasons, solid biofuels and biogas are to be phased out during 2030–2050 in the NYS plan.

3. Change in NYS power demand upon conversion to WWS

Table 1 summarizes the changes in global, U.S., and NYS end-use power demand between 2010 and 2030 upon a conversion to a 100% WWS infrastructure (zero fossil fuels, biofuels, and nuclear

Table 1
Contemporary (2010) and projected (2030) end-use power demand (TW) for all purposes by sector, for the world, U.S., and NYS if conventional fossil-fuel and wood use continue as projected and if all conventional fuels are replaced with WWS technologies.
Source: Jacobson and Delucchi (2011) for the world and U.S., NYS values are calculated with the same methodology but using EIA (Energy Information Administration, U.S.), 2012a end-use demand data. The U.S. and NYS populations in 2010 were 307,910,000 and 19,378,000, respectively. Those in 2030 are estimated to be 358,410,000 (USCB (United States Census Bureau), 2011) and 19,795,000 (Cornell Program on Applied Demographics, 2011), respectively, giving the U.S. and NYS population growths as 16.4% and 2.15%, respectively.

Energy sector	Conventional fossil fuels and wood 2010			Conventional fossil fuels and wood 2030			Replacing fossil fuels and wood with WWS 2030		
	World	U.S.	NYS	World	U.S.	NYS	World	U.S.	NYS
Residential	1.77	0.38	0.026	2.26	0.43	0.025	1.83	0.35	0.020
Commercial	0.94	0.28	0.023	1.32	0.38	0.025	1.22	0.35	0.022
Industrial	6.40	0.86	0.009	8.80	0.92	0.009	7.05	0.74	0.007
Transportation	3.36	0.97	0.036	4.53	1.10	0.037	1.37	0.33	0.011
Total	12.47	2.50	0.094	16.92	2.83	0.096	11.47	1.78	0.060
Percent change							(−32%)	(−37%)	(−37%)

energy). The table was derived on a spreadsheet from annually-averaged end-use power demand data as in Jacobson and Delucchi (2011). All end uses that feasibly can be electrified will use WWS power directly, and remaining end uses (some heating, high-temperature industrial processes, and some transportation) will use WWS power indirectly in the form of electrolytic hydrogen (hydrogen produced by splitting water with WWS power). As such, electricity requirements will increase, but the use of oil and gas for transportation and heating/cooling will decrease to zero. The increase in electricity use will be much smaller than the decrease in energy embodied in gas, liquid, and solid fuels because of the high efficiency of electricity for heating and electric motors.

The power required in 2010 to satisfy all end use power demand worldwide for all purposes was about 12.5 trillion watts (terawatts, TW). (End-use power excludes losses incurred during production and transmission of the power.) About 35% of primary energy worldwide in 2010 was from oil, 27% was from coal, 23% was from natural gas, 6% was from nuclear power, and the rest was from biofuel, sunlight, wind, and geothermal power. Delivered electricity was about 2.2 TW of all-purpose end-use power.

If the world follows the current trajectory of fossil-fuel growth, all-purpose end-use power demand will increase to ~17 TW by 2030, U.S. demand will increase to ~3 TW, and NYS power demand will increase to ~96 GW (Table 1). Conventional power demand in NYS will increase much less in 2030 than in the U.S. as a whole because the NYS population is expected to grow by only 2.15% between 2010 and 2030, whereas the U.S. population is expected to grow by 16.4% (Table 1, footnote).

Table 1 indicates that a conversion to WWS will reduce world, U.S., and NYS end-use power demand and power required to meet that demand by ~32%, ~37%, and ~37%, respectively. The reductions in NYS by sector are 21.0% in the residential, 12.3% in the commercial, 20.0% in the industrial, and 69.5% in the transportation sectors. Only 5–10 percentage points of each reduction are due to modest energy-conservation measures. Some of the remainder is due to the fact that conversion to WWS reduces the need for upstream coal, oil, and gas mining and processing of fuels, such as petroleum or uranium refining. The remaining reason is that the use of electricity for heating and electric motors is more efficient than is fuel combustion for the same applications (Jacobson and Delucchi, 2011). Also, the use of WWS electricity to produce hydrogen for fuel cell vehicles, while less efficient than the use of WWS electricity to run BEVs, is more efficient and cleaner than is combusting liquid fossil fuels for vehicles (Jacobson et al., 2005). Combusting electrolytic hydrogen is slightly less efficient but cleaner than is combusting fossil fuels for direct heating, and this is accounted for in the table.

4. Numbers of electric power Generators needed

How many WWS power plants or devices are needed to power NYS for all purposes assuming end use power requirements in Table 1 and accounting for electrical transmission and distribution losses?

Table 2 provides one of several possible future scenarios for 2030. In this scenario, onshore wind comprises 10% of New York's

Table 2
Number of WWS power plants or devices needed to provide New York's total annually-averaged end-use power demand for all purposes in 2030 (0.061 TW from Table 1) assuming the given fractionation of demand among plants or devices and accounting for transmission, distribution, and array losses. Also shown are the footprint and spacing areas required to power NYS as a percentage of New York's land area, 122,300 km^2.

Energy technology	Rated power of one plant or device (MW)	Percent of 2030 power demand met by plant/device	Number of plants or devices needed for NYS	Nameplate capacity of all devices (MW)	Footprint area (percent of NYS land area)	Spacing area (percent of NYS land area)
Onshore wind	5	10	4020	20,100	0.000041	1.46
Offshore wind	5	40	12,700	63,550	0.00013	4.62
Wave device	0.75	0.5	1910	1435	0.00082	0.039
Geothermal plant	100	5	36	3600	0.010	0
Hydroelectric plant	1300	5.5	6.6[a]	8520	3.50[a]	0
Tidal turbine	1	1	2600	2600	0.00061	0.0095
Res. roof PV system	0.005	6	4.97 million[b]	24,900	0.15[c]	0
Com/gov roof PV system	0.10	12	0.497 million	49,700	0.30[c]	0
Solar PV plant	50	10	828[b]	41,400	0.25	0[c]
CSP plant	100	10	387	38,700	0.60	0[c]
Total		100		254,000	4.82	6.13
Total new land required					0.96[d]	1.46[e]

Rated powers assume existing technologies. Percent power of each device assumes wind and solar are the only two resources that can power NYS independently (Section 5) and should be in approximate balance to enable load matching (Section 6) but that wind is less expensive (Section 7) so will dominate more. The number of devices is calculated by multiplying the NYS end use power demand in 2030 from Table 1 by the fraction of power from the source and dividing by the annual power output from each device, which equals the rated power multiplied by the annual capacity factor of the device. The capacity factor is determined for each device as in the Supplementary Information spreadsheet of Jacobson (2009), except that onshore wind turbines are assumed here to be located in mean annual wind speeds at hub height of 7.75 m/s and offshore turbines, 8.5 m/s (Dvorak et al., 2012a). From that study, 9200 km^2 of NYS land area has mean wind speeds >7.75 m/s at 90 m, and the average wind speed in those areas is 8.09 m/s. From the present table, only 1786 km^2 of onshore wind is needed. Land and spacing areas are similarly calculated as in the Supplementary Information of Jacobson (2009).

[a] NYS already produces about 89% of the hydroelectric power needed for the plan (Section 5). See Jacobson (2009) for a discussion of apportioning the hydroelectric footprint area by use of the reservoir.

[b] The solar PV panels used for this calculation were Sun Power E20 panels. The average capacity factor for solar assumed was 18%.

[c] For central solar PV and CSP plants, nominal "spacing" between panels is included in the plant footprint area.

[d] The total footprint area requiring new land is equal to the footprint area for onshore wind and geothermal, plus 2.75% of the footprint area for hydroelectric, plus the footprint area for solar PV and CSP plants. Offshore wind, wave and tidal are in water, and so do not require new land. The footprint area for rooftop solar PV does not entail new land because the rooftops already exist and are not used for other purposes (that might be displaced by rooftop PV). Only 2.75% of the hydropower requires new land because 89% of hydroelectric capacity is already in place and, of the remaining 11%, three-quarters will come from existing reservoirs or run-of-the-river.

[e] Only onshore wind entails new land for spacing area. The other energy sources are either in water or on rooftops, or do not use additional land for spacing. The spacing area for onshore wind can be used for multiple purposes, such as open space, agriculture, grazing, etc.

supply; offshore wind, 40%; residential solar rooftop PV, 6%; commercial/government solar rooftop PV, 12%; PV power plants, 10%; CSP plants, 10%; hydroelectric power, 5.5% (of which 89% is already in place), geothermal power, 5%; tidal power, 1%; and wave power, 0.5%.

Rooftop PV in this scenario is divided into residential (5-kW systems on average) and commercial/government (100-kW systems on average). Rooftop PV can be placed on existing rooftops or on elevated canopies above parking lots and structures without taking up additional undeveloped land. PV power plants are sized, on average, relatively small (50 MW) to allow them to be placed optimally in available locations.

Wind (50%) and solar (38%) are the largest generators of electric power under this plan because they are the only resources sufficiently available to power NYS on their own, and both are needed in combination to ensure the reliability of the grid. Wind is currently less expensive than solar, particularly at latitudes as high as in NYS, so wind is proposed to play a slightly larger role.

Since most wind and all wave and tidal power will be offshore under the plan, most transmission will be under water and out of sight. Transmission for new onshore wind, solar power plants, and geothermal power plants will be along existing pathways but with enhanced lines to the greatest extent possible, minimizing zoning issues. Four methods of increasing transmission capacity without requiring additional rights of way or increasing the footprint of transmission lines include the use of dynamic line rating equipment; high-temperature, low-sag conductors; voltage up-rating; and flexible AC transmission systems (e.g., Holman, 2011). To the extent existing pathways need to be expanded or new transmission pathways are required, they will be applied for using regulatory guidelines already in place.

Footprint is the physical space on the ground needed for each energy device, whereas spacing is the space between some devices, such as wind, tidal, and wave power. Spacing area can be used for open space, agriculture, grazing, etc. Table 2 provides footprint and spacing areas required for each energy technology. The table indicates that the total new land footprint required for this plan is about 0.96% of New York's land area, mostly for solar PV and CSP power plants (as mentioned, rooftop solar does not take up new land). Some additional footprint is proposed for hydroelectric as well, but that portion may not be needed if run-of-the-river hydro, imported hydro, or hydro from existing reservoirs that do not currently produce electric power is used. Additional space is also needed between onshore wind turbines. This space can be used for multiple purposes and can be reduced if more offshore wind resources are used than proposed here. The total additional land footprint needed (0.96% of the state) is minimal compared with the footprint of agriculture in the state (23.8%) and the footprint of house lots, ponds, roads, and wasteland used for agriculture (1.9%) (USDA (United States Department of Agriculture), 2011). Fig. 1 shows the relative footprint and spacing areas required in NYS.

The number of devices takes into account the availability of clean resources as well as of land and ocean areas. NYS has more wind, solar, geothermal, and hydroelectric resources than is needed to supply the state's energy for all purposes in 2030. These resources are discussed next.

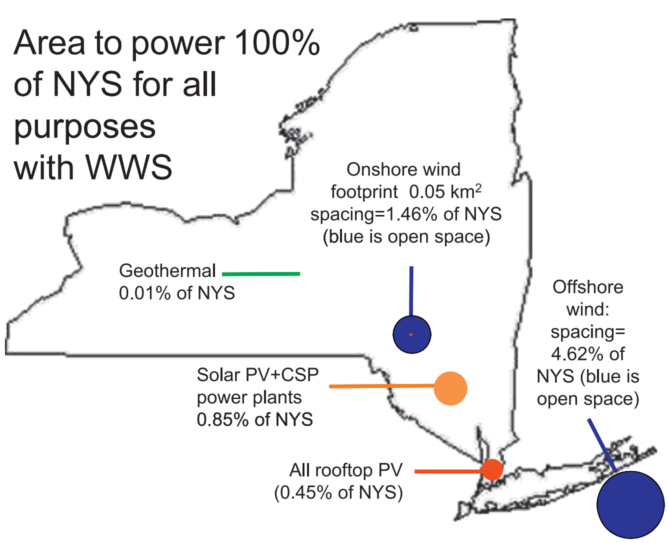


Fig. 1. Spacing and footprint areas required to implement the plan proposed here for NYS, as derived in Table 2. Actual locations would differ. The dots are only representative areas. For wind, the small red dot in the middle is footprint on the ground and the blue is spacing. For the others, the footprint and spacing are similar to each other. In the case of rooftop PV, the dot represents the rooftop area to be used. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

5. WWS resources available

This section discusses raw WWS resources available in NYS. Fig. 2 shows NYS's onshore and offshore annual wind resources from Dvorak et al. (2012a) in terms of a wind turbine's capacity factor, which is the annual average power produced divided by the rated power of a turbine. If only half the high-wind-speed land (capacity factor > 30%) in NYS were used for wind development, 327 TWh of wind energy would be harnessed, enough to provide more than 60% of NYS's 2030 WWS end-use power demand for all purposes. However, this plan proposes that only 10% of NYS's 2030 power demand come from onshore wind.

Dvorak et al. (2012a) mapped the East Coast offshore wind resources and Dvorak et al. (2012b) proposed locations for an efficiently interconnected set of offshore East Coast wind farms, one of which would be off of Long Island's coast. Offshore resources significantly exceed those onshore. The U.S. has not yet built an offshore wind farm, and some have expressed a concern over their potential environmental impacts. However, a study of over a decade of experience of offshore wind in Denmark by the International Advisory Panel of Experts on Marine Ecology found little damage to wildlife (Dong Energy, Vattenfall Danish Energy Authority, and Danish Forest and Nature Agency, 2006).

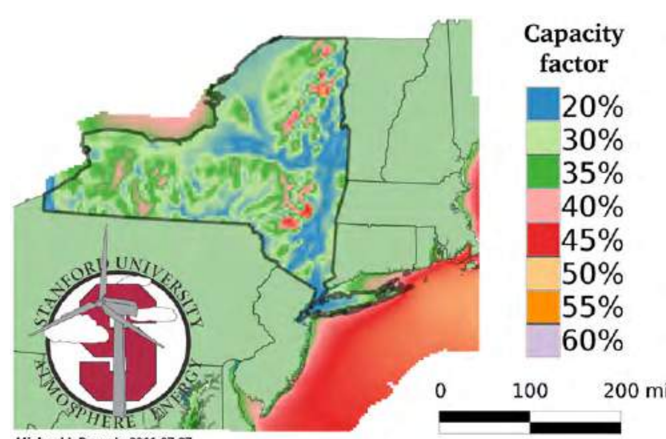


Fig. 2. Capacity factors at 90-m hub height in NYS and offshore in Lake Ontario, Lake Erie, and the Eastern seaboard, as calculated with a 3-D computer model evaluated against data assuming 5-MW RE-Power wind turbines with rotor diameter $D = 126$ m from simulations run in Dvorak et al. (2012a, 2012b). Capacity factors of 30% or higher are the most cost-effective for wind energy development.

Despite NYS's high latitude, solar resources in the state are significant. NREL (National Renewable Energy Laboratory) (2008) estimates NYS's solar resources as 4–4.5 kWh/m^2/day. Based on these numbers, only 0.85% of additional land (beyond existing rooftops) is needed to provide 38% of the state's energy for all purposes in 2030 in the forms of CSP plants, PV power plants, and rooftop PV. This assumes that 18% of the state's new energy comes from rooftop PV on existing urban structures (Table 2).

Geothermal resources in NYS (NREL (National Renewable Energy Laboratory), 2009) are also abundant. Geothermal energy production requires little land area (Table 2) and is proposed to provide only 5% of NYS's total energy in 2030.

NYS has a hydroelectric potential of 38.6 kW/km^2 (5 GW, or 43.8 TWh/yr) of delivered power (DOE (Department of Energy), 2004). It can currently produce about 60% of this. For example, in 2009, hydroelectric supplied about 26.1 TWh/yr (3 GW delivered power), or 21% of NYS's electric power consumption of 131 TWh/yr. Under the plan, hydro will produce about 3.3 GW, or 5.5% of the total delivered power for all purposes in NYS in 2030. Hydro currently produces 89% of this amount. Sufficient in-state and, if necessary, imported hydroelectric power is available to provide the difference. Most additional in-state hydro may be obtainable from existing dams that do not have turbines associated with them.

Tidal (or ocean current) and wave power are proposed to comprise a combined 1.5% of NYS's overall power in 2030 (Table 2). Tidal and wave resources off the East Coast are both modest. However, tidal power has already been used to generate electricity in the East River through the Verdant Power Roosevelt Island Tidal Energy Project.

6. Matching electric power supply with demand

An important concern to address in a clean-energy economy is whether electric power demand can be met with WWS supply on a minutely, daily, and seasonal basis. Previous work has described multiple methods to match renewable energy supply with demand and to smooth out the variability of WWS resources (Delucchi and Jacobson, 2011). Such methods include (A) combining geographically-dispersed WWS resources as a bundled set of resources rather than separate resources and using hydroelectric or stored concentrated solar power to balance the remaining load; (B) using demand-response management to shift times of demand to better match the availability of WWS power; (C) over-sizing WWS peak generation capacity to minimize the times when available WWS power is less than demand and provide power to produce heat for air and water and hydrogen for transportation and heating when WWS power exceeds demand; (D) integrating weather forecasts into system operation; (E) storing energy in batteries or other storage media at the site of generation or use; and (F) storing energy in electric-vehicle batteries for later extraction (vehicle-to-grid). Here, we discuss updated information on only a couple of these methods since Delucchi and Jacobson (2011) discuss the other methods.

Several studies have examined whether up to 100% penetrations of WWS resources could be used reliably to match power demand (e.g., Jacobson and Delucchi, 2009; Mason et al., 2010; Hart and Jacobson, 2011, 2012; Connolly et al., 2011; Elliston et al., 2012; NREL (National Renewable Energy Laboratory), 2012; Rasmussen et al., 2012; Budischak et al., 2013). Using hourly load and resource data and accounting for the intermittency of wind and solar, both Hart and Jacobson (2011) and Budischak et al. (2013) found that up to $>99.8\%$ of delivered electricity could be produced carbon-free with WWS resources over multiple years. The former study obtained this conclusion for the California grid over 2 years; the latter, over the PJM Interconnection in the eastern U.S., adjacent to NYS, over 4 years. Both studies accounted for the variability in the weather, including extreme events. Although WWS resources differ in NYS compared with these other regions, the differences are not expected to change the conclusion that a WWS power system in NYS can be reliable. NYS has WWS resources not so different from those in PJM (more offshore wind and hydroelectric than PJM but less solar).

Eliminating remaining carbon emission is challenging but can be accomplished in several ways. These include using demand response and demand management, which will be facilitated by the growth of electric vehicles; oversizing the power grid and using the excess power generated to produce district heat through heat pumps and thermal stores and hydrogen for other sectors of the energy economy (e.g. heat for buildings, high-temperature processes, and fuel-cell vehicles); using concentrated solar power storage to provide solar power at night; and storing excess energy at the site of generation with pumped hydroelectric power, compressed air (e.g., in underground caverns or turbine nacelles), flywheels, battery storage packs, or batteries in electric vehicles (Kempton and Tomic, 2005).

Oversizing the peak capacity of wind and solar installations to exceed peak inflexible power demand can reduce the time that available WWS power supply is below demand, thereby reducing the need for other measures to meet demand. The additional energy available when WWS generation exceeds demand can be used to produce hydrogen (a storage fuel) by electrolysis for heating processes and transportation and to provide district heating. Hydrogen must be produced in any case as part of the WWS solution. Oversizing and using excess energy for hydrogen and district heating would also eliminate the current practice of shutting down (curtailing) wind and solar resources when they produce more energy than the grid can accommodate. Denmark currently uses excess wind energy for district heating using heat pumps and thermal stores (e.g., Elsman, 2009).

7. Costs

An important criterion in the evaluation of WWS systems is to ensure that the full costs per unit energy delivered, including capital, land, operating, maintenance, storage, and transmission costs, are comparable with or better than costs of conventional fuels.

Table 3 presents estimates of 2005–2012 and 2020–2030 costs of electric power generation for WWS technologies, assuming standard (but not extra-long-distance) transmission and excluding distribution. The table also shows the average U.S. delivered electricity cost for conventional fuels (mostly fossil) under the same assumptions. For fossil-fuel generation, the externality cost, which includes the hidden costs of air pollution morbidity and mortality and global warming damage (e.g., coastline loss, agricultural and fish losses, human heat stress mortality, increases in severe weather and air pollution), is also shown. Table 4 breaks down the externality costs.

Table 3 indicates that the 2005–2012 costs of onshore wind, hydroelectric, and geothermal plants are the same or less than those of typical new conventional technologies (such as new coal-fired or natural gas power plants) when externality costs of the conventional technologies are ignored. Solar costs are higher. When externality costs are included, WWS technologies cost less than conventional technologies.

The costs of onshore wind, geothermal, and hydroelectric power are expected to remain low (4–8.8 cents/kWh) in 2020–2030. Costs of other WWS technologies are expected to decline to 5–11 cents/kWh (Table 3). These estimates include the costs of local AC transmission. However, many wind and solar farms may be sufficiently far from population centers to require long-distance transmission.

For long-distance transmission, high-voltage direct-current (HVDC) lines are common because they result in lower transmission

Table 3
Approximate fully annualized generation and short-distance transmission costs for WWS power (2007 U.S. cents/kWh-delivered), including externality costs. Also shown are generation costs and externality costs (from Table 4) of new conventional fuels. Actual costs in NYS will depend on how the overall system design is optimized as well as how energy technology costs change over time.

Energy technology	2005–2012*	2020–2030*
Wind onshore	4[a]–10.5[b]	≤4[a]
Wind offshore	11.3[c]–16.5[b]	7[b]–10.9[c]
Wave	>11.0[a]	4–11[a]
Geothermal	9.9–15.2[b]	5.5–8.8[g]
Hydroelectric	4.0–6.0[d]	4[a]
CSP	14.1–22.6[b]	7–8[a]
Solar PV (utility)	11.1–15.9[b]	5.5[g]
Solar PV (commercial rooftop)	14.9–20.4[b]	7.1–7.4[h]
Solar PV (residential rooftop)	16.5–22.7[e]	7.9–8.2[h]
Tidal	>11.0[a]	5–7[a]
New conventional (plus externalities)[f]	**9.6–9.8 (+5.3)=14.9–15.1**	**12.1–15.0 (+5.7)=17.8–20.7**

* $0.01/kWh for transmission was added to all technologies as in Delucchi and Jacobson (2011) except for distributed generation projects (i.e. commercial and residential solar PV).

[a] Delucchi and Jacobson (2011).

[b] Lazard (2012).

[c] Levitt et al. (2011).

[d] REN21 (Renewable Energy Policy Network for the 21st Century) (2010).

[e] SEIA (Solar Energy Industries Association) (2012). Residential LCOE: Calculated by multiplying the Lazard (2012) Commercial LCOE by the ratio of the Residential PV $/Watt to the Commercial PV $/Watt=$0.149 ($5.73/$5.16)–$0.204($5.73/$5.16).

[f] The current levelized cost of conventional fuels in NYS is calculated by multiplying the electric power generation by conventional source in NYS (EIA (Energy Information Administration, U.S.), 2012b) by the levelized cost of energy for each source (Lazard, 2012 for low estimate; EIA (Energy Information Administration, U.S. (2012c) for high estimate) and dividing by the total generation. The future estimate assumes a 26.5% increase in electricity costs by 2020 (the mean increase in electricity prices in NYS from 2003 to 2011, EIA (Energy Information Administration, U.S.), 2012d), and twice this mean increase by 2030. Externality costs are from Table 4.

[g] Google (2011), 2020 projection.

[h] The ratio of present-day utility PV to present-day commercial and residential PV multiplied by the projected LCOE of utility PV.

Table 4
Mean (and range) of environmental externality costs of electricity generation from coal and natural gas (Business as Usual—BAU) and renewables in the U.S. in 2007 (U.S. cents/kWh). Water pollution costs from natural gas mining and current energy generation are not included. Climate costs are based on a 100-year time frame. For a 20-year time frame, the NG climate costs are about 1.6 times those of coal for the given shale:conventional gas mixes.
Source: Delucchi and Jacobson (2011) but modified for mean shale and conventional natural gas carbon equivalent emissions from Howarth et al. (2011) assuming a current shale:conventional NG mix today of 30:70 and 50:50 in 2030 and a coal/NG mix of 73%/27% in 2005 and 60%/40% in 2030. The costs do not include costs to worker health and the environment due to the extraction of fossil fuels from the ground. (These estimates apply to the U. S. Section 8 estimates external costs specifically for NYS.)

	2005			2030		
	Air pollution	Climate	Total	Air pollution	Climate	Total
Coal	3.2	3.0	6.2 (1.2–22)	1.7	4.8	6.5 (3.3–18)
Natural gas (NG)	0.16	2.7	2.9 (0.5–8.6) [a]	0.13	4.5	4.6 (0.9–8.9) [a]
Coal/NG mix	2.4	2.9	5.3 (1.0–18)	1.1	4.6	5.7 (2.7–15)
Wind, water, and solar	<0.01	<0.01	<0.02	<0.01	<0.01	<0.02

[a] McCubbin and Sovacool (2013) estimate slightly higher air pollution-plus-climate-change costs for natural-gas fired power plants in California: 1.4–9.5 cents/kWh for 1987–2006, and 1.8–11.8 cents/kWh projected for 2012–2031 (2010 dollars).

losses per unit distance than alternating-current (AC) lines. The cost of extra-long-distance HVDC transmission on land (1200–2000 km) ranges from 0.3 to 3 U.S. cents/kWh, with a median estimate of ~1 U.S. cent/kWh (Delucchi and Jacobson, 2011). A system with up to 25% undersea transmission would increase the additional long-distance transmission cost by less than 20%. Transmission costs can be reduced by considering that decreasing transmission capacity by 20% reduces aggregate power among interconnected wind farms by only 1.6% (Archer and Jacobson, 2007). The main barrier to long distance transmission is not cost, but local opposition to the siting of lines and decisions about who will pay the costs. These issues must be addressed during the planning process.

In sum, even with extra-long-distance HVDC transmission, the total social costs of all WWS resources in 2020–2030, including solar PV, are expected to be less than the 17.8–20.7 cents/kWh average direct plus externality cost of conventional electricity.

WWS will provide a stable, renewable source of electric power not subject to the same fuel supply limitations as fossil fuels and nuclear power. Due to the eventual depletion of coal, oil, natural gas, and uranium resources, their prices should ultimately rise although technology improvements may delay this rise. Table 5 projects fuel costs from 2009 to 2030 of selected conventional fossil fuels used for transportation, heating, and electricity production in NYS. The table indicates a 19–37% anticipated increase in the cost of natural gas and a 109% increase in the cost of gasoline during this period. A benefit of WWS is that it hedges NYS against volatility and rises in long-term fossil fuel prices by providing energy price stability due to zero cost of WWS fuel.

Table 5
Projected unit costs of selected conventional fossil fuels over the period 2009–2030 in NYS.
Source: NYSEPB (New York State Energy Planning Board) (2009), Energy Price and Demand Long-Term Forecast (2009–2028). Annual growth rate factors provided in reference document have been extrapolated for the period 2029–2030.

Fuel type	Projected changes in fuel cost, 2009–2030 (2009 dollars/ MMBTU)		Percent change (%)
	2009	2030	
Gasoline—all grades	$19.30	$40.39	109
Natural gas—electric	$6.30	$10.14	27
Natural gas—residential	$13.58	$16.19	19
Natural gas—commercial	$10.27	$13.06	27
Natural gas—industrial	$8.73	$11.98	37

8. Air pollution and global warming cost Reductions in NYS due to WWS

Conversion to a WWS energy infrastructure will reduce air pollution mortality and morbidity, health costs associated with mortality and morbidity, and global warming costs in NYS. These impacts are quantified here.

Air pollution mortality in New York is estimated in two ways, a top-down approach and a bottom-up approach. The top-down approach is described first. The premature mortality rate in the U.S. due to cardiovascular disease, respiratory disease, and complications from asthma due to air pollution has been calculated conservatively to be at least 50,000–100,000 per year by several sources. From Braga et al. (2000), the U.S. air pollution mortality rate was estimated at about 3% of all deaths. The all-cause death rate in the U.S. is about 804 deaths per 100,000 population and the U.S. population in 2011 was 308.7 million. This suggests an air pollution mortality rate in the U.S. of ~75,000 per year. Similarly, from Jacobson (2010b), the U.S. death rate due to ozone and particulate matter was calculated with a three-dimensional air pollution-weather model to be 50,000–100,000 per year. These results are consistent with those of McCubbin and Delucchi (1999), who estimated 80,000–137,000 due to all anthropogenic air pollution in the U. S. in 1990, when air pollution levels were higher than today.

The population of NYS in 2011 was 19.5 million, or 6.3% of the U.S. population. A simple scaling of population to the U.S. premature mortality rate from Jacobson (2010b) yields at least 3000–6000 annual premature deaths in NYS. Since a large segment of New York's population lives in cities, this estimate is likely conservative since the intake fraction of air pollution is much greater in cities than in rural areas.

Mortalities from airborne inhalation of particulate matter ($PM_{2.5}$) and ozone (O_3) are next calculated with a bottom-up approach. This involves combining measured countywide or regional concentrations of each pollutant with a relative risk as a function of concentration and U.S. Census Bureau population by county or region. From these three pieces of information, low, medium, and high mortality estimates of $PM_{2.5}$ and O_3 are calculated with a health-effects equation (Jacobson, 2010b).

Tables 6 and 7 show the resulting low, medium, and high 2006 premature mortalities estimates in NYS due to $PM_{2.5}$ and ozone respectively. The medium values for the state as a whole were about 3300 $PM_{2.5}$ mortalities/yr, with a range of 800–6500/yr and ~710 O_3 mortalities/yr, with a range of 360–1100/yr. Thus, overall, the bottom-up approach gave ~4000 (1200–7600) premature mortalities per year for $PM_{2.5}$ plus O_3. The top-down estimate falls within this range.

Table 6
NYS annually-averaged 2006 $PM_{2.5}$ concentrations and resulting estimated annual premature mortalities. Appendix Table A1 contains details and data by county.

New York State	2006 $PM_{2.5}$ ($\mu g/m^3$)	Population (thousands)	Total 2006 Mortalities from $PM_{2.5}$		
			Low estimate	Medium estimate	High estimate
Total	**9.3**	**19,380**	**820**	**3260**	**6480**

Concentration data were from NYSDH (New York State Department of Health) (2011). The methodology is described in the text.

Table 7
Average Annual 2009–2011 premature mortalities due to ground-level ozone by New York region.

	Annual premature mortalities due to ground-level ozone		
	Low estimate	Medium estimate	High estimate
Region 1	55.1	110	164
Region 2	103	205	306
Region 3	37.7	75.1	112
Region 4	10.7	21.4	32.0
Region 5	26.5	52.8	78.9
Region 6	8.4	16.8	25.1
Region 7	18.9	37.7	56.4
Region 8	15.8	31.5	46.8
Region 9	80.8	164	244
Total	**356**	**713**	**1070**

Hourly ozone data at individual monitoring stations were obtained for January 2009–October 2011 from NYDEC (New York State Department of Environmental Conservation (2011). The 1-h maximum ozone for each day was determined from all hourly values during the day. Monitoring stations were then grouped by regions defined by the NYS Department of Environmental Conservation. Region 1=Western New York, Great Lakes Plain; Region 2=Catskill Mountains and West Hudson River Valley; Region 3=Southern Tier; Region 4=New York City and Long Island; Region 5=East Hudson and Mohawk River Valleys; Region 6=Tug Hill Plateau; Region 7=Adirondack Mountains. Mortalities were calculated each day for each region based on ozone relative risks and a health-risk equation, as in Jacobson (2010b). The low-threshold for ozone premature mortality referenced in this study was 35 ppbv.

USEPA (United States Environmental Protection Agency) (2006) and Levy et al. (2010) provided a central estimate to the value of a statistical life at $7.7 million in 2007 dollars (based on 2000 GDP). The value of life is determined by economists based on what people are willing to pay to avoid health risks as determined by how much employers pay their workers to take additional risks (Roman et al., 2012). With this value of life, 4000 (1200–7600) premature mortalities (both adult and infant) due to air pollution cost NYS roughly $31 ($9–$59) billion/yr.

Additional costs due to air pollution result from increased illness (morbidity from chronic bronchitis, heart disease, and asthma), hospitalizations, emergency-room visits, lost school days, lost work days, visibility degradation, agricultural and forest damage, materials damage, and ecological damage. USEPA (United States Environmental Protection Agency), 2011 estimates that these non-mortality-related costs comprise an additional ~7% of the mortality-related costs. These are broken down into morbidity (3.8%), recreational plus residential visibility loss (2.8%), agricultural plus forest productivity loss (0.45%), and materials plus ecological loss (residual) costs. These estimates are conservative, as other studies in the economics literature indicate considerably higher non-mortality costs. McCubbin and Delucchi's (1999) detailed, comprehensive analysis of air-pollution damages at every air quality monitor in the U.S found that the morbidity cost of air pollution (mainly chronic illness from exposure to particulate matter) is 25–30% of the mortality costs. Delucchi and McCubbin (2011) summarize studies that indicate that the cost of visibility and agriculture damages from motor-vehicle air pollution in the U.S. is at least 15% of the cost of health damages (including morbidity damages) from motor-vehicle air pollution. Thus, the total cost of air pollution, including morbidity and non-health damages, is at the very least ~\$8.2 million/death, and probably over \$10 million/death.

Given this information, the total social cost due to air pollution mortality, morbidity, lost productivity, and visibility degradation in NYS is conservatively estimated to be \$33 (10–76 [using \$10 million/death for the upper end]) billion per year. Reducing these costs represents a savings equivalent to ~3% of NYS's gross 2010 domestic product of \$1.1 trillion.

One set of cost estimates for global warming (in 2006 U.S. dollars) to the U.S. alone is \$271 billion/yr by 2025, \$506 billion/yr by 2050, \$961 billion/yr by 2075, and \$1.9 trillion/yr by 2100 (Ackerman et al, 2008). That analysis accounted for severe-storm and hurricane damage, real estate loss, energy-sector costs, and water costs. The largest of these costs was water costs. It did not account for increases in mortality and illness due to increased heat stress, influenza, malaria, and air pollution or increases in forest-fire incidence; thus, it may be conservative.

Averaged between 2004 and 2009, NYS contributed to 3.39% of U.S. and 0.636% of world fossil-fuel CO_2 emissions (EIA (Energy Information Administration, U.S.), 2011). Since the global warming cost to the U.S. is caused by emissions from all states and countries worldwide, it is necessary to multiply the cost of global warming to the U.S. by NYS's fraction of global CO_2 emissions to give the cost of global warming to the U.S. due to NYS's greenhouse gas emissions. The result is \$1.7 billion/yr by 2025, \$3.2 billion/yr by 2050; \$6.1 billion/yr by 2075; and \$12 billion/yr by 2100. NYS's emissions are also increasing the health and climate costs to other countries of the world.

In sum, the current fossil-fuel energy infrastructure in NYS causes ~4000 (1200–7600) annual premature mortalities, which together with other air-pollution damages cost the state ~\$33 billion/yr (~3% of its annual GDP). Fossil fuels emitted in the state will also result in ~\$1.7 billion/yr in global warming costs to the U.S. alone by 2025. Converting to WWS in the state will eliminate these externalities and their costs.

Since every 1 MW of installed WWS capacity costs ~\$2.1 million averaged over all generation technologies needed, the \$33 billion annual air-pollution cost is equivalent to ~16 GW of installed WWS power every year. Since the state needs ~271 GW of installed WWS power to deliver the 60 GW needed (Table 1) to power the state for all purposes in 2030, the payback time to convert the state as a whole to WWS, is ~16 years from the mean air-pollution-cost savings alone. The payback time accounting for air-pollution plus global-warming-cost savings is ~15 years; that accounting for air-pollution plus warming-cost benefits plus electricity sales at no profit is 10 years; that accounting for these plus 7% profit is ~9.8 years.

9. Jobs and earnings due to new electric power plants and devices

This section discusses job creation and earnings resulting from implementing the WWS electric power infrastructure described in Table 2. The analysis is limited to the electric power generation sector to provide an example. Additional jobs are expected in the electricity transmission industry, electric vehicle and hydrogen fuel cell vehicle industries, in the heating and cooling industries, and with respect to energy use for high-temperature industrial processes, but estimates for these sectors are not provided here due to the large undertaking such a calculation requires.

9.1. Onshore and offshore wind

The job creation and revenue stream resulting from generating half of NYS's all-purpose power in 2030 from onshore plus offshore wind (Table 2) were estimated with the Jobs and Economic Development Impact (JEDI) wind model (DOE (Department of Energy), 2012).

Scenarios were run assuming the development by 2025 of 200 onshore wind farms containing 4020 5-MW turbines with a total nameplate capacity of 20,100 MW and 400 offshore wind farms containing 12,700 turbines with a total nameplate capacity of 63,550 MW.

The development of the onshore wind farms is calculated to create ~61,300 full-time jobs and >\$4 billion in earnings in the form of wages, services, and supply-chain impacts during the construction period. It is also estimated to create ~2260 annual full-time jobs and >\$162 million in annual earnings in the form of wages, local revenue, and local supply-chain impacts post-construction.

The development of the offshore wind farms is estimated to create 320,000 full-time jobs and >\$21.4 billion in earnings during construction and 7140 annual full-time jobs and >\$514 million in annual earnings post-construction. (Section 9.5 discusses the extent to which WWS jobs merely displace jobs in the current energy sector.)

9.2. Concentrated solar power plants, solar PV power plants, and rooftop solar PV

The job creation and revenue stream resulting from generating 38% of NYS's all-purpose energy in 2030 with concentrated solar power (CSP, 10%) and solar PV plants and residential rooftop devices (PV, 28%), were estimated with the JEDI Concentrated Solar Power Trough and PV models (DOE (Department of Energy), 2012).

Scenarios were run assuming the development by 2025 of 38,700 MW in nameplate capacity of CSP projects, 41,400 MW of solar PV plant projects, and 75,000 MW of residential, commercial, and government rooftop PV projects.

The CSP projects are estimated to create ~401,000 full-time jobs and >\$41 billion in earnings during construction and ~15,700 full-time jobs and >\$2 billion in annual earnings post-construction.

Solar PV plants are estimated to create ~1,160,000 full-time jobs (>\$83 billion in earnings) during construction and ~5690 full-time jobs (>\$390 million in annual earnings) post-construction.

Rooftop PV systems are estimated to create ~2,420,000 full-time jobs (~\$159 billion in earnings) during construction and ~9620 full-time jobs (>\$676 million in annual earnings) post-construction.

9.3. Hydroelectric, tidal, and wave

In line with the guidelines of PlaNYC, nearly 7% of NYS's total energy in 2030 will be generated from hydroelectric, tidal, and wave power (Table 2). At most, about 944 MW of additional installed hydroelectric will be needed for the present plan, since 89% of hydroelectric is in place (Table 2). This translates into 2360 additional post-construction full time jobs assuming 2–3 full time jobs are created per MW of hydropower generated in 2025 (Navigant Consulting, 2009). Temporary construction and other supply chain jobs are not included in this projection. Temporary construction jobs for hydroelectric are estimated as 6.5 full-time equivalent (FTE) jobs/MW. FTEs are jobs during the life of the construction phase (Navigant Consulting, 2009). This gives 6200 construction jobs for hydroelectric. With the approximate ratio of

$70,000 per job (based on the ratios determined here for wind and solar), the earnings during construction of hydroelectric plants are estimated as ~$430 million during construction and $165 million/yr after construction.

For wave power (1430 MW needed) and tidal power (2600 MW needed) the same number of construction and permanent jobs per installed MW as offshore wind power are assumed, giving 7200 construction jobs and 161 annual permanent jobs for wave power and 13,100 construction jobs and 292 annual permanent jobs for tidal power. Earnings during the construction period of wave farms are estimated as ~$504 million, and those during operation, ~$11 million/yr. Earnings during construction of tidal farms are estimated as ~$920 million, and those during operation, ~$20.5 million/yr.

9.4. Geothermal

The construction of 5635 MW of geothermal capacity in the western United States has been estimated previously to create 90,160 construction and manufacturing jobs plus 23,949 full time jobs after construction (Western Governor's Association, 2010). Assuming the same relationship holds for NYS in 2025, the 3600 MW of geothermal energy (5% of total) needed for NYS will amount to the creation of ~57,600 construction and manufacturing jobs and ~15,300 post-construction jobs. With the approximate ratio of $70,000 per job, the earnings during construction of geothermal plants will be ~$4 billion during the construction period and $1 billion/yr thereafter.

9.5. Summary of jobs and earnings

Summing the job production from each sector above gives ~4.5 million jobs created during construction and ~58,000 permanent annual jobs thereafter for the energy facilities alone developed as part of this plan. Total earnings during the construction period for these facilities (in the form of wages, local revenue, and local supply-chain impacts) are estimated as ~$314 billion and permanent annual earnings during operation of the facilities, ~$5.1 billion/yr

Additional jobs and earnings are associated with the enhancement of the transmission system and with the conversion to electric and hydrogen fuel cell vehicles, electricity-based appliances for home heating and cooling, and electricity and hydrogen use for some heating and high-temperature industrial processes.

The number of permanent jobs created by the electric power sector alone is expected to exceed significantly the number of lost jobs in current fossil-fuel industries. The reason is that nearly all energy for NYS with the proposed plan will be produced within the state, whereas currently, most oil, natural gas, and coal used in the state is mined out of the state or country, so jobs in those industries are not in NYS. In fact, the total number of mining jobs (for all natural resources combined) in NYS in 2011 was approximately 5700 (NYSDL (New York State Department of Labor), 2011). The total number of workers in the NYS utility industry in 2011 was about 37,100 (NYSDL (New York State Department of Labor), 2011). Even if the current electric utility industry plus mining jobs were lost due to a conversion with the present plan, they would be more than made up by with the 58,000 permanent jobs resulting from the present plan. The present plan would also result in the replacement of gas stations with electric charging and hydrogen fueling stations, likely exchanging the jobs between the industries. Similarly, the plan will require the growth of some appliance industries at the expense of others, resulting in job exchange between industries.

The increase in the number of jobs due to WWS versus the current fossil fuel infrastructure is supported independently by Pollin et al. (2009), who determined from economic modeling that, for each million dollars spent on energy production in the United States, oil and gas create 3.7 direct and indirect jobs, whereas wind and solar create 9.5 and 9.8 jobs, respectively. The difference in relative numbers of jobs created in NYS is likely to be larger than this due to the fact that many oil and gas workers and suppliers come from out of state. Since WWS resources are generated in state, their capture will provide more jobs to NYS residents. In addition, even though some of the jobs in NYS might come at the expense of jobs in other states, Pollin et al. (2009) indicate that for the U.S. as a whole, the wind and solar power industry will employ many more people than will an energy-equivalent fossil-fuel industry.

In addition, the development of the large-scale energy infrastructure proposed here should motivate research and development of new technologies and methods of improving efficiency. Much of this research will come from higher education and research institutes in NYS, creating jobs in these sectors. Demands created by infrastructure development should similarly motivate inner-city job training programs in the energy-efficient building and renewable energy industries.

10. State and local tax revenue and other cost considerations

The implementation of this plan will likely affect NYS's tax revenue and may require tax policy changes to ensure that state revenue remains at the level needed. Some revenues will increase and others will decline.

The increase in the number of jobs due to the plan over the current energy infrastructure is expected to increase personal income tax receipts. In addition, as more of NYS's infrastructure is electrified under the plan, revenues from the Utility Tax, which currently accounts for slightly less than 1.5% of state tax revenue, will increase.

NYS may experience higher property tax revenues than under an alternative, natural gas, infrastructure. Property values may decrease with shale gas drilling due to the increases in noise, conflicts with neighbors, lawsuits with gas companies, health complaints, and increases in crime in previously sparsely populated rural areas. In addition, banks may be unwilling to issue residential-rate mortgages on residential properties in gas drilling areas since industrial activity and the storing of hazardous material on the property violate residential mortgage requirements. Similarly, some insurance companies may not issue policies on such properties. Property tax revenues are expected to increase with some WWS technologies, such as rooftop PV and solar thermal due to the higher home values that result from installation of these local energy technologies. A study of the effects of 24 existing wind farms within 10 miles of residential properties in 9 states found no effect on property values (Hoen et al., 2009). Thus, a conversion to WWS should result in higher property values and tax revenues than should a fossil fuel-based infrastructure.

Finally Delucchi and Murphy (2008) show that in 1991 and 2000, the effective U.S. federal corporate income tax rate (tax paid divided by taxable income) in the oil industry was half that of all other industries, resulting in a tax "subsidy" in the year 2000 of $9.4 billion. Replacing fossil fuels with WWS energy in NYS alone could result in higher corporate income-tax revenues to the nation and may set an example for other states.

Revenues directly associated with the sale of petroleum fuels, such as the Motor Fuel Tax and the Petroleum Business Tax, will diminish as the vehicle fleet is made more efficient and ultimately transitions away from petroleum altogether. These tax revenues currently account for less than 2.5% of state tax revenue; however, they are sources of funds for the Highway and Bridge Trust Fund, the Dedicated Mass Transportation Trust Fund, and the

Mass Transportation Operating Assistance Fund. Another potential loss in tax revenue will be from the ad valorem tax on shale gas development.

As diesel fuel is phased out, goods will increasingly be transported by means other than commercial freight, and revenue from the Highway Use Tax will diminish. This tax accounts for less than 0.2% of state tax revenue at present, but is also a large contributor to transportation infrastructure and operation funds (NYSA (New York State Assembly), 2011).

Other tax revenues associated with passenger vehicle use are not expected to decrease significantly. These include Motor Vehicle Fees, Taxi Surcharge fees, and Auto Rental Tax. These collectively account for approximately 2% of State tax revenue and contribute to the state's dedicated mass transportation and highway and bridge funds.

Some lost revenues can be regained by applying a mileage-based road use tax on noncommercial vehicles similar to the Highway Use Tax levied on commercial vehicles in NYS. This has been considered at the Federal level (NSFIFC (National Surface Transportation Infrastructure Financing Commission), 2009) and piloted in Oregon (ODT (Oregon Department of Transportation), 2007).

There are other cost considerations. For example, the conversion from fossil fuels to WWS will likely reduce environmental externality costs, thereby possibly preserving some jobs that would otherwise be lost under future fossil fuel development in NYS. Some industries that are vital to upstate NY economies and require clean water and air include agriculture, tourism, organic farming, wine making, hunting and fishing, and other outdoor recreation industries. WWS development is unlikely to adversely impact these industries, whereas future shale gas development may negatively impact these industries.

It is expected that costs to communities in NYS will increase with shale gas development, and these costs will likely be much lower or not exist with WWS development. Such costs include increased demand on police, fire departments, first responders, social services, and local hospitals. Damage to roads and resulting repair and maintenance costs have been substantial where shale gas development has taken place, especially in Texas and Arkansas. WWS development is unlikely to cause such extensive long-term damage to roads and infrastructure.

Thousands of miles of natural gas pipelines represent an opportunity cost to NYS, as future building and economic development will not be possible on or adjacent to the pipelines. The tradeoff for these pipelines with WWS is an increase in transmission lines. However, transmission lines, while resulting in some similar issues, do not carry the risk of gas leakage or explosive fires, such as the $5 billion fire that destroyed a residential neighborhood in San Bruno, California, on September 10, 2010.

Finally, extractive industries, including fossil fuels, are known for their boom and bust cycles. Renewable energy industries, and in particular WWS, are long-term sustainable industries, unlikely to be subject to boom and bust cycles.

11. Reducing energy use in Buildings, Neighborhoods, and commercial complexes

The proposed plan will continue existing efforts to improve energy efficiency in residential, commercial, institutional, and government buildings to reduce the demand for electric power in NYS. It will also encourage the conversion of buildings, neighborhoods, and commercial complexes to sustainable ones that use and store their energy more efficiently.

First, energy efficiency measures in buildings, appliances, and processes have the potential to reduce end-use power demand in the U.S. by up to 23% by 2020 (McKinsey and Company, 2009). Such a demand reduction exceeds the modest reduction of 5–10% proposed in Table 1 of the present study. The NYS demand reduction is conservative to ensure that it does not underestimate the number of energy devices and plants needed for NYS. If demand reduction is larger than 5–10%, then the NYS plan will be easier to implement. Efficiency measures include improving wall, floor, ceiling, and pipe insulation, sealing leaks in windows, doors, and fireplaces, converting to double-paned windows, using more passive solar heating, monitoring building energy use to determine wasteful processes, performing an energy audit to discover energy waste, converting to LED light bulbs, changing appliances to those using less electricity, and using hot water circulation pumps on a timer, among others.

Historically, efficiency programs targeting multifamily households have resulted in overall energy savings of approximately 20% (Falk and Robbins, 2010). For such households, the NYSERDA Home Performance with Energy Star program reportedly achieved annual savings of approximately 15% of average household electricity usage and over 50% of heating fuel savings for natural gas-heated homes (NYSERDA (New York State Energy Research and Development Authority), 2011).

Second, designing new buildings, neighborhoods and commercial complexes or retrofitting existing ones to use and store energy more efficiently has the potential to reduce significantly building energy required from the grid, transmission needs, and costs. Four methods of improving energy use and storage in buildings include: (1) extracting heat in the summer and cold in the winter from the air and solar devices and storing it in the ground for use in the opposite season, (2) recovering heat from air conditioning systems and using it to heat water or air in the same or other buildings, (3) extracting heat (or cold) from the ground, air, or water with heat pumps and using it immediately to heat (or cool) air or water, and (4) using solar energy to generate electricity through PV panels, to recover heat from water used to cool the panels, and to heat water directly for domestic use (e.g., Tolmie et al., 2012). The Drake Landing solar community is a prototype community designed primarily around the first method, that of seasonal energy storage (Drake Landing, 2012).

12. Timing of plan

This plan anticipates that the fraction of new electric power generators as WWS will increase starting today such that, by 2020, all new generators will be WWS generators. Existing conventional generators will be phased out gradually, but no later than 2050. Similarly, all new heating and cooling technologies will be WWS technologies by 2020 and existing technologies will be replaced over time, but by no later than 2050.

For transportation, the transition to BEVs and HFCVs has potential to occur rapidly due to the rapid turnover time of the vehicle fleet ($\sim$15 years) and the efficiency of BEVs and HFCVs over fossil-fuel combustion vehicles. However, the actual rate of transition will depend on policies put in place and the resulting vehicle and energy costs. BEVs and HFCVs exist today, but due to their efficiency over combustion, they are proposed to be the only new vehicles sold in NYS by 2020. Several electric vehicles are currently available (e.g., Tesla Model S, 499 km (310 mile) range; Tesla Roadster, 391 km (243 mile); Renault Fluence Z.E., 185 km (115 mile); Citroen C-Zero, 177 km (110 mile); Mitsubishi I MiEV, 177 km (110 mile); Tazzari Zero, 140 km (87 mile); Ford Focus, 129 km (80 mile); Nissan Leaf, 117 km (73 mile)). The growth of electric vehicles will be accompanied by an increase in electric charging stations in residences, commercial parking spaces, and service stations. Most charging will be done with 220 V chargers over several hours, but 440 V chargers are now available for faster charging. For example, the Tesla Model S includes 440 V, 160 A charging capability that will allow sufficient power for a 310 mile range in about 1 h.

13. Recommended first Steps

Below are recommended short-term policy steps to start the conversion to WWS in NYS.

13.1. Large energy projects: offshore/onshore wind; solar PV/CSP, geothermal, hydro

- Direct the New York State Energy Research and Development Authority (NYSERDA) to issue a new main tier solicitation to meet its existing renewable portfolio standard (RPS) commitments through 2015, selecting and contracting with sufficient wind and solar projects to do so.
- Extend the RPS in NYS. The 30% RPS currently sunsets in 2015. Propose to ramp up the RPS each year to get to 50% by 2025 (2% per year).
- Set a goal of at least 5000 MW offshore wind by 2020. Direct the New York Power Authority (NYPA) and the Long Island Power Authority (LIPA) to issue requests for proposals (RFPs) for new power generation from offshore wind as part of their generation and procurement budgets.
- Set up a Green Bank, which is a vehicle for public–private financing in conjunction with long-term contracts for large wind and solar development projects in NYS. An example Green Bank exists in Connecticut. The Green Bank would include a statewide version of the Department of Energy Loan Guarantee Program that focuses specifically on WWS energy generation projects. Such a program will reinvigorate private lending activity.
- Lock in upstate coal-fired power plants to retire under enforceable commitments. At the same time, streamline the permit approval process for WWS power generators and the associated high-capacity transmission lines and eliminate bureaucratic hurdles involved in the application process. Promote expanding transmission of power between upstate and downstate and between onshore and offshore, in particular.
- Work with regions and localities, and the federal government (in the case of offshore wind) to reduce the costs and uncertainty of projects by expediting their physical build-out by managing zoning and permitting issues or pre-approving sites.
- Encourage regulators to require utilities to obtain permission for a certain capacity of electric power to be installed before auctioning off projects to lowest-bidding developers. Currently, a pre-approved Power Purchase Agreement between a utility and particular project developer is required before permission from the regulators can be obtained. This change will ensure end-users obtain electricity at the lowest price.

13.2. Small energy projects: residential commercial, and government rooftop solar PV

- Extend the New York Sun (NY Sun) program to a multi-year program to finance rooftop and on-site solar projects in the state.
- Implement virtual net metering (VNM) for small-scale energy systems. The following recommendations will render utility-scale wind and solar power net metering conducive to corporate clients, and pave the way for a more widespread subscription to off-site generating project for the public at large.

(1) Remove the necessity for subscribers to have proprietorship in the energy-generating site.
(2) Expand or eliminate the capacity limit of renewable power under remote net-metering for each utility.
(3) Remove the barrier to inter-load zone transmission of net-metered renewable power.
(4) Expand Public Service Law 66.j to reduce red tape and enable off-site virtual net-metering from upstate to downstate, and from the outer boroughs to Manhattan.

- Streamline the small-scale solar and wind installation permitting process. Currently, each municipality has its own permitting process and fee structure. Creating common codes, fee structures, and filing procedures across a state would reduce a barrier to the greater implementation of small-scale solar and wind.
- Develop community renewable energy facilities, whereby a community buys power from a centralized generation facility. The facility feeds power into the grid, and the utility credits the kilowatt-hours to the accounts of individuals, businesses, and any other electricity customer that sign up. The facility may be located anywhere in the utility's service territory, since all that is required is a bill crediting arrangement by the utility. This brings many advantages: economies of scale of the facility, siting in an ideal location, and broader inclusiveness. Many electricity users cannot install a renewable energy system, because they are renters or because their property is not suitable for a system. Community renewable energy is inclusive because it enables anyone, whether living in rural New York or an apartment building in Manhattan, to buy the power without having to host the system. New York already has a community renewable energy program, but it is restrictive. A simple legislative fix would enable this approach to be used widely.
- Encourage clean-energy backup emergency power systems rather than diesel/gasoline generators. For example, work with industry to implement home energy storage (through battery systems) accompanying rooftop solar to mitigate problems associated with grid power losses.
- Implement feed-in tariffs (FITs) for small-scale energy systems. FITs are financial incentives to promote investment in renewable power generation infrastructure, typically by providing payments to owners of small-scale solar PV systems to cover the difference between renewable energy generation cost (including grid connection costs) and wholesale electricity prices.

13.3. Energy efficiency in buildings and the grid

- The current target for energy efficiency is 15% less energy use below forecasted levels by 2015. Expand the target significantly beyond 2015 and increase investment fivefold from both public and private sources. This requires the New York State Public Service Commission (NYSPSC) to increase NYSERDA and utility requirements and budgets for efficiency.
- Promote, through municipal financing, incentives, and rebates, energy efficiency measures in buildings, appliances, and processes. Efficiency measures include improving wall, floor, ceiling, and pipe insulation, sealing leaks in windows, doors, and fireplaces, converting to double-paned windows, using more passive solar heating, monitoring building energy use to

determine wasteful processes, performing an energy audit to discover energy waste, converting to LED light bulbs, changing appliances to those using less electricity, and using hot water circulation pumps on a timer, among others.

- Encourage conversion from natural gas water and air heaters to heat pumps (air and ground-source) and rooftop solar thermal hot water pre-heaters. Incentivize the use of efficient lighting in buildings and on city streets.
- Encourage utilities to use demand-response grid management to reduce the need for short-term energy backup on the grid. This is a method of giving financial incentives to electricity users to shift times of certain electricity uses to times when more energy is available.
- Institute, through Empire State Development Corporation, a revolving loan fund to pay for feasibility analyses for commercial Energy Services Agreements. The revenues from these retrofits are amortized as a majority percentage of the Energy-Cost Savings realized as direct result of these retrofits. ROI's can be realized in 5–10 years with 10–20 year Energy Services Contracts. Allocating some of these revenues back to the fund will render it sustainable.
- Extract heat in the summer and cold in the winter from the air and solar devices and store it in the ground for use in the opposite season. The Drake Landing solar community is a prototype community designed primarily around seasonal energy storage (Drake Landing, 2012).
- Recover heat from air conditioning systems and use it to heat water or air in the same or other buildings at the same time.
- Extract heat (or cold) from the ground, air, or water with heat pumps and use it immediately to heat (or cool) air or water.
- Recover heat from water used to cool solar PV panels to heat water directly for domestic use.

13.4. Vehicle electrification

- Coordinate items below so that vehicle programs and public charging stations are developed in sync. Create a governor-appointed EV Advisory Council, as has been done in states such as Illinois and Connecticut, to recommend strategies for EV infrastructure and policies. Council members should include representatives from state agencies, environmental groups, utilities, auto companies, and EV charging infrastructure companies.
- Leverage and augment the technical and financial assistance of the U. S. Department of Energy's "Clean Cities Program" activities, focusing on the deployment of EVs.
- Adopt legislation mandating the transition to plug-in electric vehicles for short- and medium distance government transportation and encouraging the transition for commercial and personal vehicles through purchase incentives and rebates.
- Encourage fleets of electric and/or hydrogen fuel cell/electric hybrid buses starting with a few and gradually growing the fleets. Electric or hydrogen fuel cell ferries, riverboats, and other local shipping should be encouraged as well.
- Encourage and ease the permitting process for the installation of electric charging stations in public parking lots, hotels, suburban metro stations, on streets, and in residential and commercial garages.
- Ensure that new charging infrastructure is vehicle-to-grid (V2G)-capable, and integrated into a statewide "smart grid" system.
- Set up time-of-use electricity rates to encourage charging at night.
- Provide electric vehicle drivers access to high-occupancy vehicle (HOV) lanes.
- Use excess wind and solar produced by WWS electric power generators to produce hydrogen (by electrolysis) for transportation and industry and to provide district heating (as done in Denmark) instead of curtailing the wind and solar.

13.5. Industrial processes

- Provide incentives for industry to convert to electricity and electrolytic hydrogen for high temperature and manufacturing processes where they are not currently used.
- Encourage industries to use WWS electric power generation for on-site electric power (private) generation.

14. Conclusions

This study examined the technical and economic feasibility of and proposed policies for converting New York State's energy infrastructure for all purposes into a clean and sustainable one powered by wind, water, and sunlight producing electricity and hydrogen. Such a conversion is estimated to improve the health and welfare of NYS residents, thereby lowering their medical, insurance, and related costs, and is expected to create jobs to manufacture, install, and manage the infrastructure.

The study found that complete conversion to WWS in NYS will reduce end-use power demand by $\sim$37%, due mostly to the efficiency of electricity versus combustion, but also due partly to energy efficiency measures.

If complete conversion to WWS occurs, the 2030 NYS power demand for all purposes (not only electricity) could be met by 4020 onshore 5-MW wind turbines (providing 10% of NYS's energy for all purposes), 12,770 off-shore 5-MW wind turbines (40%), 387 100-MW concentrated solar plants (10%), 828 50-MW solar-PV power plants (10%), 5 million 5-kW residential rooftop PV systems (6%), 500,000 100-kW commercial/government rooftop systems (12%), 36 100-MW geothermal plants (5%), 1910 0.75-MW wave devices (0.5%), 2600 1-MW tidal turbines (1%), and 7 1300-MW hydroelectric power plants (5.5%), of which 89% are already in place. The onshore wind capacity installed under this plan ($\sim$20.1 GW) would be less than twice the 2012 installed capacity of Texas.

Several methods exist to match renewable energy supply with demand and to smooth out the variability of WWS resources. These include (A) combining geographically-dispersed WWS resources as a bundled set of resources rather than as separate resources and using hydroelectric power to fill in remaining gaps; (B) using demand-response grid management to shift times of demand to match better with the timing of WWS power supply; (C) over-sizing WWS peak generation capacity to minimize the times when available WWS power is less than demand and to provide power to produce heat for air and water and hydrogen for transportation and heating when WWS power exceeds demand; (D) integrating weather forecasts into system operation to reduce reserve requirements; (E) storing energy in thermal storage media, batteries or other storage media at the site of generation or use; and (F) storing energy in electric-vehicle batteries for later extraction (vehicle-to-grid).

The additional footprint on land for WWS devices is equivalent to about 0.96% of New York's land area, mostly for CSP and PV. An additional on-land spacing area of about 1.46% is required for on-shore wind, but this area can be used for multiple purposes, such as open space, agricultural land, or grazing land, for example.

The land footprint and spacing areas (open space between devices) in the proposed scenario can be reduced by shifting more land based WWS generators to the ocean, lakes, and rooftops.

2020–2030 electricity costs are estimated to be 4–8.8 cents/kWh for most WWS technologies and 5–11 cents/kWh for others (including local transmission and distribution), which compares with about 17.8–20.7 cents/kWh for fossil-fuel generators in 2030, of which 5.7 cents/kWh are externality costs. Long-distance transmission costs on land are estimated to be 1 (0.3–3) cent/kWh for 1200–2000 km high-voltage direct current transmission lines.

Although the cost of WWS electricity is expected to be lower than that of fossil fuels and all energy in a WWS world will be transformed to electricity, infrastructure conversion will result in other cost tradeoffs not quantified here. For example, conversion from combustion vehicles to electric and hydrogen fuel cell vehicles and from current combustion-based heating technologies to electricity based technologies may result in large initial cost increases to consumers, when relatively low levels of vehicles are being manufactured. However, as production of new vehicles increases and technology matures, manufacturing costs will decline, and this, combined with the lower energy and operating costs of electric vehicles, may result eventually in electric vehicles having a total lifetime cost comparable with that of conventional gasoline vehicles (Delucchi and Lipman, 2010),

The plan is estimated to create ~4.5 million jobs during construction and ~58,000 permanent annual jobs thereafter for the proposed energy facilities alone. Total earnings during the construction period for these facilities (in the form of wages, local revenue, and local supply-chain impacts) will be ~$314 billion and permanent annual earnings during operation of the facilities will be ~$5.1 billion/yr

The implementation of this plan will likely increase personal income, property, and utility tax revenues in NYS relative to the current infrastructure. At the same time, it will reduce fuel-tax revenues. These can be made up from either the utility taxes or mileage-base road fees.

The plan effectively pays for the 100% WWS energy generation infrastructure to power NYS for all purposes over 15 years solely by the reduction in air-pollution costs to the state and global warming costs to the U.S. from state emissions. Annual electricity sales equal to the cost of the plant divided by its expected life (~30 years) reduce the payback time to ~10 years. The current fossil-fuel infrastructure does not provide the air-quality benefits to NYS, so it's payback time with annual electricity sales equal to the cost of the plant and fuel divided by the expected plant life is ~30 years; assuming a 7% profit, it is ~28 years.

This plan may serve as a template for plans in other states and countries. Results here suggest that the implementation of plans such as this in countries worldwide should reduce global warming, air, soil, and water pollution, and energy insecurity.

Acknowledgments

This study was not funded by any interest group, company, or government agency. We would like to thank Mark A. Ruffalo, Josh Fox, Marco Krapels, Peter Bardaglio, Gianluca Signorelli, Jon Wank, Elaine Hart, Charles Komanoff, and Andrea Romano for helpful suggestions and comments.

Appendix A1

See Appendix Table A1.

Table A1
NYS annually-averaged 2006 $PM_{2.5}$ concentrations and resulting estimated annual premature mortalities by county.

County	2006 $PM_{2.5}$ ($\mu g/m^3$)	Population (thousands)	Total 2006 Mortalities from $PM_{2.5}$		
			Low estimate	Medium estimate	High estimate
Albany	9.4	304	8.4	33.4	66.5
Alleghany*	8.2	49	0.9	3.5	6.9
Bronx	13.9	1385	88.4	351	695
Broome**	10.3	201	7.0	27.8	55.4
Cattaraugus*	9.6	80	2.3	9.3	18.6
Cayuga*	8.3	80	1.5	5.9	11.8
Chautauqua	8.3	135	2.5	10.0	20.0
Chemung*	8.2	89	1.6	6.3	12.6
Chenango*	10.3	50	1.8	7.0	13.9
Clinton*	5.5	82	0.9	3.6	7.3
Columbia*	9.4	63	1.7	6.9	13.8
Cortland*	8.3	49	0.9	3.7	7.3
Delaware*	10.3	48	1.7	6.7	13.2
Dutchess**	10.7	297	11.3	45.1	89.7
Erie	10.9	919	36.4	145	289
Essex	5.5	39	0.4	1.7	3.5
Franklin*	6.0	52	0.6	2.5	4.9
Fulton*	11.5	56	2.5	9.8	19.6
Genesee*	10.3	60	2.1	8.3	16.5
Greene*	9.4	49	1.4	5.4	10.8
Hamilton*	6.0	5	0.1	0.2	0.5
Herkimer*	6.4	65	0.8	3.3	6.6
Jefferson*	6.4	116	1.5	6.0	12.0
Kings	12.8	2505	138	547	1090
Lewis*	6.4	27	0.4	1.4	2.8
Livingston*	8.9	65	1.5	6.0	12.0
Madison*	8.3	73	1.4	5.5	10.9
Monroe	9.5	744	21.1	84.1	168
Montgomery*	11.5	50	2.2	8.9	17.7
Nassau	10.8	1340	52.0	207	412
New York	14.4	1586	108	427	845
Niagara	10.4	216	7.7	30.7	61.2
Oneida**	10.5	235	8.5	34.1	67.8
Onondaga	8.3	467	8.7	34.7	69.1
Ontario*	8.9	108	2.5	9.9	19.8
Orange	9.7	373	11.2	44.5	88.7
Orleans*	10.0	43	1.4	5.5	10.9
Oswego*	8.3	122	2.3	9.1	18.1
Otsego*	10.5	62	2.3	9.0	18.0
Putnam*	10.4	100	3.5	14.0	27.9
Queens	11.6	2231	101	402	800
Rensselaer*	9.4	159	4.4	17.5	34.9
Richmond	12.2	469	23.5	93.5	186
Rockland*	10.4	312	11.0	43.7	87.1
St. Lawrence	6.4	112	1.4	5.8	11.5
Saratoga*	11.5	220	9.8	38.9	77.3
Schenectady**	11.5	155	6.9	27.4	54.5
Schoharie*	9.4	33	0.9	3.6	7.2
Schuyler*	8.2	18	0.3	1.3	2.6
Seneca*	8.2	35	0.6	2.5	5.0
Steuben**	8.2	99	1.8	7.0	14.0
Suffolk	10.4	1493	53.1	212	422
Sullivan*	9.7	78	2.3	9.3	18.4
Tioga*	10.3	51	1.8	7.1	14.1
Tompkins*	9.4	102	2.8	11.0	21.9
Ulster*	9.7	182	5.5	21.8	43.4
Warren*	5.5	66	0.7	2.9	5.8
Washington*	5.5	63	0.7	2.8	5.6
Wayne*	9.5	94	2.7	10.6	21.1
Westchester	11.0	949	38.4	153	304
Wyoming*	10.9	42	1.7	6.7	13.2
Yates*	8.7	25	0.5	2.2	4.3
Total	**9.3**	**19,380**	**820**	**3260**	**6480**

Concentration data were from NYSDH (New York State Department of Health) (2011). The methodology is described in the text.

* 2006 data for these counties were not available, so an average of data from adjacent or nearby counties was used.

** 2006 data for these counties were not available, so 2003 values were used.

References

Ackerman, F., Stanton, E.A., Hope, C., Alberth, S., Fisher, J., Biewald, B., 2008. The Cost of Climate Change. www.nrdc.org/globalwarming/cost/cost.pdf (accessed 21.07.11).

Alliance for Climate Protection, 2009. Repower America. ⟨http://climatereality project.org/⟩ (accessed 26.08.12).

Alvarez, R.A., Pacala, S.W., Winebrake, J.J., Chameides, W.L., Hamburg, S.P., 2012. Greater focus needed on methane leakage from natural gas infrastructure. Proceedings of the National Academy of Sciences 109, 6435–6440, http://dx.doi.org/10.1073/pnas.1202407109.

Anderson, L.G., 2009. Ethanol fuel use in Brazil: air quality impacts. Energy and Environmental Science 2, 1015–1037.

Archer, C.L., Jacobson, M.Z., 2007. Supplying baseload power and reducing transmission requirements by interconnecting wind farms. Journal of Applied Meteorology and Climatology 46, 1701–1717, http://dx.doi.org/10.1175/2007JAMC1538.1.

Beyond Zero Emissions, 2010. Zero Carbon Australia Stationary Energy Plan, Melbourne Energy Institute. University of Melbourne, July, 2010. ⟨http://beyondzeroemissions.org/⟩ (accessed 26.08.12).

Braga, A.L.F., Zanobetti, A., Schwartz, J., 2000. Do respiratory epidemics confound the association between air pollution and daily deaths. European Respiratory Journal 16, 723–728.

Bringezu, S., Schutz, H., O'Brien, M., Kauppi, L., Howarth, R., McNeely, J., 2009. Towards Sustainable Production and Use of Resources: Assessing Biofuels. International Panel for Sustainable Resource Management, United Nations Environment Program, Paris, France. ⟨http://www.unep.fr/scp/rpanel/biofuels.htm⟩ (accessed 15.07.12).

Budischak, C., Sewell, D., Thomson, H., Mach, L., Veron, D.E., Kempton, W., 2013. Cost-minimized combinations of wind power, solar power, and electrochemical storage, powering the grid up to 99.9% of the time. Journal of Power Sources 225, 60–74.

Campbell, J.E., Lobell, D.B., Field, C.B., 2009. Greater transportation energy and GHG offsets from bioelectricity than ethanol. Science 324, 1055–1057.

Carmichael, G.R., Streets, D.G., Calori, G., Amann, M., Jacobson, M.Z., Hansen, J., Ueda, H., 2002. Changing trends in sulfur emissions in Asia: implications for acid deposition, air pollution, and climate. Environmental Science and Technology 36, 4707–4713.

Connolly, D., Lund, H., Mathiesen, B., Leahy, M., 2011. The first step towards a 100% renewable energy-system for Ireland. Applied Energy 88, 502–507.

Cornell Program on Applied Demographics, 2011. New York State Projection Data by County. ⟨http://pad.human.cornell.edu/counties/projections.cfm⟩ (accessed 17.10.11).

Delucchi, M.A., 2010. Impacts of biofuels on climate change, land use, and water use. Annals of the New York Academy of Sciences 1195, 28–45.

Delucchi, M.A., 2006. Lifecycle Analyses of Biofuels. www.its.ucdavis.edu/publications/2006/UCD-ITS-RR-06-08.pdf (accessed 26.08.2012).

Delucchi, M.A., Jacobson, M.Z., 2011. Providing all global energy with wind, water, and solar power, Part II: reliability, system and transmission costs, and policies. Energy Policy 39, 1170–1190, http://dx.doi.org/10.1016/j.enpol.2010.11.045.

Delucchi, M.A., Lipman, T.E., 2010. Lifetime cost of battery, fuel-cell, and plug-in hybrid electric vehicles. In: Pistoia, G., Elsevier, B.V. (Eds.), Electric and Hybrid Vehicles: Power Sources, Models, Sustainability, Infrastructure and the Market. Amsterdam, The Netherlands, pp. 19–60. (Chapter 2).

Delucchi, M.A., McCubbin, D.M., D.M., 2011. External Costs of Transport in the United States. In: de Palma, A., Lindsey, R., Quinet, E., Vickerman, R. (Eds.), A Handbook Transport Economics. Edward Elgar Publishing, Cheltenham, U.K, pp. 341–368. (Chapter 15).

Delucchi, M.A., Murphy, J., 2008. How large are tax subsidies to motor-vehicle users in the U.S? Journal of Transport Policy 15, 196–208.

DOE (Department of Energy), 2004. Water Energy Resources of the United States. ⟨http://hydropower.inel.gov/resourceassessment/pdfs/03-11111.pdf⟩, ⟨http://nationalatlas.gov/articles/people/IMAGES/energy_hydromap_lrg.gif⟩ (accessed 13.09.11).

DOE (Department of Energy), 2012. Job and Economic Development Impact (JEDI) Model. ⟨http://www.windpoweringamerica.gov/filter_detail.asp?itemid=707⟩ (accessed 10.06.12).

Dong Energy, Vattenfall Danish Energy Authority, and Danish Forest and Nature Agency, 2006. Danish Offshore Wind: Key Environmental Issues. www.ens.dk/graphics/Publikationer/Havvindmoeller/havvindmoellebog_nov_2006_skrm.pdf (accessed 26.08.12).

Drake Landing, 2012. Drake Landing Solar Community. ⟨http://www.dlsc.ca/⟩ (accessed 27.10.12).

Dvorak, M.J., Corcoran, B.A., Ten Hoeve, J.E., McIntyre, N.G., Jacobson, M.Z., 2012a. U.S. East Coast offshore wind energy resources and their relationship to peak-time electricity demand. Wind Energy, http://dx.doi.org/10.1002/we.1524.

Dvorak, M.J., Stoutenburg, E.D., Archer, C.L., Kempton, W., Jacobson, M.Z., 2012b. Where is the ideal location for a U.S. East Coast offshore grid. Geophysical Research Letters 39, L06804, http://dx.doi.org/10.1029/2011GL050659.

EIA (Energy Information Administration, U.S.), 2011. State CO_2 Emissions. ⟨http://www.eia.gov/environment/emissions/state/state_emissions.cfm⟩ (accessed 23.11.11).

EIA (Energy Information Administration, U.S.), 2012a. 2010 Consumption Summary Tables. ⟨http://www.eia.gov/state/seds/seds-data-complete.cfm#summary⟩ (accessed 20.12.12).

EIA (Energy Information Administration, U.S.), 2012b. Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923). ⟨http://www.eia.gov/electricity/data/state/⟩ (accessed 17.01.13).

EIA (Energy Information Administration, U.S.), 2012c. Levelized Cost of New Generation Resources in the Annual Energy Outlook 2012. ⟨http://www.eia.gov/forecasts/aeo/electricity_generation.cfm⟩ (accessed 10.11.12).

EIA (Energy Information Administration, U.S.), 2012d. Electricity Sales, Revenue, and Average Price. ⟨http://www.eia.gov/electricity/sales_revenue_price/⟩ (accessed 23.11.12).

Elliston, B., Diesendorf, M., MacGill, I., 2012. Simulations of scenarios with 100% renewable electricity in the Australian national electricity market. Energy Policy 45, 606–613.

Elsman, P., 2009. Copenhagen District Heating System. ⟨http://www.copenhagenenergysummit.org/applications/Copenhagen,%20Denmark-District%20Energy%20Climate%20Award.pdf⟩ (accessed 13.01.13).

European Climate Foundation (ECF), 2010. Roadmap 2050: A Practical Guide to a Prosperous, Low-Carbon Europe. ⟨http://www.europeanclimate.org/⟩ (accessed 26.08.12).

European Renewable Energy Council (EREC), 2010. RE-Thinking 2050: A 100% Renewable Energy Vision for the European Union. www.erec.org (accessed 26.08.12).

Falk, L., Robbins, L., 2010. Results from NYSERDA's multifamily performance programs: Getting 20% reduction in multifamily buildings. ACEEE Summer study on energy efficiency in buildings, 2, 60–75, ⟨http://eec.ucdavis.edu/ACEEE/2010/data/papers/1958.pdf⟩ (accessed 10.06.12).

Ginnebaugh, D.L., Liang, J., Jacobson, M.Z., 2010. Examining the temperature dependence of ethanol (E85) versus gasoline emissions on air pollution with a largely-explicit chemical mechanism. Atmospheric Environment 44, 1192–1199, http://dx.doi.org/10.1016/j.atmosenv.2009.12.024.

Ginnebaugh, D.L., M.Z., Jacobson, M.Z., 2012. Examining the impacts of ethanol (E85) versus gasoline photochemical production of smog in a fog using near-explicit gas- and aqueous-chemistry mechanisms. Environmental Research Letters 7, 045901, http://dx.doi.org/10.1088/1748-9326/7/4/045901.

Google, 2011. The Impact of Clean Energy Innovation: Examining the Impact of Clean Energy Innovation on the United States Energy System and Economy. ⟨http://www.google.org/energyinnovation/The_Impact_of_Clean_Energy_Innovation.pdf⟩ (accessed 29.11.12).

Hart, E.K., Jacobson, M.Z., 2011. A Monte Carlo approach to generator portfolio planning and carbon emissions assessments of systems with large penetrations of variable renewables. Renewable Energy 36, 2278–2286, http://dx.doi.org/10.1016/j.renene.2011.01.015.

Hart, E.K., Jacobson, MZ, M.Z., 2012. The carbon abatement potential of high penetration intermittent renewables. Energy and Environmental Science 5, 6592–6601, http://dx.doi.org/10.1039/C2EE03490E.

Hoen, B., Wiser, R., Cappers, P., Thayer, M., Sethi, G., 2009. ⟨http://eetd.lbl.gov/ea/ems/reports/lbnl-2829e.pdf⟩ (accessed 22.07.12).

Holman, J., 2011. Increasing Transmission Capacity. Wind Systems Magazine. ⟨http://windsystemsmag.com/article/detail/191/increasing-transmission-capacity⟩ (accessed 29.08.12).

Howarth, R.W., Bringezu, S., (eds). 2009. Biofuels: Environmental Consequences and Interactions with Changing Land Use. Proceedings of the International SCOPE Biofuels Project Rapid Assessment, 22-25 September 2008, Gummersbach Germany. Scientific Committee on Problems of the Environment, International Council of Science (SCOPE/ICSU) (⟨http://cip.cornell.edu/biofuels/⟩), Accessed August 26, 2012.

Howarth, R.W., Ingraffea, A., 2011. Should fracking stop? Nature 477, 271–275, http://dx.doi.org/10.1038/477271a.

Howarth, R.W., Santoro, R., Ingraffea, A., 2011. Methane and the greenhouse gas footprint of natural gas from shale formations. Climatic Change 106, 679–690, http://dx.doi.org/10.1007/s10584-011-0061-5.

Howarth, R.W., Santoro, R., Ingraffea, A., 2012a. Venting and leaking of methane from shale gas development: response to Cathles et al.. Climatic Change, doi: 10.1007/s10584-012-0401-0.

Howarth, R.W., Shindell, D., Santoro, R., Ingraffea, A., Phillips, N., Townsend-Small, A., 2012b. Methane emissions from natural gas systems. Background paper prepared for the National Climate Assessment, Reference # 2011-003, Office of Science & Technology Policy Assessment, Washington, DC. ⟨http://www.eeb.cornell.edu/howarth/Howarth%20et%20al.%20–%20National%20Climate%20Assessment.pdf⟩ (accessed 26.08.12).

Hughes, D. 2011. Will Natural Gas Fuel America in the 21st Century? Post Carbon Institute, Santa Rosa, CA. ⟨http://www.postcarbon.org/report/331901-will-natural-gas-fuel-america-in⟩ (accessed 26.08.12).

Intergovernmental Panel on Climate Change (IPCC), 2007. Fourth Assessment Report, The Physical Science Basis. Cambridge University Press, Cambridge, UK and New York, NY, USA.

Jacobson, M.Z., Colella, W.G., Golden, D.M., 2005. Cleaning the air and improving health with hydrogen fuel cell vehicles. Science 308, 1901–1905.

Jacobson, M.Z., 2009. Review of solutions to global warming, air pollution, and energy security. Energy and Environmental Science 2, 148–173, http://dx.doi.org/10.1039/b809990c.

Jacobson, M.Z., 2010a. Short-term effects of controlling fossil-fuel soot, biofuel soot and gases, and methane on climate, Arctic ice, and air pollution health. Journal of Geophysical Research 115, D14209, http://dx.doi.org/10.1029/2009JD013795.

Jacobson, M.Z., 2010b. Enhancement of local air pollution by urban CO_2 domes. Environmental Science, and Technology 44, 2497–2502.

Jacobson, M.Z., Delucchi, M.A., November 2009. A Path to Sustainable Energy by 2030. Scientific American.

Jacobson, M.Z., Delucchi, M.A., 2011. Providing all global energy with wind, water, and solar power, Part I: technologies, energy resources, quantities and areas of infrastructure, and materials. Energy Policy 39, 1154–1169, http://dx.doi.org/10.1016/j.enpol.2010.11.040.

Kansas Energy Report, 2011. 〈http://www.ars.usda.gov/SP2UserFiles/Place/62060000/almanac/KansasEnergyReport.pdf〉 (accessed 15.07.12).

KeelyNet, 2009. Hydrogen to Heat your House, 〈http://keelynet.wordpress.com/2009/02/04/hydrogen-to-heat-your-house/〉 (accessed 29.11.11).

Kemp, M., Wexler, J., eds., 2010. Zero Carbon Britain 2030, Centre for Alternative Technology Publications, Wales, 2010. 〈http://www.zerocarbonbritain.org/〉 (accessed 30.08.12).

Kempton, W., Tomic, J., 2005. Vehicle-to-grid power fundamentals: calculating capacity and net revenue. Journal of Power Sources 144, 268–279.

Lazard, 2012. Lazard's Levelized Cost of Energy Analysis—Version 6. pp 1–15.

Levitt, C., Kempton, W., Smith, A.P., Musial, W., Firestone, J., 2011. Pricing offshore wind power. Energy Policy 39, 6408–6421.

Levy, J.I., Buonocore, J.J., von Stackelberg, K., 2010. Evaluation of the public health impacts of traffic congestion: a health risk assessment. Environmental Health, 9, http://dx.doi.org/10.1186/1476-069X-9-65.

Mason, I., Page, S., Williamson, A., 2010. A 100% renewable electricity generation system for New Zealand utilising hydro, wind, geothermal and biomass resources. Energy Policy 38, 3973–3984.

McCubbin, D.R., Delucchi, M.A., 1999. The health costs of motor-vehicle related air pollution. Journal of Transport Economics and Policy 33, 253–286.

McCubbin, D., Sovacool, B.K., 2013. Quantifying the health and environmental benefits of wind power to natural gas. Energy Policy 53, 429–441.

McKinsey and Company, 2009. Unlocking Energy Efficiency in the U.S. Economy. www.mckinsey.com/USenergyefficiency (accessed 12.09.12).

Myhrvold, N.P., Caldeira, K., 2012. Greenhouse gases, climate change and the transition from coal to low-carbon electricity. Environmental Research Letters 7, 014019, http://dx.doi.org/10.1088/1748-9326/7/1/014019.

Navigant Consulting, 2009. Job Creation Opportunities in Hydropower. 〈http://hydro.org/wp-content/uploads/2010/12/NHA_JobsStudy_FinalReport.pdf〉 (accessed 9.06.12).

NREL (National Renewable Energy Laboratory), 2008. Photovoltaic Solar Resource of the United States. 〈http://www.nrel.gov/gis/images/map_pv_national_lo-res.jpg〉 (accessed 13.09.11).

NREL (National Renewable Energy Laboratory), 2009. Geothermal Resource of the United States. http://www.nrel.gov/gis/geothermal.html (accessed 13.09.11).

NREL (National Renewable Energy Laboratory), 2012. Renewable Electricity Futures Study. NREL/TP-6A20-52409, Golden, CO. http://www.nrel.gov/analysis/re_futures/ (accessed 26.08.12).

NSFIFC (National Surface Transportation Infrastructure Financing Commission), 2009. Paying Our Way: A New Framework for Transportation Finance. 〈http://financecommission.dot.gov/Documents/NSTIF_Commission_Final_Report_Exec_Summary_Feb09.pdf〉 (accessed 10.06.2012).

NYDEC (New York State Department of Environmental Conservation, 2011. Hourly Ozone Data. 〈http://www.dec.ny.gov/airmon/regionMap.php?national〉 (accessed 18.11.11).

NYSA (New York State Assembly), 2011, New York State Assembly Revenue Report. 〈http://assembly.state.ny.us/Reports/WAM/2011Revenue/2011Revenue.pdf〉 (accessed 10.06.12).

NYSDH (New York State Department of Health), 2011. Average Annual PM2.5 Data. 〈https://apps.nyhealth.gov/statistics/environmental/public_health_tracking/tracker/air/mapaction.map〉 (accessed 18.11.11).

NYSDL (New York State Department of Labor), 2011. Current Employment Statistics. 〈http://www.labor.ny.gov/stats/cesemp.asp〉 (accessed 23.08.11).

NYSEPB (New York State Energy Planning Board), 2009. New York State Energy Plan. http://www.nysenergyplan.com/2009stateenergyplan.html (accessed 20.10.11).

NYSERDA (New York State Energy Research and Development Authority), 2011. Home Performance with Energy Start Program. 〈http://www.nyserda.ny.gov/en/Page-Sections/Residential/Programs/Existing-Home-Renovations.aspx〉 (accessed 10.06.12).

NYSERDA (New York State Energy Research and Development Authority), 2012, New York Renewable Portfolio Standard. www.nyserda.ny.gov/en/Programs/Energy-and-Environmental-Markets/Renewable-Portfolio-Standard.aspx (accessed 19.05.12).

ODT (Oregon Department of Transportation), 2007. Oregon's Mileage Fee Concept and Road User Fee Pilot Program. 〈http://www.oregon.gov/ODOT/HWY/RUFPP/docs/RUFPP_finalreport.pdf〉 (accessed 10.06.12).

PlaNYC, 2011. PlaNYC. 〈http://www.nyc.gov/html/planyc2030/html/home/home.shtml〉 (accessed 26.08.12).

Pappas, S., 2012. When Will Arctic Ice Completely Disappear, 〈http://www.livescience.com/23362-arctic-summer-ice-disappearance.html〉 (accessed 17.01.13).

Parsons-Brinckerhoff, 2009. Powering the Future: Mapping our Low-Carbon Path to 2050. www.pbpoweringthefuture.com/pdf/pb_ptf_summary_report.pdf (accessed 26.08.12).

Pétron, G., et al., 2012. Hydrocarbon emissions characterization in the Colorado front range: a pilot study. Journal of Geophysical Research 117, D04304, http://dx.doi.org/10.1029/2011JD016360.

Pollin, R., Heintz, J., Garrett-Peltier, H., 2009. The economic benefits of investing in clean energy. Political Economy Research Institute, University of Massachusetts Amherst, 〈http://www.peri.umass.edu/fileadmin/pdf/other_publication_types/green_economics/economic_benefits/economic_benefits.PDF〉 (accessed 23.07.12).

Power, N.Y., 2011. Power NY. 〈http://www.andrewcuomo.com/powerNY〉 (accessed 13.08.12).

Price-Waterhouse-Coopers, 2010. 100% Renewable Electricity: A Roadmap to 2050 for Europe and North Africa. www.pwcwebcast.co.uk/dpliv_mu/100_percent_renewable_electricity.pdf (accessed 26.08.12).

Rasmussen, M.G., Andresen, G.B., Grenier, M., 2012. Storage and balancing synergies in a fully or highly renewable pan-European power system. Energy Policy 51, 642–651.

REN21 (Renewable Energy Policy Network for the 21st Century), 2010. Renewables 2010 Global Status Report. http://www.ren21.net/Portals/97/documents/GSR/REN21_GSR_2010_full_revised%20Sept2010.pdf (accessed 4.12.12).

Roman, H.A., Hammitt, J.K., Walsh, T.L., Stieb, D.M., 2012. Expert Elicitation of the Value Per Statistical Life in an Air Pollution Context. Risk Analysis, 10.1111/j.1539-6924.2012.01826.x.

Searchinger, T., Heimlich, R., Houghton, R.A., Dong, F., Elobeid, A., Fabiosa, J., Tokgoz, S., Hayes, D., Yu, T.-H., 2008. Use of U.S. cropland for biofuels increases greenhouse gases through emissions from land-use change. Science 319, 1238–1240.

SEIA (Solar Energy Industries Association), 2012. Q2 Solar Market Insight Report. 〈http://www.seia.org/research-resources/solar-market-insight-report-2012-q2〉 (accessed 23.11.12).

Shindell, D.T., Faluvegi, G., Koch, D.M., Schmidt, G.A., Unger, N., Bauer, S.E., 2009. Improved attribution of climate forcing to emissions. Science 326, 716–718.

Shindell, D., et al., 2012. Simultaneously mitigating near-term climate change and improving human health and food security. Science 335, 183–189, http://dx.doi.org/10.1126/science.1210026.

Streets, D.G., Jiang, K., Hu, X., Sinton, J.E., Zhang, X.-Q., Xu, D., Jacobson, M.Z., Hansen, J.E., 2001. Recent reductions in China's greenhouse gas emissions. Science 294, 1835–1837.

Tolmie, R., Thomsen, V., Wilson, D., Brahn, B., Lohrenz, E., Rosen, M., 2012. Atmosphere Energy for City Blocks. Sustainability Journal Canada, October, 2012. 〈http://kanata-forum.ca/ae-for-city-blocks.pdf〉 (accessed 27.10.12).

UNEP (United Nations Environmental Program), 2012. Climate and Clean Air Coalition to Reduce Short-lived Climate Pollutants. 〈http://www.unep.org/CCAC/〉 (accessed 26.08.12).

USCB (United States Census Bureau), 2011. Projections of the Population and Components of Change for the United States: 2010 to 2050. 〈http://www.census.gov/population/www/projections/files/nation/summary/NP2009-T1-C.xls〉 (accessed 17.10.11).

USDA (United States Department of Agriculture), 2011. Economic Research Service, State Fact Sheets: New York. 〈http://www.ers.usda.gov/StateFacts/NY.HTM〉 (accessed 26.08.12).

USEPA (United States Environmental Protection Agency), 2006. 2006 National Ambient Air Quality Standards for Particulate Pollution. Washington, D.C.

USEPA (United States Environmental Protection Agency), 2011. Benefits and Costs of the Clean Air Act, Second Prospective Study—1990 to 2020. 〈http://www.epa.gov/air/sect812/feb11/benefitsfullreport.pdf〉, 〈http://www.epa.gov/air/sect812/prospective2.html〉 (accessed 23.11.11).

Western Governor's Association, 2010. Geothermal Basics. 〈http://www.geo-energy.org/geo_basics_employement.aspx〉 (accessed 9.06.12).

Wigley, T.M.L., 2011. Coal to gas: the influence of methane leakage. Climatic Change 108, 601–608.

Winton, M., 2006. Does the Arctic sea ice have a tipping point? Geophysical Research Letters 33, L23504, http://dx.doi.org/10.1029/2006GL028017.

Woodbury, P.B., Volk, T., Germain, R.H., Castellano, P., Buchholz, T., Wightman, J., Melkonian, J., Mayton H., Ahmed, Z., Peters, C., 2010. Analysis of sustainable feedstock production potential in New York State, Appendix E. In: Wojnar, Z., et al. Renewable fuels roadmap and sustainable biomass feedstock supply for New York. New York State Energy Research and Development Authority Report 10-05. April, 2010. Available from: 〈http://www.nyserda.org/publications/renewablefuelsroadmap/default.asp〉 (accessed 26.08.12).

World Wildlife Fund, 2011. The Energy Report: 100% Renewable Energy by 2050. 〈http://wwf.panda.org/what_we_do/footprint/climate_carbon_energy/energy_solutions/renewable_energy/sustainable_energy_report〉 (accessed 26.08.12).

Quantifying sources of methane using light alkanes in the Los Angeles basin, California

J. Peischl,[1,2] T. B. Ryerson,[2] J. Brioude,[1,2] K. C. Aikin,[1,2] A. E. Andrews,[3] E. Atlas,[4] D. Blake,[5] B. C. Daube,[6] J. A. de Gouw,[1,2] E. Dlugokencky,[3] G. J. Frost,[1,2] D. R. Gentner,[7] J. B. Gilman,[1,2] A. H. Goldstein,[7,8] R. A. Harley,[7] J. S. Holloway,[1,2] J. Kofler,[1,3] W. C. Kuster,[1,2] P. M. Lang,[3] P. C. Novelli,[3] G. W. Santoni,[6] M. Trainer,[2] S. C. Wofsy,[6] and D. D. Parrish[2]

[1] Cooperative Institute for Research in Environmental Sciences, University of Colorado Boulder, Boulder, CO

[2] Chemical Sciences Division, National Oceanic and Atmospheric Administration Earth System Research Laboratory, Boulder, CO

[3] Global Monitoring Division, National Oceanic and Atmospheric Administration Earth System Research Laboratory, Boulder, CO

[4] Rosenstiel School of Marine and Atmospheric Science, University of Miami, Miami, FL

[5] Department of Chemistry, University of California, Irvine, CA

[6] School of Engineering and Applied Science and Department of Earth and Planetary Sciences, Harvard University, Cambridge, MA

[7] Department of Civil and Environmental Engineering, University of California, Berkeley, CA

[8] Department of Environmental Science, Policy, and Management, University of California, Berkeley, CA

This article has been accepted for publication and undergone full peer review but has not been through the copyediting, typesetting, pagination and proofreading process, which may lead to differences between this version and the Version of Record. Please cite this article as doi: 10.1002/jrgd.50413

Abstract

Methane (CH_4), carbon dioxide (CO_2), carbon monoxide (CO), and C_2–C_5 alkanes were measured throughout the Los Angeles (L.A.) basin in May and June 2010. We use these data to show that the emission ratios of CH_4/CO and CH_4/CO_2 in the L.A. basin are larger than expected from population-apportioned bottom-up state inventories, consistent with previously published work. We use experimentally determined CH_4/CO and CH_4/CO_2 emission ratios in combination with annual State of California CO and CO_2 inventories to derive a yearly emission rate of CH_4 to the L.A. basin. We further use the airborne measurements to directly derive CH_4 emission rates from dairy operations in Chino, and from the two largest landfills in the L.A. basin, and show these sources are accurately represented in the California Air Resources Board greenhouse gas inventory for CH_4. We then use measurements of C_2–C_5 alkanes to quantify the relative contribution of other CH_4 sources in the L.A. basin, with results differing from those of previous studies. The atmospheric data are consistent with the majority of CH_4 emissions in the region coming from fugitive losses from natural gas in pipelines and urban distribution systems and/or geologic seeps, as well as landfills and dairies. The local oil and gas industry also provides a significant source of CH_4 in the area. The addition of CH_4 emissions from natural gas pipelines and urban distribution systems and/or geologic seeps and from the local oil and gas industry is sufficient to account for the differences between the top-down and bottom-up CH_4 inventories identified in previously published work.

1. Introduction

In California, methane (CH_4) emissions are regulated by Assembly Bill 32, enacted into law as the California Global Warming Solutions Act of 2006, requiring the state's greenhouse gas (GHG) emissions in the year 2020 not to exceed 1990 emission levels. To this end, the California Air Resources Board (CARB) was tasked with compiling and verifying an inventory of GHG emissions for the state. Two published works [*Wunch et al.*, 2009; *Hsu et al.*, 2010] have concluded that atmospheric emissions of CH_4 in the Los Angeles (L.A.) area were greater than expected from a per capita apportionment of the statewide 2006 CARB GHG inventory and from a bottom-up accounting of CH_4 sources, respectively.

Several recent works have estimated CH_4 emissions to the South Coast Air Basin (SoCAB; Fig. 1a), which are summarized in Table 1. *Wunch et al.* [2009] used a Fourier transform infrared spectrometer at the Jet Propulsion Laboratory (JPL) in Pasadena, California to measure vertically-integrated total column enhancement ratios of CH_4 relative to CO and to CO_2. The observed column enhancement ratios, multiplied by CARB inventory values of CO for 2008 and an average of 2006 CARB GHG inventory and 2005 Emission Database for Global Atmospheric Research (EDGAR) for CO_2, were used to derive a lower limit to CH_4 emissions of 400 ± 100 Gg CH_4/yr (based on CO) or 600 ± 100 Gg CH_4/yr (based on CO_2) for the SoCAB. One reason for the discrepancy in their top-down analysis was that their observed CO/CO_2 enhancement ratio of 11 ± 2 ppb CO/ppm CO_2 was greater than the 8.6 ppb CO/ppm CO_2 calculated from the inventories. *Wunch et al.* [2009] contrasted these top-down assessments to a bottom-up estimate of 260 Gg CH_4/yr using the statewide 2006 CARB GHG inventory apportioned by population after removal of agricultural and forestry emissions, and concluded that 140 – 340 Gg CH_4/yr were not accounted for in the CARB CH_4 inventory for the SoCAB.

Hsu et al. [2010] took a similar top-down approach and used observed atmospheric enhancement ratios of CH_4 to CO from *in situ* whole air samples taken at Mt. Wilson (34.22° N, 118.06° W, 1770 m above sea level), scaled by the projected CARB CO inventory for 2008, to derive CH_4 emissions of 200 ± 10 Gg CH_4/yr for just the Los Angeles (L.A.) County (Figure 1b) portion of the SoCAB (L.A. County ∩ SoCAB). They used methods prescribed by the Intergovernmental Panel for Climate Change (IPCC) to create the CARB GHG inventory and reached a bottom-up estimate of 140 Gg CH_4/yr, or 60 Gg less than their top-down calculation for the L.A. County portion of the SoCAB. *Hsu et al.* [2010] used higher spatial resolution emissions data from CARB to construct their bottom-up inventory, and therefore did not have to rely on population apportionment methods used by *Wunch et al.* [2009].

The difference between the top-down CH_4 emissions reported by *Wunch et al.* [2009] and by *Hsu et al.* [2010] (400 Gg and 200 Gg, respectively, both based on the CARB CO inventory) are in part due to the different geographic areas for which they calculate CH_4 emissions, and in part due to differences in observed CH_4/CO enhancements between these two studies: 0.66 ± 0.12 mol/mol for *Wunch et al.* [2009] [*Wennberg et al.*, 2012] and 0.52 ± 0.02 mol/mol for *Hsu et al*. [2010]. Both works suggested that fugitive losses of natural gas (NG) could be the source of the CH_4 missing from the bottom-up inventories.

More recently, *Townsend-Small et al.* [2012] analyzed stable CH_4 isotope ratios in atmospheric samples taken at Mt. Wilson and elsewhere in the western L.A. basin and showed they were consistent with isotope ratios in natural gas sources.

Wennberg et al. [2012] used the different atmospheric ethane/CH_4 enhancement ratios observed from research aircraft during the Arctic Research of the Composition of the Troposphere from Aircraft and Satellites (ARCTAS) field project in 2008 and the California Research at the Nexus of Air Quality and Climate Change (CalNex) field project [*Ryerson et al.*, in review] in 2010 to estimate an upper limit of 390 Gg CH_4/yr from natural gas leakage in the SoCAB. Further, their top-down analysis resulted in a calculated total emission of 440 Gg CH_4/yr in the SoCAB. *Wennberg et al.* [2012] also recalculated the data used by *Hsu et al.* [2010] to derive CH_4 emissions for the entire SoCAB, and calculated a SoCAB CH_4 emission from 2008 using data from ARCTAS. The results are summarized in Table 1.

Here we use ambient measurements in the SoCAB taken in May and June 2010 aboard the National Oceanic and Atmospheric Administration (NOAA) P-3 research aircraft during the CalNex field study to derive CH_4 emissions from the SoCAB using methods different from *Wennberg et al.* [2012]. We further examine CH_4 emissions from landfills and dairy farms in the SoCAB identified in the bottom-up CH_4 inventories reported by *Hsu et al.* [2010] and *Wennberg et al.* [2012]. We then expand on these previous studies by examining light alkane emissions from Los Angeles area data sets. In addition to CH_4 and ethane, we examine propane, *n*- and *i*-butane, and *n*- and *i*-pentane measurements to derive emissions of each of these light alkanes in the SoCAB, and use them in a system of linear equations to further quantify the source apportionment of CH_4 in the L.A. basin.

2. Measurements

We use trace gas measurements from a subset of platforms and sites from the CalNex field study. The NOAA P-3 research aircraft flew all or parts of 16 daytime flights in and around the L.A. basin. Two independent measurements of CH_4 and CO_2 were made aboard the aircraft by wavelength-scanned cavity ring-down spectroscopy (WS-CRDS; Picarro 1301-m) [*Peischl et al.*, 2012], and by quantum cascade laser direct absorption spectroscopy (QCLS) [*Kort et al.*, 2011]. Imprecision of the 1-Hz Picarro CH_4 measurement is ± 1.4 ppbv (all uncertainties herein are 1-σ) and inaccuracy is estimated at ± 1.2 ppbv. Imprecision of the 1-Hz QCLS CH_4 measurement is ±1 ppbv and inaccuracy is estimated at ± 15 ppbv. Imprecision of the 1-Hz Picarro CO_2 measurement is ± 0.14 ppmv and inaccuracy is estimated at ± 0.12 ppmv. Imprecision of the 1-Hz QCLS CO_2 measurement is ± 0.05 ppmv and inaccuracy is estimated at ± 0.10 ppmv. All CH_4 and CO_2 measurements are reported as dry air mole fractions. For this work, CH_4 and CO_2 data from the Picarro instrument are used, and QCLS CH_4 data from May 8 are used when the Picarro instrument was not operating. The 1-Hz CO data used in this analysis were measured by vacuum ultraviolet fluorescence spectroscopy [*Holloway et al.*, 2000]. Imprecision of the 1-Hz CO data is ± 1 ppbv; inaccuracy is estimated at ± 5%. C_2 to C_5 alkanes, and their structural isomers, were measured in whole air samples [*Colman et al.*, 2001], periodically filled during flight. Imprecision of these alkane measurements is ±5%; inaccuracies are estimated at ±10%. Wind measurements were derived from various sensors aboard the NOAA P-3; the uncertainty of the 1-Hz wind speed is estimated to be ± 1 m/s. Sensors aboard the NOAA P-3 also measured relative humidity, ambient temperature, and potential temperature with an estimated 1-Hz uncertainty of ± 0.5° C, ± 0.5° C, and ± 0.5 K, respectively.

At the CalNex Pasadena ground site, located on the California Institute of Technology (Caltech) campus, measurements of C_2–C_5 alkanes were made by a gas chromatograph-mass spectrometer (GC-MS) on 5 minute integrated samples taken every half hour [*Gilman et al.*, 2010]. Imprecision of these measurements are ±8% for ethane and ±6% for propane; inaccuracy is estimated at ± 15% for each. Data from the ground site were taken between 15 May and 15 June, 2010. CH_4 was not measured at the Pasadena ground site.

Additionally, whole-air flask samples were taken twice daily at the Mount Wilson Observatory (MWO) for most days during May and June 2010, and analyzed for a variety of trace gas species, including CH_4, CO_2, CO, and hydrocarbons [*Dlugokencky et al.*, 2011; *Conway, et al.*, 2011; *Novelli et al.*, 2010]. Imprecision of the CH_4 measurement is ± 1 ppb; imprecision of the CO_2 measurement is ± 0.1 ppm; imprecision of the CO measurement is ± 1 ppbv, and inaccuracy of CO measurement is estimated to be ± 5%.

We also analyze alkane data from whole air samples taken in the L.A. basin prior to 2010. Ethane and propane were measured in whole air samples taken on four flights in L.A. aboard an instrumented National Aeronautics and Space Administration (NASA) DC-8 research aircraft during ARCTAS in June 2008 [*Simpson et al.*, 2010]. Ethane and propane were also measured on one flight in L.A. aboard the NOAA P-3 during the Intercontinental Transport and Chemical Transformation (ITCT) study in May 2002 [*Schauffler et al.*, 1999].

3. Methods

To ensure sampling from the L.A. basin, we consider aircraft data collected between 33.6 and 34.3° N latitude and 118.5 and 116.8° W longitude (Figure 1d, dashed box) in the following analysis. Aircraft data were further limited to samples taken between 1000 and 1700 PST, between 200 and 800 m above ground, and below 1400 m above sea level, to ensure daytime sampling was within the well-mixed boundary layer, which averaged 1000 ± 300 m above ground level for the daytime L.A. flights [*Neuman et al.*, 2012]. Ground-based measurements at Pasadena were retained between 1000 and 1700 PST to ensure sampling of a well-mixed daytime boundary layer. For MWO measurements, afternoon samples, which typically occurred between 1400 and 1500 PST, were retained to capture upslope transportation from the L.A. basin [*Hsu et al.*, 2010]. Linear fits to the data presented below are orthogonal distance regressions [*Boggs et al.*, 1989] weighted by instrument imprecision [*Bevington*, 1969] (weighted ODR). The total uncertainty in the fitted slope is calculated by quadrature addition of the fit uncertainty and the measurement uncertainties.

For flux determinations, crosswind transects were flown downwind of known point sources. Enhancements of CH_4 above background levels were integrated along the flight track, and a flux was calculated using the following equation:

$$flux = v\ cos(\alpha) \int_{Z_0}^{Z_1} n(z)\,dz \int_{-y}^{y} X_m(y)\,dy \qquad (1)$$

where v cos(α) is the component of the average wind velocity normal to the flight track, n is the number density of the atmosphere, z_0 is the ground level, z_1 is the estimated boundary layer height, and X_m is the measured mixing ratio enhancement above the local background along the flight track [*White et al.*, 1976; *Trainer et al.*, 1995; *Ryerson et al.*, 1998; *Nowak et al.*, 2012]. Boundary layer heights are estimated from vertical profiles of relative humidity, ambient temperature, and potential temperature made prior to and after the crosswind transects.

We assume the plume is vertically homogeneous within the mixed layer at the point of measurement and the wind velocity is constant between emission and measurement. We estimate the uncertainty in these assumptions, combined with the uncertainties of the wind speed, wind direction, temperature, and integrated atmospheric enhancements, to be ± 50% for the plumes studied here [*Nowak et al.*, 2012]. Weighted averages of the fluxes are calculated following *Taylor* [1997]. When calculating the CH_4 flux from dairies, CH_4 variability immediately upwind of the dairies is sufficiently large to complicate interpolation from the downwind local background. To account for this, we take the weighted ODR slope of CH_4/CO immediately upwind, multiply this ratio by the measured CO downwind of the dairies, and integrate the plume CH_4 enhancement calculated from CO (CO × $[CH_4/CO]_{upwind}$), similar to the integrations performed by *Nowak et al.* [2012]. This assumes the dairies emit a negligible amount of CO.

As with previously published works [*Wunch et al.*, 2009; *Hsu et al.*, 2010; *Wennberg et al.*, 2012], we estimate total CH_4 emissions in the SoCAB by multiplying enhancement ratios of CH_4 to CO and CO_2 by inventory estimates of CO and CO_2 for that region:

$$E_{CH_4} = \left(\frac{CH_4}{X}\right)_{ODR\ slope} \times \left(\frac{MW_{CH_4}}{MW_X}\right) \times E_X \qquad (2)$$

where E_{CH4} is the emission of CH_4, X is either CO or CO_2, MW is the molecular weight, and E_X is the inventory emission value of either CO or CO_2. Although not necessarily emitted from the same sources, we assume emissions of CH_4, CO, and CO_2 are well-mixed by the time they are sampled from the NOAA P-3.

We use the following latest-available inventories for our analysis below: the 2010 CARB emissions inventory for CO projected from the base-year 2008 inventory (http://www.arb.ca.gov/app/emsinv/fcemssumcat2009.php), and the 2009 CARB GHG inventory (http://www.arb.ca.gov/cc/inventory/data/data.htm). Both inventories were accessed in November 2012.

CARB projects the total 2010 annually averaged CO emissions in the SoCAB at 979 Gg CO/yr (Table 2). We use the annually averaged CARB inventory that excludes biomass burning CO emissions because no known biomass burning events were observed in the L.A. basin during CalNex. This estimate is 4% less than the summertime CO inventory without biomass burning emissions, and approximately 6% less than the annually averaged CO inventory including biomass burning emissions used by *Wennberg et al.* [2012]. To estimate 2010 CH_4 emissions in the SoCAB using the 2009 CARB GHG inventory, we follow the method used by *Wunch et al.* [2009], and take the total statewide emission of 1525 Gg CH_4/yr, less agricultural and forestry CH_4 emissions of 898 Gg CH_4/yr, then apportion the remainder by population. In 2010, the SoCAB comprised 43% of California's population (http://www.arb.ca.gov/app/emsinv/trends/ems_trends.php). However, unlike *Wunch et al.* [2009], we include SoCAB dairy emissions of 31.6 Gg CH_4/yr, calculated in section 4.3 below. Therefore, we attribute a total of 301 Gg CH_4/yr to the SoCAB based on the 2009 CARB GHG inventory (Table 2).

According to CARB's mobile source emission inventory (EMFAC 2011) for the Los Angeles County portion of the SoCAB (http://www.arb.ca.gov/jpub/webapp//EMFAC2011WebApp/emsSelectionPage_1.jsp), mobile source CO_2 emissions remained essentially unchanged between 2009 and 2010 (39.94 versus 39.95 Tg CO_2/yr). Additionally, the statewide CARB GHG inventory for CO_2, with out-of-state electricity generation emissions removed, decreased by less than 2% between 2008 and 2009. Therefore, we assume errors due to sampling year are negligible in examining the CO_2 emission inventories in the SoCAB from 2009–2010. To estimate 2010 CO_2 emissions in the SoCAB using the 2009 CARB GHG inventory, we take the total statewide emission of 465.7 Tg CO_2/yr, subtract out-of-state electricity generation of 47.9 Tg CO_2/yr, then apportion the remainder by population. We therefore attribute 180 Tg CO_2/yr to the SoCAB using the 2009 CARB GHG inventory (Table 2). We do not compare to the Vulcan CO_2 inventory [*Gurney et al.*, 2009] because at present it is only available for the 2002 reporting year.

4. Results and Discussion

4.1. Total derived emission of CH_4 in L.A. and comparison to inventories

In this section, we use P-3 measurements of CH_4, CO, and CO_2 to calculate enhancement ratios representative of the integrated emissions from the L.A. basin. We then use tabulated CO and CO_2 emissions taken from the CARB inventories to derive total CH_4 emissions based on enhancement ratios observed in CalNex, and compare to earlier estimates of total CH_4 emissions in L.A.

Figure 1c shows known stationary sources of CH_4 in the L.A. area, which include landfills, dairies, wastewater treatment facilities, and oil fields, as well as the location of measurement sites used in this study. Dairy sources are sized by estimated CH_4 emissions from enteric fermentation, as explained in section 4.3. Landfills are sized by CH_4 emissions from the 2008 CARB GHG inventory (L. Hunsaker, personal communication, 2011).

Point sources are sized by 2009 CARB individual facility CH_4 emissions (https://ghgreport.arb.ca.gov/eats/carb/index.cfm), but do not stand out in the map due to their low CH_4 emissions relative to the landfills and dairies. Figure 1d shows the locations of daytime boundary-layer CH_4 data from the P-3, colored by observed mixing ratio, that were retained for the analysis as described previously. The largest concentrations of CH_4 were typically encountered along the mountains at the north edge of the L.A. basin, likely driven by transport of air within the basin, as typical daytime winds in the L.A. basin were from the west and southwest during May and June 2010 [*Washenfelder et al.*, 2011]. CalNex CH_4 data are plotted against observed CO in Figure 2a. Weighted ODR fits to these data resulted in derived enhancement ratios of 0.74 ± 0.04 and 0.68 ± 0.03 ppbv CH_4/ppbv CO from the NOAA P-3 and MWO, respectively. We note that the same CH_4/CO enhancement ratio of 0.74 ± 0.03 was reported by *Wennberg et al.* [2012] using the CalNex P-3 data with different selection criteria. We include box and whisker plots in Figure 2a to show that the weighted ODR fit to the data is insensitive to the relatively few data points of higher CH_4. The ratio calculated from the CARB inventory (Table 2) is 0.54 ppb CH_4/ppb CO, and is displayed for comparison.

CalNex CH_4 data are plotted against observed CO_2 in Figure 2b. The slope from a weighted ODR of P-3 data is 6.70 ± 0.01 ppb CH_4/ppm CO_2 and of MWO data is 6.60 ± 0.04 ppb CH_4/ppm CO_2. The ratio of the CARB inventories from Table 2 is 4.64 ppb CH_4/ppm CO_2, and is displayed for comparison. In this case, because CH_4 and CO_2 are measured with high precision and accuracy, the largest uncertainties in interpreting the slope as an emissions ratio are likely determined by the extent of mixing of emissions from different sources within the Los Angeles air shed. Similarly, Figure 2c shows a correlation plot of CO against CO_2.

The slope from a weighted ODR of P-3 data is 9.4 ± 0.5 ppb CO/ppm CO_2 and of MWO data is 10.4 ± 0.5 ppb CO/ppm CO_2. The ratio of the CARB inventories from Table 2 is 8.5 ppb CO/ppm CO_2, and is plotted for comparison. We estimate a ± 7.5% uncertainty in each of the CARB CO and CO_2 inventories, which is sufficient to explain the difference between the CO/CO_2 enhancement ratio measured from the NOAA P-3 and the ratio calculated from the CARB inventories. Quantitative agreement between emission ratios derived from P-3 and MWO data (Figures 2a–c) is likely due to the fact that the transport within the basin was driven by the land-sea breeze, meaning typical daytime winds in the Pasadena area near Mt. Wilson were from the southwest [*Washenfelder et al.*, 2011]. This transport, and the highest values of CH_4 and CO_2 in the P-3 data that are not seen at MWO (Figures 2a and b), also suggests that MWO preferentially samples the western part of the L.A. basin [*Hsu et al.*, 2009]. We therefore use enhancement ratios determined from the NOAA P-3 data to derive CH_4 emissions from the entire basin.

We note that the ratio of the latest CARB CO and CO_2 inventories (Table 2) are in better agreement with ambient enhancement ratios in the CalNex data than was the case for *Wunch et al.* [2009]. This is likely due to either improved CARB inventories, the present use of a basin-wide data set to determine basin-wide emission ratios, or both.

With the slopes and inventory values quantified, we next derive a CH_4 emission using equation (2). Using the CH_4/CO slope derived from the weighted ODR fit to the 2010 NOAA P-3 data and the projected 2010 CARB annually-averaged CO emission inventory in equation (2) yields an estimated SoCAB emission of 410 ± 40 Gg CH_4/yr. The stated uncertainty is the quadrature propagation of the measurement uncertainty, errors on the slope of the ODR fit to P-3 data, and an estimated uncertainty in the CARB CO inventory. We note our derived emission of 410 ± 40 Gg CH_4/yr is similar to that derived from the P-3 data by *Wennberg et al.* [2012], which was 440 ± 100 Gg CH_4/yr using different selection criteria. It is further consistent with the emission derived by *Wunch et al.* [2009] of 400 ± 100 Gg CH_4/yr, which assumed a CARB CO inventory uncertainty of 15%. We also determine CH_4 emissions using estimates of CO_2 emissions in the SoCAB. P-3 measurements of the CH_4/CO_2 enhancement ratio observed during CalNex and SoCAB CO_2 emissions inferred from the 2009 CARB GHG inventory result in a derived CH_4 emission rate of 440 ± 30 Gg CH_4/yr, with the stated uncertainties determined by quadrature propagation of the measurement uncertainty, errors on the slope of the ODR fit to P-3 data, and an estimated uncertainty in the CARB CO_2 inventory. This value, based on the CO_2 inventory, is consistent with that derived using P-3 measurements and the CO inventory, further supporting both our assessment of uncertainties in the CARB CO and CO_2 inventories, and our assumption of sampling well-mixed emissions in the SoCAB, since any outlying CH_4 data do not affect the overall emission estimates significantly.

The derived 2010 top-down SoCAB CH_4 emission of 410 and 440 Gg CH_4/yr reported here using the CARB CO or CO_2 inventories, respectively, are in quantitative agreement, in contrast to that reported for 2008 [*Wunch et al.*, 2009]. The 2010 estimates are a factor of 1.35 to 1.45 greater than the modified population-apportioned 2009 CARB GHG inventory value of 301 Gg CH_4/yr (Table 2). A concurrent inverse modeling study by *Brioude et al.* [2012] has found no statistical difference between the total SoCAB CO emissions reported by CARB for 2010 and a top-down approach that estimated CO emissions in the SoCAB region using the same CO measurements used in this paper. For this reason, and for consistency with published works [*Wunch et al.*, 2009; *Hsu et al.*, 2010; *Wennberg et al.*, 2012], we use 410 ± 40 Gg CH_4/yr from the top-down CH_4 assessment based on 2010 P-3 measured CH_4/CO enhancement ratios and the CARB CO inventory for the remainder of our analysis.

4.2. Methane emissions from L.A. basin landfills

Landfills are the largest non-fossil fuel CH_4 emission source in the bottom-up inventories compiled by *Hsu et al.* [2010] and by *Wennberg et al.* [2012], but these two studies disagree on the magnitude of this source. *Hsu et al.* [2010] estimated annual emissions from landfills totaled 90 Gg CH_4/yr from the Los Angeles County portion of the South Coast Air Basin. *Wennberg et al.* [2012] reported landfill emissions of just 86 Gg CH_4/yr for the entire South Coast Air Basin. However, that number is too low due to an error in their gridded landfill emissions inventory [*P. Wennberg,* personal communication, 2012] and is discarded in the following analysis.

In the CARB GHG inventory, CH_4 emissions are calculated for individual landfills using methods prescribed by the IPCC and summed over all landfills to estimate a statewide total. Annual CH_4 emission values for individual landfills were obtained directly from CARB [*L. Hunsaker,* personal communication, 2011] to facilitate direct comparison to the P-3 data from CalNex. We use the P-3 data to calculate emissions from two of the largest CH_4-emitting landfills in the statewide GHG inventory, both of which are located in the SoCAB.

The first landfill results we examine are from the Olinda Alpha landfill (33.934° N, 117.841° W) in Brea, Orange County, California. The NOAA P-3 flew five daytime boundary-layer transects on five different days downwind of this landfill (Figure 3), and a CH_4 emission flux was determined for each transect using equation (1). The results are summarized in Table 3.

For the three transects when both the WS-CRDS and QCLS CH_4 instruments were sampling ambient air, flux determinations using these independent CH_4 measurements agreed within 3%. In these cases, the flux was averaged and reported in Table 3. Three nearby CH_4 point sources are identified in the 2009 CARB GHG inventory: an oil and gas field power plant, which burns natural gas for fuel; the landfill power plant at Olinda Alpha, which burns landfill gas for fuel; and general stationary combustion from the landfill operations. Inventory data suggest that these three sources together emit between 0.0004 and 0.0015 Gg CH_4/yr, negligible amounts relative to CH_4 emitted directly from the landfill. On 19 May, the NOAA P-3 sampled plumes from the nearby oil and gas power plant and the landfill's power plant, both of which burn natural gas as fuel (Figure 3c). A large spike in CO_2, some CH_4, and perhaps a small amount of CO were encountered in the landfill power plant plume. However, downwind of the landfill in the large plume of CH_4, the CO_2 enhancement does not stand out significantly above the background variability. Therefore, our analysis of P-3 data supports the conclusion from the inventory that landfill CH_4 emissions dominate the observed plume enhancements downwind of Olinda Alpha landfill. Using NOAA P-3 CH_4 data from all five transects, we directly calculate a weighted average CH_4 emission flux via equation (1) of $(1.49 \pm 0.35) \times 10^{25}$ molecules/s, equal to 12.5 ± 2.9 Gg CH_4/yr assuming a constant emission, where the weights are the 50% uncertainty of each determination. For comparison, the CARB GHG inventory emission estimate from the Olinda Alpha landfill is 11.0 Gg/yr for 2008, showing agreement within the errors of the direct estimate using P-3 airborne data.

The second landfill results we examine in-depth are from the Puente Hills landfill (34.020° N, 118.006° W) in City of Industry, Los Angeles County, California. Of all California landfills, Puente Hills is the largest emitter of CH_4 in the 2008 CARB GHG inventory.

Nearby sources of CH_4 in the 2008 CARB GHG inventory include the Puente Hills power plant (0.00045 Gg CH_4/yr) and the Savage Hills Canyon landfill (1.1 Gg CH_4/yr), both of which are small relative to the CARB GHG inventory of 39 Gg CH_4/yr emission rate for Puente Hills. The NOAA P-3 conducted three daytime boundary layer plume transects from which we determine an average emission flux of $(4.06 \pm 1.18) \times 10^{25}$ molecules/s, which extrapolates to 34.0 ± 9.9 Gg CH_4/yr assuming a constant emission (Table 3). Similar to the findings for Olinda Alpha, the CARB GHG inventory of 39 Gg CH_4/yr for the Puente Hills landfill is in agreement within the errors of the direct estimate using P-3 airborne data.

Quantitative agreement between CH_4 flux estimates from the NOAA P-3 and the 2008 CARB GHG inventory for these two examples supports the use of that inventory to quantify total CH_4 emissions from landfills in the South Coast Air Basin. According to the 2008 CARB GHG inventory, CH_4 emissions from landfills totaled 117 Gg CH_4/yr in the L.A. County portion of the SoCAB, 30% higher than the 90 Gg CH_4/yr for the same geographic area using the CARB GHG inventory in 2008 reported by *Hsu et al.* [2010], which we attribute to different versions of the CARB GHG inventory.

The 2008 CARB GHG inventory further predicts an emission from landfills of 164 Gg CH_4/yr for the entire SoCAB. On the basis of the agreement with the CARB inventory described above for the emission rates from the two landfills quantified directly by the CalNex P-3 data (50 Gg CH_4/yr, or 30% of the inventory total for the SoCAB), we assume the remaining CARB landfill CH_4 emission estimates are accurate.

4.3. Methane emissions from L.A. basin dairies

Salas et al. [2008] published dairy locations in California for the year 2005, with an estimate of dairy cow population for each. The locations are plotted as filled yellow circles in Figure 1c, and sized by the expected CH_4 emission from enteric fermentation according to the 2009 CARB GHG inventory (144 kg CH_4 per cow per year). According to *Salas et al.* [2008], all dairies in San Bernardino and Riverside counties were also located in the SoCAB, and 87% of the dairy cows in the SoCAB in 2005 were located in the Chino area (the large grouping of dairies in Figure 1c). The Chino-area dairy operations, which at one time were distributed across the Riverside-San Bernardino county line in satellite images, now appear to be located mainly in San Bernardino County as the Riverside dairies have been converted to residential neighborhoods (*e.g.*, see Google Earth historical imagery since 2000). This declining number of dairies is confirmed by the United States Department of Agriculture (USDA) (http://www.nass.usda.gov/Statistics_by_State/California/Publications/County_Estimates/201005lvscef.pdf), which reports a decrease in dairy cows in San Bernardino and Riverside Counties from 200,000 head in 2005 to 137,500 head in 2010. In addition to dairy cows, dairies also stock immature heifers. Further, there are beef operations in the SoCAB, but these are negligible compared to the San Bernardino and Riverside dairy populations. According to the USDA, there were a total of 431,000 cattle in San Bernardino and Riverside counties in 2005, and 295,000 cattle in 2010. For both years, dairy cows represented approximately 46.5% of the cattle population in the SoCAB. From these dairy and cattle populations, we construct a bottom-up emissions inventory for the SoCAB using the same emission factors as the CARB GHG inventory.

We begin with CH_4 emissions from enteric fermentation. We assign to each of the 137,500 dairy cows in the SoCAB an emission factor of 144 kg CH_4/yr. We assume the remaining 157,500 head are dairy replacements, and assign each an emission factor of 57.7 kg CH_4/yr, or the average emission factor for 0–1 and 1–2 year old dairy replacements in the CARB GHG inventory. We calculate a total of 28.9 Gg CH_4/yr emitted solely from enteric fermentation in the SoCAB.

In addition to enteric fermentation, manure management practices have a substantial effect on CH_4 emissions from livestock operations. In the L.A. basin, dairies typically practice solid storage (http://www.aqmd.gov/rules/doc/r1127/pr1127_task1rpt_20020101.pdf and http://www.arb.ca.gov/planning/sip/sjv_report/addtl_resources.pdf), which emits relatively low levels of CH_4 (17 kg/yr per cow) according to the 2009 CARB GHG inventory. The tradeoff for this practice is that it emits larger amounts of NH_3 than other types of manure management (http://www.epa.gov/ttn/chief/ap42/ch09/draft/draftanimalfeed.pdf). Therefore, if we attribute dry manure management emissions to the SoCAB dairy cow population, and the dry lot emission rate of 2.1 kg CH_4/yr for the remaining heifers, we get an additional 2.7 Gg CH_4/yr from dairy operation manure management in the SoCAB. This results in a total of 31.6 Gg CH_4/yr from enteric fermentation and manure management for the SoCAB dairy operations. This is the emission from agriculture and forestry that we add back into the population-apportioned CARB CH_4 inventory above (Table 2).

Our estimate of 31.6 Gg CH_4/yr, based on inventory data, is less than half of the 76 Gg CH_4/yr estimated by *Wennberg et al.* [2012]. We attribute this difference in bottom-up inventories to the different assumptions of manure management practices.

Wennberg et al. [2012] scaled total California CH_4 emissions by livestock population, which also assumes the manure management practices from the San Joaquin Valley apply to the L.A. basin. For example, the anaerobic lagoons more commonly used in the San Joaquin Valley emit 325 kg CH_4 per cow per year according to the 2009 CARB GHG inventory, significantly higher than 17 kg CH_4 per cow per year from dry manure management practices typical of the L.A. basin.

Nowak et al. [2012] used P-3 data from CalNex to derive emissions of ammonia (NH_3) from dairy farms in the Chino area. From NOAA P-3 measurements, we determine a CH_4 flux from the Chino-area dairies for the same three downwind transects analyzed by *Nowak et al.* [2012]. Using the Chino to SoCAB population apportionment by *Salas et al.* [2008], we expect these same Chino-area dairies to emit approximately 28 Gg CH_4/yr. CH_4 fluxes determined from equation (1) range from 24 ± 12 to 88 ± 44 Gg CH_4/yr, and the average of the three transects is 49 ± 25 Gg CH_4/yr. This value derived from airborne flux determination lies between the 28 Gg CH_4/yr calculated from the inventory assuming dry manure management practices described above, and the estimate by *Wennberg et al.* [2012] of 76 Gg CH_4/yr (less livestock emissions from the SoCAB that are not in the Chino area) assuming mainly wet management practices. We attribute the differences to actual practices in the region, which are likely a mixture of the two manure management approaches. Satellite images of the area show what appear to be several anaerobic lagoons near Chino, California. Our flux determination is therefore consistent with our bottom-up CH_4 emission inventory, with room for a mixture of manure management practices, including some anaerobic lagoons, in the L.A. basin.

4.4. Spatial distribution of methane sources

Townsend-Small et al. [2012] concluded that the CH_4 emissions in the L.A. region had a stable isotope ratio similar to that of fossil-fuel CH_4. This conclusion was based on measurements made at the Mt. Wilson Observatory. A back-trajectory [*White et al.*, 2006; http://www.esrl.noaa.gov/psd/programs/2010/calnex/traj/] from MWO for 5 August 2009, the specific day that *Townsend-Small et al.* [2012] used to determine the excess CH_4 stable isotopic ratio, shows the prevailing winds to MWO were from the southwest, or from downtown L.A. and the coast west of downtown L.A. The trajectory tool also shows winds from the eastern basin on the previous day, which was excluded by *Townsend-Small et al.* [2012] due to lower correlation between the excess CH_4 and $\delta^{13}C$. We conclude that the MWO data interpreted by *Townsend-Small et al.* [2012] were dominated by emissions from the western basin only, and were not influenced by emissions from either the largest landfills (Puente Hills and Olinda Alpha), or from the dairies in the eastern part of the L.A. basin. This spatially-biased sampling is consistent with their conclusion that landfills do not contribute significantly to the total atmospheric CH_4 burden in L.A.

Evidence for the heterogeneous spatial distribution of CH_4 sources in the SoCAB can be seen in the NOAA P-3 data. Figure 4 shows that the correlation of ethane with CH_4 is dependent on the sample location in the L.A. basin. Also shown in Figure 4 is the slope used by *Wennberg et al.* [2012] to represent the ethane/CH_4 ratio (16.5 ± 2.5 ppt ethane/ppb CH_4) in pipeline-quality dry natural gas from the Southern California Gas Company (SoCalGas), the major provider of natural gas to the SoCAB, for 2010.

The chemical data in Figure 4 reflect the known source types shown on the map in Figure 1c: the large CH_4 sources in the eastern L.A. basin, primarily landfills and dairies, are not significant sources of ethane relative to CH_4.

We can reconcile the conclusions of *Townsend-Small et al.* [2012] and *Wennberg et al.* [2012] with the CARB GHG inventory by noting that fossil fuel CH_4 emissions predominate in the western basin, and that landfill and livestock CH_4 emissions predominate in the eastern basin. However, in contrast to the findings of *Wennberg et al.* [2012], we find that natural gas leaks from the SoCalGas and in-home pipelines are not the only possible source of fossil fuel CH_4 to the western basin, as described below.

4.5. Light alkane emissions from local natural gas production

Los Angeles was one of only three out of 28 cities characterized by propane and ethane levels within 10% of one another in the atmosphere [*Baker et al.*, 2008], consistent with an enhanced propane source term in L.A. Figure 5 shows correlations of propane vs. ethane in whole-air samples from various aircraft projects in the Los Angeles region (ITCT 2002, ARCTAS 2008, and CalNex 2010), as well as measurements from the CalNex Pasadena ground site in 2010. Also plotted are lines representing the composition ratios of other possible sources of ethane and propane in Los Angeles.

The L.A. basin is home to oil and gas operations (see Figure 1c); the composition ratios depicting possible emissions from local natural gas (gray lines) and local geologic seeps (salmon lines) in Figure 5 are those reported by *Jeffrey et al.* [1991]. The lower propane content relative to ethane seen in the seeps (*e.g.*, the La Brea tar pits) compared to the local natural gas is attributed to near-surface microorganisms forming shorter-chain alkanes from longer-chain alkanes during the time the natural gas migrates toward the surface [*Jeffrey et al.*, 1991]. The average propane/ethane ratio for processed gas in SoCalGas pipelines [*Wennberg et al.*, 2012] is plotted as a dashed black line. Pipeline-quality dry natural gas has a low propane/ethane ratio because the natural gas has been processed (*i.e.*, the higher alkanes have been removed from the natural gas) before distribution. The SoCalGas ratio is representative of natural gas piped in from out of state (*e.g.*, from Texas, Wyoming, and Canada); approximately 90% of natural gas used in California is imported (http://www.socalgas.com/regulatory/documents/cgr/2010_CGR.pdf). The on-road emissions are taken from a San Francisco Bay-area tunnel study by *Kirchstetter et al.* [1996], who reported a vehicular emission ratio of 0.13 mol propane/mol ethane roughly similar to those by *Fraser et al.* [1998] (0.27 mol propane/mol ethane) and by *Lough et al.* [2005] (0.06 – 0.18 mol propane/mol ethane). Vehicle engine exhaust typically contains small, decreasing amounts of CH_4, ethane, and propane due to incomplete combustion, as gasoline and diesel fuel do not contain significant amounts of these light alkanes. The on-road emissions, local geologic seeps, and the pipeline-quality dry natural gas from SoCalGas contain 3–5 times more ethane than propane, and therefore cannot alone explain the ambient ratios measured in the L.A. basin. The propane and ethane composition of unprocessed natural gas from local wells, on the other hand, closely matches the SoCAB ambient measurements from three aircraft campaigns, the CalNex ground site measurements, and the *Baker et al.* study [2008]. Propane and ethane were also typically enhanced at the same time, with the exception of one sample with elevated propane near the Long Beach area (Figure 1e).

The data in Figure 5 suggest that local oil and gas wells contribute significantly to the atmospheric propane burden in the SoCAB. However, *Wennberg et al.* [2012] invoked a large source of propane from fugitive losses from the liquefied petroleum gas (LPG) industry (*i.e.*, propane tanks), in addition to leaks from the pipeline-quality dry natural gas distribution system in the L.A. basin. This would be consistent with past works that have found significant fugitive losses of propane in other cities, such as Mexico City [*Blake and Rowland*, 1995]. We therefore extend our analysis to incorporate ethane, propane, and C_4 (*n*- and *i*-butane) and C_5 (*n*- and *i*-pentane) isomers to better attribute and quantify the sources of light alkanes and CH_4 to the SoCAB atmosphere. Light alkanes are plotted in Figure 6, with lines depicting the composition of natural gas in SoCalGas pipelines [*Wennberg et al.*, 2012] and of on-road emissions [*Kirchstetter et al.*, 1996]. We neglect chemical processing of these long-lived alkanes ($\tau \geq 3$ days at OH = 1×10^6 molecules/cm^3) as we find no detectable difference between daytime and nighttime enhancement ratios relative to CO, similar to the findings of *Borbon et al.* [2013] for *n*-butane and CO at the CalNex Pasadena ground site. Atmospheric enhancement ratios of propane, *n*-butane, and *i*-butane (Figures 6b–d) relative to ethane are consistent with emissions having the composition of local natural gas [*Jeffrey et al.*, 1991]. On-road emissions do not appear to contribute significantly to the CH_4, ethane, and propane in the L.A. atmosphere, and pipeline-quality dry natural gas and/or local geologic seeps do not appear to contribute significantly to the propane and *n*-butane relative to ethane in the L.A. atmosphere. Based on these observations, we conclude that the local natural gas industry contributes a significant fraction to the total atmospheric C_2-C_4 alkane abundances, including propane, in the L.A. basin. We infer CH_4 emissions from the local natural gas industry are non-negligible as well, as discussed below.

4.6. Source Attribution

Here we quantify total emissions of C_2–C_5 alkanes in the L.A. basin by multiplying their observed enhancement ratios to CO by the CARB SoCAB emission inventory for CO. Figure 7 shows C_2–C_5 alkanes plotted versus CO with their respective ODR fits. The slopes from these fits are used in equation (2) along with the projected 2010 CARB CO inventory to calculate annual alkane emissions in the SoCAB. We assume the slopes represent a direct emission with no chemical aging. These emissions are listed in the right-most column of Table 4. Also listed in Table 4 are the estimated contributions from mobile sources in the SoCAB, using C_1–C_5 to CO emission ratios from *Kirchstetter et al.* [1996] (modified as discussed below) and CO emissions from the mobile sources category in the projected 2010 CARB CO inventory, equal to 920 Gg CO/yr, in equation (2).

Wennberg et al. [2012] attributed the inventory CH_4 shortfall [*Wunch et al.*, 2009; *Hsu et al.*, 2010] by ascribing much of the CH_4 and ethane enhancements to fugitive losses of processed pipeline-quality dry natural gas. They further suggest the majority of atmospheric propane is due to LPG industry/propane tank fugitive losses. Here, we consider other possible explanations of the sources of CH_4 and light alkanes in the L.A. basin for the following two reasons. First, the source attribution by *Wennberg et al.* [2012] leaves little room for CH_4 emissions from landfills, wastewater treatment plants, and dairies in the L.A. basin. This solution seems unlikely based on direct emissions flux estimates using the P-3 data downwind of landfills and dairies in the SoCAB, as described above. Second, the attribution by *Wennberg et al.* [2012] would leave a shortfall in both *n*- and *i*-butane emissions that cannot be explained by gasoline evaporation or emissions from mobile sources.

We use a multivariate approach based on a linear combination of the CH_4 and light alkane compositions from known sources in order to attribute and quantify total CH_4 and C_2–C_5 alkane emissions in the South Coast Air Basin.

We include 7 different source types (sectors) with distinct and known CH_4 and C_2–C_5 alkane compositions (Figure 8) in the following analysis: 1) Leaks of processed dry natural gas from pipelines, and/or emissions from local geologic seeps (this approach cannot distinguish between pipeline-quality dry natural gas and local seeps); 2) CH_4-dominated emissions, such as from landfills, wastewater treatment plants, and dairies; 3) Leaks of unprocessed, local natural gas; 4) Leaks of liquefied petroleum gas from propane tanks; 5) On-road combustion emissions from mobile sources; 6) Emissions of CH_4 and C_2–C_5 alkanes in the SoCAB from other source sectors; and 7) Evaporative emissions from gasoline. These are described briefly below.

1. The South Coast Air Basin contains 14.8 million people, and SoCalGas delivers approximately 11 Tg/yr of natural gas to the Los Angeles area. Additionally, the Earth's natural degassing is a known source of CH_4, ethane, and propane to the atmosphere [*Etiope et al.*, 2008; *Etiope and Ciccioli*, 2009], and the L.A. basin contains abundant geologic hydrocarbon reserves [*Jeffrey et al.*, 1991]. We group fugitive losses from processed pipeline-quality dry natural gas with the emissions from local geologic seeps because the C_1–C_4 emissions from these sources are not sufficiently different to be treated separately in our linear combination analysis (illustrated by the similarity in slopes of the dashed black and salmon-colored lines in Figure 6).

Both pipeline-quality dry natural gas and local seep emissions contain similar amounts of CH_4 and ethane relative to one another, and have less C_3–C_5 alkanes relative to ethane than local, unprocessed natural gas. For pipeline-quality dry natural gas, most C_{3+} alkanes are removed during the processing stage, which is typically done close to the source, which for ~90% of the natural gas used in California is in Canada, Wyoming, and/or Texas. For local seeps, most C_{3+} alkanes are either preferentially adsorbed in shallow sediments compared to CH_4, or biodegraded by microbes in the earth's crust during the seepage of local natural gas to the surface [*Jeffrey et al.*, 1991]. We use SoCalGas samples of pipeline-quality natural gas from 2010 [*Wennberg et al.*, 2012] to represent this source, and estimate the uncertainty of the composition at 15%.

2. CH_4-dominant emission sources, which for this analysis include landfills, wastewater treatment plants, and livestock, emit CH_4 but no significant amounts of C_2–C_5 alkanes. This is represented in our analysis as a unit vector containing only CH_4.
3. From 2007–2009, the oil and gas industry in the L.A. basin produced roughly 12–13 billion cubic feet of natural gas per year, mostly associated gas from oil wells (http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx). We use an average of the samples reported by *Jeffrey et al.* [1991] weighted by 2009 gross natural gas production per field, and estimate the uncertainty of this composition at 25%.
4. Two types of LPG are sold in the Los Angeles area: one is almost completely composed of propane, the other has traces of *n*- and *i*-butane (http://www.arb.ca.gov/research/apr/past/98-338_1.pdf).

We use the ratios reported by *Blake and Rowland* [1995] from direct analysis of LPG in Los Angeles, which is consistent with an average of the two types of LPG sold in L.A, and estimate the uncertainty of the composition at 10%.

5. On-road combustion emissions are modified from the work of *Kirchstetter et al.* [1996] by multiplying emission ratios of alkanes to CO by the 925 Gg CO/yr from on-road sources in the projected 2010 CARB CO inventory. The C_4–C_5 emissions represent unburned fuel and are typically proportional to the fuel composition; the C_1–C_3 emissions typically represent incomplete combustion products. To account for differing fuel compositions since the time of the *Kirchstetter et al.* [1996] study, the *i*- and *n*-butane emissions calculated for mobile sources in the SoCAB (Table 4) have been scaled to the *i*-pentane emissions based on their relative abundance in gasoline [*Gentner et al.*, 2012].
6. There are additional sources of light alkanes in the SoCAB. We use the 2010 CARB speciated inventory for total organic gases (http://arb.ca.gov/ei/speciate/interopt10.htm) and projected 2010 total organic gas emissions (http://www.arb.ca.gov/app/emsinv/fcemssumcat2009.php) for the SoCAB to estimate emissions of light alkanes not specified in other source sectors. These include emissions from aerosol spray cans and other consumer products, coatings and solvents, adhesives and sealants, and fiberglass and plastics manufacturing. For example, propane, *n*- and *i*-butane are commonly used as propellants in aerosol spray cans, having replaced CFCs in the United States in the 1970s (*e.g.*, CARB estimates 0.6 Gg of aerosol antiperspirant vapors were emitted to the SoCAB in 2010, of which 0.14 Gg, 0.03 Gg, and 0.15 Gg were propane, *n*-, and *i*-butane, respectively).

These emissions are summed and listed in the "CARB other" column in Table 4. Emissions from natural gas leaks, petroleum refining, petroleum marketing (gas stations), landfills and composting, and mobile sources are not included in these totals, because they are accounted for elsewhere in other source sectors. We estimate a 25% uncertainty in the "CARB other" inventory.

7. Emissions ratios from evaporated gasoline were calculated from ten gasoline samples from five Pasadena gas stations in the summer of 2010, weighted by estimated sales of 80% regular and 20% premium [*Gentner et al.*, 2012]. Uncertainties are those reported by *Gentner et al.* [2012].

First, we start with estimated annual C_1–C_5 emissions in the SoCAB (right-most column of Table 4), then subtract modified on-road emissions [*Kirchstetter et al.*, 1996] and projected emissions of C_1–C_5 alkanes from other sources (source sector 6, above). Next, we place the remaining source sector characteristics into a matrix and solve for the fraction each source contributes to the remaining alkane observations for the L.A. basin based on each source's relative abundances of various light alkanes. The matrix has five columns representing the five remaining source sectors, and seven rows containing C_1–C_5 alkanes. We solve the equation [*e.g.*, see §4.2 *Kim et al.*, 2011]

$$\mathbf{A}_{i,j}\,\mathbf{x}_j = \mathbf{b}_i \tag{3}$$

where $\mathbf{A}_{i,j}$ is a matrix of the C_1–C_5 alkane composition, i, for the source sectors, j, defined above; x_j is the fraction each source contributes to the total observed emissions, and b_i is the total observed emission of alkane i minus the contributions from the mobile and "other" source sectors (Table 4). The columns of the matrix **A** are proportional to the first five columns of

Table 4. We use LAPACK (http://www.netlib.org/lapack/) to solve for the linear least squares solution that minimizes (**Ax** – **b**). Uncertainties in the derived $\mathbf{x}_j$ are estimated by a sensitivity study, where we run the solution 1,000,000 times by randomly varying $\mathbf{A}_{i,j}$ and $\mathbf{b}_i$ according to their estimated uncertainties, then use the standard deviation of the 1,000,000 $\mathbf{x}_j$ determinations to estimate the uncertainty in the source attribution fraction. The source attribution fractions and their uncertainties are multiplied by the total estimated SoCAB emission for each alkane, then are summed with the uncertainties added in quadrature. CH_4 and C_2–C_5 alkane emissions totals, their uncertainties, and the contributions from each source type are given in Table 4. The source attribution solution solves the observed SoCAB alkane emission to within each alkane's emission uncertainty.

Our modeled source attribution differs from the alkane source distribution in the L.A. basin as set forth by *Wennberg et al.* [2012]. From a total calculated source of 410 ± 40 Gg CH_4/yr in the SoCAB, we determine that 47% comes from leaks of processed pipeline-quality dry natural gas and/or from local geologic seeps; 44% of the CH_4 comes from the sum of landfill, wastewater treatment, and dairy emissions; 8% from the leaks of unprocessed natural gas from production in the western L.A. basin; and 1% from mobile sources. The attribution is presented graphically in Figure 8. Figure 8a displays the total SoCAB emissions as a black horizontal line in each panel, with contributions from the different source sectors given below the line by the filled bars. Figure 8b shows the proportion that each source sector contributes to the derived total emissions of each alkane.

Our analysis attributes CH_4 emissions of 192 ± 54 Gg CH_4/yr to leaks of pipeline-quality dry processed natural gas and/or leaks from local geologic seeps, but does not distinguish further between these two different sources. This value is nearly a factor of 5 greater than the population-apportioned 2009 CARB GHG emissions inventory estimate of 40 Gg CH_4/yr lost from natural gas pipelines in the SoCAB. Our estimate of 192 Gg CH_4/yr is less than the maximum emission of 400 ± 150 Gg CH_4/yr estimated by *Wennberg et al.* [2012]. Our estimate would represent approximately 2% of the natural gas delivered to customers in the SoCAB and, including storage and deliveries to customers outside the SoCAB, 1% of the gas flowing into the basin [*Wennberg et al.*, 2012]. These percentages would decrease linearly with any CH_4 emissions attributed to local geologic seeps. *Farrell et al.* [*in press*, 2012] estimate up to 55 Gg CH_4/yr are emitted from the La Brea Tar Pits in western L.A. County alone; if accurate, this would imply pipeline leaks of only 0.7% of the gas flowing into the basin, or a factor of at least two lower than the 2% proposed by *Wennberg et al.* [2012].

Our analysis attributes 182 ± 54 Gg CH_4/yr in the SoCAB to emissions from landfills, wastewater treatment, and dairies. SoCAB landfills account for 164 Gg CH_4/yr in the 2008 CARB GHG inventory, a value supported by our analysis in section 4.2. In section 4.3, we estimated in a bottom-up inventory that SoCAB dairies emitted 31.6 Gg CH_4/yr. *Wennberg et al.* [2012] estimated an emission of 20 Gg CH_4/yr from wastewater treatment. These independent estimates sum to 216 Gg CH_4/yr and are consistent with our source apportionment using NOAA P-3 data.

CH_4 emissions of 31.9 ± 6.5 Gg CH_4/yr are ascribed to leaks of local, unprocessed natural gas, and would represent 17% of the local production in 2009, the latest year for which data are available (http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx). This number assumes a CH_4 composition of 72.5% by volume for natural gas produced in the South Coast Air Basin, which is calculated as an average from the samples reported by *Jeffrey et al.* [1991] weighted by 2009 production. Our derived value of 17%, although a surprisingly high amount of local production, is consistent with a nascent bottom-up estimate under way at CARB. A new bottom-up inventory survey, conducted by CARB for the calendar year 2007 but not yet incorporated into the official GHG inventory, indicates that 109 Gg CH_4/yr, since revised to 95.5 Gg CH_4/yr [*S. Detwiler,* personal communication, October 2012], were emitted throughout California by the oil and gas industry via combustion, venting, and fugitive losses (table 3-1, http://www.arb.ca.gov/cc/oil-gas/finalreport.pdf). This updated value is a factor of 2.5 larger than the current CARB GHG inventory tabulation of 38 Gg CH_4/yr from oil and gas extraction for 2007 in California. CH_4-specific emissions for the South Coast Air Management District in the new CARB survey report show 24.6 Gg CH_4/yr were emitted in the SoCAB [S. Detwiler, personal communication, October 2012]. According to the survey, emissions in the SoCAB accounted for 26% of the revised statewide total oil and gas operations CH_4 emission in 2007, despite accounting for only 4.4% of statewide natural gas production in the basin that year (http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx). Thus, the survey responses suggest a CH_4 leak rate of 12% of local production in the L.A. basin.

Thus, our estimate of CH_4 emissions from local natural gas for 2010 based on P-3 data from CalNex is within a factor of 1.5 of the CARB bottom-up inventory currently in development based on the 2007 survey. According to the survey, other oil and gas producing regions in California show smaller CH_4 loss rates than that from the SoCAB. For instance, statewide losses of CH_4 represent approximately 2.1% of statewide production, and CH_4 losses from the San Joaquin Air Quality District represent approximately 1.4% of production (from Oil and Gas Districts 4 and 5). This indicates that losses from natural gas production are proportionally larger in the L.A. basin than elsewhere in the State of California.

A propane emission of 6.6 ± 2.9 Gg/yr from LPG/propane tanks would represent approximately 1% of sales (http://www.aqmd.gov/ceqa/documents/2012/aqmd/finalEA/PAR1177/1177_FEA.pdf), which is less than the ~4% calculated by *Wennberg et al.* [2012], and closer to the 0.6% estimated from the document cited.

Finally, our analysis suggests a resolution to the discrepancies noted above between previous top-down assessments and the bottom-up inventory calculations for CH_4 in the SoCAB [*e.g.*, *Wunch et al.*, 2009; *Hsu et al.*, 2010; *Townsend-Small et al.*, 2012; *Wennberg et al.*, 2012]. We conclude the most probable source for the excess atmospheric CH_4 is likely due to a combination of primarily leaks, not accurately represented in the current CARB GHG inventory, from natural gas pipelines and urban distribution systems and/or from local geologic seeps, and secondarily leaks of unprocessed natural gas from local oil and gas production centered in the western L.A. basin.

This finding is based on the characteristic enhancement ratios of CH_4 and the various C_2–C_5 alkanes consistently observed in the L.A. atmosphere, and is further supported by the spatial information provided by P-3 samples during CalNex. Finally, the updated values for local oil and gas industry emissions in the recent GHG survey commissioned by CARB, when incorporated fully into the official CARB GHG record, will likely help to reduce this long-standing discrepancy between top-down assessments and bottom-up inventories.

5. Conclusions

We use aircraft measurements of CH_4, CO, and CO_2 during the CalNex field campaign to show that emissions of CH_4 to the L.A. basin are greater than can be explained by official state bottom-up inventories apportioned by population, consistent with published work. The ratio of the CARB CO and CO_2 inventories is in better agreement with our measurements of CO/CO_2 in the Los Angeles atmosphere than was the case for the analysis by *Wunch et al.* [2009], which we attribute either to improved CARB inventories, the present use of a basin-wide data set to determine basin-wide emission ratios, or both.

From crosswind plume transects downwind of the two largest landfills in the basin, we determine CH_4 fluxes that are consistent with the 2008 CARB GHG inventory values, which total 164 Gg CH_4/yr emitted from all landfills in the South Coast Air Basin. CH_4 emission fluxes were also determined for Chino-area dairies in the eastern L.A. basin. Flux estimates from these dairies ranged from 24 ± 12 to 87 ± 44 Gg CH_4/yr, and the average flux is consistent with a revised bottom-up inventory originally compiled by *Salas et al.* [2008] and with previous inventory estimates [*Wennberg et al.*, 2012].

Finally, we present a top-down assessment of C_2–C_5 alkane sources in the L.A. basin, then apportion CH_4 and the C_2–C_5 alkanes to specific source sectors in the region. Using this source apportionment approach, we estimate that 32 ± 7 Gg of CH_4/yr, or 8% of the total CH_4 enhancement observed in the SoCAB during CalNex, came from the local oil and gas industry. This number represents approximately 17% of the natural gas produced in the region, within a factor of 1.5 of that calculated from a recent survey that will be used to update the CARB bottom-up inventory. We estimate 182 ± 54 Gg CH_4/yr are emitted by landfills, dairies, and wastewater treatment, which is consistent with bottom-up inventories, and 192 ± 54 Gg CH_4/yr are emitted of processed pipeline-quality dry natural gas and/or from geologic seeps in the region. We further conclude that leaks of processed pipeline-quality dry natural gas and/or local geologic seeps, and unprocessed natural gas from local oil and gas production are the most likely major contributors to the previously noted discrepancy between CH_4 observations and State of California inventory values for the South Coast Air Basin. Our findings suggest that basin-wide mobile studies targeting CH_4 and C_2–C_5 alkane emissions from natural gas pipelines and urban distribution systems, geologic seeps, and local oil and gas industry production sites would be useful to further distinguish the sources of CH_4 in the L.A. basin.

Acknowledgments

The NOAA Climate Change and Air Quality programs supported this work. We thank Larry Hunsaker of CARB for landfill CH_4 emission data, and Stephanie Detwiler of CARB for the updated bottom-up oil and gas inventory data.

References

Andrews, A. E., et al. (2009), Carbon Dioxide and Carbon Monoxide Dry Air Mole Fractions from the NOAA ESRL Tall Tower Network, 1992–2009, Version: 2011-06-02, Path: ftp://ftp.cmdl.noaa.gov/ccg/towers/.

Baker, A. K., A. J. Beyersdorf, L. A. Doezema, A. Katzenstein, S. Meinardi, I. J. Simpson, D. R. Blake, and F. S. Rowland (2008), Measurements of nonmethane hydrocarbons in 28 United States cities, *Atmos. Environ.*, *42*, 170–182, doi:10.1016/j.atmosenv.2007.09.007.

Bevington, P. R. (1969), *Data Reduction and Error Analysis for the Physical Sciences*, McGraw-Hill Book Company, New York, N. Y.

Blake, D. R., and F. S. Rowland (1995), Urban Leakage of Liquefied Petroleum Gas and Its Impact on Mexico City Air Quality, *Science*, *269*, 953 – 956.

Boggs, P. T., et al. (1989), Algorithm 676 – ODRPACK: Software for Weighted Orthogonal Distance Regression, *ACM Transactions on Mathematical Software*, *15*, 348–364.

Borbon, A., et al. (2013), Emission ratios of anthropogenic VOC in northern mid-latitude megacities: observations vs. emission inventories in Los Angeles and Paris, *J. Geophys. Res.*, doi:10.1029/2012JD018235, in press.

Brioude, J., et al. (2012), Top-down estimate of surface flux in the Los Angeles Basin using a mesoscale inverse modeling technique: assessing anthropogenic emissions of CO, NO_x, and CO_2 and their impacts, Atmos. Chem. Phys. Discuss., 12, 31439–31481, doi:10.5194/acpd-12-31439-2012.

Colman, J. J., A. L. Swanson, S. Meinardi, B. C. Sive, D. R. Blake, and F. S. Rowland (2001), Description of the Analysis of a Wide Range of Volatile Organic Compounds in Whole Air Samples Collected during PEM-Tropics A and B, *Anal. Chem.*, *73*(15), 3723–3731, doi:10.1021/ac010027g.

Conway, T. J., et al. (2011), Atmospheric Carbon Dioxide Dry Air Mole Fractions from the NOAA ESRL Carbon Cycle Cooperative Global Air Sampling Network, 1968–2010, Version: 2011-10-14, Path: ftp://ftp.cmdl.noaa.gov/ccg/co2/flask/event/.

Dlugokencky, E. J., R. C. Myers, P. M. Lang, K. A. Masarie, A. M. Crotwell, K. W. Thoning, B. D. Hall, J. W. Elkins, and L. P. Steele (2005), Conversion of NOAA atmospheric dry air CH_4 mole fractions to a gravimetrically prepared standard scale, *J. Geophys. Res.*, 110, D18306, doi:10.1029/2005JD006035.

Dlugokencky, E. J., et al. (2011), Atmospheric Methane Dry Air Mole Fractions from the NOAA ESRL Carbon Cycle Cooperative Global Air Sampling Network, 1983–2010, Version: 2011-10-14, Path: ftp://ftp.cmdl.noaa.gov/ccg/ch4/flask/event/.

Etiope, G., and P. Ciccioli (2009), Earth's Degassing: A Missing Ethane and Propane Source, *Science*, *323*, doi:10.1126/science.1165904.

Etiope, G., K. R. Lassey, R. W. Klusman, and E. Boschi (2008), Reappraisal of the fossil methane budget and related emission from geologic sources, *Geophys. Res. Lett.*, *35*, L09307, doi:10.1029/2008GL033623.

Farrell, P., D. Culling, and I. Leifer (2012), Transcontinental Methane Measurements: Part 1. A Mobile Surface Platform for Source Investigations, *Atmos. Environ.*, *in press*.

Fraser, M. P., G. R. Cass, and B. R. T. Simoneit (1998), Gas-phase and particle-phase organic compounds emitted from motor vehicle traffic in a Los Angeles roadway tunnel, *Environ. Sci. Technol.*, *32*, 2051–2060.

Gentner, D. R., et al. (2012), Elucidating secondary organic aerosol from diesel and gasoline vehicles through detailed characterization of organic carbon emissions, *Proc. Natl. Acad. Sci. U. S. A.*, *109*(45), 18318–18323, doi:10.1073/pnas.1212272109.

Gilman, J. B., et al. (2010), Surface ozone variability and halogen oxidation throughout the Arctic and sub-Arctic springtime, *Atmos. Chem. Phys.*, *10*, 10,223–10,236, doi:10.5194/acp-10-10223-2010.

Gurney, K. R., D. L. Mendoza, Y. Zhou, M. L. Fischer, C. C. Miller, S. Geethakumar, and S. de la Rue du Can (2009), High Resolution Fossil Fuel Combustion CO_2 Emissions Fluxes for the United States, *Environ. Sci. Technol.*, *43*, 5535–5541, doi:10.1021/es900806c.

Holloway, J. S., R. O. Jakoubek, D. D. Parrish, C. Gerbig, A. Volz-Thomas, S. Schmitgen, A. Fried, B. Wert, B. Henry, and J. R. Drummond (2000), Airborne intercomparison of vacuum ultraviolet fluorescence and tunable diode laser absorption measurements of tropospheric carbon monoxide, *J. Geophys. Res.*, *105*(D19), 24,251–24,261, doi:10.1029/2000JD900237.

Hsu, Y.-K., T. VanCuren, S. Park, C. Jakober, J. Herner, M. FitzGibbon, D. R. Blake, and D. D. Parrish (2010), Methane emissions inventory verification in southern California, *Atmos. Environ.*, *44*, 1–7, doi:10.1016/j.atmosenv.2009.10.002.

Jeffrey, A. W. A. et al. (1991), Geochemistry of Los Angeles Basin Oil and Gas Systems, in Biddle, K. T. (ed.), Active Margin Basins, *Amer. Assoc. Petr. Geologists*, Memoir 52, p. 197–219.

Kim, S.-W., et al. (2011), Evaluations of NO_X and highly reactive VOC emission inventories in Texas and their implications for ozone plume simulations during the Texas Air Quality Study 2006, *Atmos. Chem. Phys.*, *11*, 11361 – 11386, doi:10.5194/acp-11-11361-2011.

Kirchstetter, T. W., B. C. Singer, R. A. Harley, G. R. Kendall, and W. Chan (1996), Impact of Oxygenated Gasoline Use on California Light-Duty Vehicle Emissions, *Environ. Sci. Technol.*, *30*, 661–670.

Kort, E. A., P. K. Patra, K. Ishijima, B. C. Daube, R. Jiménez, J. Elkins, D. Hurst, F. L. Moore, C. Sweeney, and S. C. Wofsy (2011), Tropospheric distribution and variability of N_2O: Evidence for strong tropical emissions, *Geophys. Res. Lett.*, 38, L15806, doi:10.1029/2011GL047612.

Lough, G. C., J. J. Schauer, W. A. Lonneman, and M. K. Allen, Summer and Winter Nonmethane Hydrocarbon Emissions from On-Road Motor Vehicles in the Midwestern United States, *J. Air & Waste Manage. Assoc.*, *55*:629–646.

Mays, K. L., P. B. Shepson, B. H. Stirm, A. Karion, C. Sweeney, and K. R. Gurney (2009), Aircraft-Based Measurements of the Carbon Footprint of Indianapolis, *Environ. Sci. Technol.*, *43*, 7816 – 7823.

Novelli, P. C. and K. A. Masarie (2010), Atmospheric Carbon Monoxide Dry Air Mole Fractions from the NOAA ESRL Carbon Cycle Cooperative Global Air Sampling Network, 1988–2009, Version: 2011-10-14, Path: ftp://ftp.cmdl.noaa.gov/ccg/co/flask/event/.

Nowak, J. B., J. A. Neuman, R. Bahreini, A. M. Middlebrook, J. S. Holloway, S. A. McKeen, D. D. Parrish, T. B. Ryerson, and M. Trainer (2012), Ammonia sources in the California South Coast Air Basin and their impact on ammonium nitrate formation, *Geophys. Res. Lett.*, *39*, L07804, doi:10.1029/2012GL051197.

Peischl, J., et al. (2012), Airborne observations of methane emissions from rice cultivation in the Sacramento Valley of California, *J. Geophys. Res.*, *117*, D00V25, doi:10.1029/2012JD017994.

Ryerson, T. B., et al. (1998), Emissions lifetimes and ozone formation in power plant plumes, *J. Geophys. Res.*, *103*, D17, 22,569–22,583.

Salas, W. A., et al. (2008), Developing and Applying Process-Based Models for Estimating Greenhouse Gas and Air Emission From California Dairies, *California Energy Commission, PIER Energy-Related Environmental Research*, *CEC-500-2008-093*, http://www.energy.ca.gov/2008publications/CEC-500-2008-093/CEC-500-2008-093.PDF.

Schauffler, S. M., E. L. Atlas, D. R. Blake, F. Flocke, R. A. Lueb, J. M. Lee-Taylor, V. Stroud, and W. Travnicek (1999), Distributions of brominated organic compounds in the troposphere and lower stratosphere, *J. Geophys. Res.*, *104*(D17), 21,513–21,535, doi: 10.1029/1999JD900197.

Simpson, I. J., et al. (2010), Characterization of trace gases measured over Alberta oil sands mining operations: 75 speciated C_2–C_{10} volatile organic compounds (VOCs), CO_2, CO, CH_4, NO, NO_y, O_3 and SO_2, *Atmos. Chem. Phys.*, *10*, 11,931–11,954, doi: 10.5194/acp-10-11931-2010.

Taylor, J. R. (1997), *An Introduction to Error Analysis, The Study of Uncertainties in Physical Measurements*, 2nd Edition, University Science Books, Sausalito, Calif.

Townsend-Small, A., S. C. Tyler, D. E. Pataki, X. Xu, and L. E. Christensen (2012), Isotopic measurements of atmospheric methane in Los Angeles, California, USA: Influence of “fugitive” fossil fuel emissions, *J. Geophys. Res.*, *117*, D07308, doi:10.1029/2011JD016826.

Trainer, M., B. A. Ridley, M. P. Buhr, G. Kok, J. Walega, G. Hübler, D. D. Parrish, and F. C. Fehsenfeld (1995), Regional ozone and urban plumes in the southeastern United States: Birmingham, a case study, *J. Geophys. Res.*, *100*, D9, 18,823–18,834.

Warneke, C., J. A. de Gouw, J. S. Holloway, J. Peischl, T. B. Ryerson, E. Atlas, D. Blake, M. Trainer, and D. D. Parrish (2012), Multi-Year Trends in Volatile Organic Compounds in Los Angeles, California: Five Decades of Decreasing Emissions, *J. Geophys. Res.*, *117*, D00V17, doi:10.1029/2012JD017899.

Washenfelder, R. A., et al. (2011), The glyoxal budget and its contribution to organic aerosol for Los Angeles, California, during CalNex 2010, *J. Geophys. Res.*, *116*, D00V02, doi:10.1029/2011JD016314.

Wennberg, P. O., et al. (2012), On the Sources of Methane to the Los Angeles Atmosphere, *Environ. Sci. Technol.*, *46*(17), 9282–9289, doi:10.1021/es301138y.

White, A. B., C. J. Senff, A. N. Keane, L. S. Darby, I. V. Djalalova, D. C. Ruffieux, D. E. White, B. J. Williams, and A. H. Goldstein (2006), A wind profiler trajectory tool for air quality transport applications, *J. Geophys. Res.*, *111*, D23S23, doi:10.1029/2006JD007475.

White, W. H., J. A. Anderson, D. L. Blumenthal, R. B. Husar, N. V. Gillani, J. D. Husar, and W. E. Wilson Jr. (1976), Formation and transport of secondary air pollutants: Ozone and aerosols in the St. Louis urban plume, *Science*, *194*, 187–189, doi:10.1126/science.959846.

Wunch, D., P. O. Wennberg, G. C. Toon, G. Keppel-Aleks, and Y. G. Yavin (2009), Emissions of greenhouse gases from a North American megacity, *Geophys. Res. Lett.*, 36, L15810, doi:10.1029/2009GL039825.

Table 1. Summary of past studies investigating CH_4 emissions in the L.A. basin.

Study	Time of study	Geographic area	Percentage of California population in geographic area	CH_4 Emission (Gg/yr)	Inventory referenced	Bottom-up CH_4 emission inventory (Gg/yr)
Wunch et al. [2009]	August 2007 – June 2008	SoCAB	43%	400 ± 100	CARB CO 2007	260[b]
				600 ± 100	(CARB CO_2 2006 + EDGAR CO_2 2005)/2	
Hsu et al. [2010]	April 2007 – May 2008	L.A. County ∩ SoCAB	27%	200 ± 10	CARB CO 2007	140
Wennberg et al. [2012]	April 2007 – May 2008	SoCAB	43%	380[a] ± 100	CARB CO 2007	---
	June 2008	SoCAB	43%	470 ± 100	CARB CO 2008	---
	May 2010 – June 2010	SoCAB	43%	440 ± 100	CARB CO 2010	---

[a] *Wennberg et al.* [2012] recalculated the data reported by *Hsu et al.* [2010] to estimate a CH_4 emission from the entire SoCAB.

[b] *Wunch et al.* [2009] apportioned the statewide CARB GHG inventory for CH_4, less agriculture and forestry emissions, by population

Table 2. Inventories used in current analysis

Emission	Inventory	Year	Geographic Area
180 Tg CO_2/yr	CARB GHG[a]	2009	SoCAB[c]
979 Gg CO/yr	CARB[b]	2010	SoCAB[c]
301 Gg CH_4/yr	CARB GHG[a]	2009	SoCAB[c]

[a] 2009 CARB CO_2 and CH_4 emissions (http://www.arb.ca.gov/cc/inventory/data/data.htm)

[b] projected 2010 CARB CO emissions (http://www.arb.ca.gov/app/emsinv/fcemssumcat2009.php)

[c] statewide inventory apportioned by SoCAB population

Table 3. Landfill emission fluxes determined aboard the NOAA P-3 in 2010 from downwind plume transects.

Landfill	Transect Date	Flux, 10^{25} molecules/s	Flux, Gg/yr	2008 CARB GHG inventory,[a] Gg/yr
Olinda Alpha	8 May	1.13	9.5	
	14 May	1.45	12.2	
	16 May	1.74	14.6	
	19 May	1.61	13.5	
	20 June	2.90	24.3	
	average[b]	**1.49 ± 0.35**	**12.5 ± 2.9**	**11.0**
Puente Hills	8 May	4.29	36.0	
	19 May	3.62	30.4	
	20 June	4.48	37.6	
	average[b]	**4.06 ± 1.18**	**34.0 ± 9.9**	**38.8**

[a] data from CARB [L. Hunsaker, personal communication, June 2011]

[b] weighted average, assuming a 50% uncertainty in the individual flux determinations [*Taylor*, 1997]

Table 4. Derived emissions in the South Coast Air Basin (in Gg/yr) for 2010 from each source sector used in linear analysis.

	Pipeline-quality dry NG/ local seeps	CH_4-dominant (landfills, dairies, etc.)	Local NG	LPG/propane	Evaporated gasoline	Mobile sources	CARB other	Summed source totals	Estimated SoCAB total[a]
CH_4	192 ± 54	182 ± 54	32 ± 7	---	---	4.9 ± 1.3	1.2 ± 0.3	411 ± 77	411[b] ± 37
ethane	5.9 ± 1.7	---	4.5 ± 1.0	0.05 ± 0.02	0.0 ± 0.0	0.6 ± 0.1	0.3 ± 0.1	11.4 ± 1.9	11.4[b] ± 1.6
propane	1.5 ± 0.4	---	9.9 ± 2.0	6.6 ± 2.9	0.006 ± 0.001	0.1 ± 0.0	1.6 ± 0.4	19.8 ± 3.6	19.8 ± 2.7
n-butane	0.3 ± 0.1	---	5.9 ± 1.2	0.02 ± 0.01	0.5 ± 0.1	0.3 ± 0.1	1.4 ± 0.4	8.5 ± 1.3	8.3 ± 1.2
i-butane	0.3 ± 0.1	---	2.2 ± 0.5	0.13 ± 0.06	0.08 ± 0.02	0.04 ± 0.01	1.8 ± 0.5	4.6 ± 0.6	5.1 ± 0.7
n-pentane	0.07 ± 0.02	---	2.2 ± 0.5	---	2.6 ± 0.4	1.0 ± 0.1	0.3 ± 0.1	6.6 ± 0.6	6.5 ± 0.9
i-pentane	0.11 ± 0.03	---	2.4 ± 0.5	0.003 ± 0.001	7.6 ± 1.0	3.9 ± 0.5	0.03 ± 0.01	14.1 ± 1.2	14.1 ± 1.8

[a] includes measurement, ODR fit, and inventory uncertainty

[b] *Wennberg et al.* [2012] estimate emissions to the SoCAB of 440 ± 100 Gg CH_4/yr and 12.9 ± 0.9 Gg ethane/yr

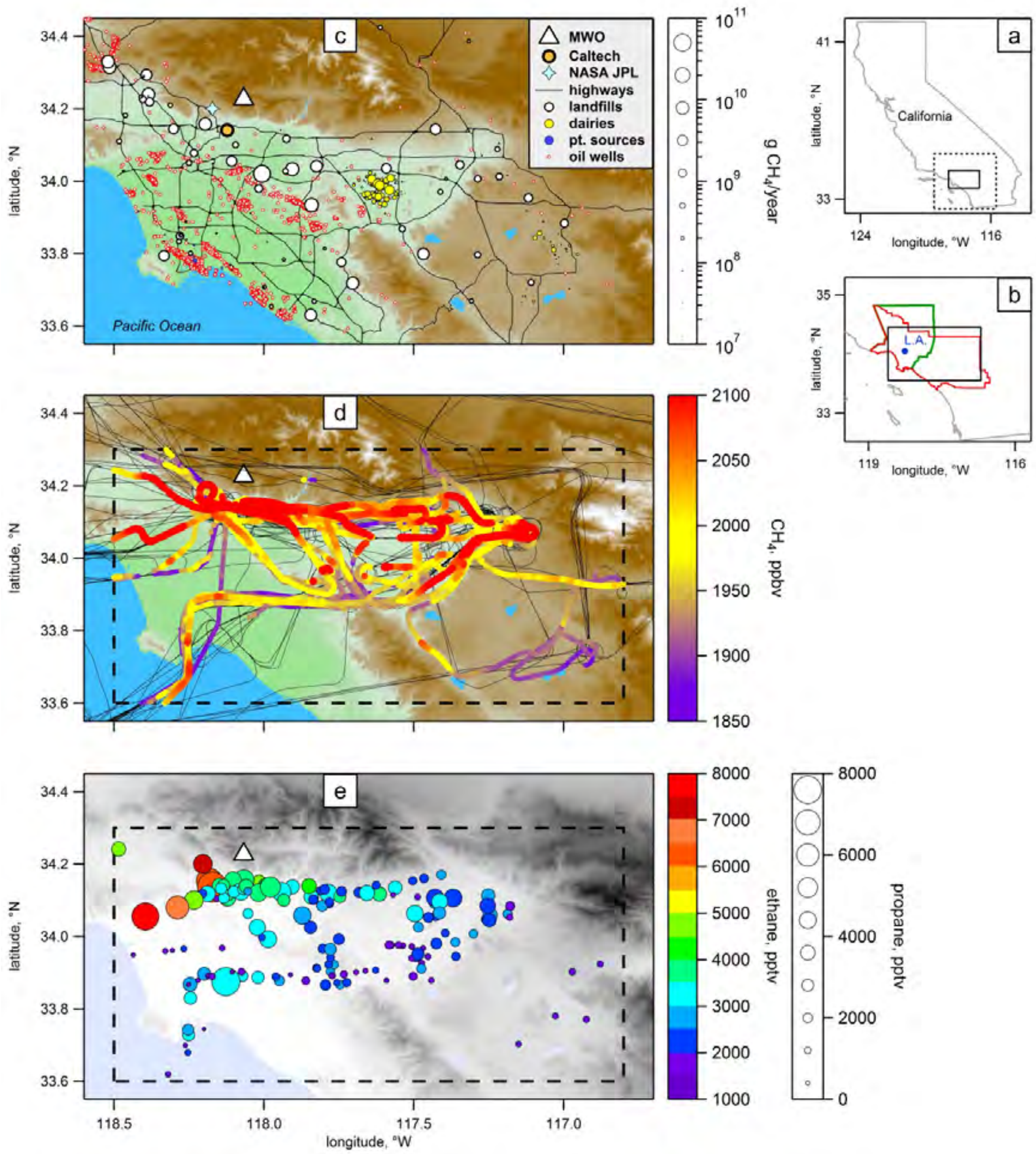


Figure 1. a) Map of California. The dashed box shows the inset for panel (b), the solid box shows the extent of the map boundaries for panels (c) – (e). **b)** Map of southern California showing the location of downtown L.A. (blue dot), the Los Angeles County boundary (green), the South Coast Air Basin boundary (red), and the extent of the map boundaries for panels (c) – (e) (black box). **c)** Map of the L.A. region showing known sources of CH_4 in the L.A. basin. The white triangle shows the location of the Mt. Wilson Observatory, where ground-based measurements were made by *Hsu et al.* [2010] and in this study. The light blue star shows the location of the Jet Propulsion Laboratory, where *Wunch et al.* [2009] made their measurements. The CalNex Pasadena ground site was located on the California Institute of Technology (Caltech) campus, located at the orange filled circle. Landfills (white circles) and CH_4 point sources (filled blue circles; negligibly small) are sized by emissions in the 2008 CARB greenhouse gas inventory. Dairies (filled yellow circles) are sized by the estimated emissions from the number of cows from *Salas et al.* [2008] multiplied by the 2009 CARB GHG inventory annual CH_4 emission per cow from enteric fermentation. **d)** Same map of the Los Angeles region as in (c), with flight tracks from 16 daytime flights of the NOAA P-3 (thin black lines). CH_4 measurements from the daytime boundary layer are color-coded atop these tracks according to the legend to the right. **e)** Locations of whole air samples in the L.A. basin, colored by ethane mixing ratio and sized by propane mixing ratio as indicated in the legends to the right.

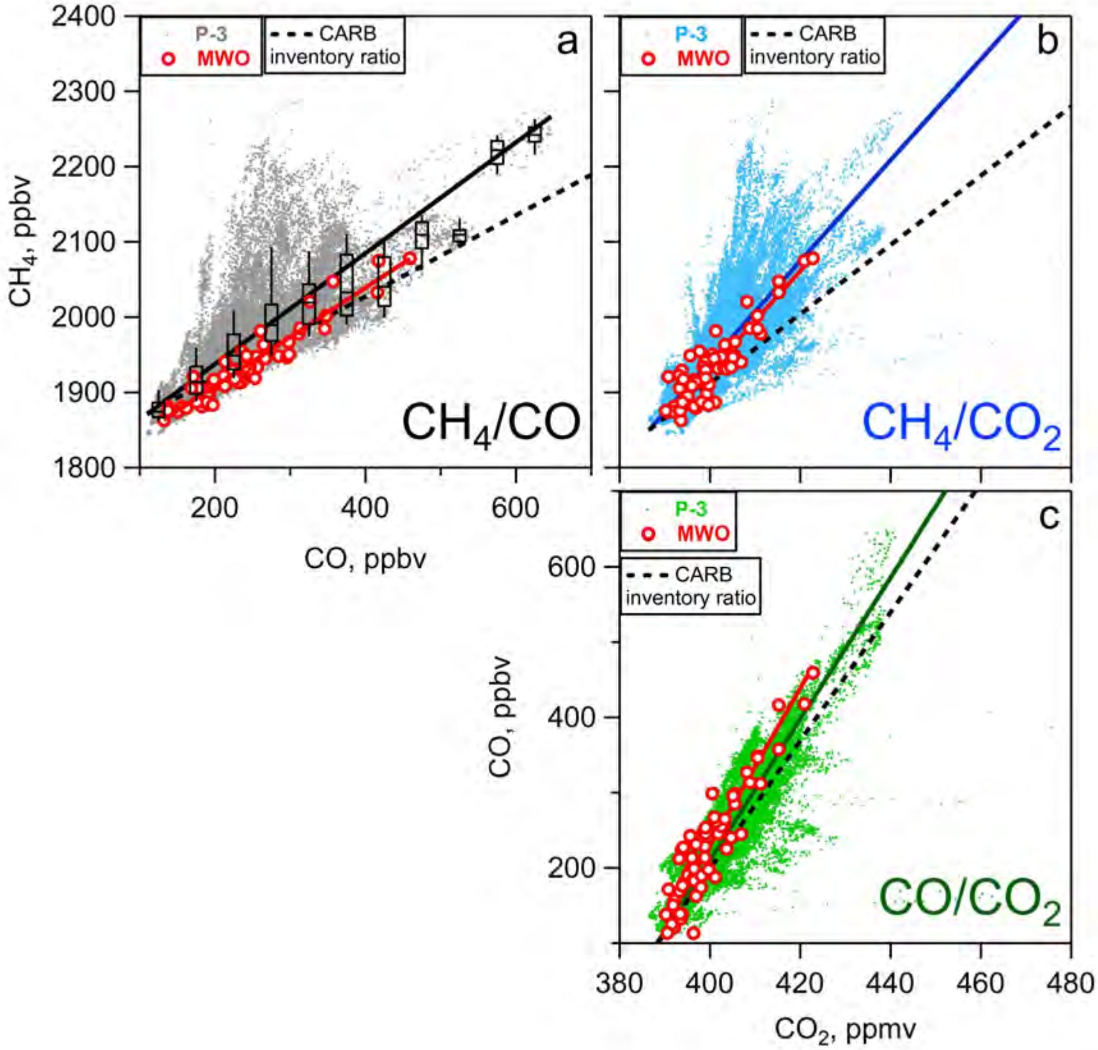


Figure 2. Scatter plots of CH_4, CO_2, and CO from all 1-second data points along flight track highlighted in Figure 1. Dots are from the NOAA P-3, while red circles are from NOAA GMD flask samples taken at the Mt. Wilson Observatory during CalNex. Weighted ODRs (solid lines) result in slopes of **(a)** 0.74 ± 0.04 and 0.68 ± 0.04 ppb CH_4/ppb CO; **(b)** 6.70 ± 0.01 and 6.60 ± 0.04 ppb CH_4/ppm CO_2; and **(c)** 9.4 ± 0.5 and 10.4 ± 0.5 ppb CO/ppm CO_2 from the NOAA P-3 and Mt. Wilson Observatory, respectively. The black dotted lines represent molar ratios of the CARB inventories listed in Table 2: CH_4:CO = 0.54, CH_4:CO_2 = 4.64×10^{-3}, and CO:CO_2 = 8.5×10^{-3}, where the background values used are the same as those determined from the fitted slopes. Also plotted in Figure 2a are boxes (25^{th}–75^{th} percentiles), whiskers (10^{th}–90^{th} percentiles), and the median (horizontal line) for distributions of CH_4 data calculated for 50 ppbv-wide bins from the NOAA P-3 CO data.

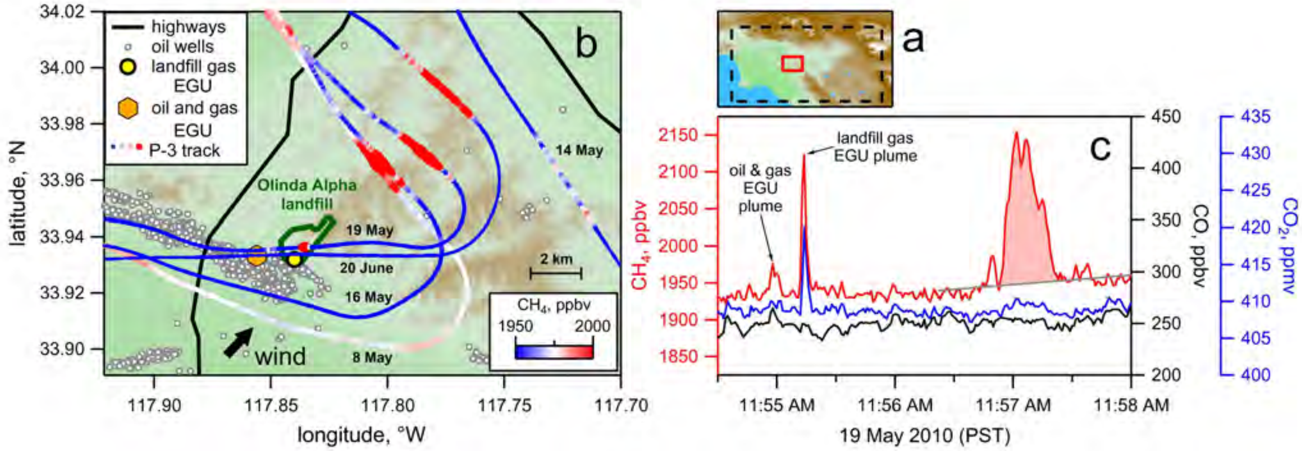


Figure 3. a) The map from Figure 1c–e shows the inset for part (b) in red. **b)** Five downwind transects, sized and colored by CH_4 mixing ratio, showing enhancements in CH_4 downwind of the Olinda Alpha landfill (green outline). Winds were from the southwest, except on 14 May, when they were from the west-southwest. **c)** Example of integration of the CH_4 plume from the 19 May flight. The filled pink area is integrated above the surrounding background (gray line). The upwind transect on this day passed downwind of two power plant (EGU) plumes.

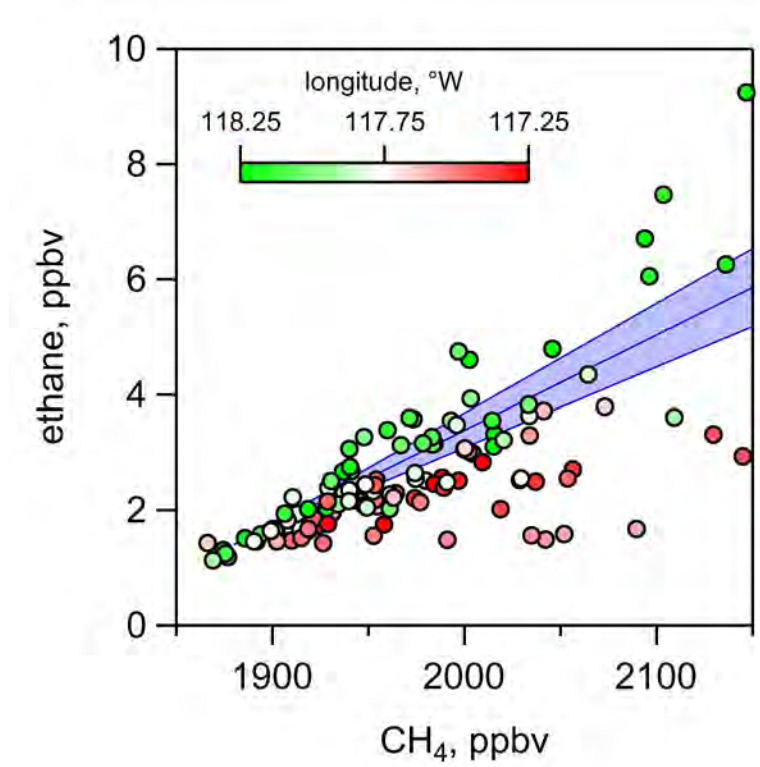


Figure 4. Scatter plot of ethane vs. CH_4 from the NOAA P-3 data in the L.A. basin. Data points are colored by longitude to show the different distributions of ethane to CH_4 in the eastern (red) and western (green) parts of the basin. The blue line represents the slope of 1.65 ± 0.25 % used by *Wennberg et al.* [2012] to represent the estimated ethane/CH_4 ratio of pipeline-quality dry natural gas from the Southern California Gas Company's pipelines.

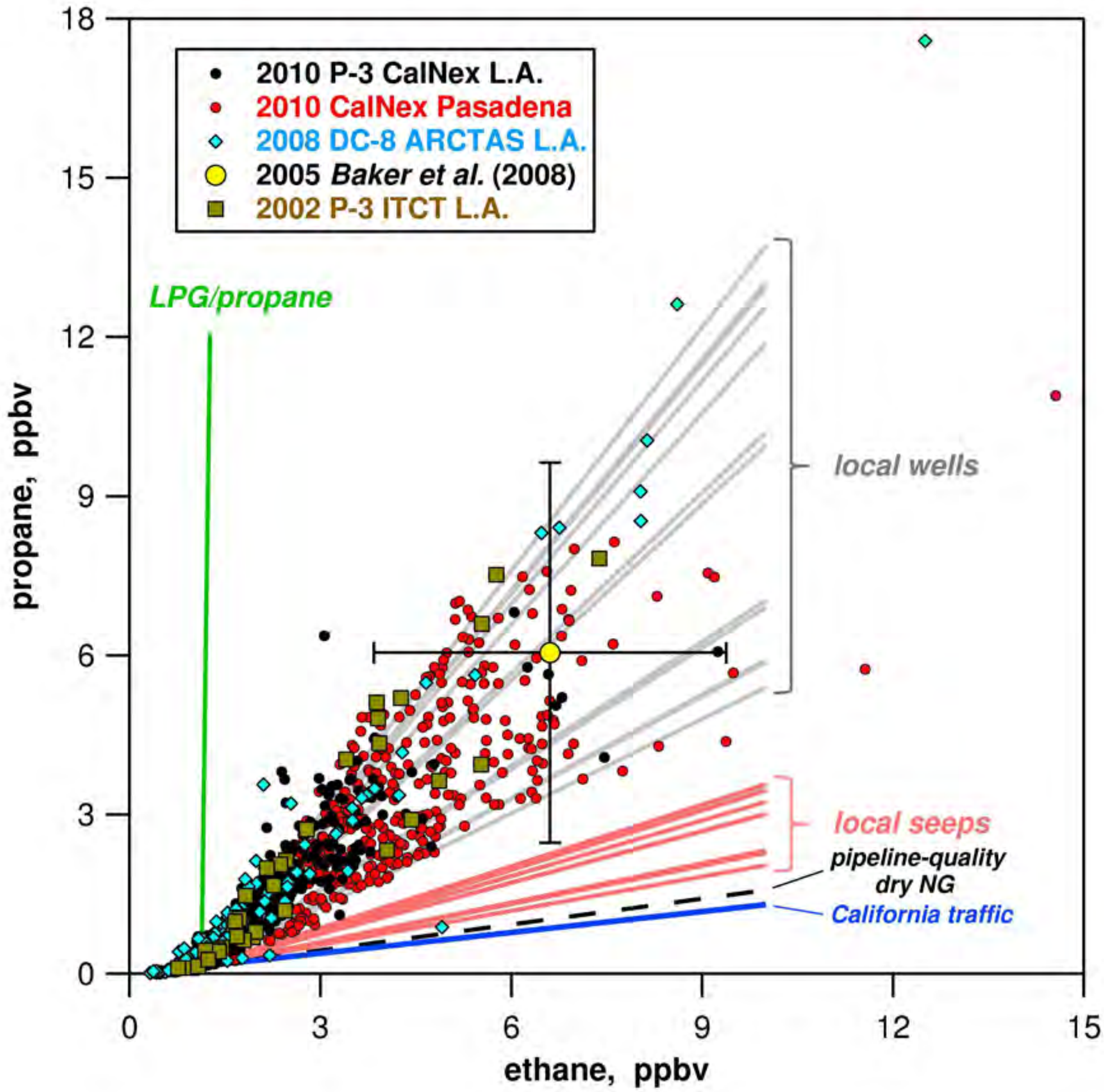


Figure 5. Correlation plot of propane vs. ethane from four Los Angeles datasets. Also plotted are composition ratios of local wells (gray lines) and local seeps (salmon lines) reported by *Jeffrey et al.* [1991], the composition ratio of pipeline-quality dry natural gas (black dashed line), the propane/ethane emission ratio from a San Francisco Bay-area tunnel study reported by *Kirchstetter et al.* [1996], and the average composition ratio of liquefied petroleum gas (LPG), or propane (green line).

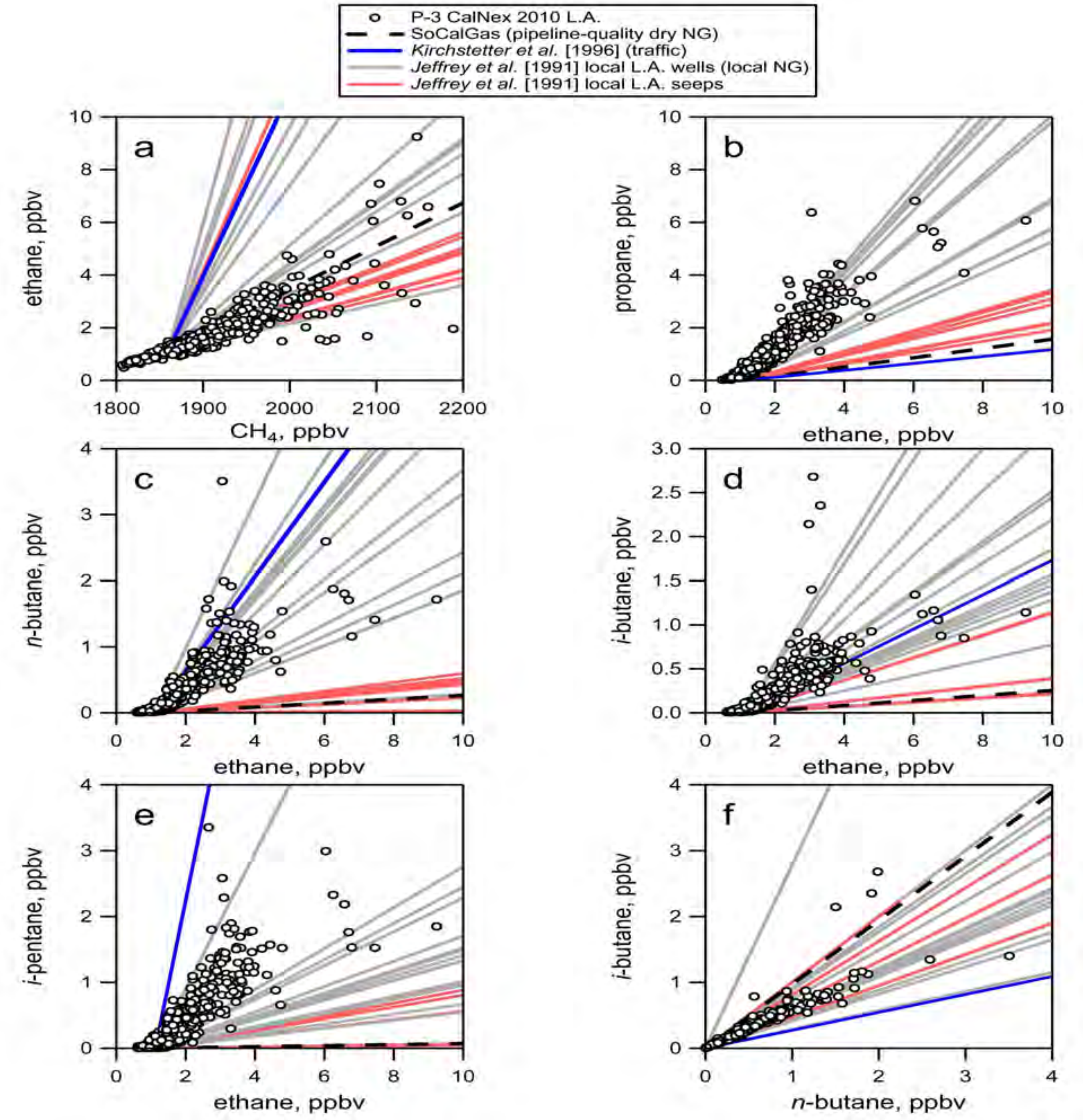


Figure 6. Plots of CH_4 and C_2–C_5 alkanes from the NOAA P-3 CalNex data set, selected for the SoCAB (black circles). Nighttime and high-altitude data are included. Also included for reference are the emission ratios of mobile sources from *Kirchstetter et al.* [1996] (blue line), composition ratios measured by *Jeffrey et al.* [1991] for local natural gas (gray lines) and local geologic seeps (salmon lines), and composition ratios from pipeline-quality dry natural gas (NG) delivered by SoCalGas (dashed black line). These ratios were plotted from daytime background levels.

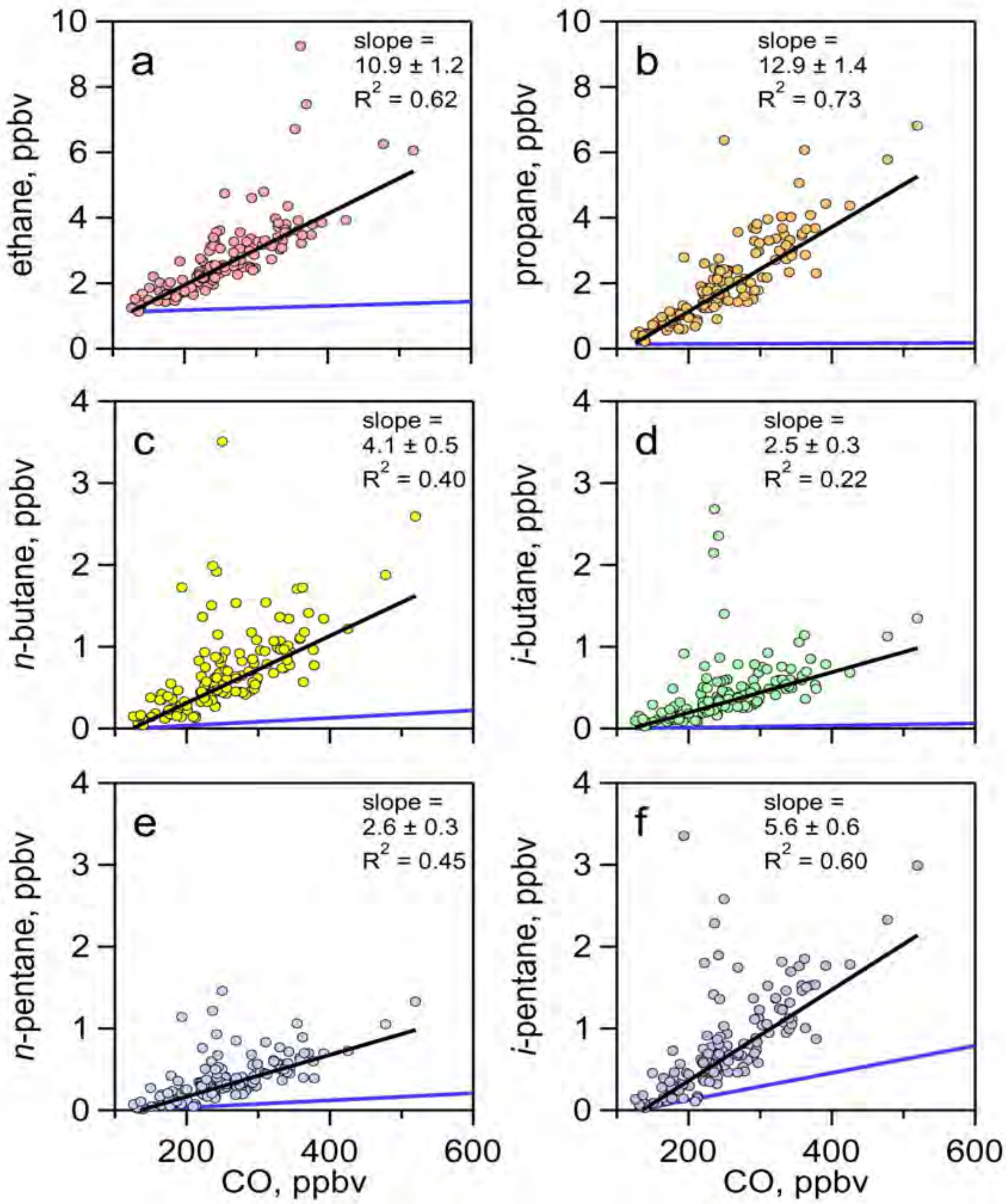


Figure 7. a–f) Daytime measurements of alkanes vs. CO from the NOAA P-3 in the L.A. basin during CalNex are plotted as filled circles. For comparison, the alkane/CO emission ratios from a San Francisco Bay-area tunnel study [*Kirchstetter et al.*, 1996] are plotted as a solid blue line, which extends to the edge of the right axis. The slope from a weighted ODR (given as ppt alkane/ppb CO), total slope uncertainty, and R^2 are given in each panel.

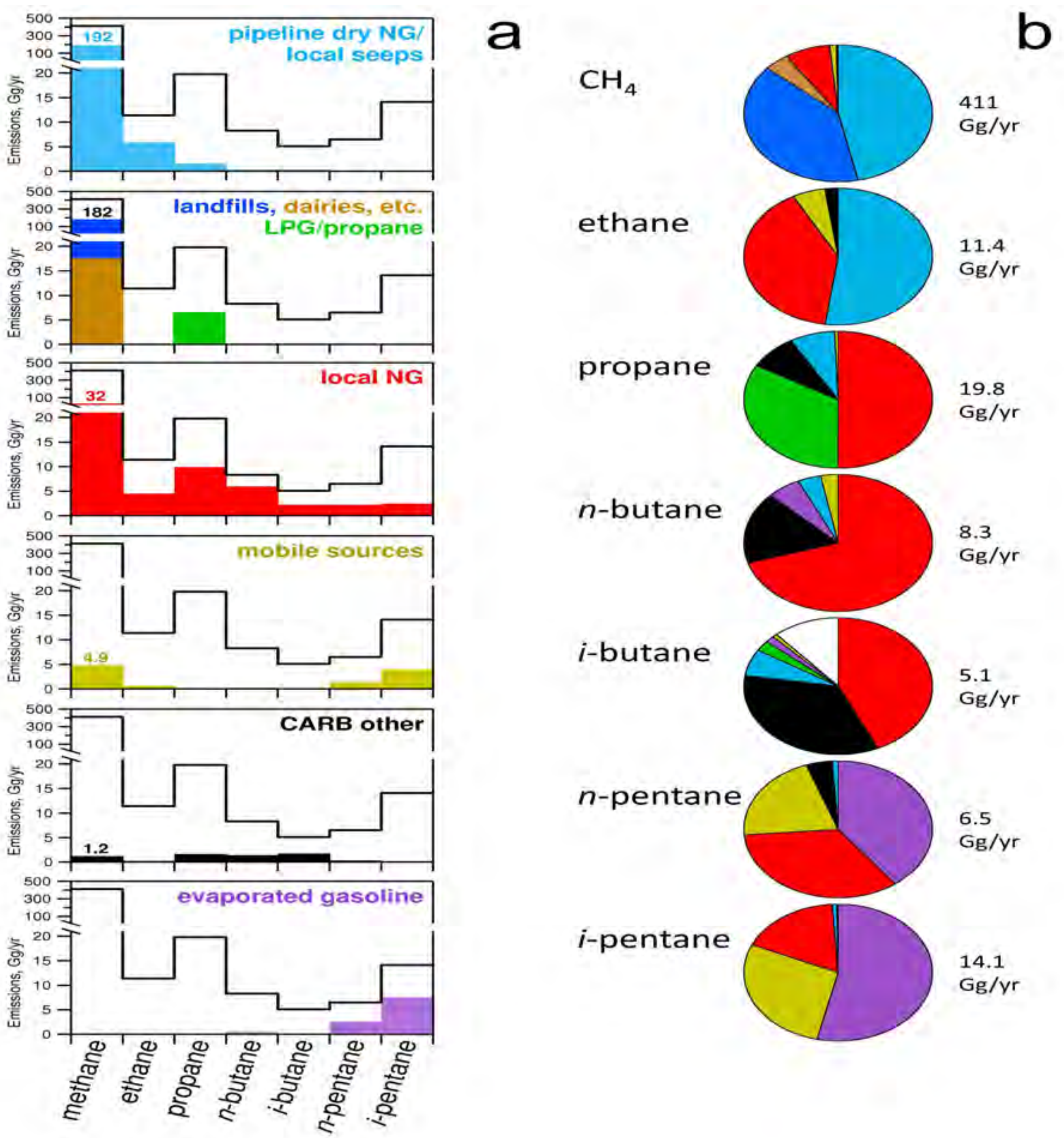


Figure 8. a) Results from a linear least squares solution to a combination of six sources and seven trace gas species in the SoCAB. The thick black line represents the estimated total annual emission to the SoCAB for seven hydrocarbons (CH_4 and C_2–C_5). The colored bars represent the fraction of the total contributed by each of the six source sectors used in the linear analysis. CH_4 emissions are written above the bar. **b)** Pie charts for the same data in (a) showing the relative contributions from each source for each of seven alkanes, colored as in part (a). The white region in the *i*-butane pie chart represents the 11% shortfall between our source attribution and our estimated emission to the SoCAB, though it is within the uncertainties of these two values. The total emission of the alkane to the SoCAB is given to the right of each pie chart.

Environmental Pollution 173 (2013) 1–4

Contents lists available at SciVerse ScienceDirect

Environmental Pollution

journal homepage: www.elsevier.com/locate/envpol

Rapid communication

Mapping urban pipeline leaks: Methane leaks across Boston

Nathan G. Phillips [a,*], Robert Ackley [b], Eric R. Crosson [c], Adrian Down [d], Lucy R. Hutyra [a], Max Brondfield [a], Jonathan D. Karr [d], Kaiguang Zhao [d], Robert B. Jackson [d]

[a] Boston University, Department of Earth and Environment, 675 Commonwealth Avenue, Boston, MA 02215, USA
[b] Gas Safety, Inc., Southborough, MA 01772, USA
[c] Picarro, Inc., Santa Clara, CA 95054, USA
[d] Duke University, Nicholas School of the Environment and Center on Global Change, Durham, NC 27708, USA

ARTICLE INFO

Article history:
Received 25 July 2012
Received in revised form
31 October 2012
Accepted 3 November 2012

Keywords:
Carbon isotopes
Infrastructure
Methane
Natural gas
Urban

ABSTRACT

Natural gas is the largest source of anthropogenic emissions of methane (CH_4) in the United States. To assess pipeline emissions across a major city, we mapped CH_4 leaks across all 785 road miles in the city of Boston using a cavity-ring-down mobile CH_4 analyzer. We identified 3356 CH_4 leaks with concentrations exceeding up to 15 times the global background level. Separately, we measured $\delta^{13}CH_4$ isotopic signatures from a subset of these leaks. The $\delta^{13}CH_4$ signatures (mean $= -42.8‰ \pm 1.3‰$ s.e.; $n = 32$) strongly indicate a fossil fuel source rather than a biogenic source for most of the leaks; natural gas sampled across the city had average $\delta^{13}CH_4$ values of $-36.8‰$ ($\pm 0.7‰$ s.e., $n = 10$), whereas CH_4 collected from landfill sites, wetlands, and sewer systems had $\delta^{13}CH_4$ signatures $\sim 20‰$ lighter ($\mu = -57.8‰$, $\pm 1.6‰$ s.e., $n = 8$). Repairing leaky natural gas distribution systems will reduce greenhouse gas emissions, increase consumer health and safety, and save money.

1. Introduction

Methane (CH_4) is a greenhouse gas more potent molecule for molecule than carbon dioxide (Shindell et al., 2012). In the United States, leaks of CH_4 from natural gas extraction and pipeline transmission are the largest human-derived source of emissions (EPA, 2012). However, CH_4 is not just a potent greenhouse gas; it also influences air quality and consumer health. CH_4 reacts with NO_x to catalyze ozone formation in urban areas (West et al., 2006). Incidents involving transmission and distribution pipelines for natural gas in the U. S. cause an average of 17 fatalities, 68 injuries, and \$133 M in property damage each year (PHMSA, 2012). A natural gas pipeline explosion in San Bruno, CA, for instance, killed eight people and destroyed 38 homes in 2010. Detecting and reducing pipeline leaks of CH_4 and other hydrocarbons in natural gas are critical for reducing greenhouse gas emissions, improving air quality and consumer safety, and saving consumers money (West et al., 2006; Han and Weng, 2011; Shindell et al., 2012; Alvarez et al., 2012).

To assess CH_4 emissions in a major urban metropolis, we mapped CH_4 emissions over the entire 785 centerline miles of Boston's streets. To evaluate the likely source of the street-level CH_4 emissions, we also measured the $\delta^{13}C{-}CH_4$ carbon isotope composition, which can differentiate between biogenic (e.g., landfill, wetland, sewer) and thermogenic (e.g., natural gas) sources (Schoell, 1980).

2. Materials and methods

We conducted 31 mobile surveys during the period 18 August, 2011–1 October, 2011, covering all 785 road miles within Boston's city limits. We measured CH_4 concentration ([CH_4], ppm) using a mobile Picarro G2301 Cavity Ring-Down Spectrometer equipped with an A0491 Mobile Plume Mapping Kit (Picarro, Inc, Santa Clara, CA). This instrument was factory-calibrated on 15 August 2011, immediately prior to use in this study, and follow-up tests of the analyzer were made during 11–21 August, 2012, comparing analyzer output to a National Oceanic and Atmospheric Administration (NOAA) primary standard tank. In both pre- and post-checks, the analyzer output was found to be within 2.7 parts per billion of known [CH_4] in standard tanks, three orders of magnitude below typical atmospheric concentrations. Spectrometer and mobile GPS data were recorded every 1.1 s. To correct for a short time lag between instantaneous GPS location and a delay in [CH_4] measurement due to inlet tube length ($\sim$3 m), we used an auxiliary pump to increase tubing flow throughput to within 5 cm of the analyzer inlet; we also adjusted the time stamp on the [CH_4] readings based on a 1-s delay observed between analyzer response to a standard CH_4 source that we injected into the instrument while driving, and the apparent GPS location. We also checked the GPS-based locations of leaks with dozens of street-level sampling to confirm specific leak locations and the estimated sampling delay. Air was sampled through a 3.0 um Zefluor filter and Teflon tubing placed $\sim$30 cm above road surfaces.

For our mobile survey data, we defined a "leak" as a unique, spatially contiguous group of [CH_4] observations, all values of which exceed a concentration threshold of 2.50 ppm. This was used as a threshold because it corresponded to the 90th

* Corresponding author.
E-mail address: nathan@bu.edu (N.G. Phillips).

0269-7491/\$ – see front matter © 2012 Elsevier Ltd. All rights reserved.
http://dx.doi.org/10.1016/j.envpol.2012.11.003

percentile of the distribution of data from all road miles driven, and, relative to global background, is ~37% above 2011 mean mixing ratios observed at Mauna Loa (NOAA, 2012).

Independently of mobile street sampling of CH_4, we measured $\delta^{13}CH_4$ from a subset of the leaks with a Picarro G2112i Cavity Ring-Down Spectrometer (Crosson, 2008). This instrument is calibrated monthly using isotopic standards from Isometric Instruments (Victoria, BC, Canada). The instrument was checked at least once daily to ensure analyzer output was within 1‰ of a tank of CH_4 with $\delta^{13}CH_4$ measured by a private lab (Isotech Labs, IL). Samples were collected in 1-L Tedlar sampling bags with valve and septa fittings, manufactured by Environmental Supply Company (Durham, NC). A Gas Sentry CGO-321 handheld gas detector (Bascom-Turner, MA) was used to identify the area of highest ambient [CH_4] at each site sampled for $\delta^{13}CH_4$. Sampling bags were pre-evacuated and filled at the area of highest ambient concentration at the sampling site using a hand pump. $\delta^{13}CH_4$ was analyzed using a Picarro G2112i with a sample hold time typically of a few days and always less than two weeks.

At a subset of sampling sites ($n = 12$), we collected duplicate samples in glass vials to assess potential leaking or fractionation by the Tedlar sampling bags. We also sent duplicate samples from a different subset of sampling sites ($n = 5$) to a private lab (Isotech Labs, IL) for independent $\delta^{13}CH_4$ analysis. These analyses suggest no significant fractionation or bias either from the sampling bags or the Picarro G2112i analyzer. Most samples were analyzed at less than the maximum hold time of two weeks, at which bag diffusion could account for a 1.2‰ drift in our measurements of $\delta^{13}CH_4$.

We compared $\delta^{13}CH_4$ of these locations with samples taken from area landfills, wetlands, and the Deer Island Water Treatment Facility. Sampling equipment and procedures, as well as laboratory analyses, for landfill and wetland sites were similar to those for $\delta^{13}CH_4$ sampling locations described above. Samples were collected from three capped, inactive landfills (there are currently no active landfills in the Boston area). At one former landfill site, samples were collected at approximately three-month intervals between September, 2011 and April, 2012. The $\delta^{13}CH_4$ signature of the landfill was consistent over this period (±3.4‰ s.e.). At all wetland sampling sites, a plastic chamber (10 cm × 25 cm × 5 cm) connected to a sampling tube was placed over the surface of exposed moist sediment or shallow (>5 cm) water. Sediment below the chamber was disturbed gently before drawing air samples from the headspace within the chamber. The sample from the Deer Island Treatment Facility was drawn from the headspace of a sample bottle of anaerobic sludge, collected onsite by Deer Island staff for daily monitoring of the facility's anaerobic sludge digesters.

3. Results and discussion

We identified 3356 CH_4 leaks (Figs. 1 and 2) exceeding 2.50 parts per million. Surface concentrations corresponding to these leaks ranged up to 28.6 ppm, 14-times above a surface background concentration of 2.07 ppm (the statistical mode of the entire concentration distribution). Across the city, 435 and 97 independent leaks exceeded 5 and 10 ppm, respectively.

Based on their $\delta^{13}CH_4$ signatures, the CH_4 leaks strongly resembled thermogenic rather than biogenic sources (Fig. 3). Samples of natural gas from the gateway pipelines to Boston and from other consumer outlets in the city were statistically indistinguishable, with an average $\delta^{13}CH_4$ signature of −36.8‰ (±0.7‰ s.e., $n = 10$; ‰ vs. Vienna Pee Dee Belemnite). In contrast, CH_4 collected from landfill sites, wetlands, and sewer systems reflected a greater fractionation from microbial activity and $\delta^{13}CH_4$ signatures ~20‰ lighter. Biogenic values ranged from −53.1‰ to −64.5‰ ($\mu = -57.8$‰, ±1.6‰ s.e., $n = 8$) for samples collected in four wetlands, three capped landfills, and the primary sewage facility for the city, Deer Island Sewage Treatment Plant, which had the heaviest sample observed for non-natural-gas sources (−53.1‰). Our results for biogenic CH_4 carbon isotope signatures are consistent with other studies of the $\delta^{13}CH_4$ signature of CH_4 from landfills (Bergamaschi et al., 1998; Borjesson et al., 2001) and wetlands (Hornibrook et al., 2000).

Peaks of [CH_4] detected in the road surveys strongly reflected the signature of natural gas rather than biogenic sources (Table 1). The average $\delta^{13}CH_4$ value for peaks was −42.8‰ ± 1.3‰ ($n = 32$), reflecting a dominant signal from natural gas, likely altered in some cases by minor fractionation of natural gas traveling through soils and by mixing with background air ($\delta^{13}CH_4 = -47$‰; Dlugokencky et al., 2011). A minority of samples had $\delta^{13}CH_4$ more negative than

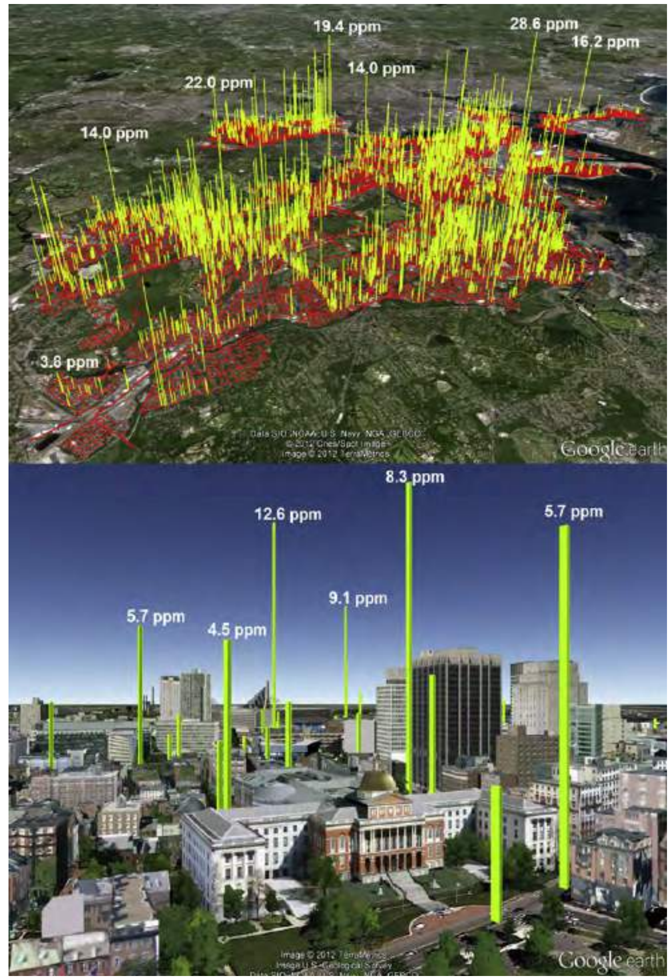


Fig. 1. Upper Panel: Methane leaks (3356 yellow spikes > 2.5 ppm) mapped on Boston's 785 road miles (red) surveyed in this study. Lower Panel: Leaks around Beacon Hill and the Massachusetts State House. Sample values of methane concentrations (ppm) are shown for each panel. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

that of background air, reflecting apparent influence of biogenic CH_4. Most samples emitted a distinct odor of the mercaptan additive associated with natural gas, including those with a larger apparent biogenic influence on $\delta^{13}CH_4$.

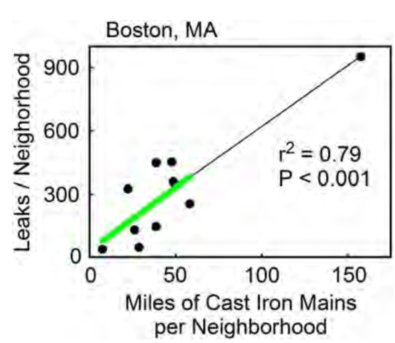


Fig. 2. Leak prevalence is associated with old cast iron pipes across ten Boston neighborhoods. (The combined line is the regression across all ten neighborhoods ($P < 0.001$); the green regression line [$r^2 = 0.34$; $P = 0.08$], which eliminates the influence of the leverage point [Dorchester neighborhood], has a slope and intercept indistinguishable ($P > 0.10$) from the combined regression.). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

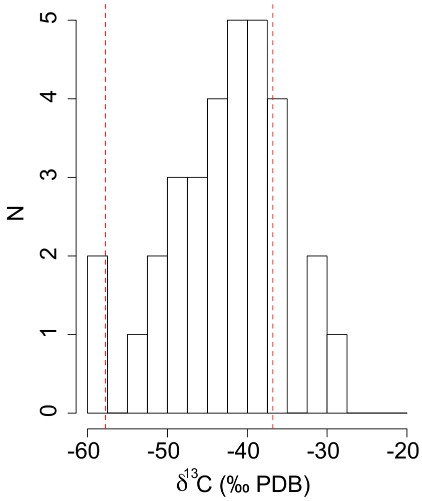


Fig. 3. $\delta^{13}CH_4$ of $[CH_4]$ peaks detected in road surveys ($n = 32$). Red lines represent means of thermogenic (−36.8‰, ±0.7‰ s.e., $n = 10$) and biogenic (−57.8‰, ±1.6‰ s.e., $n = 8$) sources, respectively. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Leaks across Boston (Fig. 1), were associated primarily with cast iron mains that were sometimes over a century old (Fig. 2). Across ten Boston neighborhoods, leak frequency was linearly related to number of miles of cast iron mains ($r^2 = 0.79$, $P < 0.001$; Fig. 2), but only marginally to miles of non-cast-iron piping ($r^2 = 0.27$; $P = 0.12$, data not shown). Leak counts did not differ statistically by neighborhood or by socio-economic indicators for the neighborhoods obtained from the 2010 US Census ($P > 0.1$ for number of housing units and ethnicity) or the 2000 US Census ($P > 0.1$ for median income and poverty rate).

Table 1
Locations and isotopic values from discrete street leak samples.

Latitude	Longitude	$\delta^{13}CH_4$ (‰ PDB)
42.3654	−71.0612	−53.959
42.3439	−71.2628	−47.898
42.3493	−71.2265	−57.590
42.3583	−71.1749	−40.818
42.3411	−71.2440	−37.323
42.3543	−71.2441	−38.241
42.3559	−71.1898	−39.412
42.3513	−71.2092	−41.978
42.3515	−71.2081	−39.531
42.3614	−71.2314	−41.796
42.3426	−71.1012	−44.100
42.3443	−71.0949	−41.848
42.3328	−71.0761	−37.516
42.3360	−71.0738	−46.414
42.3441	−71.0673	−45.490
42.3303	−71.0569	−37.476
42.3409	−71.0542	−40.029
42.3524	−71.0445	−43.127
42.3799	−71.0272	−48.182
42.3722	−71.0361	−57.693
42.3785	−71.0681	−48.429
42.3730	−71.0632	−37.471
42.3593	−71.0629	−42.689
42.3584	−71.0644	−52.033
42.3546	−71.1271	−47.241
42.2943	−71.1891	−52.028
42.2793	−71.1514	−37.648
42.2887	−71.1428	−32.467
42.3285	−71.0792	−28.251
42.3215	−71.0692	−36.214
42.3269	−71.0796	−30.662
42.3553	−71.0573	−43.836
	Mean	**−42.793**
	Standard error	**1.259**

Reducing CH_4 leaks will promote safety and help save money. Although our study was not intended to assess explosion risks, we observed six locations where gas concentrations in manholes exceeded an explosion threshold of 4% $[CH_4]$ at 20 °C (concentrations measured using a Gas Sentry CGO-321 handheld gas detector; Bascom-Turner, MA). Moreover, because CH_4, ethane (C_2H_6), and propane (C_3H_8) interact with NO_x to catalyze ozone formation, reducing these hydrocarbon concentrations should help reduce urban ozone concentrations and respiratory and cardiopulmonary disease (West et al., 2006; Shindell et al., 2012). CH_4 is also a potent greenhouse gas, with an estimated 20-year global warming potential 72 times greater than CO_2 (Alvarez et al., 2012; Townsend-Small et al., 2012). Replacing failing natural gas mains will reduce greenhouse gas emissions, thereby providing an additional benefit to the fewer mercury, SO_2 and particulate emissions that natural-gas burning emits compared to coal (Shindell et al., 2012). Finally, leaks contribute to \$3.1 B of lost and unaccounted natural gas annually in the United States (EIA, 2012; 2005–2010 average).

Our ongoing and future research evaluates how surface $[CH_4]$ values correspond to individual, and city-wide, urban leak rates and greenhouse-gas emissions. Two approaches to this question are useful: "bottom-up" chamber measurements taken on representative samples of individual leaks, and "top-down" atmospheric mass-balance estimates from rooftops of the collective urban leak rate that exploit the known isotopic signature of natural gas versus that of biogenic sources and other fossil fuel sources. The instrumentation used in this study is well-suited for both approaches.

We propose that a coordinated campaign to map urban pipeline leaks around the world would benefit diverse stakeholders, including companies, municipalities, and consumers. Repairing the leaks will bring economic, environmental, and health benefits to all.

Acknowledgments

The Barr Foundation, Conservation Law Foundation, Picarro, Inc., Duke University's Center on Global Change and Nicholas School of the Environment, and Boston University's Sustainable Neighborhood Laboratory and Center for Energy and Environmental Studies supported this research. Dr. Michael Delaney of the Massachusetts Water Resources Agency facilitated sewage influent sampling. Additional support was provided by the US National Science Foundation ULTRA-ex program (DEB 0948857). Shanna Cleveland, Adrien Finzi and Steven Wofsy provided helpful comments on the manuscript.

References

Alvarez, R.A., Pacala, S.W., Winebrake, J.J., Chameides, W.L., Hamburg, S.P., 2012. Greater focus needed on methane leakage from natural gas infrastructure. Proceedings of the National Academy of Sciences U.S.A. 109, 6435–6440.

Bergamaschi, P., Lubina, C., Knigstedt, R., Fischer, H., Veltkamp, A.C., Zwaagstra, O., 1998. Stable isotopic signatures (d13C, dD) of methane from European landfill sites. Journal of Geophysical Research 103, 8251–8265.

Borjesson, G., Chanton, J., Svensson, B.H., 2001. Methane oxidation in two Swedish landfill covers measured with carbon-13 to carbon-12 isotope ratios. Journal of Environmental Quality 30, 369–376.

Crosson, E.R., 2008. A cavity ring-down analyzer for measuring atmospheric levels of methane, carbon dioxide, and water vapor. Applied Physics B: Lasers and Optics 3, 403–408.

Dlugokencky, E.J., Nisbet, E.G., Fisher, R., Lowry, D., 2011. Global atmospheric methane: budget, changes and dangers. Philosophical Transactions of the Royal Society A 369, 2058–2072.

Energy Information Administration (EIA), 2012. http://205.254.135.7/dnav/ng/ng_sum_lsum_dcu_nus_a.htm, http://205.254.135.7/naturalgas/annual/pdf/table_a01.pdf, http://205.254.135.7/naturalgas/annual/archive/2009/pdf/table_a01.pdf.

Environmental Protection Agency (EPA), 2012. http://epa.gov/methane/sources.html.

Han, Z.Y., Weng, W.G., 2011. Comparison study on qualitative and quantitative risk assessment methods for urban natural gas pipeline network. Journal of Hazardous Materials 189, 509–518.

Hornibrook, E.R.C., Longstaffe, F.J., Fyfe, W.F., 2000. Evolution of stable carbon isotope compositions for methane and carbon dioxide in freshwater wetlands and other anaerobic environments. Geochimica Cosmochimica Acta 64, 1013–1027.

National Oceanic and Atmospheric Administration, Annual Greenhouse Gas Index (AGGI), 2012. Earth System Research Laboratory, Global Monitoring Division. http://www.esrl.noaa.gov/gmd/aggi/ (accessed 10.09.12.).

Pipeline and Hazardous Materials Safety Administration (PHMSA), 2012. www.phmsa.dot.gov/pipeline/library/data-stats.

Schoell, M., 1980. The hydrogen and carbon isotopic composition of methane from natural gases of various origins. Geochimica Cosmochimica Acta 44, 649–661.

Shindell, D., Kuylenstierna, J.C.I., Vignati, E., van Dingenen, R., Amann, M., Klimont, Z., Anenberg, S.C., Muller, N., Janssens-Maenhout, G., Raes, F., Schwartz, J., Faluvegi, G., Pozzoli, L., Kupiainen, K., Höglund-Isaksson, L., Emberson, L., Streets, D., Ramanathan, V., Hicks, K., Oanh, N.T.K., Milly, G., Williams, M., Demkine, V., Fowler, D., 2012. Simultaneously mitigating near-term climate change and improving human health and food security. Science 335, 183–189.

Townsend-Small, A., Tyler, S.C., Pataki, D.E., Xu, X., Christensen, L.E., 2012. Isotopic measurements of atmospheric methane in Los Angeles, California, USA: influence of "fugitive" fossil fuel emissions. Journal of Geophysical Research 117, D07308.

West, J.J., Fiore, A.M., Horowitz, L.W., Mauzerall, D.L., 2006. Global health benefits of mitigating ozone pollution with methane emission controls. Proceedings of the National Academy of Sciences U.S.A. 103, 3988–3993.

Greater focus needed on methane leakage from natural gas infrastructure

Ramón A. Alvarez[a,1], Stephen W. Pacala[b,1], James J. Winebrake[c], William L. Chameides[d], and Steven P. Hamburg[e]

[a]Environmental Defense Fund, 301 Congress Ave Suite 1300, Austin, TX 78701; [b]Department of Ecology and Evolutionary Biology, 106A Guyot Hall, Princeton University, Princeton, NJ 08544; [c]College of Liberal Arts, Rochester Institute of Technology, Rochester, NY 14623; [d]School of the Environment, Duke University, Durham, NC 27708; and [e]Environmental Defense Fund, 18 Tremont Street, Boston, MA 02108

Contributed by Stephen W. Pacala, February 13, 2012 (sent for review December 21, 2011)

Natural gas is seen by many as the future of American energy: a fuel that can provide energy independence and reduce greenhouse gas emissions in the process. However, there has also been confusion about the climate implications of increased use of natural gas for electric power and transportation. We propose and illustrate the use of technology warming potentials as a robust and transparent way to compare the cumulative radiative forcing created by alternative technologies fueled by natural gas and oil or coal by using the best available estimates of greenhouse gas emissions from each fuel cycle (i.e., production, transportation and use). We find that a shift to compressed natural gas vehicles from gasoline or diesel vehicles leads to greater radiative forcing of the climate for 80 or 280 yr, respectively, before beginning to produce benefits. Compressed natural gas vehicles could produce climate benefits on all time frames if the well-to-wheels CH_4 leakage were capped at a level 45–70% below current estimates. By contrast, using natural gas instead of coal for electric power plants can reduce radiative forcing immediately, and reducing CH_4 losses from the production and transportation of natural gas would produce even greater benefits. There is a need for the natural gas industry and science community to help obtain better emissions data and for increased efforts to reduce methane leakage in order to minimize the climate footprint of natural gas.

With growing pressure to produce more domestic energy and to reduce greenhouse gas (GHG) emissions, natural gas is increasingly seen as the fossil fuel of choice for the United States as it transitions to renewable sources. Recent reports in the scientific literature and popular press have produced confusion about the climate implications of natural gas (1–5). On the one hand, a shift to natural gas is promoted as climate mitigation because it has lower carbon per unit energy than coal or oil (6). On the other hand, methane (CH_4), the prime constituent of natural gas, is itself a more potent GHG than carbon dioxide (CO_2); CH_4 leakage from the production, transportation and use of natural gas can offset benefits from fuel-switching.

The climatic effect of replacing other fossil fuels with natural gas varies widely by sector (e.g., electricity generation or transportation) and by the fuel being replaced (e.g., coal, gasoline, or diesel fuel), distinctions that have been largely lacking in the policy debate. Estimates of the net climate implications of fuel-switching strategies should be based on complete fuel cycles (e.g., "well-to-wheels") and account for changes in emissions of relevant radiative forcing agents. Unfortunately, such analyses are weakened by the paucity of empirical data addressing CH_4 emissions through the natural gas supply network, hereafter referred to as CH_4 leakage.* The U.S. Environmental Protection Agency (EPA) recently doubled its previous estimate of CH_4 leakage from natural gas systems (6).

In this paper, we illustrate the importance of accounting for fuel-cycle CH_4 leakage when considering the climate impacts of fuel-technology combinations. Using EPA's estimated CH_4 emissions from the natural gas supply, we evaluated the radiative forcing implications of three U.S.-specific fuel-switching scenarios: from gasoline, diesel fuel, and coal to natural gas.

A shift to natural gas and away from other fossil fuels is increasingly plausible because advances in horizontal drilling and hydraulic fracturing technologies have greatly expanded the country's extractable natural gas resources particularly by accessing gas stored in shale deep underground (7). Contrary to previous estimates of CH_4 losses from the "upstream" portions of the natural gas fuel cycle (8, 9), a recent paper by Howarth et al. calculated upstream leakage rates for shale gas to be so large as to imply higher lifecycle GHG emissions from natural gas than from coal (1). (*SI Text*, discusses differences between our paper and Howarth et al.) Howarth et al. estimated CH_4 emissions as a percentage of CH_4 produced over the lifecycle of a well to be 3.6–7.9% for shale gas and 1.7–6.0% for conventional gas. The EPA's latest estimate of the amount of CH_4 released because of leaks and venting in the natural gas network between production wells and the local distribution network is about 570 billion cubic feet for 2009, which corresponds to 2.4% of gross U.S. natural gas production (1.9–3.1% at a 95% confidence level) (6).† EPA's reported uncertainty appears small considering that its current value is double the prior estimate, which was itself twice as high as the previously accepted amount (9).

Comparing the climate implications of CH_4 and CO_2 emissions is complicated because of the much shorter atmospheric lifetime of CH_4 relative to CO_2. On a molar basis, CH_4 produces 37 times more radiative forcing than CO_2.‡ However, because CH_4 is oxidized to CO_2 with an effective lifetime of 12 yr, the integrated, or cumulative, radiative forcings from equi-molar releases of CO_2 and CH_4 eventually converge toward the same value. Determining whether a unit emission of CH_4 is worse for the climate than a unit of CO_2 depends on the time frame considered. Because accelerated rates of warming mean ecosystems and humans have less time to adapt, increased CH_4 emissions due to substitution of natural gas for coal and oil may produce undesirable climate outcomes in the near-term.

The concept of global warming potential (GWP) is commonly used to compare the radiative forcing of different gases relative

ENVIRONMENTAL SCIENCES

SUSTAINABILITY SCIENCE

Author contributions: R.A.A., S.W.P., and S.P.H. designed research; R.A.A. performed research; R.A.A., S.W.P., and S.P.H. analyzed data; and R.A.A., S.W.P., J.J.W., W.L.C., and S.P.H. wrote the paper.

The authors declare no conflict of interest.

Freely available online through the PNAS open access option.

*Challenges also exist in the quantification of CH_4 emissions from the extraction of coal. We use the term "leakage" for simplicity and define it broadly to include all CH_4 emissions in the natural gas supply, both fugitive leaks as well as vented emissions.

†This represents an uncertainty range between −19% and +30% of natural gas system emissions. For CH_4 from petroleum systems (35% of which we assign to the natural gas supply) the uncertainty is −24% to +149%; however, this is only a minor effect because the portion of natural gas supply that comes from oil wells is less than 20%.

‡One-hundred-two times on a mass basis. This value accounts for methane's direct radiative forcing and a 40% enhancement because of the indirect forcing by ozone and stratospheric water vapor (10).

[1]To whom correspondence may be addressed. E-mail: pacala@princeton.edu or ralvarez@edf.org.

This article contains supporting information online at www.pnas.org/lookup/suppl/doi:10.1073/pnas.1202407109/-/DCSupplemental.

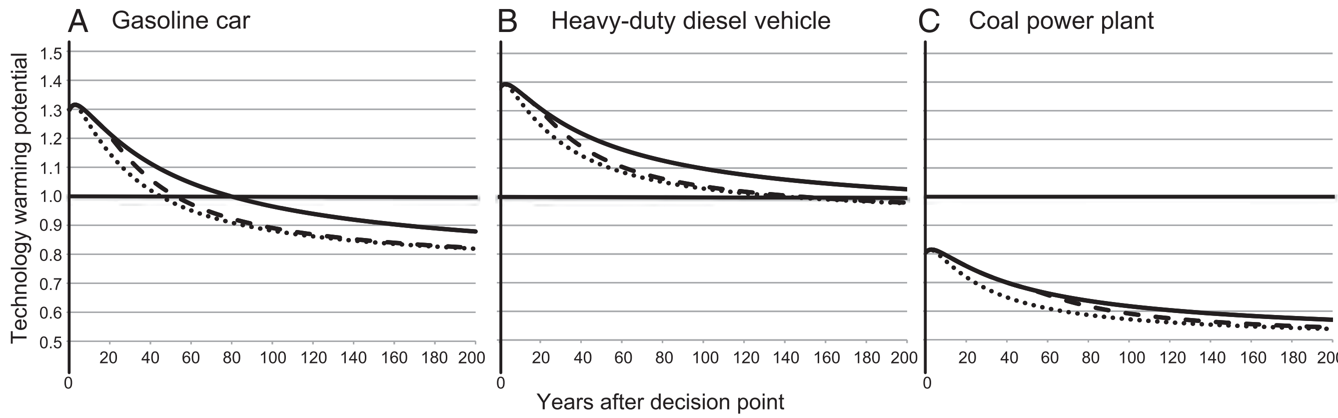


Fig. 1. Technology warming potential (TWP) for three sets of natural gas fuel-switching scenarios. (*A*) CNG light-duty cars vs. gasoline cars; (*B*) CNG heavy-duty vehicles vs. diesel vehicles; and (*C*) combined-cycle natural gas plants vs. supercritical coal plants using low-CH_4 coal. The three curves within each frame simulate real-world choices, including a single emissions pulse (dotted lines); emissions for the full service life of a vehicle or power plant (15 and 50 years, respectively, dashed lines); and emissions from a converted fleet continuing indefinitely (solid lines). For the pulse and service life analyses, our scenarios assume that the natural gas choice reverts back to the incumbent choice before the switch took place; for the fleet conversion analysis we assume that a natural gas vehicle or power plant is replaced by an identical unit at the end of its service life.

to CO_2 and represents the ratio of the cumulative radiative forcing t years after emission of a GHG to the cumulative radiative forcing from emission of an equivalent quantity of CO_2 (10). The Intergovernmental Panel on Climate Change (IPCC) typically uses 100 yr for the calculation of GWP. Howarth et al. (1) emphasized the 20-year GWP, which accentuates the large forcing in early years from CH_4 emissions, whereas Venkatesh et al. (2) adopted a 100-yr GWP and Burnham et al. (4) utilized both 20- and 100-yr GWPs.

GWPs were established to allow for comparisons among GHGs at one point in time after emission but only add confusion when evaluating environmental benefits or policy tradeoffs over time. Policy tradeoffs like the ones examined here often involve two or more GHGs with distinct atmospheric lifetimes. A second limitation of GWP-based comparisons is that they only consider the radiative forcing of single emission pulses, which do not capture the climatic consequences of real-world investment and policy decisions that are better simulated as emission streams.

To avoid confusion and enable straightforward comparisons of fuel-technology options, we suggest that plotting as a function of time the relative radiative forcing of the options being considered would be more useful for policy deliberations than GWPs. These technology warming potentials (TWP) require exactly the same inputs and radiative forcing formulas used for GWP but reveal time-dependent tradeoffs inherent in a choice between alternative technologies. We illustrate the value of our approach by applying it to emissions of CO_2 and CH_4 from vehicles fueled with CNG compared with gasoline or diesel vehicles and from power plants fueled with natural gas instead of coal.

Wigley also analyzed changes in the relative benefits over time of switching from coal to natural gas, but that was done in the context of additional complexities including specific assumptions about the global pace of technological substitution, emissions of sulfur dioxide and black carbon, and a specific model of global warming due to radiative forcing (5). We compare our results with Wigley's in the next section.

Results and Discussion

We focus on the TWPs of real-world choices faced by individuals, corporations, and policymakers about fuel-switching in the transport and power sectors. Each of the three curves within the panels of Fig. 1 represents a distinct choice and its associated emission duration: for example, whether to rent a CNG or a gasoline car for a day (Pulse TWP); whether to purchase and operate a CNG or gasoline car for a 15-yr service life (Service-Life TWP); and whether a nation should adopt a policy to convert the gasoline fleet of cars to CNG (Fleet Conversion TWP). In each of these cases, a TWP greater than 1 means that the cumulative radiative forcing from choosing natural gas today is higher than a current fuel option after t yr. Our results for pulse TWP at 20 and 100 yr are identical to fuel-cycle analyses using 20-year or 100-year GWPs for CH_4.

Given EPA's current estimates of CH_4 leakage from natural gas production and delivery infrastructure, in addition to a modest CH_4 contribution from the vehicle itself (for which few empirical data are available), CNG-fueled vehicles are not a viable mitigation strategy for climate change.[§] Converting a fleet of gasoline cars to CNG increases radiative forcing for 80 yr before any net climate benefits are achieved; the comparable cross-over point for heavy-duty diesel vehicles is nearly 300 yr.

Stated differently, converting a fleet of cars from gasoline to CNG would result in numerous decades of more rapid climate change because of greater radiative forcing in the early years after the conversion. This is eventually offset by a modest benefit. After 150 yr, a CNG fleet would have produced about 10% less cumulative radiative forcing than a gasoline fleet—a benefit equivalent to a fuel economy improvement of 3 mpg in a 30 mpg fleet. CNG vehicles fare even less favorably in comparison to heavy-duty diesel vehicles.

In contrast to the transportation cases, a fleet of new, combined-cycle natural gas power plants reduces radiative forcing on all time frames, relative to new coal plants burning low-CH_4 coal—assuming current estimates of leakage rates (Fig. 1*C*). The conclusions differ primarily because of coal's higher carbon content relative to petroleum fuels; however, fuel-cycle CH_4 leakage can also affect results. (As discussed elsewhere in this paper, our analysis considered only the emissions of CH_4 and CO_2. In *SI Text*, we examine the effect of different CH_4 leak rates in the coal and natural gas fuel cycles for the electric power scenario.)

To provide guidance to industry and policymakers, we also determined the maximum well-to-wheels or well-to-burner-tip leakage rate needed to ensure net climate benefits on all time frames after fuel-switching to natural gas (see Fig. 2). For example, if the well-to-wheels leakage was reduced to an effective leak rate of 1.6% of natural gas produced (approximately 45% below our estimate of current leakage of 3.0%), CNG cars would result

[§]The CH_4 from operation of a CNG automobile was estimated to be 20 times the value for gasoline vehicles (11), which is approximately 20% of the well-to-pump CH_4 leakage on a kg/mmBtu basis. This assumption deserves much further scrutiny.

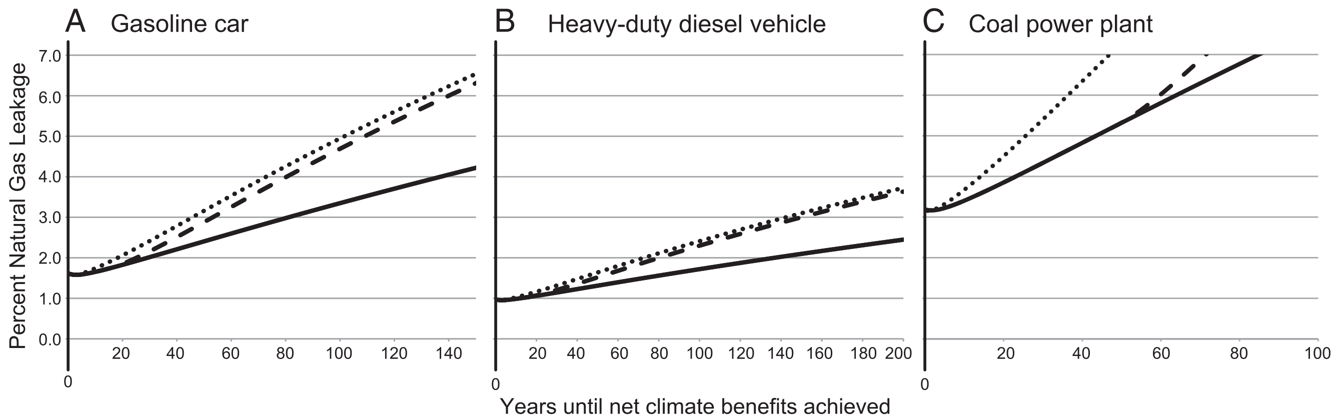


Fig. 2. Maximum "well-to-wheels" natural gas leak rate as a function of the number of years needed to achieve net climate benefits after choosing a CNG option in lieu of (*A*) gasoline cars; (*B*) heavy-duty diesel vehicles; and (*C*) coal power plants. For *A* and *B*, the maximum leakage is the sum of losses from the well through the distribution system plus losses from the CNG vehicle itself (well-to-wheels); for *C*, the maximum leakage is from the well through the transmission system where most power plants receive their fuel. When leak rates are less than the y-intercept, a fuel switch scenario would result in net climate benefits beginning immediately. The three curves within each frame follow the conventions outlined in Fig. 1 and represent: single emissions pulses (dotted lines); the service life of a vehicle or a power plant, 15 or 50 years, respectively (dashed lines); and a permanent fleet conversion (solid lines).

in climate benefits immediately and improve over time.[¶] For CNG to immediately reduce climate impacts from heavy-duty vehicles, well-to-wheels leakage must be reduced below 1%. Fig. 2*C* shows that new natural gas power plants produce net climate benefits relative to efficient, new coal plants using low-gassy coal on all time frames as long as leakage in the natural gas system is less than 3.2% from well through delivery at a power plant. Fig. 2 also shows, for a range of leakage rates, the number of years needed to reach the "cross-over point" when net climate benefits begin to occur after a fuel-technology choice is made.

We emphasize that our calculations assume an average leakage rate for the entire U.S. natural gas supply (as well for coal mining). Much work needs to be done to determine actual emissions with certainty and to accurately characterize the site-to-site variability in emissions. However, given limited current evidence, it is likely that leakage at individual natural gas well sites is high enough, when combined with leakage from downstream operations, to make the total leakage exceed the 3.2% threshold beyond which gas becomes worse for the climate than coal for at least some period of time.[||] Our analysis of reported routine emissions for over 250 well sites with no compressor engines in Barnett Shale gas well sites in Fort Worth, Texas, in 2010 revealed a highly skewed distribution of emissions, with 10% of well sites accounting for nearly 70% of emissions (see *SI Text*).[**] Natural gas leak rates calculated based on operator-reported, daily gas production data at these well sites ranged from 0% to 5%, with six sites out of 203 showing leak rates of 2.6% or greater due to routine emissions alone.[††]

Our analysis of coal-to-natural gas fuel-switching does not consider potential changes in sulfate aerosols and black carbon, short-lived climate forcers previously shown to affect the climate implications of such fuel-switching scenarios (5, 13). Recently, Wigley concluded that coal-to-gas switching on a global scale would result in increased warming on a global scale in the short term, based on examining a set of scenarios with a climate model that included both the increased warming produced by CH_4 losses from the natural gas fuel cycle and the additional cooling that occurs due to SO_2 emissions and the sulfate aerosols they form as a result of burning coal (5). The applicability of Wigley's global conclusion to the United States or any other individual country is limited due to the reliance on global emissions scenarios. Analyses such as Wigley's, which model the climate impacts of all climate forcing emissions, are useful to evaluate specific fuel-switching scenarios; however, their ultimate relevance to policymakers and fleet owners will be determined by the fidelity with which they reflect actual emissions from all phases of each fuel cycle at the relevant geographic scale (e.g., national, continental, or global). The SO_2 emissions that Wigley assumed are much higher than those of the current fleet of coal electrical generation plants in the United States, where SO_2 emissions declined by more than 50% between 2000 and 2010.[‡‡] Moreover, due to state and federal pollution abatement requirements, U.S. SO_2 emissions are projected to continue declining, to roughly 30% of 2000 levels by 2014 (see *SI Text*). This means that by 2014 the projected sulfur emissions from the U.S. coal electrical generation plant fleet, 3 TgS/GtC, will approach the emission factor that Wigley assumed the global fleet would reach in 2060 (2 TgS/GtC), when he projected the climate benefits of fuel-switching might begin, and significantly lower than Wigley's estimated 2010 value of 12 TgS/GtC. Accounting for the lower SO_2 from U.S. coal plants in an integrated way will result in greater net climate impacts of using coal than reported by Wigley and in turn the net benefits of fuel-switching will occur much sooner than he projected.

Increasingly, this will also be the case globally. The production of sulfur aerosols as a result of coal combustion causes such negative impacts on human and ecosystem health that it is prudent to assume that policies will continue to be rapidly implemented in many, if not most, countries to reduce such emissions at a much faster pace than assumed by Wigley. Indeed, it has been reported that China has already installed SO_2 scrubbers on power plants accounting for over 70% of the nation's installed coal power capacity (14), such that SO_2 emissions from power plants in 2010 were 58% below 2004 levels (15). The SO_2 emissions factor from

[¶]Our estimate that current well-to-wheels leakage is 3.0% of gas produced assumes that 2.4% of gas produced is lost between the well and the local distribution system (based on EPA's 2011 GHG emission inventory) and that 0.6% is due to emissions during refueling and from the vehicle itself. For further discussion of the climatic implication of natural gas vehicles see (12).

[||]EPA's GHG inventory suggests leakage from natural gas processing and transmission is 0.6% of gas produced, meaning production leakage must be greater than 2.6% for the total fuel cycle leakage of a power plant receiving fuel from a transmission pipeline to exceed 3.2%.

[**]Sites with compressor engines were excluded due to the contractor's assumption that all engines in the City were uncontrolled, which leads to erroneous emission estimates.

[††]Routine emissions do not include such occasional events as well completions and blowdowns. Only 203 of the 254 sites had data for gas production. An Excel spreadsheet containing the Fort Worth data and our calculations is provided in Dataset S1.

[‡‡]Emissions query performed on December 5, 2011, using the Data and Maps feature of the U.S. Environmental Protection Agency's Clean Air Markets Web page (http://camddataandmaps.epa.gov/gdm/).

ENVIRONMENTAL SCIENCES

SUSTAINABILITY SCIENCE

Chinese coal plants in 2010 has been estimated to be 204 g/GJ, comparable to the 2010 value of 229 g/GJ (4.7 TgS/GtC) for U.S. coal plants (*SI Text*).

Little work appears to have been done to evaluate fuel-switching in on-road transportation with methods that consider the implications of all climate forcing emissions, including sulfur aerosols and black carbon, although the effect of short-lived climate forcers on individual transport sectors has been studied (16, 17). One study reports that the influence of negative radiative forcing due to emissions from on-road transport is much lower than for the power generation sector in both the United States and globally (18). This implies that our approach, which considers CO_2 and CH_4 emissions alone, provides a reasonable first-order estimate of changes in radiative forcing from fuel-switching scenarios for the on-road transport sector.

Conclusions

The TWP Approach Proposed Here Offers Policymakers Greater Insights than Conventional GWP Analyses. GWPs are a valuable tool to compare the radiative forcing of different gases but are not sufficient when thinking about fuel-switching scenarios. TWPs provide a transparent, policy-relevant analytical approach to examine the time-dependent climate influence of different fuel-technology choices.

Improved Science and Data Are Needed. Despite recent changes to EPA's methodology for estimating CH_4 leakage from natural gas systems, the actual magnitude remains uncertain and estimates could change as methods are refined. Ensuring a high degree of confidence in the climate benefits of natural gas fuel-switching pathways will require better data than are available today. EPA's rule requiring natural gas industry disclosure of GHG emissions should begin to produce data in 2012, though it is unlikely that most uncertainties will be resolved and possible systematic biases eliminated. Specific challenges include confirming the primary sources of emissions and determining drivers of variance in leakage rates. Greater direct involvement of the scientific community could help improve estimates of CH_4 leakage and identify approaches that enable independent validation of industry-reported emissions.

Reductions in CH_4 Leakage Are Needed to Maximize the Climate Benefits of Natural Gas. While CH_4 leakage from natural gas infrastructure and use remains uncertain, it appears that current leakage rates are higher than previously thought. Because CH_4 initially has a much higher effect on radiative forcing than CO_2, maintaining low rates of CH_4 leakage is critical to maximizing the climate benefits of natural gas fuel-technology pathways. Significant progress appears possible given the economic benefits of capturing and selling lost natural gas and the availability of proven technologies. (EPA's Natural Gas STAR program shows many examples: www.epa.gov/gasstar/tools/recommended.html.)

Table 2. Radiative efficiency (RE) values used in this paper

	Direct RE ($W\ m^{-2}\ ppb^{-1}$)	Relative direct + indirect RE (per ppb or molar basis)	Relative direct + indirect RE (per kg basis)*
CO_2	1.4×10^{-5}	1	1
CH_4	3.7×10^{-4}	37	102

*Obtained by multiplying the molar radiative efficiency by the ratio of molecular weights of CH_4 and CO_2.

Methods

Our approach of using TWPs to compare the cumulative radiative forcing of fuel-technology combinations is a straightforward extension of the calculation of GWP, which is given by Eq. **1** over a time horizon, TH, for a pulse emission of 1 kg of a generic GHG producing time-dependent radiative forcing given by $RF_{GHG}(t)$:

$$\mathrm{GWP} = \frac{\int_0^{\mathrm{TH}} \mathrm{RF}_{\mathrm{GHG}}(t)dt}{\int_0^{\mathrm{TH}} \mathrm{RF}_{\mathrm{CO_2}}(t)dt}. \quad [1]$$

SI Text shows the analytical solution of Eq. **1** (i.e., GWP as a function of time horizon). Plotting the entire curve enables one to see the GWP values for all time horizons.

Our TWP approach extends the standard GWP calculation in two ways: by combining the effects of CH_4 and CO_2 emissions from technology-fuel combinations and by considering streams of emissions in addition to single pulses. Considering streams of emissions is more reflective of real-world scenarios that involve activities that occur over multiyear time frames.

Eq. **2** is our extension of the GWP formula Eq. **1** to calculate TWPs, with the following definitions. We label as Technology-1 the alternative that combusts natural gas and has CO_2 emissions E_{1,CO_2} and CH_4 emissions from the production, processing, storage, delivery, and use of the fuel: E_{1,CH_4}. If L_{REF} is the percent of gross natural gas produced that is currently emitted to the atmosphere over the relevant fuel cycle (e.g., electric power or transportation), then Technology-1's CH_4 emissions at leakage rate L would be: $(L/L_{REF})E_{1,CH_4}$. The calculations of TWP in this paper assume that the leakage rate L is at the national average value L_{REF} (and thus $L/L_{REF} = 1$). The scaling factor L/L_{REF} is included to allow calculations about changes in the national leakage rate or about individual wells and distribution networks that deviate from the national average. The values we used for L_{REF} are derived in *SI Text* using EPA's estimated emissions with one exception and are equal to 2.1% for a natural gas power plant and 3.0% for CNG vehicles. The exception to the last statement is that we estimated CH_4 from the operation of a CNG automobile to be 20 times that from a gasoline vehicle (11), which is approximately 20% of the well-to-pump CH_4 leakage on a kg/mmBtu basis. This assumption deserves much further scrutiny. Technology-2 combusts gasoline, diesel fuel, or coal and produces CO_2 emissions E_{2,CO_2} and methane emissions E_{2,CH_4}. Estimates of the Es for each of the technologies considered are reported in Table 1 and are explained in *SI Text*. The TWPs at each point in time can be obtained by substituting the total radiative forcing values, $TRF_{CH_4}(t)$ and $TRF_{CO_2}(t)$ for CH_4 and CO_2, respectively, and emission factors, $E_{n,GHG}$ from Table 1 into Eq. **2**:

Table 1. Emission factors used for TWP calculations in this paper

	Power Plants		Vehicles			
	Natural gas combined cycle* (kg/MW*h*)	Supercritical pulverized coal† (kg/MW*h*)	Light-duty CNG car (kg/mmBtuHHV)‡	Light-duty gasoline car (kg/mmBtuHHV)	Heavy-duty CNG truck (mg/ton-mile)	Heavy-duty diesel truck (mg/ton-mile)
Upstream CH_4	3.1	0.65	0.51	0.1	590	100
Upstream CO_2	36	7	9.4	15.9	10,000	15,000
In-Use CH_4	0	0	0.11	0.0056	15	0
In-Use CO_2	361	807	53.1	70.3	80,000	85,000
Fuel cycle CH_4	3.1	0.65	0.62	0.11	605	100
Fuel cycle CO_2	397	814	62.5	86.2	90,000	100,000

*Heat rate = 6,798 Btu/kWh.
†Heat rate = 8,687 Btu/kWh.
‡1 mmBtu = 10^6 Btu = 1.055 GJ.

Table 3. Total radiative forcing (TRF) functions for CH_4 and CO_2 used in calculation of TWP in Eq. 2 for three distinct emissions profiles

Case	$TRF_{CH_4}(t)$	$TRF_{CO_2}(t)$
Pulse TWP	$RE\{\tau_M(1-e^{-t/\tau_M})\}$	$a_0 t + \sum_{i=1}^{3} a_i\tau_i(1-e^{-t/\tau_i})$
Service Life TWP for $t \leq AMAX$	$RE\{\tau_M t - \tau_M^2(1-e^{-t/\tau_M})\}$	$a_0\frac{t^2}{2} + \sum_{i=1}^{3} a_i(\tau_i t - \tau_i^2(1-e^{-t/\tau_i}))$
Service Life TWP for $t > AMAX$	$RE\{\tau_M AMAX - \tau_M^2 e^{-t/\tau_M}(e^{AMAX/\tau_M}-1)\}$	$a_0[AMAX\,t - \frac{AMAX^2}{2}] + \sum_{i=1}^{3} a_i(\tau_i AMAX - \tau_i^2 e^{-t/\tau_i}(e^{AMAX/\tau_i}-1))$
Fleet Conversion TWP	$RE\{\tau_M t - \tau_M^2(1-e^{-t/\tau_M})\}$	$a_0\frac{t^2}{2} + \sum_{i=1}^{3} a_i(\tau_i t - \tau_i^2(1-e^{-t/\tau_i}))$

RE in these formulas is the radiative efficiency of CH_4 relative to CO_2 and equals 102.

$$TWP(t) = \frac{\frac{L}{L_{REF}} E_{1,CH_4} TRF_{CH_4}(t) + E_{1,CO_2} TRF_{CO_2}(t)}{E_{2,CH_4} TRF_{CH_4}(t) + E_{2,CO_2} TRF_{CO_2}(t)}. \qquad [2]$$

The TRF values needed for Eq. **2** are derived as follows. Let $f(t, t_E)$ be the mass of a gas left in the atmosphere at time t if 1 kg of the gas was emitted at time t_E. The cumulative radiative forcing function, $CRF(t)$ (in units of $J\ m^{-2}\ kg^{-1}$), at a later time t, due to emission of 1 kg of the gas at time t_E, is then:

$$CRF(t) \equiv \int_{t_E}^{t} RE\, f(x, t_E) dx, \qquad [3]$$

where RE is the radiative efficiency of the gas. The integral in Eq. **3** sums radiative forcing for the $t - t_E$ years from the year in which the gas was emitted, $x = t_E$, to year $x = t$. For simplicity, we adopt units which make the RE of CO_2 equal to one, and so the RE of CH_4 is expressed as a multiple of the RE of CO_2. In these units, the RE of CH_4 is determined to be 102, using the values in Table 2 taken from the IPCC (10) and following the IPCC convention that methane's direct radiative efficiency be enhanced by 25% and 15% to account for indirect forcing due to ozone and stratospheric water, respectively.

Now suppose that instead of a single pulse, the gas is emitted continuously at a rate of 1 kg/yr from $t = 0$ until some maximum time t_{max}, as would occur, for example, if emissions were to continue over the service life of a vehicle, power plant, or fleet. For such cases we define the total radiative forcing (TRF) in year t to be:

$$TRF(t) \equiv \int_0^{t_{max}} \int_{t_E}^{t} RE\, f(x, t_E) dx\, dt_E. \qquad [4]$$

In the special case of a single emission pulse, $TRF(t) = CRF(t)$. Our use of Eq. **4** assumes a constant, unit emission rate; a more general formulation could be employed to reflect potential technology improvements over time.

For CH_4, $f(t, t_E)$ is an exponential decay:

$$f(t, t_E) = e^{-\frac{t - t_E}{\tau_M}}, \qquad [5]$$

where τ_M is 12 yr. For CO_2, we follow the IPCC and use the Bern carbon cycle model (10):

$$f(t, t_E) = a_0 + \sum_{i=1}^{3} a_i e^{-\frac{t - t_E}{\tau_i}} \qquad [6]$$

where $\tau_1 = 172.9$, $\tau_2 = 18.51$, $\tau_3 = 1.186$, $a_0 = 0.217$, $a_1 = 0.259$, $a_2 = 0.338$, and $a_3 = 0.186$. Our calculations do not consider the CO_2 produced from the oxidation of CH_4, an approximation which introduces a small underestimation of the radiative forcing from a fuel cycle's CH_4 leakage.

If calculating the TWP for a single pulse of emissions (pulse TWP), then $t_E = 0$; $TRF_{CH_4}(t)$ is given by Eq. **3** with $f(t, t_E)$ given by Eq. **5**; and $TRF_{CO_2}(t)$ is given by Eq. **3** with $f(t, t_E)$ given by Eq. **6**. If calculating the TWP for a permanent fuel conversion of a fleet (fleet conversion TWP) then $TRF_{CH_4}(t)$ is given by Eq. **4** with $t_{max} = t$ and $f(t, t_E)$ given by Eq. **5**. Similarly, $TRF_{CO_2}(t)$ is given by Eq. **4** with $t_{max} = t$ and $f(t, t_E)$ given by Eq. **6**. If calculating the TWP for emissions over the service life of a vehicle or power plant (service life TWP) and $t \leq AMAX$, where AMAX is the average age at which the asset ceases to emit, then $TRF_{CH_4}(t)$ and $TRF_{CO_2}(t)$ are the same as in the fleet conversion TWP calculations. However, if $t > AMAX$, then $TRF_{CH_4}(t)$ is given by Eq. **4** with $t_{max} = AMAX$ and $f(t, t_E)$ given by Eq. **5**. Similarly, $TRF_{CO_2}(t)$ is given by Eq. **4** with $t_{max} = AMAX$ and $f(t, t_E)$ given by Eq. **6**. The solutions for all of these cases are in Table 3. We use $AMAX = 15$ yr for vehicles and $AMAX = 50$ yr for power plants.

By rearranging terms in Eq. **2** when $TWP = 1$ to bring L to the left hand side, we obtain an equation for the relationship between the cross-over time (t^*—the time at which the two technologies have equal cumulative radiative forcing) and the percent leakage that makes this happen (L^*):

$$L^* = L_{REF}\left\{\frac{E_{2,CH_4}}{E_{1,CH_4}} + \frac{E_{2,CO_2} - E_{1,CO_2}}{E_{1,CH_4}} \frac{TRF_{CO_2}(t^*)}{TRF_{CH_4}(t^*)}\right\}. \qquad [7]$$

Taking the limit of L^* as the cross-over time t^* goes to zero, we obtain an expression for the critical leakage rate L_0, which serves as an approximation of the leakage rate below which the natural gas-burning technology causes less radiative forcing on all time frames.

$$L_0 = L_{REF}\left\{\frac{E_{2,CH_4}}{E_{1,CH_4}} + \frac{E_{2,CO_2} - E_{1,CO_2}}{RE\ E_{1,CH_4}}\right\} \qquad [8]$$

where $RE = 102$. Eq. **8** must be viewed as an approximation because L^* is a nonmonotonic function of t^* for small values of t^* (see Fig. 2, which plots L^* as a function of cross-over time t^*). The small decrease in L^* for small t^* is caused by the fact that 18.6% of the emitted CO_2 decays faster than CH_4 in the Bern carbon cycle model (time scales of 1.186 vs. 12 yr). The large increase in L^* for $t_* > 3$ years is caused by the rapid decay of CH_4 relative to the remaining 81.4% of the CO_2. The decay curves for CO_2 and CH_4 are shown in *SI Text*. Calculated values of L_o using Eq. **8** are within 2–3% of the absolute minima for L^*. Calculations of TWP and L^* using Eq. **2** and Eq. **8** were performed with an Excel spreadsheet and are available in Dataset S1.

ACKNOWLEDGMENTS. The authors acknowledge helpful reviews and comments from G. Marland, J. Milford, B. O'Neill, T. Skone, C. Sweeney, and P. Tans. We also thank S. Marwah for sharing analyses of Fort Worth emissions measurements. Funding for R.A.A. and S.P.H. was provided by the Heising-Simons Foundation.

1. Howarth RW, Santoro R, Ingraffea A (2011) Methane and the greenhouse-gas footprint of natural gas from shale formations. *Clim Change* 106:679–690.
2. Venkatesh A, Jaramillo P, Griffin WM, Matthews HS (2011) Uncertainty in life-cycle greenhouse gas emissions from United States natural gas end-uses and its effect on policy. *Environ Sci Technol* 45:8181–8189.
3. Cathles LM, Brown L, Taam M, Hunter A (2012) A commentary on "The greenhouse-gas footprint of natural gas in shale formations" by R. W. Howarth, R. Santoro, and Anthony Ingraffea. *Clim Change*, 10.1007/s10584-011-0333-0.
4. Burnham A, et al. (2012) Life-cycle greenhouse gas emissions of shale gas, natural gas, coal and petroleum. *Environ Sci Technol* 46:619–627.
5. Wigley TML (2011) Coal to gas: The influence of methane leakage. *Clim Change* 108:601–608.
6. U.S. Environmental Protection Agency (2011) Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2009 (EPA Publication 430-R-11-005).
7. U.S. Energy Information Administration (2011) *Annual Energy Outlook 2011*, (www.eia.gov/forecasts/aeo/).
8. Jaramillo P, Griffin WM, Matthews HS (2007) Comparative life-cycle air emissions of coal, domestic natural gas, LNG, and SNG for Electricity Generation. *Environ Sci Technol* 41:6290–6296.
9. Kirchgessner DA, Lott RA, Cowgill RM, Harrison MR, Shires TM (1997) Estimate of methane emissions from the U.S. natural gas industry. *Chemosphere* 35:1365–1390.
10. Forster P, et al. (2007) Changes in Atmospheric Constituents and in Radiative Forcing. *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, eds S Solomon et al. (Cambridge Univ Press, New York), pp 210–214.

11. Lipman TE, Delucchi MA (2002) Emissions of nitrous oxide and methane from conventional and alternative fuel motor vehicles. *Clim Change* 53:477–516.
12. Victor DG (1992) Leaking methane from natural gas vehicles: implications for transportation policy in the greenhouse era. *Clim Change* 20:113–141.
13. Hayhoe K, Kheshgi HS, Jain AK, Wuebbles DJ (2002) Substitution of natural gas for coal: Climatic effects of utility sector emissions. *Clim Change* 54:107–139.
14. Xu Y (2011) Improvements in the operation of SO_2 scrubbers in China's coal power plants. *Environ Sci Technol* 45:380–385.
15. Lu Z, Zhang Q, Streets DG (2011) Sulfur dioxide and primary carbonaceous aerosol emissions in China and India, 1996-2010. *Atmos Chem Phys* 11:9839–9864.
16. Fuglestvedt J, Berntsen T, Myre G, Rypdal K, Skeie RB (2008) Climate forcing from the transport sectors. *Proc Natl Acad Sci USA* 105:454–458.
17. Skeie RB, et al. (2009) Global temperature change from the transport sectors: historical development and future scenarios. *Atmos Environ* 43:6260–6270.
18. Unger N, Shindell DT, Wang JS (2009) Climate forcing by the on-road transportation and power generation sectors. *Atmos Environ* 43:3077–3085.

Simultaneously Mitigating Near-Term Climate Change and Improving Human Health and Food Security
Drew Shindell*, et al.*
Science **335**, 183 (2012);
DOI: 10.1126/science.1210026

Simultaneously Mitigating Near-Term Climate Change and Improving Human Health and Food Security

Drew Shindell,[1]* Johan C. I. Kuylenstierna,[2] Elisabetta Vignati,[3] Rita van Dingenen,[3] Markus Amann,[4] Zbigniew Klimont,[4] Susan C. Anenberg,[5] Nicholas Muller,[6] Greet Janssens-Maenhout,[3] Frank Raes,[3] Joel Schwartz,[7] Greg Faluvegi,[1] Luca Pozzoli,[3]† Kaarle Kupiainen,[4] Lena Höglund-Isaksson,[4] Lisa Emberson,[2] David Streets,[8] V. Ramanathan,[9] Kevin Hicks,[2] N. T. Kim Oanh,[10] George Milly,[1] Martin Williams,[11] Volodymyr Demkine,[12] David Fowler[13]

Tropospheric ozone and black carbon (BC) contribute to both degraded air quality and global warming. We considered ~400 emission control measures to reduce these pollutants by using current technology and experience. We identified 14 measures targeting methane and BC emissions that reduce projected global mean warming ~0.5°C by 2050. This strategy avoids 0.7 to 4.7 million annual premature deaths from outdoor air pollution and increases annual crop yields by 30 to 135 million metric tons due to ozone reductions in 2030 and beyond. Benefits of methane emissions reductions are valued at $700 to $5000 per metric ton, which is well above typical marginal abatement costs (less than $250). The selected controls target different sources and influence climate on shorter time scales than those of carbon dioxide–reduction measures. Implementing both substantially reduces the risks of crossing the 2°C threshold.

Tropospheric ozone and black carbon (BC) are the only two agents known to cause both warming and degraded air quality. Although all emissions of BC or ozone precursors [including methane (CH_4)] degrade air quality, and studies document the climate effects of total anthropogenic BC and tropospheric ozone (*1*–*4*), published literature is inadequate to address many policy-relevant climate questions regarding these pollutants because emissions of ozone precursors have multiple cooling and warming effects, whereas BC is emitted along with other particles that cause cooling, making the net effects of real-world emissions changes obscure. Such information is needed, however, because multiple stakeholders are interested in mitigating climate change via control of non–carbon dioxide (CO_2)–forcing agents such as BC, including the G8 nations (L'Aquila Summit, 2009) and the Arctic Council (Nuuk Declaration, 2011). Here, we show that implementing specific practical emissions reductions chosen to maximize climate benefits would have important "win-win" benefits for near-term climate, human health, agriculture, and the cryosphere, with magnitudes that vary strongly across regions. We also quantify the monetized benefits due to health, agriculture, and global mean climate change per metric ton of CH_4 and for the BC measures as a whole and compare these with implementation costs.

Our analysis proceeded in steps. Initially, ~400 existing pollution control measures were screened with the International Institute for Applied Systems Analysis Greenhouse Gas and Air Pollution Interactions and Synergies (IIASA GAINS) model (*5*, *6*). The model estimated potential worldwide emissions reductions of particulate and gaseous species on the basis of available real-world data on reduction efficiencies of these measures where they have been applied already and examined the impact of full implementation everywhere by 2030. Their potential climate impact was assessed by using published global warming potential (GWP) values for each pollutant affected. All emissions control measures are assumed to improve air quality. We then selected measures that both mitigate warming and improve air quality, ranked by climate impact. If enhanced air quality had been paramount, the selected measures would be quite different [for example, measures primarily reducing sulfur dioxide (SO_2) emissions improve air quality but may increase warming]. The screening revealed that the top 14 measures realized nearly 90% of the maximum reduction in net GWP (table S1 and fig. S2). Seven measures target CH_4 emissions, covering coal mining, oil and gas production, long-distance gas transmission, municipal waste and landfills, wastewater, livestock manure, and rice paddies. The others target emissions from incomplete combustion and include technical measures (set "Tech"), covering diesel vehicles, clean-burning biomass stoves, brick kilns, and coke ovens, as well as primarily regulatory measures (set "Reg"), including banning agricultural waste burning, eliminating high-emitting vehicles, and providing modern cooking and heating. We refer to these seven as "BC measures," although in practice, we consider all co-emitted species (*7*).

We then developed future emissions scenarios to investigate the effects of the emissions control measures in comparison with both a reference and a potential low-carbon future: (i) a reference scenario based on energy and fuel projections of the International Energy Agency (IEA) (*8*) regional and global livestock projections (*9*) and incorporating all presently agreed policies affecting emissions (*10*); (ii) a CH_4 measures scenario that follows the reference but also adds the CH_4 measures; (iii) CH_4+BC measures scenarios that follow the reference but add the CH_4 and one or both sets of BC measures; (iv) a CO_2 measures scenario under which CO_2 emissions follow the IEA's "450 CO_2-equivalent" scenario (*8*) as implemented in the GAINS model (affecting CO_2 and co-emissions of SO_2 but not other long-lived gases); and (v) a combined CO_2 plus CH_4 and BC measures scenario. Measures are phased in linearly from 2010 through 2030, after which only trends in CO_2 emissions are included, with other emissions kept constant.

Emissions from these scenarios were then used with the ECHAM5-HAMMOZ (*11*) and GISS-PUCCINI (*12*) three-dimensional composition-climate models to calculate the impacts on atmospheric concentrations and radiative forcing (*7*). Changes in surface $PM_{2.5}$ (particles of less than 2.5 micrometers) and tropospheric ozone were used with published concentration-response relationships (*13*–*15*) to calculate health and agricultural impacts. CH_4 forcing was calculated from the modeled CH_4 concentrations. Direct ozone and aerosol radiative forcings were produced by using the fraction of total anthropogenic direct radiative forcing removed by the emission control measures, as calculated in the two models, multiplied by the best estimate and uncertainty range for direct forcing, which was determined from a literature assessment. Albedo forcing was similarly estimated on the basis of the fractional decrease of BC deposition to snow and ice surfaces. Indirect and semidirect forcings were estimated by simply assuming that these had the same fractional changes as the direct forcings (*16*). Initially, analytic equations representing rapid and slow components of the climate system

[1]NASA Goddard Institute for Space Studies and Columbia Earth Institute, Columbia University, New York, NY 10025, USA. [2]Stockholm Environment Institute, Environment Department, University of York, York YO10 5DD, UK. [3]Joint Research Centre of the European Commission, Ispra 21027, Italy. [4]International Institute for Applied Systems Analysis, Laxenburg A-2361, Austria. [5]U.S. Environmental Protection Agency, Washington, DC 20460, USA. [6]Department of Economics, Middlebury College, Middlebury, VT 05753, USA. [7]Department of Environmental Health, Harvard School of Public Health, Boston, MA 02215, USA. [8]Argonne National Laboratory, Argonne, IL 60439, USA. [9]Scripps Institute of Oceanography, University of California, San Diego, San Diego, CA 92093, USA. [10]Asian Institute of Technology, Bangkok 10400, Thailand. [11]Environmental Research Group, King's College London, London SE1 9NH, UK. [12]United Nations Environment Programme (UNEP), Nairobi 00100, Kenya. [13]Center for Ecology and Hydrology, Midlothian EH26 0QB, UK.

*To whom correspondence should be addressed. E-mail: drew.t.shindell@nasa.gov

†Present address: Eurasia Institute of Earth Sciences, Istanbul Technical University, Istanbul 34469, Turkey.

(*17*) were used to estimate global and regional (*18*) mean temperature response to the forcings.

This analytic analysis shows that the measures substantially reduce the global mean temperature increase over the next few decades by reducing tropospheric ozone, CH_4, and BC (Fig. 1). The short atmospheric lifetime of these species allows a rapid climate response to emissions reductions. In contrast, CO_2 has a very long atmospheric lifetime (hence, growing CO_2 emissions will affect climate for centuries), so that the CO_2 emissions reductions analyzed here hardly affect temperatures before 2040. The combination of CH_4 and BC measures along with substantial CO_2 emissions reductions [a 450 parts per million (ppm) scenario] has a high probability of limiting global mean warming to <2°C during the next 60 years, something that neither set of emissions reductions achieves on its own [which is consistent with (*19*)].

Work to this stage was largely in support of the Integrated Assessment of Black Carbon and Tropospheric Ozone (*20*). Here, we present detailed climate modeling and extend impact analyses to the national level, where regulations are generally applied and which provides detailed spatial information that facilitates regional impact analyses. We also provide cost/benefit analyses.

Climate modeling. We performed climate simulations driven by the 2030 CH_4 plus BC measures, by greenhouse gas changes only, and by reference emissions using the GISS-E2-S model; the same GISS atmosphere and composition models were coupled to a mixed-layer ocean (allowing ocean temperatures, but not circulation, to adjust to forcing). Direct, semidirect (aerosol effects on clouds via atmospheric heating), indirect (aerosol effects on clouds via microphysics), and snow/ice albedo (by BC deposition) forcings were calculated internally (*7*). We analyzed the equilibrium response 30 to 50 years after imposition of the measures, which is comparable with the latter decades in the analytic analysis.

The global mean response to the CH_4 plus BC measures was -0.54 ± 0.05°C in the climate model. The analytic equations yielded −0.52°C (−0.21 to −0.80°C) for 2070, which is consistent with these results. Climate model uncertainty only includes internal variations, whereas the analytic estimate includes uncertainties in forcing and climate sensitivity (but has no internal variability).

We also examined individual forcing components. Direct global mean aerosol forcings in the ECHAM and GISS models are almost identical (Table 1), despite large uncertainties generally present in aerosol forcing and the two aerosol models being fundamentally different [for example, internal versus external mixtures (*7*)]. CH_4 and ozone responses to CH_4 emissions changes are also quite similar. Ozone responses to changes in CO, volatile organic compounds, and NO_x associated with the BC measures are quite different, however. This is consistent with the nonlinear response of ozone to these precursors (*21*).

The combined indirect and semidirect radiative forcing by all aerosols in the GISS model is negative for the BC Tech and Reg measures. Although sulfate increases slightly—largely because of increases in the oxidant H_2O_2—in all emissions control scenarios, the BC measures primarily decrease BC and organic carbon (OC). The negative forcing suggests that a decreased positive semidirect effect may outweigh decreased negative indirect effects of BC and OC in this model [studies differ on the magnitude of these effects (*22*–*24*)]. Indirect effects are much larger than net direct effects for the Tech measures.

Global mean BC albedo forcing in the model is very small (Table 1), but we assume its

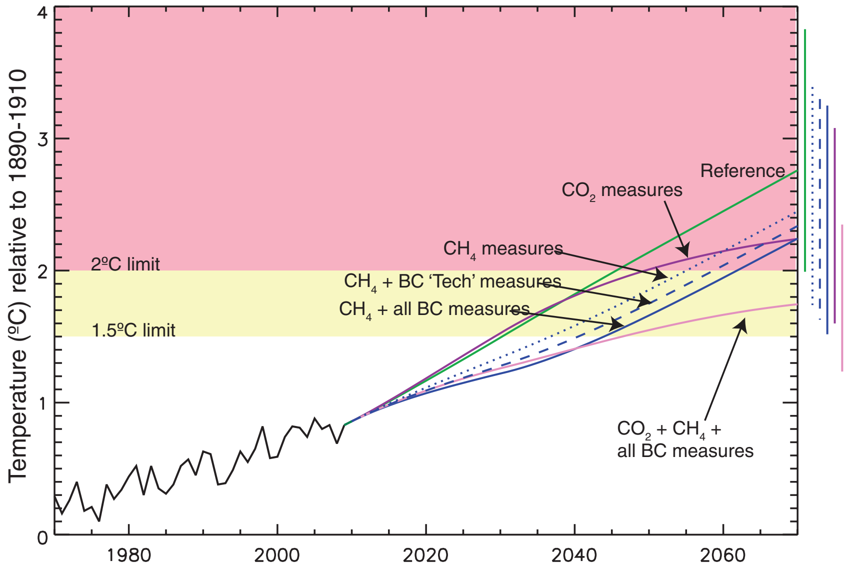


Fig. 1. Observed temperatures (*42*) through 2009 and projected temperatures thereafter under various scenarios, all relative to the 1890–1910 mean. Results for future scenarios are the central values from analytic equations estimating the response to forcings calculated from composition-climate modeling and literature assessments (*7*). The rightmost bars give 2070 ranges, including uncertainty in radiative forcing and climate sensitivity. A portion of the uncertainty is systematic, so that overlapping ranges do not mean there is no significant difference (for example, if climate sensitivity is large, it is large regardless of the scenario, so all temperatures would be toward the high end of their ranges; see www.giss.nasa.gov/staff/dshindell/Sci2012).

Table 1. ECHAM and GISS forcing (W/m^2) at 2030 due to the measures relative to the reference. Dashes indicate forcing not calculated.

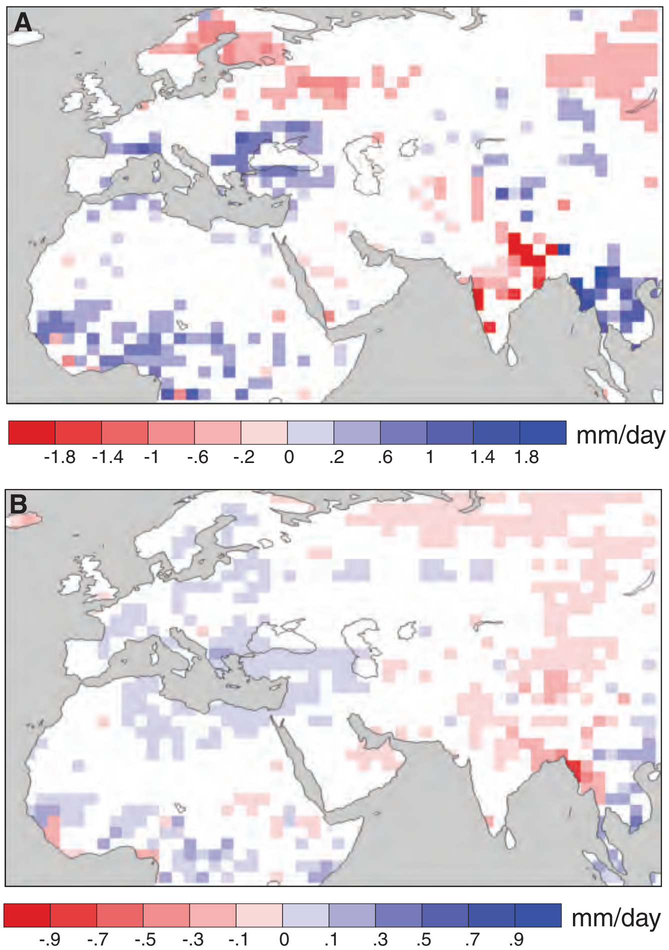
	CH_4 measures	CH_4+BC Tech measures	All measures
ECHAM ozone	−0.09	−0.10	−0.10
GISS ozone	−0.10	−0.17	−0.19
ECHAM direct aerosols*	−0.01	−0.06	−0.15
GISS direct aerosols*	−0.01	−0.06	−0.17
(BC, OC, sulfate, nitrate)	(0.00, 0.00, −0.02, 0.00)	(-0.10, 0.06, −0.02, 0.01)	(−0.22, 0.07, −0.02, 0.01)
ECHAM CH_4†	−0.22	−0.22	−0.20
GISS CH_4†	−0.20	−0.20	−0.18
GISS indirect and semidirect aerosols	—	−0.14 ± 0.03	−0.16 ± 0.04
GISS BC albedo (effective forcing ×5)	—	−0.010 (−0.05)	−0.017 (−0.09)
GISS net‡	−0.32	−0.60	−0.77

*For aerosols, the value for ECHAM is the sum of the direct BC+OC+sulfate forcing. For GISS, the same sum is presented first, and individual components are listed afterward (the ECHAM model has more realistic internally mixed aerosols, so components are not separable). †CH_4 forcing at 2030 is roughly 75% of the forcing that is eventually realized from CH_4 emission changes through 2030. ‡The net forcing given here includes the effective value for BC albedo forcing. Uncertainties due to internal variability in the models are 0.01 W/m^2 or less for direct forcings and 0.001 W/m^2 for BC albedo forcing.

"effective" forcing is five times the instantaneous value (*25*, *26*). Albedo forcing can be important regionally (Fig. 2), especially in the Arctic and the Himalayas, where the measures decrease forcing up to 4 W/m^2 (not including the factor of 5). Such large regional impacts are consistent with other recent studies (*27*, *28*) and would reduce snow and ice melting.

Roughly half the forcing is relatively evenly distributed (from the CH_4 measures). The other half is highly inhomogeneous, especially the strong BC forcing, which is greatest over bright desert and snow or ice surfaces. Those areas often exhibit the largest warming mitigation, making the regional temperature response to aerosols and ozone quite distinct from the more homogeneous response to well-mixed greenhouse gases (Fig. 2) [although the impact of localized forcing extends well beyond the forcing location (*29*)]. BC albedo and direct forcings are large in the Himalayas, where there is an especially pronounced response in the Karakoram, and in the Arctic, where the measures reduce projected warming over the next three decades by approximately two thirds and where regional temperature response patterns correspond fairly closely to albedo forcing (for example, they are larger over the Canadian archipelago than the interior and larger over Russia than Scandinavia or the North Atlantic).

The largest precipitation responses to the CH_4 plus BC measures are seen in South Asia, West Africa, and Europe (Fig. 2). The BC measures greatly reduce atmospheric forcing—defined as top-of-the-atmosphere minus surface forcing—in those parts of Asia and Africa (fig. S4), which can strongly influence regional precipitation patterns (*30*–*32*). In comparison with a semiempirical estimate (*33*), the two composition-climate models represent present-day atmospheric forcing reasonably well (fig. S4). The response to greenhouse gases alone shows different spatial structure over South Asia and Europe and is much weaker everywhere (per unit of global mean forcing). The BC measures moderate a shift in the monsoon westward away from Southeast Asia into India seen during 20th- and 21st-century GISS-E2 simulations, with especially strong impacts at the Indian west coast and from Bengal to the northwest along the Himalayan foothills. Climate models' simulations of monsoon responses to absorbing aerosols vary considerably (*30*–*32*). The results suggest that the BC measures could reduce drought risk in Southern Europe and the



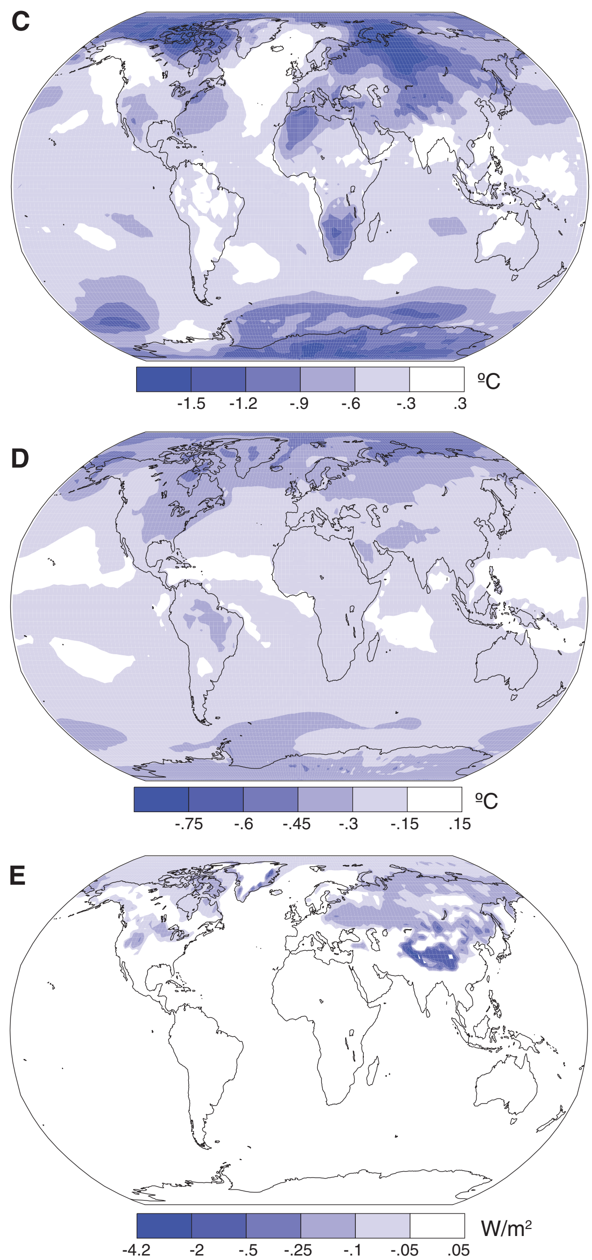


Fig. 2. (**A** and **B**) June-September precipitation change, (**C** and **D**) annual average surface temperature change, and (**E**) BC albedo forcing due to [(A), (C), and (E)] CH_4 plus BC measures and [(B) and (D)] CH_4 measures alone (the scales change in each panel). Changes are equilibrium responses relative to the reference in the GISS-E2-S climate model (mixed-layer ocean). Albedo forcings are directly simulated values rather than the enhanced "effective" values. Colored areas are statistically significant (95% confidence for temperature and forcing, 90% confidence for precipitation). Precipitation changes are small in areas not shown. Forcing from CH_4 plus BC measures is roughly double the CH_4 measures forcing (Table 1), so that equivalent colors in the two columns indicate comparable responses per unit forcing.

Sahel while reversing shifting monsoon patterns in South Asia.

Global mean impacts of packages of measures. Having established the credibility of the analytic climate calculations at the global scale [air quality simulations were shown to be realistic in (*20*)], we now briefly compare the global effects of the separate packages of measures (Table 2). The CH_4 measures contribute more than half the estimated warming mitigation and have the smallest relative uncertainty. BC Tech measures have a larger climate impact and a substantially smaller fractional uncertainty than that of the Reg measures because aerosols contribute a larger portion of the total forcing in the Reg case (and uncertainty in radiative forcing by BC or OC is much larger than for CH_4 or ozone). In the Reg case, the temperature range even includes the possibility of weak global warming, although the distribution shows a much larger probability of cooling.

For yield losses of four staple crops due to ozone, the mean values for CH_4 and BC Tech measures are comparable, whereas BC Reg measures have minimal impact. The health benefits from BC measures are far larger that those from the CH_4 measures because health is more sensitive to reduced exposure to $PM_{2.5}$ than to ground-level ozone. The large ranges for health impacts stem primarily from uncertainty in concentration-response relationships. The estimated 0.7 to 4.7 million annually avoided premature deaths are substantial in comparison with other causes of premature death projected for 2030, including tuberculosis (0.6 million), traffic accidents (2.1 million), or tobacco use (8.3 million) (*34*). There would also be large health benefits from improved indoor air quality. Because of limited data, we only estimated these for India and China, where implementation of all BC measures leads to an additional 373,000 annually avoided premature deaths (*7*).

Cost and benefit valuation. Economic analyses use the value of a statistical life (VSL) for health, world market prices for crops, and the social cost of carbon (SCC) along with global mean impacts relative to CO_2 for climate (*7*). Valuation is dominated by health effects and hence by the BC measures (Table 2). Climate valuation is large for the CH_4 measures, although it depends strongly on the metrics used. If instead of the 100-year GWP, the 100-year global temperature potential (GTP) of CH_4 is used (*35*), the value becomes $159 billion. Similarly, benefits scale with differing choices for the SCC. Climate benefits for the BC measures are based on the CH_4 measures' climate benefits times the relative global mean climate impact of the BC measures because published GWP or GTP values do not cover all species and ignore some factors affecting climate (such as aerosol indirect effects), and the ratio of the temperature responses is similar to the ratio of the integrated forcing due to a single year's emissions (GWP). This method still neglects regional effects of these pollutants on temperatures, precipitation, and sunlight available for photosynthesis.

Because the CH_4 measures largely influence CH_4 emissions alone, and CH_4 emissions anywhere have equal impact, it is straightforward to value CH_4 reductions by the metric ton. Climate benefits dominate, at $2381 per metric ton, with health second and crops third. The climate benefit per metric ton is again highly dependent on metrics. For example, instead of a $265 SCC (*36*)—a typical value assuming a near-zero discount rate—a value of $21 consistent with a ~3% discount rate could be used. Because discounting emphasizes near-term impacts, we believe a 20-year GWP or GTP should be used with the $21 SCC, in which case the valuation is $599 or $430 per metric ton, respectively. Health and agricultural benefits could also be discounted to account for the time dependence of the ozone response. Using a 5% discount rate, the mean health and agricultural benefits decrease relative to the undiscounted Table 2 values to $659 and $18 per metric ton, respectively. Climate benefits always exceed the agricultural benefits per metric ton, but climate values can be less or more than health benefits depending on the metric choices (the health benefits are similarly dependent on the assumed VSL).

A very conservative summation of benefits, using $430 for climate and discounted health and agricultural values, gives a total benefit of ~$1100 per metric ton of CH_4 (~$700 to $5000 per metric ton, using the above analyses). IEA estimates (*37*) indicate roughly 100 Tg/year of CH_4 emissions can be abated at marginal costs below $1100, with more than 50 Tg/year costing less than 1/10 this valuation (including the value of CH_4 captured for resale). Analysis using more recent cost information in the GAINS model (*38*, *39*) finds that the measures analyzed here could reduce 2030 CH_4 emissions by ~110 Tg at marginal costs below $1500 per metric ton, with 90 Tg below $250. The full set of measures reduce emissions by ~140 Tg, indicating that most would produce benefits greater than—and for approximately two-thirds of reductions far greater than—the abatement costs. Of course, the benefits would not necessarily accrue to those incurring costs.

Prior work valued CH_4 reductions at $81 ($48 to $116) per metric ton, including agriculture (grains), forestry, and nonmortality health benefits using 5% discounting (*40*). Their agricultural valuation was ~$30 ($1 to $42) per metric ton. Hence, our agriculture values are smaller but well within their large range. Those results suggest that forestry and nonmortality health effects contribute another ~$50 per metric ton of CH_4. Nonlinearities imply all valuations may shift somewhat as the background atmospheric composition changes.

GAINS estimates show that improved efficiencies lead to a net cost savings for the brick kiln and clean-burning stove BC measures. These account for ~50% of the BC measures' impact. The regulatory measures on high-emitting vehicles and banning of agricultural waste burning, which require primarily political rather than economic investment, account for another 25%. Hence, the bulk of the BC measures could probably be implemented with costs substantially less than the benefits given the large valuation of the health impacts (Table 2).

CH_4 measures by sector and region. It is also straightforward to separate the impact of CH_4 reductions in each region and sector on forcing. Because CH_4 is relatively well mixed globally, other impacts (such as crop yields) have the same proportionality as forcing. Emissions reductions in the coal mining and oil/gas production sectors

Table 2. Global impacts of measures on climate, agriculture, and health and their economic valuation. Valuations are annual values in 2030 and beyond, due to sustained application of the measures, which are nearly equal to the integrated future valuation of a single year's emissions reductions (without discounting). Climate valuations for CH_4 use GWP100 and an SCC of $265 per metric ton (*36*). Crop and health valuations use 95% confidence intervals, whereas climate valuations use ~67% uncertainty range. All values are in 2006 dollars.

	CH_4 measures	BC Tech measures	BC Reg measures
Physical Impacts			
Avoided warming in 2050 (°C)	0.28 ± 0.10	0.12 (+0.06/–0.09)	.07 (+.04/–0.09)
Annually avoided crop yield losses (millions metric tons; sum of wheat, rice, maize, and soy)	27 (+42/–20)	24 (+72/–21)	2 (+13/–3)
Annually avoided premature deaths (thousands)	47 (+40/–34)	1720 (+1529/–1188)	619 (+639/–440)
Valuation			
Climate, billions $US	331 ± 118	142 (+71/–106)	83 (+47/–106)
($US per metric ton CH_4)	(2381 ± 850)		
Crops, billions $US	4.2 ± 1.2	3.6 ± 2.6	0.4 ± 0.6
($US per metric ton CH_4)	(29 ± 8)		
Health, billions $US	148 ± 99	3717 (+3236/–2563)	1425 (+1475/–1015)
($US per metric ton CH_4)	(1080 ± 721)		

have the largest impacts, with municipal waste third (Fig. 3). Globally, sectors encompassing fossil fuel extraction and distribution account for nearly two thirds of the benefits because technology to control emissions from these sectors is readily available.

Examining benefits by sector and region, the largest by a considerable amount are from coal mining in China (Fig. 3). Oil and gas production in Central Africa, the Middle East, and Russia are next, followed by coal mining in South Asia, gas transmission in Russia (in high-pressure mains), and municipal waste in the United States and China. Ranking is obviously quite sensitive to regional groupings and country size, and there is substantial uncertainty in emissions from certain sectors in some regions. In particular, using national emission factors (instead of the Intergovernmental Panel on Climate Change default methodology) would lower the coal-mining potential from India and Southern Africa substantially. Nonetheless, those eight regional/sectoral combinations alone represent 51% of the total impact from all CH_4 measures.

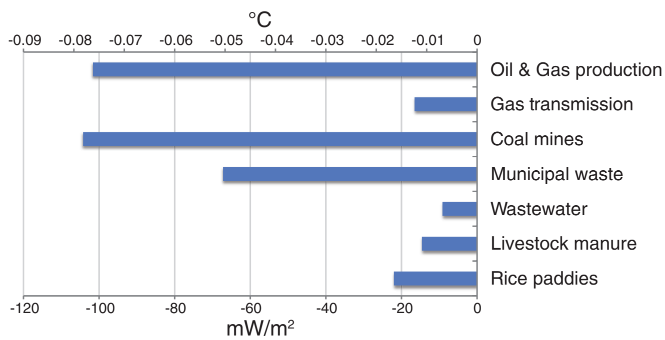
Regional and national impacts. Upon examination of impacts of the CH_4 plus BC measures, avoided warming is greatest in central and northern Asia, southern Africa, and around the Mediterranean (Fig. 4, fig. S5, and table S5). Three of the top four national-level responses are in countries with strong BC albedo forcing (Tajikistan, Kyrgyzstan, and Russia). In contrast, the atmospheric forcing linked to regional hydrologic cycle disruption is reduced most strongly in south Asia and west Africa, where the measures greatly decrease BC emissions. Total numbers of avoided premature deaths are greatest in developing nations in Asia and Africa with large populations and high PM concentrations (and large emissions changes). Turning to per capita impacts, premature deaths are reduced most strongly in countries of south Asia, followed by central Africa, then east and southeast Asia, in a pattern quite similar to the atmospheric forcing impacts.

For crop production, China, India, and the United States, followed by Pakistan and Brazil, realize the greatest total metric tonnage gains. Looking instead at percentage yield changes, impacts are largest in the Middle East, with large changes also in central and south Asia. There is a large impact on percentage crop yields in Mexico that is quite distinct from neighboring countries, reflecting the influence of local emission changes. Impacts vary greatly between crops for changes in total production (fig. S6), with largest impacts occurring where the distribution and seasonal timing of crop production coincide with high ozone concentrations (*7*). Percentage yield changes are more consistent, however. Additional crop yield benefits would result from the avoided climate change, but they are not considered here.

Avoided warming is spread much more evenly over the Earth than other impacts. Both climate benefits in terms of reductions in regional atmospheric forcing and air quality–related human health benefits are typically largest in the countries of south Asia and central Africa, whereas agricultural benefits are greatest in the Middle East, where ozone reductions are large. Because many nations in these areas face great development challenges, realization of these benefits would be especially valuable in those areas.

Discussion. The results clearly demonstrate that only a small fraction of air quality measures provide substantial warming mitigation. Nonetheless, the CH_4 and BC emissions reduction measures examined here would have large benefits to global and regional climate, as well as to human health and agriculture. The CH_4 measures lead to large global climate and agriculture benefits and relatively small human health benefits, all with high confidence and worldwide distribution. The BC measures are likely to provide substantial global climate benefits, but uncertainties are much larger. However, the BC measures cause large regional human health benefits, as well as reduce regional hydrology cycle disruptions and cryosphere melting in both the Arctic and the Himalayas and improve regional agricultural yields. These benefits are more certain and are typically greatest in and near areas where emissions are reduced. Results are robust across the two composition-climate models. Protecting public health and food supplies may take precedence over avoiding climate change in most countries, but knowing that these measures also mitigate climate change may help motivate policies to put them into practice.

We emphasize that the CH_4 and BC measures are both distinct from and complementary to CO_2 measures. Analysis of delayed implemen-



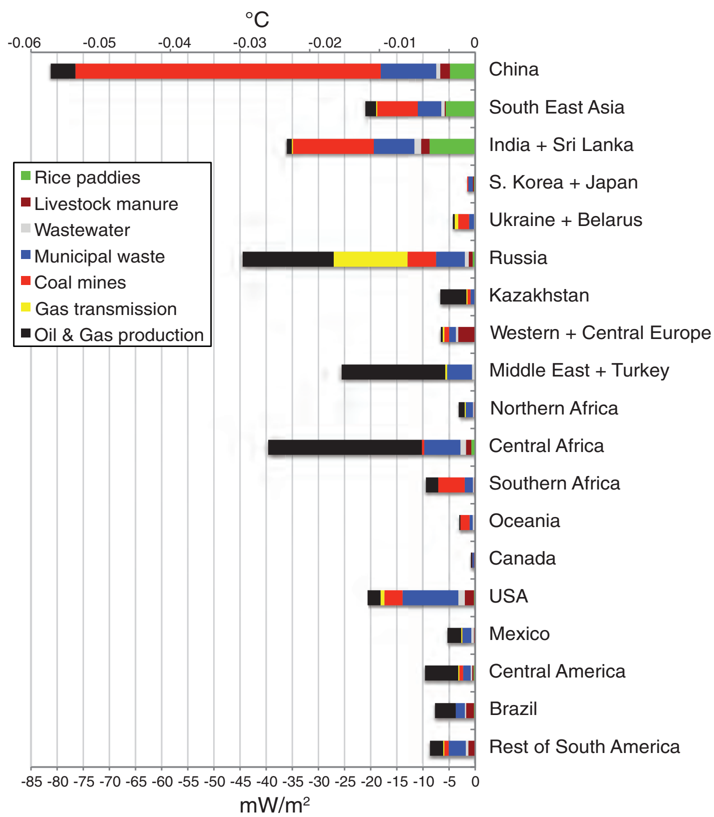


Fig. 3. Global mean radiative forcing (bottom *x* axes) and temperature response (top *x* axes) from CH_4 and ozone in response to CH_4 measures. Global totals by (**left**) emission control measure, and (**right**) values by region and sector are shown. Temperature response is the approximate equilibrium value. Uncertainties are ~10% in forcing and ~50% in response.

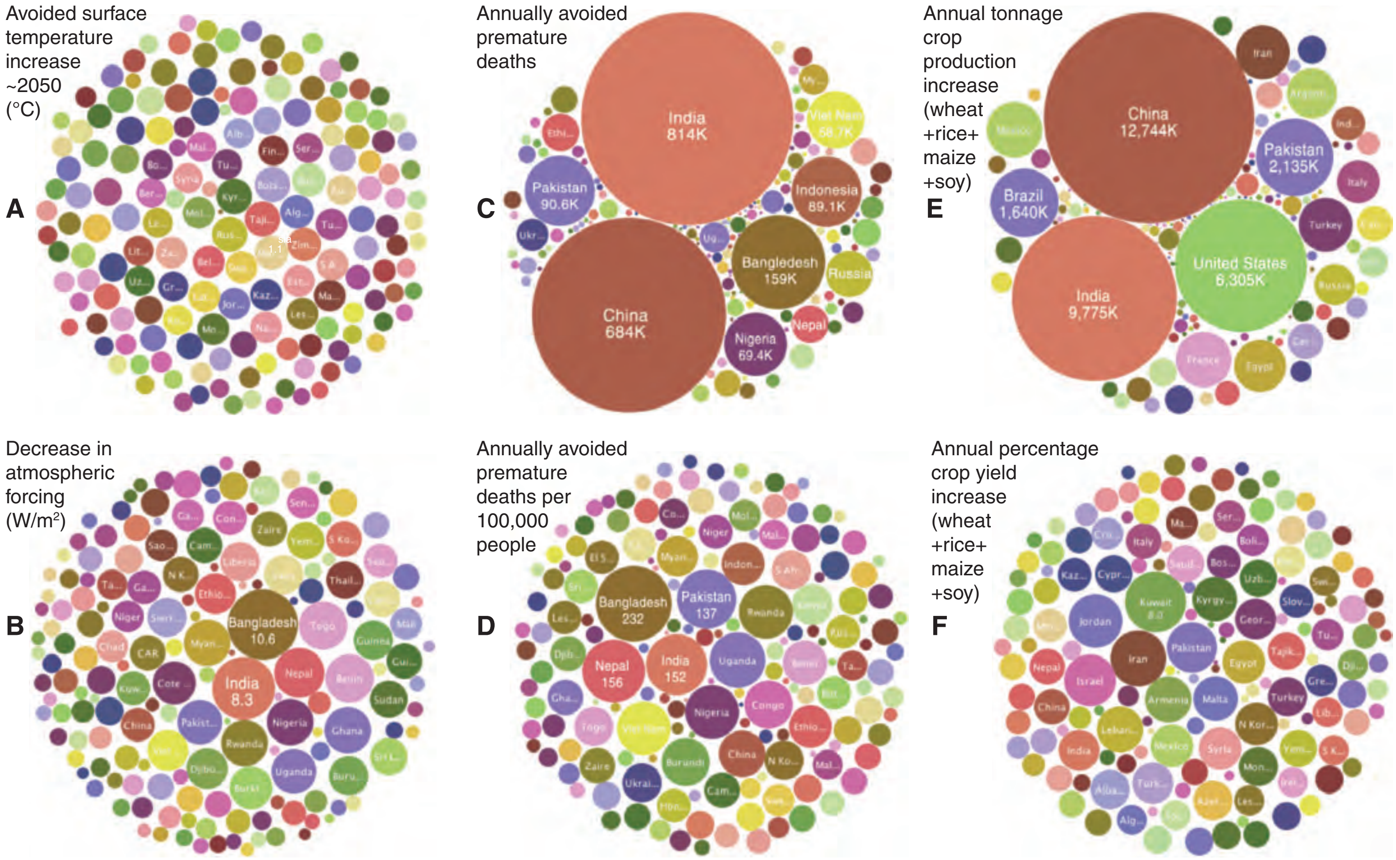


Fig. 4. National benefits of the CH_4 plus BC measures versus the reference scenario. Circle areas are proportional to values for (**A** and **B**) climate change, (**C** and **D**) human health (values for population over age 30), and (**E** and **F**) agriculture. Surface temperature changes are from the GISS-E2-S simulation. Health, agriculture, and atmospheric forcing impacts are based on the average of GISS and ECHAM concentration changes and are for 2030 and beyond. Uncertainties are ~60% for global mean temperatures, with national scale uncertainties likely greater, ~60% for atmospheric forcing, ~70% for health, and roughly –70%/+100% for crops [see (*7*) for factors included in uncertainties, most of which are systematic for atmospheric forcing, health, and agriculture so that much smaller differences between regions are still significant]. Interactive versions providing values for each country are at www.giss.nasa.gov/staff/dshindell/Sci2012, whereas alternate presentations of these data are in fig. S5 and table S5.

tation of the CH_4 and BC measures (fig. S3) shows that early adoption provides much larger near-term benefits but has little impact on long-term temperatures (*20*). Hence, eventual peak warming depends primarily on CO_2 emissions, assuming air quality–related pollutants are removed at some point before peak warming.

Valuation of worldwide health and ecosystem impacts of CH_4 abatement is independent of where the CH_4 is emitted and usually outweighs abatement costs. These benefits are therefore potentially suitable for inclusion in international mechanisms to reduce CH_4 emissions, such as the Clean Development Mechanism under the United Nations Framework Convention on Climate Change or the Prototype Methane Financing Facility (*41*). Many other policy alternatives exist to implement the CH_4 and BC measures, including enhancement of current air quality regulations. The realization that these measures can slow the rate of climate change and help keep global warming below 2°C relative to preindustrial in the near term, provide enhanced warming mitigation in the Arctic and the Himalayas, and reduce regional disruptions to traditional rainfall patterns—in addition to their local health and local-to-global agricultural benefits—may help prompt widespread and early implementation so as to realize these manifold benefits.

References and Notes

1. M. Z. Jacobson, *J. Geophys. Res.* **115** (D14), D14209 (2010).
2. D. T. Shindell *et al.*, *J. Geophys. Res.* **111**, D08302 (2006).
3. P. Forster *et al.*, in *Climate Change 2007: The Physical Science Basis*, S. Solomon, Ed. (Cambridge Univ. Press, New York, 2007).
4. P. Stier, J. Feichter, E. Roeckner, S. Kloster, M. Esch, *Atmos. Chem. Phys.* **6**, 3059 (2006).
5. Z. Klimont *et al.*, *Tellus B Chem. Phys. Meterol.* **61**, 602 (2009).
6. K. Kupiainen, Z. Klimont, *Atmos. Environ.* **41**, 2156 (2007).
7. Materials and methods are available as supporting material on *Science* Online.
8. International Energy Agency, *World Energy Outlook* (OECD/IEA, Paris, 2009).
9. N. Alexandratos *et al.*, "World agriculture: Towards 2030/2050. Interim report. Prospects for food, nutrition, agriculture and major commodity groups" (Food and Agriculture Organization, Rome, 2006).
10. J. Cofala, M. Amann, Z. Klimont, K. Kupiainen, L. Hoglund-Isaksson, *Atmos. Environ.* **41**, 8486 (2007).
11. L. Pozzoli *et al.*, *J. Geophys. Res.* **113** (D7), D07308 (2008).
12. D. T. Shindell *et al.*, *Atmos. Chem. Phys.* **6**, 4427 (2006).
13. D. Krewski *et al.*, "Extended follow-up and spatial analysis of the American Cancer Society study linking particulate air pollution and mortality" (Health Effects Institute, Boston, 2009).
14. M. Jerrett *et al.*, *N. Engl. J. Med.* **360**, 1085 (2009).
15. R. Van Dingenen *et al.*, *Atmos. Environ.* **43**, 604 (2009).
16. V. Ramaswamy *et al.*, in *Climate Change 2001*, J. T. Houghton, Ed. (Cambridge Univ. Press, Cambridge, 2001), pp. 349–416.
17. O. Boucher, P. Friedlingstein, B. Collins, K. P. Shine, *Environ. Res. Lett.* **4**, 044007 (2009).
18. D. Shindell, G. Faluvegi, *Atmos. Chem. Phys.* **10**, 3247 (2010).
19. V. Ramanathan, Y. Xu, *Proc. Natl. Acad. Sci. U.S.A.* **107**, 8055 (2010).
20. United Nations Environment Programme and World Meteorological Organization, "Integrated Assessment of Black Carbon and Tropospheric Ozone" (Nairobi, 2011).
21. S. Sillman, *Atmos. Environ.* **33**, 1821 (1999).
22. D. Koch, A. Del Genio, *Atmos. Chem. Phys.* **10**, 7685 (2010).
23. S. E. Bauer, S. Menon, D. Koch, T. C. Bond, K. Tsigaridis, *Atmos. Chem. Phys.* **10**, 7439 (2010).
24. W. T. Chen, Y. H. Lee, P. J. Adams, A. Nenes, J. H. Seinfeld, *Geophys. Res. Lett.* **37**, L09801 (2010).
25. M. G. Flanner, C. S. Zender, J. T. Randerson, P. J. Rasch, *J. Geophys. Res.* **112** (D11), D11202 (2007).
26. D. Koch *et al.*, *J. Clim.* **22**, 2659 (2009).

27. Y. Qian, M. G. Flanner, L. R. Leung, W. Wang, *Atmos. Chem. Phys.* **11**, 1929 (2011).
28. M. Kopacz *et al.*, *Atmos. Chem. Phys.* **11**, 2837 (2011).
29. D. Shindell *et al.*, *J. Geophys. Res.* **115**, D19110 (2010).
30. G. A. Meehl, J. M. Arblaster, W. D. Collins, *J. Clim.* **21**, 2869 (2008).
31. C. Wang, D. Kim, A. M. L. Ekman, M. C. Barth, P. J. Rasch, *Geophys. Res. Lett.* **36**, L21704 (2009).
32. V. Ramanathan *et al.*, *Proc. Natl. Acad. Sci. U.S.A.* **102**, 5326 (2005).
33. V. Ramanathan, G. Carmichael, *Nat. Geosci.* **1**, 221 (2008).
34. C. D. Mathers, D. Loncar, *PLoS Med.* **3**, e442 (2006).
35. J. S. Fuglestvedt *et al.*, *Atmos. Environ.* **44**, 4648 (2010).
36. R. S. J. Tol, *Economics: The Open-Access, Open-Assessment E-Journal* **2**, 1 (2008).
37. International Energy Agency, "Building the Cost Curves for the Industrial Sources of Non-CO2 Greenhouse Gases" (IEA Greenhouse Gas R&D Programme Cheltenham, UK, 2003).
38. L. Höglund-Isaksson, W. Winiwarter, A. Tohka, "Potentials and costs for mitigation of non-CO2 greenhouse gases in the European Union until 2030—Methodology" (IIASA Report, Laxenburg, Austria, 2010).
39. M. Amann *et al.*, *Environ. Model. Softw.* **26**, 1489 (2011).
40. J. J. West, A. M. Fiore, *Environ. Sci. Technol.* **39**, 4685 (2005).
41. www.globalmethanefund.org; accessed 23 May 2011.
42. J. Hansen *et al.*, *Proc. Natl. Acad. Sci. U.S.A.* **103**, 14288 (2006).

Acknowledgments: Funding was provided by UNEP and the World Meteorological Organization (WMO), NASA's Applied Sciences and Atmospheric Chemistry Modeling and Analysis Programs, and the Clean Air Task Force to IIASA. We thank all the authors and reviewers who contributed to the UNEP/WMO Integrated Assessment of Black Carbon and Tropospheric Ozone.

Supporting Online Material
www.sciencemag.org/cgi/content/full/335/6065/183/DC1
Materials and Methods
Figs. S1 to S6
Tables S1 to S5
References

20 June 2011; accepted 28 November 2011
10.1126/science.1210026

Periodic Emission from the Gamma-Ray Binary 1FGL J1018.6–5856

The Fermi LAT Collaboration*

Gamma-ray binaries are stellar systems containing a neutron star or black hole, with gamma-ray emission produced by an interaction between the components. These systems are rare, even though binary evolution models predict dozens in our Galaxy. A search for gamma-ray binaries with the Fermi Large Area Telescope (LAT) shows that 1FGL J1018.6–5856 exhibits intensity and spectral modulation with a 16.6-day period. We identified a variable x-ray counterpart, which shows a sharp maximum coinciding with maximum gamma-ray emission, as well as an O6V((f)) star optical counterpart and a radio counterpart that is also apparently modulated on the orbital period. 1FGL J1018.6–5856 is thus a gamma-ray binary, and its detection suggests the presence of other fainter binaries in the Galaxy.

Two types of interacting binaries containing compact objects are expected to emit gamma rays (*1*): microquasars—accreting black holes or neutron stars with relativistic jets (*2*)—and rotation-powered pulsars interacting with the wind of a binary companion (*3*). Microquasars should typically be powerful x-ray sources when active, and hence such gamma ray–emitting systems may already be known x-ray binaries. Indeed, the bright x-ray source Cygnus X-3 is now known to be such a source (*4*, *5*). The existence of pulsars interacting with stellar companions of early spectral types is predicted as an initial stage in the formation of high-mass x-ray binaries (HMXBs) containing neutron stars (*6*). These interacting pulsars are predicted to be much weaker x-ray emitters and may not yet be known or classified x-ray sources. Gamma-ray binaries may thus not be as rare as they appear to be, and many systems may await detection.

A gamma-ray binary is expected to show orbitally modulated gamma-ray emission due to a combination of effects, including changes in viewing angle and, in eccentric orbits, the degree of the binary interaction, both of which depend on binary phase. Periodic gamma-ray modulation has indeed been seen in LS 5039 (period 3.9 days), LS I +61° 303 (26.5 days), and Cygnus X-3 (4.8 hours) (*4*, *7*, *8*), and gamma-ray emission is at least orbital phase–dependent for the PSR B1259–63 system (3.4 years) (*9*). However, the putative gamma-ray binary HESS J0632+057, for which a 321-day x-ray period is seen, has not yet been shown to exhibit periodic gamma-ray emission (*10*). PSR B1259–63 contains a pulsar, and LS 5039 and LS I +61° 303 are suspected, but not proved, to contain pulsars, whereas Cygnus X-3 is a black hole candidate. A search for periodic modulation of gamma-ray flux from LAT sources may thus lead to the detection of further gamma-ray binaries, potentially revealing the predicted HMXB precursor population. The first Fermi LAT (*11*) catalog of gamma-ray sources ("1FGL") contains 1451 sources (*12*), a large fraction of which do not have confirmed counterparts at other wavelengths and thus are potentially gamma-ray binaries.

To search for modulation, we used a weighted photon method to generate light curves for all 1FGL sources in the energy range 0.1 to 200 GeV (*13*). We then calculated power spectra for all sources. From an examination of these, in addition to modulation from the known binaries LS I +61° 303 and LS 5039, we noted the presence of a strong signal near a period of 16.6 days from 1FGL J1018.6–5856 (Fig. 1). 1FGL J1018.6–5856 has a cataloged 1- to 100-GeV flux of 2.9×10^{-8} photons cm^{-2} s^{-1}, making it one of the brighter LAT sources. The source's location at right ascension (R.A.) = $10^h\ 18.7^m$, declination (decl.) = –58° 56.30′ (J2000; ±1.8′, 95% uncertainty) means that it lies close to the galactic plane ($b = -1.7°$), marking it as a good candidate for a binary system. 1FGL J1018.6–5856 has been noted to be positionally coincident with the supernova remnant G284.3–1.8 (*12*) and the TeV source HESS J1018–589 (*14*), although it has not been shown that these sources are actually related.

The modulation at a period of 16.6 days has a power more than 25 times the mean value of the power spectrum and has a false-alarm probability of 3×10^{-8}, taking into account the number of statistically independent frequency bins. From both the power spectrum itself (*15*) and from fitting the light curve, we derived a period of 16.58 ± 0.02 days. The folded light curve (Fig. 1) has a sharp peak together with additional broader modulation. We modeled this to determine the epoch of maximum flux T_{max} by fitting a function consisting of the sum of a sine wave and a Gaussian function, and obtained T_{max} = modified Julian date (MJD) 55403.3 ± 0.4.

The gamma-ray spectrum of 1FGL J1018.6–5856 shows substantial curvature through the LAT passband. To facilitate discussion of the lower-energy (<1 GeV) and higher-energy (>1 GeV) gamma rays, we adopted as our primary model a broken power law with photon indices $\Gamma_{0.1-1}$ and Γ_{1-10} for energies below and above 1 GeV, respectively. The best-fit values (*13*) are $\Gamma_{0.1-1} = 2.00 \pm 0.04_{stat} \pm 0.08_{syst}$ and $\Gamma_{1-10} = 3.09 \pm 0.06_{stat} \pm 0.12_{syst}$, along with an integral energy flux above 100 MeV of $(2.8 \pm 0.1_{stat} \pm 0.3_{syst}) \times 10^{-10}$ erg cm^{-2} s^{-1}. A power law with exponential cutoff (*7*, *8*), $dN/dE = N_0(E/\mathrm{GeV})^{-\Gamma} \exp(-E/E_c)$, gives an acceptable fit with $\Gamma = 1.9 \pm 0.1$ and $E_c = 2.5 \pm 0.3$ GeV (statistical errors only). Although this spectral shape is qualitatively similar to that of pulsars and of LS I +61° 303 and LS 5039, so far no detection of pulsed gamma-ray emission has been reported (*16*).

To investigate variability on the 16.6-day period, we folded the data into 10 uniform bins in orbital phase and then refit the broken power-law parameters within each phase bin. The resulting

*All authors with their affiliations appear at the end of this paper.

Climatic Change
DOI 10.1007/s10584-011-0217-3

LETTER

Coal to gas: the influence of methane leakage

Tom M. L. Wigley

Received: 19 May 2011 / Accepted: 10 August 2011

Abstract Carbon dioxide (CO_2) emissions from fossil fuel combustion may be reduced by using natural gas rather than coal to produce energy. Gas produces approximately half the amount of CO_2 per unit of primary energy compared with coal. Here we consider a scenario where a fraction of coal usage is replaced by natural gas (i.e., methane, CH_4) over a given time period, and where a percentage of the gas production is assumed to leak into the atmosphere. The additional CH_4 from leakage adds to the radiative forcing of the climate system, offsetting the reduction in CO_2 forcing that accompanies the transition from coal to gas. We also consider the effects of: methane leakage from coal mining; changes in radiative forcing due to changes in the emissions of sulfur dioxide and carbonaceous aerosols; and differences in the efficiency of electricity production between coal- and gas-fired power generation. On balance, these factors more than offset the reduction in warming due to reduced CO_2 emissions. When gas replaces coal there is additional warming out to 2,050 with an assumed leakage rate of 0%, and out to 2,140 if the leakage rate is as high as 10%. The overall effects on global-mean temperature over the 21st century, however, are small.

Hayhoe et al. (2002) have comprehensively assessed the coal-to-gas issue. What has changed since then is the possibility of substantial methane production by high volume hydraulic fracturing of shale beds ("fracking") and/or exploitation of methane reservoirs in near-shore ocean sediments. Fracking, in particular, may be associated with an increase in the amount of attendant gas leakage compared with other means of gas production (Howarth et al. 2011). In Hayhoe et al., the direct effects on global-mean temperature of differential gas leakage between coal and gas production are very small (see their Fig. 4). Their estimates of gas

Electronic supplementary material The online version of this article (doi:10.1007/s10584-011-0217-3) contains supplementary material, which is available to authorized users.

T. M. L. Wigley (✉)
National Center for Atmospheric Research, Post Office Box 3000, Boulder, CO 80307-3000, USA
e-mail: wigley@ucar.edu

T. M. L. Wigley
University of Adelaide, Adelaide, South Australia, Australia

Published online: 26 August 2011

leakage, however, are less than more recent estimates. Here, we extend and update the analysis of Hayhoe et al. to examine the potential effects of gas leakage on the climate, and on uncertainties arising from uncertainties in leakage percentages.

We begin with a standard “no-climate-policy” baseline emissions scenario, viz. the MiniCAM Reference scenario (MINREF below) from the CCSP2.1a report (Clarke et al. 2007). (Hayhoe et al. used the MiniCAM A1B scenario, Nakićenović and Swart 2000.) We chose MINREF partly because it is a more recent “no-policy” scenario, but also because there is an extended version of MINREF that runs beyond 2,100 out to 2,300 (Wigley et al. 2009). The longer time horizon is important because of the long timescales involved in the carbon cycle where changes to CO_2 emissions made in the 21st century can have effects extending well into the 22nd century. (A second baseline scenario, the MERGE Reference scenario from the CCSP2.1a report, is considered in the Electronic Supplementary Material).

In MINREF, coal combustion provides from 38% (in 2010) to 51% (in 2100) of the emissions of CO_2 from fossil fuels. (The corresponding percentages for gas are 19 to 21%, and for oil are 43 to 28%.) For our coal-to-gas scenario we start with their contributions to energy. It is important here to distinguish between primary energy (i.e., the energy content of the resource) and final energy (the amount of energy delivered to the user at the point of production). For a transition from coal to gas, we assume that there is no change in final energy. As electricity generation from gas is more efficient than coal-fired generation, the increase in primary energy from gas will be less than the decrease in primary energy from coal — the differential depends on the relative efficiencies with which energy is produced.

To calculate the change in fossil CO_2 emissions for any transition scenario we use the following relationship relating CO_2 emissions to primary energy (P)…

$$\mathrm{ECO2} = \mathrm{A\ Pcoal} + \mathrm{B\ Poil} + \mathrm{C\ Pgas} \tag{1}$$

where A, B and C are representative emissions factors (emissions per unit of primary energy) for coal, oil and gas. The emissions factors relative to coal that we use are 0.75 for oil and 0.56 for gas, based on information in EPA's AP-42 Report (EPA 2005). Using the MINREF emissions for CO_2 and the published primary energy data give a best fit emissions factor for coal of 0.027 GtC/exajoule, well within the uncertainty range for this term.

To determine the change in CO_2 emissions in moving from coal to gas under the constraint of no change in final energy we use the equivalent of Eq. (1) expressed in terms of final energy (F). This requires knowing the efficiencies for energy production from coal, oil and gas (i.e., final energy/primary energy). If F=P×(efficiency), then we have

$$\mathrm{ECO2} = (\mathrm{A/a})\mathrm{Fcoal} + (\mathrm{B/b})\mathrm{Foil} + (\mathrm{C/c})\mathrm{Fgas} \tag{2}$$

where a, b and c are the efficiencies for energy production from coal, oil and gas. For changes in final energy (ΔF) in the coal-to-gas case, ΔFoil is necessarily zero. To keep final energy unchanged, therefore, we must have ΔFgas = −ΔFcoal. Hence, from Eq. (2) …

$$\Delta\mathrm{ECO2} = (\Delta\mathrm{Fcoal})(\mathrm{A/a} - \mathrm{C/c}) \tag{3}$$

or …

$$\Delta\mathrm{ECO2} = \mathrm{A}\ \Delta\mathrm{Pcoal}[1 - (\mathrm{C/A})/(\mathrm{c/a})] \tag{4}$$

As ΔPcoal is negative, the first term here is the reduction in CO_2 emissions from the reduction in coal use, while the second term is the partially compensating increase in CO_2

emissions from the increase in gas use. Our best-fit value for A is 0.027 GtC/exajoule, and C/A=0.56. To apply Eq. (4) we need to determine a reasonable value for the relative gas-to-coal efficiency ratio (c/a), which we assume does not change appreciably over time. For electricity generation, the primary sector for coal-to-gas substitution, Hayhoe et al. (2002, Table 2) give representative efficiencies of 32% for coal and 60% for gas. Using these values, Eq. (4) becomes …

$$\Delta ECO2 = 0.027\ \Delta Pcoal[1 - 0.299] \tag{5}$$

for ΔECO2 in GtC and ΔP in exajoules. Thus, for a unit reduction in coal emissions, there is an increase in emissions from gas combustion of about 0.3 units.

To complete our calculations, we need to estimate the changes in methane, sulfur dioxide and black carbon emissions that would follow the coal-to-gas conversion. Consider methane first. Methane is emitted to the atmosphere as a by-product of coal mining and gas production. Although these fugitive emissions are relatively small, they are important because methane is a far more powerful forcing agent per unit mass than CO_2.

For coal mining we use information from Spath et al. (1999; Figs. C1 and C4). A typical US coal-fired power plant emits 1,100 gCO2/kWh, with an attendant release of methane of 2.18 gCH4/kWh, almost entirely from mining. Thus, for each GtC of CO_2 emitted from a coal-fired power plant, 7.27 TgCH4 are emitted from mining. Spath et al. give other information that can used to check the above result. They give values of 1.91 gCH4 released per ton of coal mined from surface mines, and 4.23 gCH4 per ton from deep mines. As 65% of coal comes from deep mines, the weighted average release is 3.42 gCH4/ton. Since 1 ton of coal, when burned, typically produces 1.83 kgCO2, the amount of fugitive methane per GtC of CO_2 emissions from coal-fired power plants is 6.85 TgCH4/GtC, consistent with the previous result. For our calculations we use the average of these two results, 7.06 TgCH4/GtC; i.e., if CO_2 emissions from coal-fired power generation are reduced by 1 GtC, we assume a concomitant decrease in CH_4 emissions of 7.06 TgCH4. We assume that this value for the USA is applicable for other countries.

For leakage associated with gas extraction and transport we note that every kg of gas burned produces 12/16 kgC of CO_2. If the leakage rate is "p" percent, then, for any given increase in CO_2 emissions from gas combustion, the amount of fugitive methane released is (p/100) (16/12) 1000=13.33 (p) TgCH4/GtC. For a leakage rate of 2.5%, for example (roughly the present leakage rate for conventional gas extraction), this is 33.3 TgCH4/GtC. Because the CO_2 emissions change from gas combustion is much less than that for coal (about 30%; see Eq. (5)), for the 2.5% leakage case this would make the coal mining and gas leakage effects on CH_4 quite similar (but of opposite sign), in accord with Hayhoe et al. (2002, Table 1).

SO_2 emissions are important because coal combustion produces substantial SO_2, whereas SO_2 emissions from gas combustion are negligible. Reducing energy production from coal has compensating effects — reduced CO_2 emissions leads to reduced warming in the long term, but this is offset by the effects of reduced SO_2 emissions which lead to lower aerosol loadings in the atmosphere and an attendant warming (Wigley 1991). For CO_2 and SO_2, emissions factors for coal (from Hayhoe et al. 2002, Table 1) are 25 kgC/GJ and 0.24 kgS/GJ. For each GtC of CO_2 produced from coal combustion, therefore, there will be 19.2 TgS of SO_2 emitted. We can check this using emissions factors from Spath et al. (1999, Figs. C1 and C2). For a typical coal-fired power plant these are 7.3 gSO2/kWh and 1,100 gCO2/kWh. Hence, for each GtC of CO_2 produced from coal combustion, SO_2 emissions will be 12.17 TgS. Effective global emissions factors can also be obtained from published emissions scenarios. For example, for changes over 2000 to 2010 in the MINREF scenario, the emissions factor for coal combustion is approximately 11.6 TgS/GtC.

From these different estimates it is clear that there is considerable uncertainty in the SO_2 emissions factor, echoing in part the widely varying sulfur contents in coal. Furthermore, for future emissions from coal combustion the SO_2 emissions factor is likely to decrease markedly due to the imposition of SO_2 pollution controls (as explained, for example, in Nakićenović and Swart 2000). It is difficult to quantify this effect, a difficulty highlighted, for example, by the fact that, in the second half of the 21st century, many published scenarios show increasing CO_2 emissions, but decreasing SO_2 emissions — with large differences between scenarios in the relative changes.

For the coal-to-gas transition, it is not at all clear how to account for the effects that SO_2 pollution controls, that will likely go on in parallel with any transition from coal to gas, will have on the SO_2 emissions factor. However, future coal-fired plants will certainly employ such controls, so emissions factors for SO_2 will decrease over time. To account for this we assume a value of 12 TgS/GtC for the present (2010) declining linearly to 2 TgS/GtC by 2,060 and remaining at this level thereafter. This limit and the attainment date are consistent with the fact that many of the SRES scenarios tend to stabilize SO_2 emissions at a finite, non-zero value at around this time.

For black carbon (BC) aerosol emissions we use the relationship between BC and SO_2 emissions noted by Hayhoe et al. (2002, p. 125) and make BC forcing proportional to SO_2 emissions. Using best-estimate forcings from the IPCC Fourth Assessment Report, this means that the increase in sulfate aerosol forcing changes due to SO_2 emissions reductions are reduced by approximately 30% by the attendant changes in BC emissions. This is a larger BC effect than in Hayhoe et al. However, compared with the large overall uncertainty in aerosol forcing, the difference between what we obtain here and the results of Hayhoe et al. are relatively small.

For our coal-to-gas emissions scenario we assume that primary energy from coal is reduced linearly (in percentage terms) by 50% over 2010 to 2050 (1.25%/yr), and that the reduction in final energy is made up by extra energy from gas combustion. (A second, more extreme scenario is considered in the Electronic Supplementary Material). In this way, there are no differences in final energy between the MINREF baseline scenario and the coal-to-gas perturbation scenario. Hayhoe et al. consider scenarios where coal production reduces by 0.4, 1.0 and 2.0%/yr over 2000 to 2025. After 2050 we assume no further percentage reduction in coal-based energy (i.e., the reduction in emissions from coal relative to the baseline scenario remains at 50%). This is an idealized scenario, but it is sufficiently realistic to be able to assess the relative importance of different gas leakage rates. We consider leakage rates of zero to 10%,

Baseline and perturbed (coal to gas) primary energy scenarios for coal and gas are shown in Fig. 1, together with the corresponding fossil-fuel CO_2 emissions. The changes in primary energy breakdown are large: e.g., in 2100, primary energy from coal is 37% more than from gas in the baseline case, but 50% less than gas in the perturbed case. The corresponding reduction in emissions is less striking. In the perturbed case, 2100 emissions are reduced only by 19%. (Cases where there are larger emissions reductions are considered in the Electronic Supplementary Material).

To determine the consequences of the coal-to-gas scenario we use the MAGICC coupled gas-cycle/upwelling-diffusion climate model (Wigley et al. 2009; Meinshausen et al. 2011). These are full calculations from emissions through concentrations and radiative forcing to global-mean temperature consequences. We do not make use of Global Warming Potentials (as in Howarth et al. 2011, for example), which are a poor substitute for a full calculation

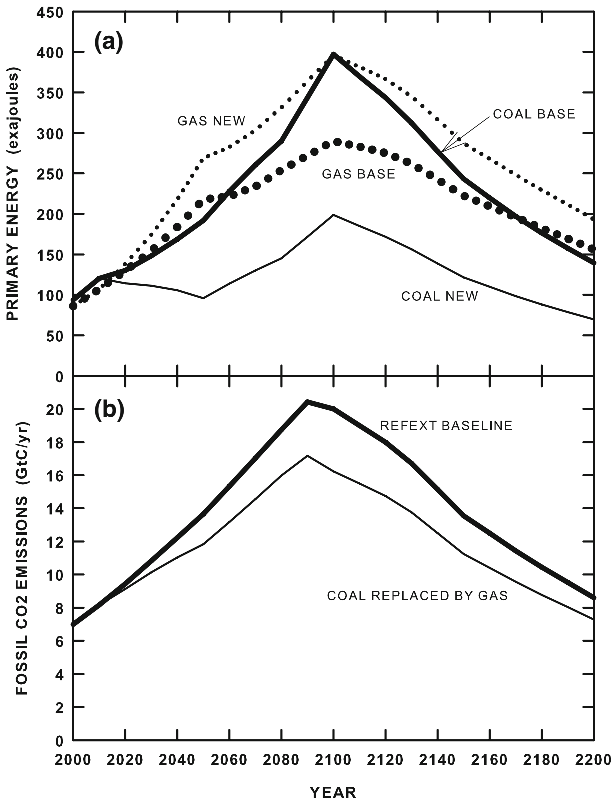


Fig. 1 **a** Primary energy scenarios. Baseline data to 2100 are from the CCSP2.1a MiniCAM Reference scenario. After 2100, baseline primary energy data have been constructed to be consistent with emissions data in the extended MiniCAM Reference scenario (Wigley et al. 2009 — REFEXT). Full lines are for coal, dotted lines are for gas. "NEW" data correspond to the coal-to-gas scenario. Under the final energy constraint that ΔFgas = −ΔFcoal, ΔPgas = −(a/c) ΔPcoal = −0.533 ΔPcoal. **b** Corresponding fossil CO_2 emissions data

(see, e,g., Smith and Wigley 2000a, b). MAGICC considers all important radiative forcing factors, and has a carbon cycle model that includes climate feedbacks on the carbon cycle. Methane lifetime is affected by atmospheric loadings on methane, carbon monoxide, nitrogen oxides (NOx) and volatile organic compounds. The effects of methane on tropospheric ozone and stratospheric water vapor are considered directly. For component forcing values we use central estimates as given in the IPCC Fourth Assessment Report (IPCC 2007, p.4). We also assume a central value for the climate sensitivity of 3°C equilibrium warming for a CO_2 doubling. (A second case using a higher sensitivity is considered in the Electronic Supplementary Material).

Figure 2 shows the relative and total effects of the coal-to-gas transition for a leakage rate of 5%. This is within the estimated leakage rate range (1.7–6.0%; Howarth et al. 2011) for conventional methane production (the effects of well site leakage, liquid uploading and gas processing, and transport, storage and processing). For methane from shale, Howarth et al. estimate an additional leakage of 1.9% (their Table 2) with a range of 0.6–3.2% (their Table 1). The zero to 10.0% leakage rate range considered here spans these estimates — although we note that the high estimates of Howarth et al. have been criticized (Ridley 2011, p. 30).

The top panel of Fig. 2 shows that the effects of CH_4 leakage and reduced aerosol loadings that go with the transition from coal to gas can appreciably offset the effect of reduced CO_2 concentrations, potentially (see Fig. 3) until well into the 22nd century. For the leakage rate ranges considered here, however, the overall effects of the coal to gas transition on global-mean temperature are very small throughout the 21st century, both in absolute and relative terms (see Fig. 2a). This is primarily due to the relatively small reduction in CO_2 emissions that is effected by the transition away from coal (see Fig. 1b). Cases where the CO_2 emissions reductions are larger (due to a more extreme substitution scenario, or a different baseline) are considered in the Electronic Supplementary Material. The relative contributions to temperature change are similar, but the magnitudes of temperature change scale roughly with the overall reduction in CO_2 emissions.

Figure 3 shows the sensitivity of the temperature differential to the assumed leakage rate. The CO_2 and aerosol terms are independent of the assumed leakage rate, so we only show the methane and total-effect results. These results are qualitatively similar to those of Hayhoe et al. who considered only a single leakage rate case (corresponding approximately to our 2.5% leakage case). For leakage rates of more than 2%, the methane leakage contribution is positive (i.e., replacing coal by gas produces higher methane concentrations) — see the "CH4 COMPONENT" curves in Fig. 3. Depending on leakage rate, replacing coal by gas leads, not to cooling, but to additional warming out to between 2,050 and 2,140. Initially, this is due mainly to the influence of SO_2 emissions changes, with the effects of CH_4 leakage becoming more important over time. Even with zero leakage from gas production, however, the cooling that eventually arises from the coal-to-gas transition is only a few tenths of a degC (greater for greater climate sensitivity — see Electronic Supplementary Material). Using climate amelioration as an argument for the

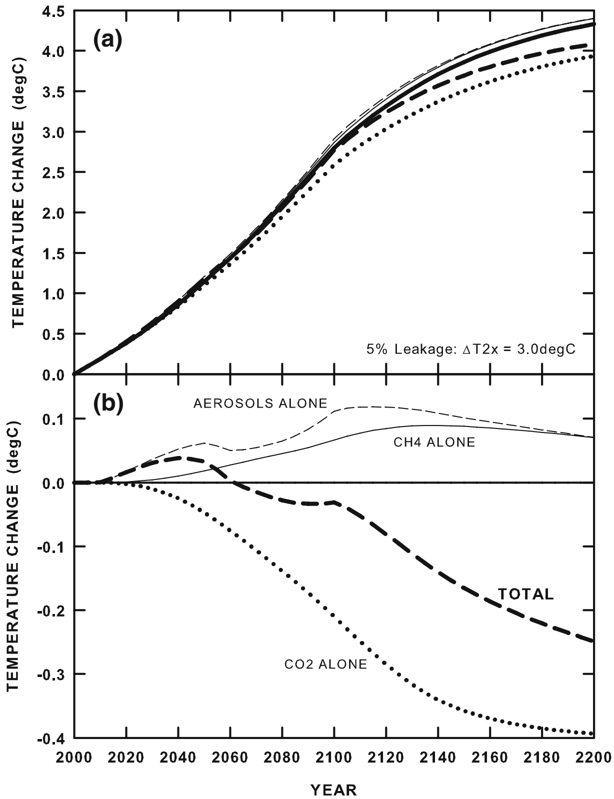


Fig. 2 **a** Baseline global-mean warming (*solid bold line*) from the extended CCSP2.1a Mini-CAM reference scenario together with the individual and total contributions due to reduced CO_2 concentrations, reduced aerosol loadings and increased methane emissions for the case of 5% methane leakage. The *bold dashed line* gives the result for all three components, the *dotted line* shows the effect of CO_2 alone. The *top two thin lines* show the CH_4 and aerosol components. **b** Detail showing differences from the baseline

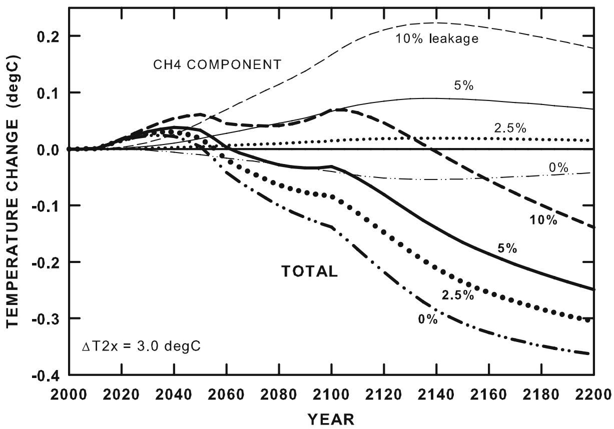


Fig. 3 The effects of different methane leakage rates on global-mean temperature. The *top four curves* (CH4 COMPONENT) show the effects of methane concentration changes, while the *bottom four curves* (TOTAL) show the total effects of methane changes, aerosol changes and CO_2 concentration changes. The latter two effects are independent of the leakage rate, and are shown in Fig. 2. Results here are for a climate sensitivity of 3.0°C

transition is, at best, a very weak argument, as noted by Hayhoe et al. (2002), Howarth et al. (2011) and others.

In summary, our results show that the substitution of gas for coal as an energy source results in increased rather than decreased global warming for many decades — out to the mid 22nd century for the 10% leakage case. This is in accord with Hayhoe et al. (2002) and with the less well established claims of Howarth et al. (2011) who base their analysis on Global Warming Potentials rather than direct modeling of the climate. Our results are critically sensitive to the assumed leakage rate. In our analysis, the warming results from two effects: the reduction in SO_2 emissions that occurs due to reduced coal combustion; and the potentially greater leakage of methane that accompanies new gas production relative to coal. The first effect is in accord with Hayhoe et al. In Hayhoe et al., however, the methane effect is in the opposite direction to our result (albeit very small). This is because our analyses use more recent information on gas leakage from coal mines and gas production, with greater leakage from the latter. The effect of methane leakage from gas production in our analyses is, nevertheless, small and less than implied by Howarth et al.

Our coal-to-gas scenario assumes a linear decrease in coal use from zero in 2010 to 50% reduction in 2050, continuing at 50% after that. Hayhoe et al. consider linear decreases from zero in 2000 to 10, 25 and 50% reductions in 2025. If these authors assumed constant reduction percentages after 2025, then their high scenario is very similar to our scenario.

In our analyses, the temperature differences between the baseline and coal-to-gas scenarios are small (less than 0.1°C) out to at least 2100. The most important result, however, in accord with the above authors, is that, unless leakage rates for new methane can be kept below 2%, substituting gas for coal is not an effective means for reducing the magnitude of future climate change. This is contrary to claims such as that by Ridley (2011) who states (p. 5), with regard to the exploitation of shale gas, that it will "accelerate the decarbonisation of the world economy". The key point here is that it is not decarbonisation *per se* that is the goal, but the attendant reduction of climate change. Indeed, the shorter-term effects are in the opposite direction. Given the small climate differences between the baseline and the coal-to-gas scenarios, decisions regarding further exploitation of gas reserves should be based on resource availability (both gas and water), the economics of extraction, and environmental impacts unrelated to climate change.

Acknowledgments Comments from Chris Green and the external reviewers helped improve the original version of this manuscript. The National Center for Atmospheric Research is supported by the National Science Foundation.

References

Clarke LE, Edmonds JA, Jacoby HD, Pitcher H, Reilly JM, Richels R (2007) Scenarios of Greenhouse Gas Emissions and Atmospheric Concentrations. Sub-report 2.1a of Synthesis and Assessment Product 2.1. A Report by the Climate Change Science Program and the Subcommittee on Global Change Research, Washington, DC, 154pp

EPA (2005) Compilation of Air Pollutant Emission Factors, vol. I, Stationary Point and Area Sources. Report AP-42, Office of Air and Radiation, U.S. EPA, Research Triangle Park, NC 27711

Hayhoe K, Kheshgi HS, Jain AK, Wuebbles DJ (2002) Substitution of natural gas for coal: Climatic effects of utility sector emissions. Climatic Change 54:107–139

Howarth RW, Santoro R, Ingraffea A (2011) Methane and the greenhouse-gas footprint of natural gas from shale formations. Climatic Change. doi:10.1007/s10584-011-0061-5

IPCC (2007) Summary for Policymakers. In: Solomon S, Qin D, Manning M, Chen Z, Marquis M, Averyt KB, Tignor M, Miller HL (eds) Climate change 2007: The Physical Science Basis; Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, pp 1–18

Meinshausen M, Raper SCB, Wigley TML (2011) Emulating coupled atmosphere-ocean and carbon cycle models with a simpler model, MAGICC6 – Part I: model description and calibration. Atmos Chem Phys 11:1417–1456

Nakićenović N, Swart R (eds) (2000) Special report on emissions scenarios. Cambridge University Press, Cambridge, 570 pp

Ridley M (2011) The shale gas shock. GWPF Report 2, Global Warming Policy Foundation, London, UK, 34 pp

Smith SJ, Wigley TML (2000a) Global warming potentials: 1. Climatic implications of emissions reductions. Climatic Change 44:445–457

Smith SJ, Wigley TML (2000b) Global warming potentials: 2. Accuracy. Climatic Change 44:459–469

Spath PL, Mann MK, Kerr DR (1999) Life cycle assessment of coal-fired power production. National Renewable Energy Laboratory Technical Paper, NREL/TP-570-25119, 172pp

Wigley TML (1991) Could reducing fossil-fuel emissions cause global warming? Nature 349:503–506

Wigley TML, Clarke LE, Edmonds JA, Jacoby HD, Paltsev S, Pitcher H, Reilly JM, Richels R, Sarofim MC, Smith SJ (2009) Uncertainties in climate stabilization. Climatic Change 97:85–121. doi:10.1007/s10584-009-9585-3

September 11, 2013

DRBC Public Hearing Comments

In Dec of 2012, The AP reported that a USGS team based in Menlo Park, CA found that a quake in Colorado and a damaging 5.6 magnitude earthquake in Oklahoma were induced by underground disposal of fracking waste. A detailed report by Young Kim of The Lamont-Doherty Laboratory (published in the Journal of Geophysical Research) in concert with USGS concluded that the occurrence of over 100 earthquakes within a 14 month period near Youngstown, Ohio were also the result of fracking waste injection wells. Scientists concluded that 95 quakes in the Raton Basin between 2001 and 2011 were also the result of deep injection of oil and gas drilling waste. USGS scientists concluded that most quakes this past decade were located within 3 miles of an active wastewater injection well. USGS scientist Justin Rubinstein, co-author of the report said that "This is a societal risk you need to be considering. At the moment we're the only people who have done this work and our evidence is pretty conclusive."

The same thing is happening elsewhere in the US including Arkansas, West Virginia, Texas and Wyoming where there are injection wells. ProPublica reported that "Records from disparate corners of the US show that wells drilled to bury this waste deep beneath the ground have repeatedly leaked, sending dangerous chemicals and waste gurgling to the surface or on occasion, seeping into shallow aquifers that store a significant portion of the nation's drinking water." The waste is comprised of millions of gallons of water mixed with toxic, carcinogenic chemicals combined with “produced water” that comes to the surface during fracking operations. “Produced water” has high levels of BTEX chemicals, and salts such as chloride and bromides and heavy metals and is also radioactive.

Migration of fluids from wells have been documented to travel faster and farther than researchers thought possible. In a 2000 case that wasn't caused by injection but brought important lessons about how fluids could move underground, hydrogeologists concluded that bacteria-polluted water migrated horizontally underground for several thousand feet in just 26 hours, contaminating a water supply in Walkerton, Ontario and sickening thousands of residents.

Deep well injection takes place in 32 states from PA to CA. The energy industry has its own injection well category, Class 2, which includes disposal wells and wells in which fluids are injected to force out trapped gas and oil. All hydrofracked gas wells are injection wells. Class 2 is very lightly regulated, a problem that allows unsupervised injection operations - one of the contributing factors of the fatal contamination of 38-mile long Dunkard Creek.

Tom Myers, a hydrologist, drew on research showing that natural faults and fractures are more prevalent than commonly understood to create a model that predicts how chemicals might move in the Marcellus Shale. Myers new model said that chemicals could leak through natural cracks into aquifers tapped for drinking water in about 100 years, far more quickly than had been thought. In areas where there is hydrofracking or drilling, man-made faults and natural ones could intersect and chemicals could migrate to the surface in as little as a few years - or less. "It's out of sight, out of mind. Simply put, they are not impermeable, it's not a matter of if fluid will move through rock layers, but when." he said referring to injected waste and the rock layers.

Until recently injection wells were not considered suitable in the PA geology and wastewater from fracking has been shipped to the injection wells in Ohio (which are the subject of earthquakes). But a recent change in policy - certainly not geology, has paved the way for the installation of fracking wastewater wells in PA. That means that if PA regulations were to be implemented in the DRB there would be fracking and injection wells here in the basin.

The DRB is within a seismically active region that has a documented history of earthquakes. Fracking induced earthquakes and migration of toxic fluids as a result, in addition to the risks that earthquakes pose to potentially hundreds or thousands of gas wells is much too dangerous a risk and should cause this commission to ban fracking in this basin.

Joe Levine,
Damascus Citizens

Reference attachments

Induced seismicity associated with fluid injection into a deep well in Youngstown, Ohio

Won-Young Kim [1]

Received 1 February 2013; revised 6 June 2013; accepted 10 June 2013; published 19 July 2013.

[1] Over 109 small earthquakes (M_w 0.4–3.9) were detected during January 2011 to February 2012 in the Youngstown, Ohio area, where there were no known earthquakes in the past. These shocks were close to a deep fluid injection well. The 14 month seismicity included six felt earthquakes and culminated with a M_w 3.9 shock on 31 December 2011. Among the 109 shocks, 12 events greater than M_w 1.8 were detected by regional network and accurately relocated, whereas 97 small earthquakes ($0.4 < M_w < 1.8$) were detected by the waveform correlation detector. Accurately located earthquakes were along a subsurface fault trending ENE-WSW—consistent with the focal mechanism of the main shock and occurred at depths 3.5–4.0 km in the Precambrian basement. We conclude that the recent earthquakes in Youngstown, Ohio were induced by the fluid injection at a deep injection well due to increased pore pressure along the preexisting subsurface faults located close to the wellbore. We found that the seismicity initiated at the eastern end of the subsurface fault—close to the injection point, and migrated toward the west—away from the wellbore, indicating that the expanding high fluid pressure front increased the pore pressure along its path and progressively triggered the earthquakes. We observe that several periods of quiescence of seismicity follow the minima in injection volumes and pressure, which may indicate that the earthquakes were directly caused by the pressure buildup and stopped when pressure dropped.

Citation: Kim, W.-Y. (2013), Induced seismicity associated with fluid injection into a deep well in Youngstown, Ohio, *J. Geophys. Res. Solid Earth*, *118*, 3506–3518, doi:10.1002/jgrb.50247.

1. Introduction

[2] Since the early 1960s, it has been known that waste disposal by fluid injection at high pressure into subsurface rock formations can cause earthquakes known as induced seismicity [e.g., *Nicholson and Wesson*, 1992; *McGarr et al.*, 2002]. There are well-documented cases of induced seismicity including Rocky Mountain Arsenal (RMA), Colorado, in the 1960s [*Healy et al.*, 1968]; Ashtabula, Ohio, in the 1980s [*Seeber et al.*, 2004]; Paradox Valley, Colorado, in the 1990s [*Ake et al.*, 2005]; and Guy, Arkansas, during 2011 [*Horton*, 2012], among others. The largest events at those induced seismicities range from M_w 3.9 at Ashtabula, Ohio, M_w 4.3 at Paradox Valley, M_w 4.7 at Guy, Arkansas, and M_w 4.85 at Rocky Mountain Arsenal [*Herrmann et al.*, 1981].

[3] Since early 2011, many significant earthquakes suspected to be induced events occurred in the United States midcontinent region [*Ellsworth et al.*, 2012]. They are M_w 5.7 earthquake on 06 November 2011 at Prague, Oklahoma [*Keranen et al.*, 2013]; M_w 5.3 event on 23 August 2011 at Trinidad, Colorado [*Rubinstein et al.*, 2012; *Viegas et al.*, 2012]; M_w 4.8 event on 20 October 2011 at Fashing, Texas [*Brunt et al.*, 2012]; M_w 4.8 earthquake on 17 May 2012 at Timpson, Texas [*Brown et al.*, 2012]; M_w 4.3 earthquake on 11 September 2011 at Cogdell oil field, Snyder, Texas [*Davis and Pennington*, 1989]; and M_w 3.3 event on 16 May 2009 at Dallas-Fort Worth, Texas [*Frohlich et al.*, 2011], and are listed in Table 1. These are broadly related to fluid injection into subsurface strata through disposal wells such as; for secondary recovery of oil (Cogdell, TX), waste fluid from coal bed methane production (Trinidad, CO), wastewater (Prague, OK) and brine from hydraulic fracturing of shale gas (Dallas-Fort Worth, TX).

[4] Over the last several years, hydraulic fracturing has become widely used in the northeastern United States to extract natural gas from the Marcellus Shale (tight Devonian black shale) [see, e.g., *National Academy of Sciences*, 2012]. Much of the hydraulic fracturing of shale gas has been carried out in Pennsylvania, but the wastewater (brine) from the hydraulic fracturing process is being transported to Ohio and disposed of by injecting into deep wells at a depth range of 2.2–3.0 km under high pressure of up to 17.2 MPa (2500 psi [pounds per square inch]). The target injection intervals are usually sandstone layers in the Knox Dolomite (Lower Ordovician to Upper Cambrian) to Mt. Simon sandstone (Middle Cambrian). Five deep injection wells were drilled in

Additional supporting information may be found in the online version of this article.

[1]Lamont-Doherty Earth Observatory, Columbia University, Palisades, New York, USA.

Corresponding author: W.-Y. Kim, Lamont-Doherty Earth Observatory, Columbia University, 61 Rt. 9W, Palisades, NY 10964, USA. (wykim@ldeo.columbia.edu)

2169-9313/13/10.1002/jgrb.50247

Table 1. Recent Potentially Induced Earthquakes Occurring in the United States[a]

Date	Time	Lat.	Long.	Depth	Magnitude	Location
(year-mo-dy)	(hh:mm:ss)	(ºN)	(ºW)	(km)	(M_w)	(references)
2011-11-06	03:53:10	35.53	96.77	5	5.7	Prague, OK[b]
2011-08-23	05:46:18	37.06	104.70	4	5.3	Trinidad, CO[c]
2011-10-20	12:24:41	28.86	98.08	5	4.8	Fashing, TX[d]
2012-05-17	08:12:00	31.93	94.37	5	4.8	Timpson, TX[e]
2011-02-28	05:00:50	35.27	92.34	3	4.7	Guy, AR[f]
2011-09-11	12:27:44	32.85	100.77	5	4.3	Snyder, TX[g]
2011-12-31	20:05:01	41.12	80.68	5	3.9	Youngstown, OH[h]
2009-05-16	16:24:06	32.79	97.02	4	3.3	Dallas-Fort Worth, TX[i]

[a]Listed according to their magnitudes.
[b]*Keranen et al*. [2013].
[c]*Meremonte et al*. [2002], *Rubinstein et al*. [2012], and *Viegas et al*. [2012].
[d]*Brunt et al*. [2012].
[e]*Brown et al*. [2012].
[f]*Horton* [2012].
[g]*Davis and Pennington* [1989], http://www.eas.slu.edu/eqc/eqc_mt/MECH.NA/20110911122745.
[h]*ODNR* [2012].
[i]*Frohlich et al*. [2011].

the Youngstown, Ohio area since 2010, but only the Northstar 1 injection well was operational during 2011 (Figure 1). Since the Northstar 1 waste disposal well became operational in late December 2010, Youngstown, Ohio has experienced small earthquakes. On 17 March 2011, residents in Youngstown, Ohio felt a M_w 2.3 earthquake. By 25 November 2011, nine earthquakes (M_w ~1.8–2.8) occurred near Youngstown, Ohio. These shocks are reported by the Division of Geological Survey of the Ohio Department of Natural Resources (ODNR) [see *Ohio Department of Natural Resources (ODNR)*, 2012, Table 5] by using data from sparse seismic stations in the region [*Hansen and Ruff*, 2003]. Prior to 2011, no earthquakes were recorded around Youngstown [*Stover and Coffman*, 1993; *Hansen*, 2012]. Although these earthquakes could not be accurately located due to sparse coverage of seismic stations in the region, these shocks were occurring close to a deep waste injection well Northstar 1 (Figure 1). On 1 December 2011, Lamont Cooperative Seismographic Network deployed four portable seismographic stations around Youngstown at the request of and in collaboration with ODNR to monitor seismicity at close distances and to determine hypocenters of the small earthquakes accurately for assessing whether these shocks were induced by the deep waste disposal well injecting fluid since the end of 2010 in the area (see Figure 1).

[5] On 24 December 2011, a magnitude 2.7 shock occurred in the epicentral area, which was well recorded by the four-station local network in the distance range from 1.9 to 6.5 km from the epicenter. The hypocenter of the shock was very well determined by the local station data, which had adequate coverage with the station azimuthal gap of 119° and distance to the two closest stations less than the focal depth. The shock was located about 0.8 ± 0.4 km west of the Northstar 1 well at a focal depth of 3.6 ± 0.8 km (95% confidence level). On 30 December 2011, ODNR requested the operator to shut down the Northstar 1 well, because the 24 December 2011 event was located close to the injection well with high confidence. On 31 December 2011 at 20:05 (UTC), a magnitude M_w 3.9 earthquake occurred in the same epicentral area within 24 h from the shutdown of the injection operation.

[6] This is a rare case of likely induced seismicity in the northeastern United States where major events in a sequence have been well recorded by local portable seismographs in place (with a high sample rate of up to 500 samples/s), providing an opportunity to study the sequence of seismicity in detail. In this study, we analyzed the spatiotemporal distribution of seismicity in detail and compared it with available fluid injection parameters to determine if the seismicity in Youngstown area during January 2011 to February 2012 was triggered by the fluid injection into a deep well or not. We also analyzed seismic data in detail in an attempt to shed light on relations between the induced seismicity and physical injection parameters of the deep well injection in the Youngstown area. The *study area* or *Youngstown area* refers to an area about 15 km radius from the main shock on 31 December 2011 (41.118°N, 80.692°W) around Youngstown, Ohio (Figure 1) [see *ODNR*, 2012, Figures 20 and 22].

2. Geologic and Geohydrologic Setting

[7] The study area (northeast Ohio around Youngstown) is located in a stable continental region of North America. Subhorizontal Paleozoic sedimentary strata composed of carbonates, evaporates, shale, sandstone, and siltstone of approximately 2.7 km thickness overlies the Precambrian basement. The bedrock units of the study area dip gently (~1°) to the southeast into the Appalachian Basin [*ODNR*, 2012]. The Precambrian crystalline basement in northeast Ohio is composed of igneous and metamorphic rocks, extending the ~1.1 billion years old Grenville Province exposed to the north in Canada. Geologic structures, including faults, pervasive in the Grenville terrain, are considered as the origin of many faults and general structures within the overlying sedimentary strata [*Baranoski*, 2002].

[8] Most known fault systems in the study area trend ESE-WNW [*Baranoski*, 2002]. The Smith Township fault, located about 20 km southwest of the study area, is the closest known fault system, which is a northwest-southeast oriented fault with the upthrown side to the northeast [*Baranoski*, 2002, Map PG-23]. This fault can be mapped on multiple units from the Precambrian surface through the Berea Sandstone (Late Devonian) and above based on well logs and driller's reported formation tops, illustrating that it has had recurrent movement throughout geologic

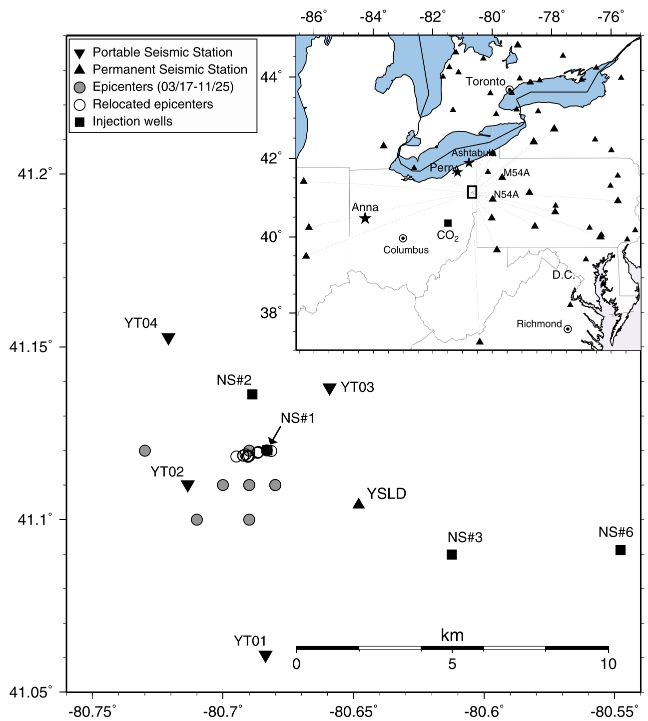


Figure 1. Nine earthquakes that occurred in Youngstown area during March–November 2011 are plotted by solid circles. These shocks were reported by ODNR and are scattered around the area. Twelve relocated earthquakes that have occurred in the area during March 2011 to January 2012 are plotted with open circles. The relocated earthquakes include M_w 2.7 shock on 24 December 2011, M_w 3.9 shock on 31 December 2011, and M_w 2.1 shock on 13 January 2012, which are recorded by local portable stations, and hence, located accurately by seismic data. Four portable seismographic stations deployed during 01 December 2011 to 30 April 2012 are plotted with inverted triangles, and a new seismographic station YSLD (Youngstown State University) an ANSS NetQuake strong motion instrument (solid triangle) are plotted for reference. Deep injection wells in the area are plotted with solid squares. Only Northstar 1 (NS#1) was operational during 2011. (inset) Permanent seismographic stations whose data were used to locate small earthquakes around Youngstown, Ohio are plotted with (solid triangles). Stations used for focal mechanism inversion are indicated by their source-receiver paths. Anna indicates Anna western Ohio seismic zone; Perry denotes 31 January 1986 M 5 earthquake; CO_2 denotes CO_2 No. 1 Well in Tuscawara County; Ashtabula denotes location of 1987 and 2001 earthquakes which occurred near the town.

time [*ODNR*, 2012]. Recent earthquakes that occurred in northeast Ohio with well-determined focal mechanisms indicate that left-lateral strike-slip faulting along E-W trending, steeply dipping faults are the predominant style of faulting due to broad-scale ENE-WSW trending horizontal compression, σ_{Hmax} [*Nicholson et al.*, 1988; *Zoback and Zoback*, 1991; *Du et al.*, 2003; *Seeber et al.*, 2004].

[9] The earthquakes in this study occurred exclusively in the Precambrian crystalline basement, whereas the potential reservoir strata in the injection interval are Paleozoic sedimentary rocks of alternating sandstone and dolomite layers. The Northstar 1 well was drilled into Precambrian granite for a total depth of 2802 m. The production casing was cemented in at a depth of 2504 m, and the well was completed open hole to depth 2802 m. Open hole electric logs indicate that the two largest porosity zones within the open hole section are the B zone Sandstone of the Knox Dolomite Group (Ordovician) with a total of 9.8 m net thickness averaging 9.4% porosity and the Mt. Simon Sandstone (Basal Sandstone) of Conasauga Group (Cambrian), which showed 15 m net thickness averaging 10.3% porosity [*ODNR*, 2012]. These two high-porosity zones are considered the reservoirs for brine injection at the site, although the target fluid injection zone is the entire open hole section of the well ~298 m (depth interval between 2504 and 2802 m).

[10] Within the Northstar 1 well, the Precambrian was encountered from a depth of 2741 m through total depth of 2802 m. Just above and at the Precambrian unconformity surface, porosity and permeability zones are indicated on the geophysical logs from 2736 to 2742 m depth. These porosity zones may be due to weathering of the Precambrian unconformity surface [*ODNR*, 2012]. The magnetic resonance log, which can detect higher and lower permeability zones of the rocks, showed a high-permeability zone with a high percentage of moveable fluid in the upper portion of the Precambrian strata (depth 2765–2769 m). Another high-permeability zone with a high percentage of moveable water is found from 2773 to 2776 m. At this same depth, high-angle natural fractures or fault zones have been identified from the well log and images. A clear ENE-WSW trending fracture zone has been identified from compass orientations of natural fractures plotted from fracture and breakout roseplots during geophysical logging at Northstar 1 well [*ODNR*, 2012].

3. Seismicity

[11] More than 200 felt earthquakes have been noted in Ohio since 1776, including at least 15 events that have caused minor to moderate damage [*Stover and Coffman*, 1993; *Hansen*, 2012]. The largest and most damaging earthquake occurred on 9 March 1937, in western Ohio, and the M 5.4 shock caused notable damage in the town of Anna, Shelby County, where nearly every chimney in town was toppled. The seismic activity in western Ohio around Anna is relatively frequent compared to other parts of Ohio, and hence, the area is referred to as the Anna seismic zone. A number of earthquakes have occurred in northeast Ohio; for example, M 5.0 event on 31 January 1986 near Perry [*Nicholson et al.*, 1988] (see Figure 1), and M 3.8 earthquake on 13 July 1987 and a M_w 3.9 earthquake on 26 January 2001 near Ashtabula [*Seeber and Armbruster*, 1993; *Seeber et al.*, 2004]. The 1987 and 2001 earthquakes in Ashtabula have been reported as induced events due to injection of waste fluid at a deep Class I well.

[12] There were no earthquakes reported within the study area (Youngstown, Mahoning County) prior to 2011 [*Stover and Coffman*, 1993]. During 17 March through 25 November 2011, nine small earthquakes (M_w 1.8–2.7) occurred around Youngstown, Ohio (Figure 1). Although, the locations of these shocks were not very accurate due to sparse seismic station coverage, the shocks occurred close to an operating deep waste injection well (Northstar 1 well)

Table 2. List of 12 Regional and 9 Local Events Relocated by Using Double-Difference Method[a]

Id	Date (year-mo-dy)	Time (hh:mm:sec)	Latitude (ºN)	Longitude (ºW)	Depth (km)	Mag (M_w)	Erh (km)	Erz (km)
				Twelve Regional Events Located by Regional Seismographic Network				
1	2011-03-17	10:42:20.49	41.12008	80.68321	3.76	1.78	2.02	4.10
2	2011-03-17[b]	10:53:09.69	41.11983	80.68148	3.84	2.28	1.61	-
3	2011-08-22	08:00:31.55	41.11846	80.68999	3.75	2.00	1.30	2.35
4	2011-08-25	19:44:21.36	41.11937	80.68675	3.86	2.15	2.06	3.46
5	2011-09-02[b]	21:03:26.06	41.11960	80.68639	3.98	2.16	2.86	6.79
6	2011-09-26[b]	01:06:09.83	41.11847	80.69048	3.77	2.33	1.22	2.57
7	2011-09-30[b]	00:52:37.57	41.11945	80.68675	3.89	2.77	1.10	2.28
8	2011-10-20	22:41:09.96	41.11821	80.69044	3.82	2.18	1.51	-
9	2011-11-25	06:47:27.03	41.11885	80.69138	3.67	2.02	1.44	3.07
10	2011-12-24[b]	06:24:57.98	41.11850	80.69235	3.56	2.66	0.38	0.84
11	2011-12-31[b]	20:05:00.04	41.11855	80.69215	3.67	3.88	0.41	0.86
12	2012-01-13	22:29:34.00	41.11828	80.69484	3.65	2.09	0.34	0.82
				Small Events Located by Local Portable Seismographic Network				
13	2012-01-11	21:29:28.06	41.12294	80.67929	3.50	0.39	0.41	1.08
14	2012-01-12	03:01:45.43	41.12304	80.68028	3.57	0.07	0.41	1.10
15	2012-01-13	01:47:29.55	41.12252	80.68132	3.47	−0.05	0.43	1.34
16	2012-01-14	12:53:36.94	41.1203	80.6837	3.90	0.09	0.46	0.84
17	2012-01-17	02:25:59.60	41.11901	80.69127	3.91	0.34	0.43	1.01
18	2012-01-17	07:09:08.73	41.12413	80.67020	3.61	−0.06	0.46	1.37
19	2012-01-18	12:12:01.21	41.11866	80.69570	3.59	0.41	0.41	0.86
20	2012-01-22	12:06:20.37	41.12316	80.67916	3.53	−0.11	0.41	1.10
21	2012-02-11	06:47:19.09	41.12459	80.67278	3.66	−0.40	0.53	1.49

[a]Event #16 was not relocated by double-difference method; Events 10, 11, and 12 are also relocated by using local seismographic network data; Mag = moment magnitude; Erh = horizontal location error; Erz = vertical location error; Location errors are from single event locations and correspond to 95% confidence error ellipse.
[b]Felt earthquakes.

located in Youngstown. The error ellipses of these shocks were up to 1.99 × 1.57 km at 68% confidence level as reported by ODNR (M. Hansen, personal communication, 2011). Hence, these shocks were suspected as induced earthquakes. The seismicity continued, and on 24 December 2011, a magnitude 2.7 shock occurred in the study area, which was followed by a M_w 3.9 event on 31 December 2011. The M_w 2.1 event on 13 January 2012 was the last $M_w > 2.0$ earthquake of the 2011–2012 sequence (Table 2).

3.1. Single Event Location and Location Accuracy

[13] Twelve regional events with $M_w \geq 1.8$ that occurred during 17 March 2011 to 13 January 2012 in Youngtown area were first located by using HYPOINVERSE [*Klein*, 2007]. The velocity model used for location is an average 1D model for northeastern Ohio that consists of the top layer with *P* wave velocity of 4.5 km/s and thickness of 2.7 km, and a 7.3 km thick crystalline basement with *P* wave velocity of 6.12 km/s [*Seeber et al.*, 2004]. The *S* wave velocities are considered to be $V_P/\sqrt{3}$ (Table 3). All events were located with *P* and *S* wave arrival times from at least a dozen seismographic stations around Youngstown, Ohio. For the nine earthquakes during March–November 2011, the nearest station is at about 60 km, but most stations were at distances 100 to 300 km with azimuthal gap of about 90° (Figure 1); hence, the location uncertainties are large—horizontal error is up to 2.8 km for 95% confidence level as listed in Table 2. The locations of 12 earthquakes with their horizontal error ellipse are plotted in Figure 2.

[14] The last three events among the 12 shocks were also recorded by a four-station local network deployed during 1 December 2011 to 30 April 2012 around the epicentral area (Figures 1 and 2). Hence, these shocks were accurately located by the local network data. Three shocks exceed the network criteria [e.g., *Gomberg et al.*, 1990], which are based on the geometry of stations, and can be used to assess the reliability of the location. For three shocks, the number of local *P* or *S* wave arrival times used for each event were greater than eight (nobs = 8–10) of which half are *S* wave arrivals; the greatest azimuthal gap without observation was less than 180° (gap = 90–120°); distance to the closest station was less than focal depth (dmin = 1.9 km); and at least one *S* wave arrival time was within a distance of about 1.4 times the focal depth for good depth constraint [*Gomberg et al.*, 1990]. Three earthquakes that were recorded both by regional and local networks provide data to assess the event location uncertainty and will be used in a later section to anchor relocation of earlier shocks with no local data coverage.

[15] To assess the effect of vertical velocity heterogeneities on focal depth and epicenter determination, we constructed 1D Earth models from the available acoustic well logs in the study area (NS#1 and CO_2 No. 1 Well, see Figure 1). We inferred crustal velocity structure for the top 2.74 km of Paleozoic sedimentary rocks in the region (see the supporting information). The Youngstown well log velocity model consists of 19 layers and is characterized by interbedded high-velocity carbonate rock layers and thick low-velocity shale strata. The prominent strata are the Salina Group of Upper Silurian formation with interbedded salt, anhydrite, dolomite, and shale, which show large velocity and density fluctuations, followed by Lockport Dolomite of Lower Silurian that exhibit very high *P* wave velocity (see Figure S1). At the injection target interval depth

Table 3. Youngstown, Ohio Layered Earth Models

Depth	V_P	V_S	Depth	V_P	V_S	Density	Depth	V_P	V_S	Density	V_P/V_S
(km)	(km/s)	(km/s)	(km)	(km/s)	(km/s)	(kg/m^3)	(km)	(km/s)	(km/s)	(kg/m^3)	
Northeastern Ohio[a]			*Youngstown well log A*[b]				*Youngstown well log B*[c]				
0.00	4.50	2.60	0.00	3.86	2.19	2630	0.00	3.86	2.26	2630	1.71
			0.93	4.98	2.83	2600	0.93	4.98	2.80	2600	1.78
			2.11	6.13	3.48	2710	2.11	6.13	3.50	2710	1.75
2.74	6.12	3.54	2.74	6.15	3.49	2710					
10.0	6.62	3.83	10.0	6.62	3.76	2710	10.0	6.62	3.83	2710	1.73

[a]Constant $V_P/V_S = 1.73$ and density = 2700 kg/m^3.
[b]Constant $V_P/V_S = 1.76$.
[c]Variable V_P/V_S. The Moho is at 41 km depth with $V_P = 8.1$ km/s, $V_S = 4.68$ km/s, and density = 2700 kg/m^3; at the top of the upper mantle.

range of 2.3–2.74 km, low-velocity sandstone and high-velocity dolomite strata are interbedded.

[16] In order to assess uncertainties in earthquake location, we inferred a simple average 1D velocity model by averaging groups of strata with similar characteristics. Hence, the model Youngstown well log A has three layers with constant V_P/V_S ratio of 1.76, and a two-layer model Youngstown well log B has various V_P/V_S ratio for each layer (Table 3). Locations using these velocity models indicate that two layers over the basement Youngstown well log B model, with variable V_P/V_S ratios for each layer, yielded the location with the least root-mean-square (RMS) travel time residuals; however, the differences in location parameters are negligible. The northeastern Ohio velocity model that we used yields the focal depths of 3.52, 3.67, and 3.64 km for 24 December 2011, 31 December 2011, and 13 January 2012 events, respectively, with their 95% confidence error ellipsoids extending up to 0.86 km in the vertical direction. The horizontal error is up to 0.41 km at 95% confidence level (see Table 2).

[17] Three different velocity models yield very similar locations with negligible differences in their location errors. The differences in focal depths are less than 0.15 km depending upon the three models used. If we take the centroid of the source region to be at 3.5 km depth, then these location uncertainties in the vertical direction stretch between 2.7 and 4.3 km depths, which puts the earthquake sources firmly in the Precambrian basement. We consider the location accuracy given is well constrained by velocity structure from well log data, and the solution is reliable considering the network criteria discussed above.

3.2. Focal Mechanism of the Earthquake on 31 December 2011

[18] The shock on 31 December 2011 was large enough to allow us to determine its seismic moment, focal mechanism, and focal depth by modeling observed seismic records at permanent seismographic stations around the study area and inverting for these parameters (Figure 1). We employed a regional waveform inversion method described in *Kim and Chapman* [2005], which is essentially a grid search inversion technique over strike (θ), dip (δ), and rake (λ) developed by *Zhao and Helmberger* [1994]. The results of the waveform modeling and inversion indicate that the focal mechanism of the main shock on 31 December 2011 shock is predominantly strike-slip faulting along steeply dipping nodal planes (see Figure 3). The best fitting double-couple source mechanism parameters are θ = 265°, δ = 72°, λ = 12° (second nodal plane; θ = 171°, δ = 79°, and λ = 162°), and seismic moment, $M_0 = 8.30 \pm 8.0 \times 10^{14}$ Nm (M_w 3.88). The subhorizontal *P* axis trends southwest-northeast (219°) with a plunge of 5° whereas the *T* axis trends SE-NW (127°) with a plunge of 20°. The *P* axis orientation is about 15° rotated counterclockwise from that of the 26 January 2001 earthquake in Ashtabula, Ohio, which is the nearest earthquake with known focal mechanism [*Du et al.*, 2003]. The waveform modeling indicates that the synthetics calculated for focal depth of 3 ± 1 km fit the observed data well.

3.3. Accurate Relocations of 12 Regional Earthquakes

[19] We relocated 12 regional earthquakes by using the double-difference earthquake relocation method to minimize the effect of velocity model errors [*Waldhauser and Ellsworth*,

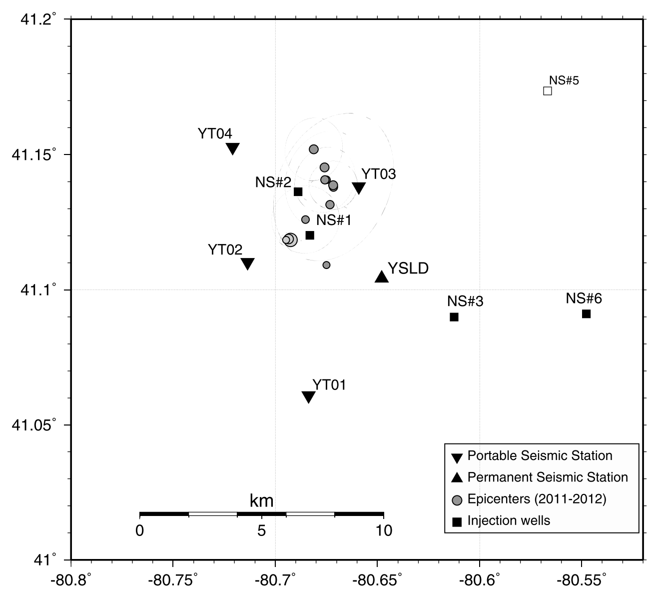


Figure 2. Single event locations of the 12 regional earthquakes that occurred in Youngstown, Ohio during March 2011 to January 2012 are plotted with shaded circles. The horizontal location errors are represented by 95% confidence error ellipses. Four portable seismographic stations around the region deployed during 01 December 2011 to 30 April 2012 and a new seismographic station YSLD (Youngstown State University) are plotted for reference. The last three events were located by using *P* and *S* wave readings from four portable seismographic stations located within 2–6.5 km from the earthquake source area.

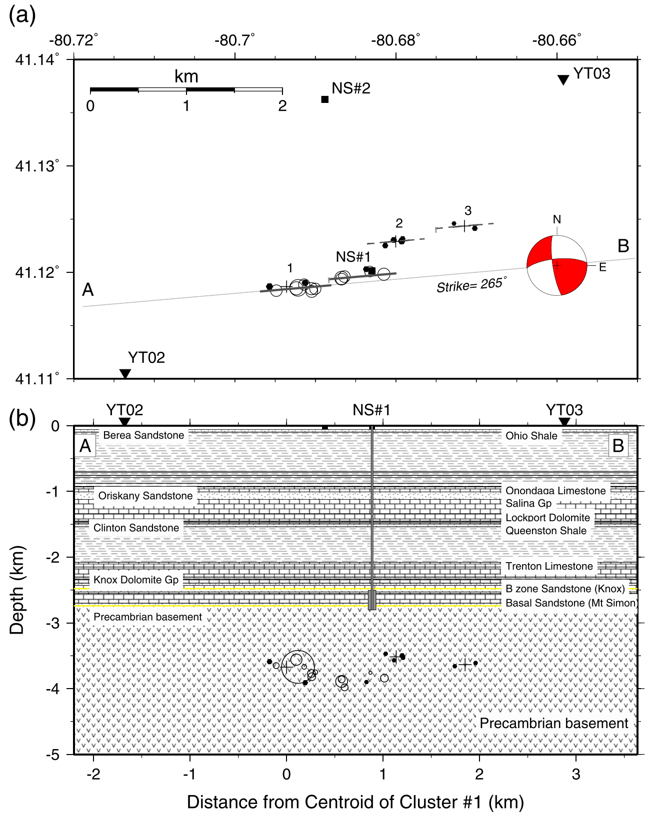


Figure 3. (a) Relocated 12 regional earthquakes (circles) and 9 local earthquakes (black hexagons) which occurred during 17 March 2011 to 18 February 2012. Earthquakes are relocated in three clusters. Focal mechanism of the M_w 3.9 shock on 31 December 2011 is represented by a beachball indicating predominantly a left-lateral strike-slip faulting mechanism. Line A-B is parallel to the trends of the earthquake distribution striking N85°. Deep injection wells in the area NS#1 and NS#2 are indicated (solid squares) and portable seismographs YT02 and YT03 are plotted with solid inverted triangles. Centroid of clusters is plotted with plus symbols. (b) Geologic section along A-B at NS#1. Most of the rocks above the crystalline Precambrian basement are Paleozoic strata that consist of sandstone, limestone, shale, and dolomite. The injection well, NS#1, is indicated with a vertical shaded bar down to a depth of 2802 m. Open section of the well between 2504 and 2802 m is indicated by shaded rectangle. Target injection zone is between B zone sandstone of the Knox Dolomite Group and Mt. Simon sandstone (basal sandstone). Hypocenters are plotted with open circles, whose size is proportional to source radius of each event determined by empirical Green's function analysis and circular source model of *Madariaga* [1976].

2000]. We employed the waveform cross-correlation technique to reduce arrival time picking errors of weak regional *P* and *S* wave arrivals. The relocated regional events show that the epicenters align along a trend striking ENE-WSW (N85°) and at focal depths from 3.5 to 4.0 km (see Table 2 and Figure 3). Hence, these regional events are within a 1.2 km long near-vertical en echelon fault just below the Northstar 1 wellbore (Figure 3). A geologic section along the line A-B below the Northstar 1 well shown in Figure 3 indicates that all the events occurred in the Precambrian basement. Distribution of the main shock and other shocks suggest that the nodal plane striking 265° and dipping 72° to North is the likely fault plane and that the mechanism is left-lateral strike-slip faulting along E-W trending subsurface faults.

3.4. Small Earthquakes Located by Portable Seismograph Data

[20] Nine small earthquakes with magnitude M_w −0.40 and 0.41 were detected and located by the four-station local network during 11 January to 11 February 2012 (Table 2). We relocated these nine events by using the double-difference earthquake relocation method with the waveform cross-correlation technique to reduce arrival time picking errors. The accurate relocation shows that the epicenters align into three distinct clusters (Figure 3). Three events are located in cluster #1 (events #16, #17, and #19), whereas four small events are in cluster #2 (events #13, #14, #15, and #20) and two small events are in cluster #3 (events #18 and #21; Figure 3). The cross sections of the clusters indicate that hypocenters of these shocks are at focal depth between 3.5 and 3.9 km and on near-vertical en echelon faults trending ENE-WSW (N85°; Figure 3), which is consistent with the locations of 12 regional events.

3.5. Regional Seismicity and Magnitude Distribution

[21] The distribution of felt earthquakes as well as small shocks detected and located by local network data in Youngstown suggests that there must have been a number of small shocks (less than $M \leq 2.0$) in the area that may have been undetected by the sparse regional seismic network. We applied a waveform correlation detector using the regional station data to detect those small shocks. The correlation detector is known to lower the seismic event detection threshold by about 1.0 magnitude unit beyond what standard processing detects [e.g., *Schaff*, 2008; *Schaff and Waldhauser*, 2010; *Gibbons and Ringdal*, 2012]. The method is well suited for this study, as we are dealing with small and repeating shocks with similar waveforms located within about a quarter wavelength from each other. We detected 97 additional small earthquakes ($0.4 < M_w < 1.8$) that occurred within about 1 km from the main shock during January 2011 to May 2012 by using the multichannel correlation detector. Hence, the method was able to find additional events by a factor of 10 increase in number of events such as those predicted by the Gutenberg-Richter magnitude-frequency relation. Three-component records from two USArray stations, M54A ($\Delta = 56$ km) and N54A ($\Delta = 107$ km) were the most useful (Figure 1). Three-component waveform records of 24 December and 31 December 2011 shocks were used as master templates.

[22] Figure 4 shows all detected seismic events plotted with their occurrence date against moment magnitude of the events, since commencement of the fluid injection on 29 December 2010 until the end of January 2012. A total of 109 earthquakes with magnitude between M_w ~0.4 and 3.9 detected by the correlation detector are plotted with solid bars, whereas 58 small earthquakes with magnitude $0.0 \leq M_w < 1.0$ detected by the local network are plotted with red bars. Among the 58 shocks, only four events were located by the local network data, as 54 events were only detected by a single station (YT01) which was the only station recording

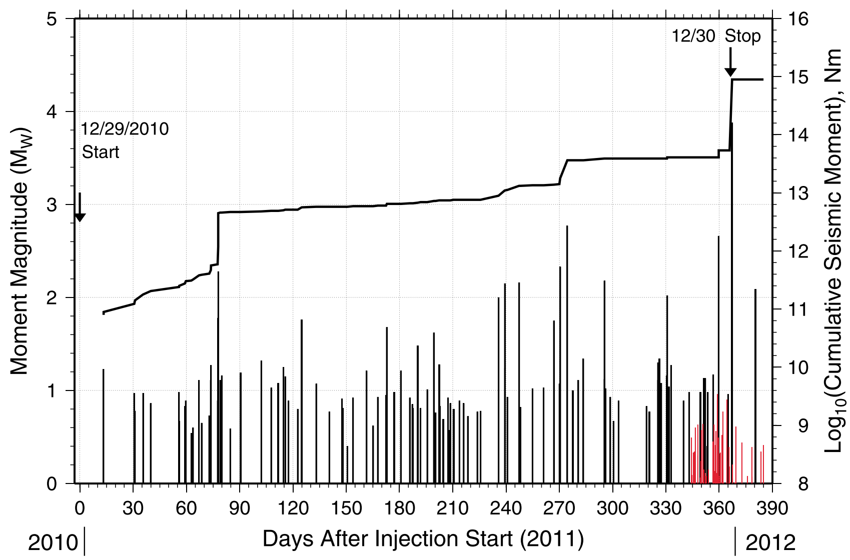


Figure 4. Earthquakes that occurred during 29 December 2010 to January 2012 in Youngstown area are plotted by vertical bars against their occurrence date, whose lengths are proportional to their moment magnitude, M_w (left vertical axis). Small earthquakes that occurred during December 2011 to January 2012 that are only recorded by local portable stations are plotted with red bars. Cumulative seismic moment is plotted by a continuous solid line (right vertical axis). The cumulative moment release is dominated by a few large ($M_w \geq 2.5$) events.

continuously during December 2011. Moment magnitudes (M_w) of earthquakes that occurred in the Youngstown area were determined from RMS (root-mean-square) amplitude of *S* or *Lg* waves and calibrated to that of the M_w 3.88 main shock on 31 December 2011 [*Shi et al.*, 2000]. For 58 small shocks, moment magnitudes were determined by using peak amplitude of *S* arrivals scaled to that of the main shock.

[23] These shocks might have been related to the fluid injection operation, and their spatiotemporal distribution can help us to understand the relationship between the injection parameters and induced seismicity in the area. Cumulative seismic moment of 167 earthquakes with M_w 0.0–3.9 is plotted against occurrence date as a thick continuous line in Figure 4. The seismic moment release is dominated by a few large ($M_w > 2.5$) earthquakes (Figure 4). We estimate that the detection threshold for the regional earthquakes using the correlation detector is about M_w 1.0 in the Youngstown, Ohio region, whereas the detection threshold for local earthquakes in the study area is about $M_w \geq -0.5$ by using local network data.

4. Waste Fluid Injection at Northstar 1 Deep Well, Youngstown, Ohio

[24] The Northstar 1 well was drilled to a total depth of 2802 m, and the waste fluid injection commenced on 29 December 2010. Daily injection volumes and start injection pressures are plotted in Figure 5 for the entire fluid injection operation [*ODNR*, 2012]. The maximum surface injection pressure was 13.0 MPa (=1890 psi) based upon the actual specific gravity of the injection fluid. The maximum injection pressure was permitted to increase up to 15.5 MPa on 16 March 2011 and increased to 17.2 MPa on 3 May 2011 [*ODNR*, 2012]. Three episodes of injection pressure changes are indicated in Figure 5. In the first 60 days, the fluid injection was carried out with a low level of injection pressure ~5 MPa, and the injection volume was less than 100 m^3/day. The injection parameters slowly increased with the injection pressure of about 10–12 MPa, and the daily injection volume of about 100–200 m^3/day during the days 60–110 (Figure 5). During days 110–140, the injection pressure increased sharply to 15.5 MPa and consistently held, and injection volume exceeded 300 m^3/day (Figure 5). The fluid injection at the well reached operational injection pressure of 17.2 MPa and injection volume of about 320 m^3/day around 19 May 2011 (day 141; Figure 5). These injection parameters are kept during June through December 2011 (see Figure 5).

[25] We can recognize several instances of gaps in surface injection pressure—a sudden drop in injection pressure followed by prolonged low pressure. These gaps are present in the daily injection volumes as well (Figure 5). The drops in injection pressure correspond to 2–4 days of no pumping at the wellhead followed by 8 to 20 days of gradual increase of injection pressure (Figure 5). Most of the short and sharp pressure drops correspond to no pump running for a day on national holidays—Memorial Day, 4 July, and among others. The longer gaps are due to injection tests, on Labor Day (246–250), pump maintenance (days 283–285), and Thanksgiving holidays (days 331–334), etc.

[26] The surface injection pressures shown in Figure 5 are listed as *average pressure* in the Northstar 1 injection log, which lists average wellhead pressure between start pressure at the beginning of injection each day and stop pressure at the end of injection each day. The wellhead pressure drops substantially after days of no injection operation as shown as minima in the pressure plot (Figure 5). Dissipation of injection pressure during the gaps is estimated to be about 0.069 MPa/h drop in the wellhead pressure. The average injection rate (number of hours the pump ran over a total daily injection volume) was about 15 m^3/h and remained nearly constant over the whole year

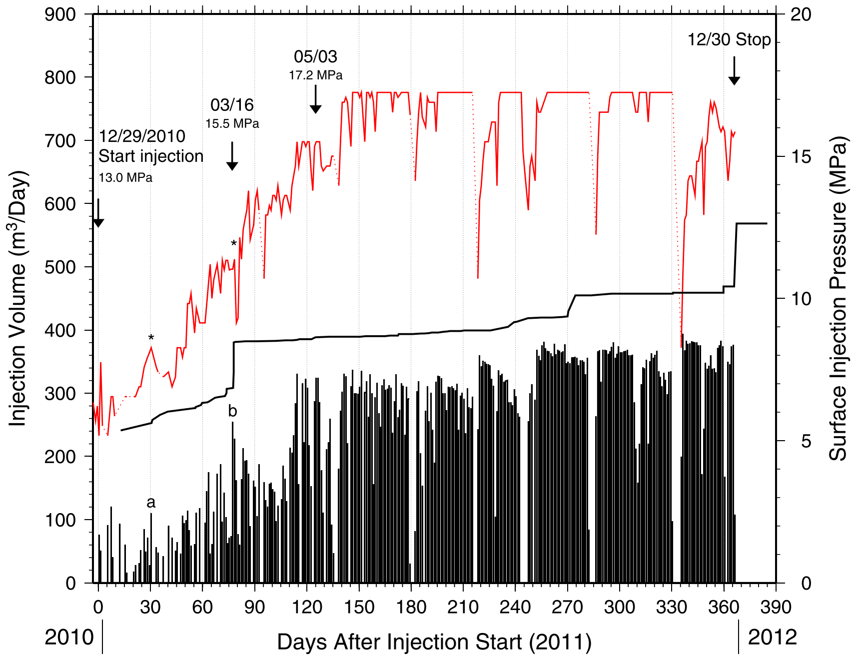


Figure 5. Average surface injection pressure in each day at Northstar 1 well during its operation 29 December 2010 to 30 December 2011 in MPa is plotted with red line (right vertical axis). Dotted portions indicate no entries in the injection log. Daily total injection volume in cubic meters, m^3, is plotted with solid bars (left vertical axis). Average injection volume is about 350 m^3/day when the well is running full time at the maximum surface injection pressure of 17.2 MPa. A total of 78,797.6 m^3 of fluid have been injected into the Northstar 1 well. Cumulative seismic moment of 167 earthquakes that occurred during the fluid injection period is plotted as continuous solid line for reference. Instances of sharp increase of daily injection volume are indicated **a** and **b**, which correspond to occurrence of earthquakes (see the text).

of injection operation at Northstar 1 well. During the summer months, June–August, the injection rate was somewhat low at 12.6 m^3/h.

[27] On 30 December 2011, ODNR requested the operator of the Northstar 1 cease injection at the well based upon the proximity of the 24 December 2011 hypocenter to the Northstar 1 injection wellbore. As of 31 December 2011, a total of 78,797.6 m^3 (495,622 barrels) of fluid had been injected into the Northstar 1 well. It is the only well out of 177 class II (brine disposal) waste disposal wells operating in the state of Ohio during 2011 that has been linked to potentially induced earthquakes. Daily total injection volume is proportional to the product of pump run time and injection pressure, and it may be an appropriate parameter to assess the effect of fluid injection on the subsurface hydraulic system (injection interval). The injection pressure alone is not sufficient to represent the injection; it needs sufficient fluid to exert the pressure on subsurface rocks.

4.1. Peaks and Minima of Injection Parameters and Seismicity at Youngstown, Ohio

[28] When the seismicity in the Youngstown area during 2011–2012 is compared with the fluid injection parameters at the deep injection well Northstar 1, there is some correlation between the injection parameters and occurrence of earthquakes. No felt earthquakes occurred prior to the injection operation on 29 December 2010. Once the injection at the well commenced, and the injection pressure was slowly applied, the first earthquake of M_w 1.2 occurred on 11 January 2011 at 11:16, about 13 days after the commencement. As the fluid injection progressed and injection parameters steadily increased, the seismicity in the area also increased as shown in the cumulative seismic moment release from days 13 to 76, 2011 (Figure 5). The seismicity shown in Figure 4, in particular, the cumulative moment closely follows the increased surface injection pressure as well as injection volume (Figure 5).

[29] There are a pair of peaks in injection volumes as marked **a** and **b** in Figure 5. These sharp peaks in the injection flow rate (m^3/day) appear to be correlated to the occurrence of earthquakes that followed such sharp increases closely. Such a short-term—several hours to a few days—response of the injection medium to the fluid injection may be an indication that the injection target strata are highly fractured, and the storage volume is hydraulically connected to the injection fluid dissipation pathways. The cross correlation between the earthquake series and the fluid pressure as well as injection flow rate series were calculated to determine whether there was a lag between peak fluid pressure and peak seismic activity. The cross correlation is not symmetrical and indicates that the peak of seismicity follows the peak pressure by approximately five days. The lack of symmetry in the cross correlation is due to delayed seismic activity at the beginning and continued seismic activity after the injection of fluid. About 10+ days of short-term response is also reported at RMA [*Healy et al.*, 1968] and is suggested that it was due to fractured Precambrian crystalline bedrock at the site. Although, the Precambrian basement in the Youngstown area was not the primary target interval, the fractured Precambrian rock directly below the wellbore shares similar fractured reservoir characteristics as the RMA site.

4.1.1. Quiescence of Seismicity and Minima of Fluid Injection Pressure

[30] There are quiescences in seismicity during certain time intervals such as days: 285–296 and 305–320 (see Figure 4), as marked with yellow bars in Figure 6. Those quiescent periods are defined as time intervals at least four consecutive days without earthquakes ($M_w \geq 0.9$), and they appear to follow the minima in the injection pressure as represented by vertical red lines in Figure 6. Although not all the injection pressure minima correlate with the quiescence in seismicity, 75% of the pressure minima (18 out of 24 minima) fall within the quiescent intervals (Figure 6), whereas about 62% of the quiescent intervals (18 out of 29 intervals) are associated with the pressure minima (Figure 6). We suggest that the cessation of fluid injection may have caused quiescences of earthquakes as illustrated in Figure 6. We are unable to model such behavior with reservoir analysis due to lack of detailed knowledge on the ambient pore pressure at the Northstar 1 well [e.g., *Hsieh and Bredehoeft*, 1981].

4.2. Physical Basis of the Induced Seismicity in Youngstown, Ohio

[31] The basic mechanism for initiation of induced earthquakes during fluid injection into deep wells is well understood [e.g., *Hubbert and Rubey*, 1959; *Healy et al.*, 1968; *Raleigh et al.*, 1976]: tectonic strain stored in the basement rock is released via earthquakes that are triggered by the injection of fluid into the basement rock. The Mohr-Coulomb fracture criterion may be written as [*Healy et al.*, 1968; *Yeats et al.*, 1997]:

$$\tau = \tau_0 + \mu \sigma_n, \tag{1}$$

where τ is the shear stress on the fault plane at failure, τ_0 is the fracture cohesion, μ is the coefficient of friction, and σ_n is the effective normal stress. Under the presence of pore pressure, the effective normal stress consists of two parts, a pore pressure P and the total stress S; hence, $\sigma_n = (S_n - P)$, in which S_n is the total normal stress acting on the fault plane, and P is the pressure of the ambient fluid [*Healy et al.*, 1968]. For fault slip on preexisting faults, the cohesive strength (τ_0) is taken to be close to zero [*Zoback and Healy*, 1984; *Zoback*, 1992]. μ ranges from 0.6 to 1.0 [*Zoback and Townend*, 2001], and *Byerlee* [1978] reports μ = 0.85 for a variety of rock types at normal stress up to 200 MPa. The right side of the equation consists of a frictional term μ ($S_n - P$), plus the cohesive strength, τ_0 and, hence as long as the right side is greater than the shear stress (τ), fault slip will not occur. This empirical relation indicates that the effect of increasing pore pressure is to reduce the friction resistance to fault slip by decreasing the effective normal stress (σ_n) acting on the fault plane.

[32] If the area has preexisting weak zones (fractures and faults), and the area is already close to failure, then a small increase in pore pressure would trigger earthquakes. Therefore, the gaps in injection parameters at the Northstar 1 well reduced the pore pressure (P) in the above equation and effectively strengthened the friction resistance on the subsurface fault. This leads to reduced size and number of triggered earthquakes and the quiescence in seismicity as shown in Figure 6.

[33] The parameters in the above equation can be evaluated for the Youngstown area on the basis of the following assumptions and relations between τ, σ_n, and the principal stresses. For strike-slip faulting in Youngstown area, the least (S_3) and greatest (S_1) principal stresses are horizontal [*Yeats et al.*, 1997]. We take the least principal stress (S_3) to be the bottom hole pressure (BHP) of 27.5 MPa (=1000 kg/m$^3 \times 9.8$ m/s$^2 \times 2802$ m); the intermediate principal stress S_2 is vertical and equal to the lithostatic pressure (mainly overburden) [*Healy et al.*, 1968]. S_2 at the bottom of injection well at 2802 m is 74.1 MPa (=2700 kg/m$^3 \times 9.8$ m/s$^2 \times 2802$ m). The greatest principal stress S_1 must be at least 74.1 MPa. Estimates of the pore pressure before the fluid injection (P) at the Northstar 1 well is unknown. If we take a similar value to that of RMA well, which was about 75% of the BHP, P is 20.6 MPa (=27.5 MPa x 0.75) which corresponds to the static fluid level of 700 m below the wellhead after injection stopped [*Hsieh and Bredehoeft*, 1981]. From the Mohr failure envelope, the shear and effective normal stresses are given as [*Healy et al.*, 1968; *Yeats et al.*, 1997]:

$$\tau = \frac{(S_1 - S_3)}{2} \sin 2\alpha \tag{2}$$

$$\sigma_n = \frac{(S_1 + S_3 - 2P)}{2} + \frac{(S_1 - S_3)}{2} \cos 2\alpha \tag{3}$$

where α is the angle between the fault plane and the plane normal to σ_1. $\alpha \sim 45°$ for the strike-slip focal mechanism with P axis trending 219° and fault plane striking 265° given in the previous section for Youngstown area. Given $S_1 = 74.1$ MPa, $S_3 = 27.5$ MPa, $P = 20.6$ MPa, and $\alpha = 45°$, the shear and effective normal stresses on a potential fault plane are $\tau = 28.3$ MPa and $\sigma_n = 30.2$ MPa. Therefore, according to the Mohr-Coulomb failure criterion, the cohesive strength, τ_0 would have to be at least 2.6 MPa to prevent fault slip in the reservoir rocks in Youngstown area prior to fluid injection. If the cohesive strength is taken to be $\tau_0 = 0$ on the fault plane, then pore pressure (P) must be less than ~17.5 MPa to prevent failure.

[34] Average injection pressure of 7.5 MPa for two days and a daily total injection volume of 102 m^3/day may have triggered an M_w 1.0 shock on 3 February 2011 (day 35, Figure 6). If we use this injection pressure, the pore pressure is raised to 35.5 MPa (27.5 MPa + 7.5 MPa; BHP plus surface injection pressure), and it yields; $\tau = 28.3$ MPa, $\sigma_n = 15.3$ MPa, and $\tau_0 = 15.3$ MPa. The occurrence of faulting upon reduction of the frictional term due to increased pore pressure indicates a value for τ_0 of 15.3 MPa or less. This is comparable to $\tau_0 = 15.1$ MPa estimated for the RMA [*Healy et al.*, 1968]. The cohesive strength for crystalline basement rocks is about 50 MPa [*Healy et al.*, 1968]. The cohesive strength of 15.3 MPa may be reasonable for the fractured injection media at the Youngtown area, which appears to be fractured Precambrian rocks with preexisting fault or fracture zones, to hold the fault together.

5. Discussion

[35] The earthquakes did not stop immediately after the shutdown of the injection operation at Northstar 1, although the rate and size of earthquakes steadily dropped within a

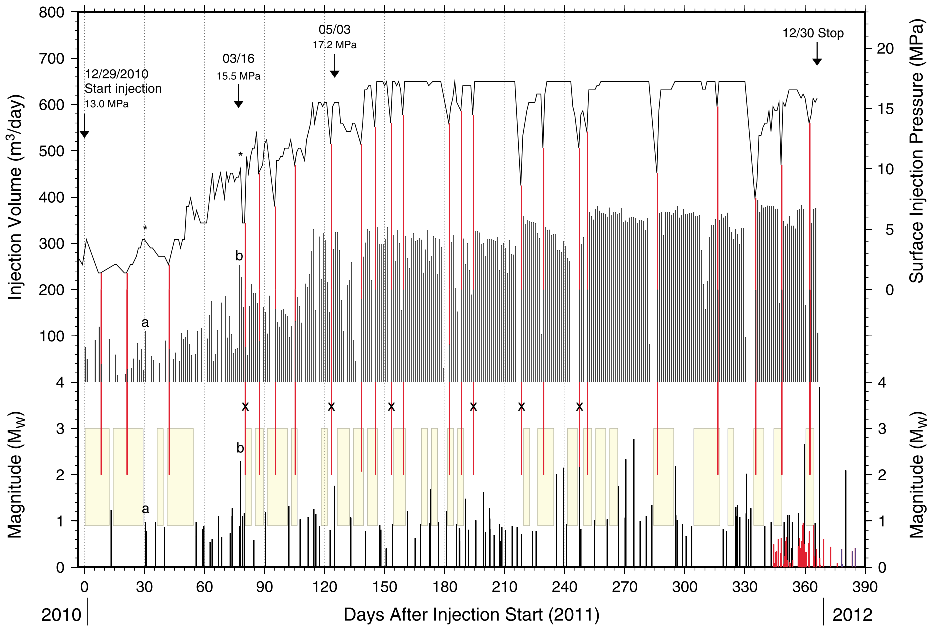


Figure 6. Surface injection pressure in MPa in each day during the whole operation of the Northstar 1 well 29 December 2010 to 30 December 2011 is plotted with black line (right vertical axis). Daily total injection volume in cubic meters (m^3) is plotted with solid bars (left vertical axis) and the earthquakes that occurred during December 2010 to January 2012 are plotted with vertical bars whose lengths are proportional to their moment magnitude, M_w. The minima in the injection pressure are represented by vertical red lines, and quiescent intervals of seismicity are indicated by yellow bars. These injection pressure minima are due to no pumping at the wellhead during equipment services and holidays, and 75% of the minima appear to be correlated to quiescent intervals of seismicity. The minima that are not related to the quiescent intervals are marked by x.

month following shutdown. The largest shock on 31 December 2011 occurred about 24 h after the end of injection on 30 December 2011 at Northstar 1. The largest earthquakes postdated the end of injection at other sites such as, Ashtabula, Ohio, and RMA near Denver, Colorado. At RMA, the largest earthquake (M_w 5.2) occurred on 10 April 1967 more than a year after injection ceased on February 1966 [*Healy et al.*, 1968]. Usually, pore pressure buildup from several months of fluid injection would require time to return to the preinjection level.

5.1. Migration of Seismicity From East to West

[36] Twelve relocated regional earthquakes cluster along ENE-WSW (Figure 7a), and their vertical distribution suggests that the rupture area can be represented by a pair of rectangular planes aligned en echelon with overall length of about 1.2 km and width of about 0.5 km (Figure 7b). The linear trend is consistent with a nodal plane striking 265° of the focal mechanism for the main shock on 31 December 2011 (Figure 7a). A pair of earthquakes on 17 March 2011 (events #1 and #2) occurred at the eastern end of a 1.2 km long rupture area close to the wellbore (Figure 7a), then the subsequent shocks in August and September 2011 occurred in the further western part of the rupture area (events #3 through #7; Figure 7). The shocks on December 2011 and January 2012 including the main shock on 31 December 2011 occurred at the western end of the rupture area (events #10–#12; Figure 7). Hence, the seismicity migrated gradually from the eastern end of the fault area close to the injection wellbore toward the western end, away from the injection point (Figure 7).

[37] The west-south-west (WSW) migration of the seismicity from the injection point can be explained by the outward expansion of the high fluid pressure front which increases pore pressure along its path on the fault zone and triggers earthquakes, and the progressive westward migration of seismicity continues until injection stops. The effect of increased pore pressure is to reduce the frictional resistance to faulting by decreasing the effective normal stress across the fracture plane [*Healy et al.*, 1968]. A predominantly WSW-ENE trending seismicity with narrow depth ranges of 3.5–4.0 km indicates the existence of a fractured Precambrian rock in the form of en echelon rectangular faults as conduits of fluid migration. A migration of seismicity was also observed at RMA [*Healy et al.*, 1968; *Hsieh and Bredehoeft*, 1981]. There is minor seismic activity in the northeast from the injection well within the ENE-WSW trending fractured Precambrian basement, suggesting the existence of step-like en echelon rupture planes (see Figure 3a). Deep basement fault(s) in the study area may act as vertical fluid conduits and provides a hydraulic connection between the fluid disposal well injection depths and the earthquake source depths (Figure 7).

5.2. Speed of the Earthquake Migration

[38] The seismicity migrated from East to West for about 1.2 km during 17 March 2011 to 13 January 2012. Although the migration rate is not homogeneous in time, an average speed is about 4.0 m per day (= 1.2 km/300 days) or ~120 m per month. Somewhat higher migration speed of 2 to 40 m/h was observed in a water injection experiment at the Nojima

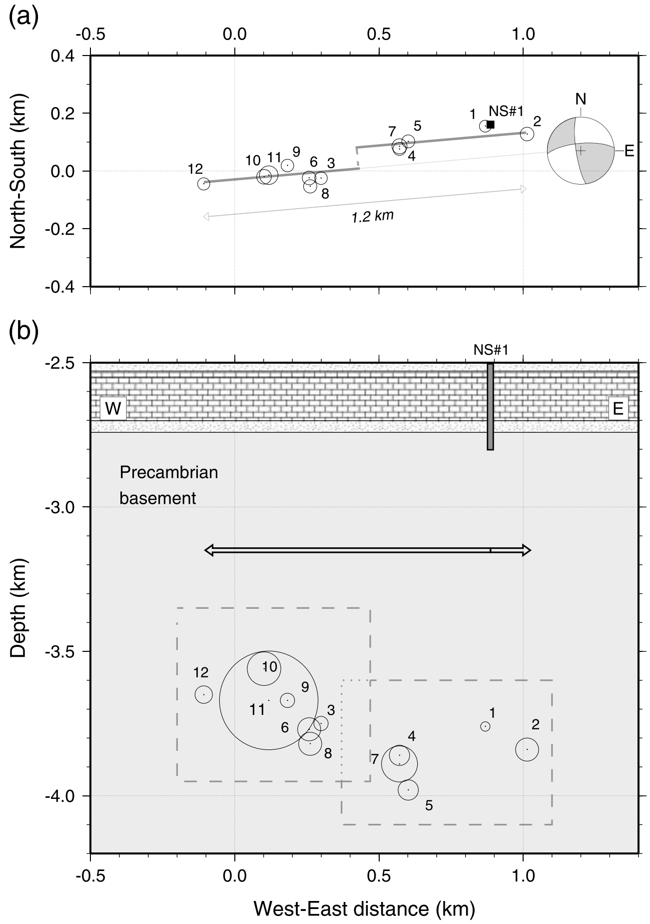


Figure 7. (a) Accurately relocated regional earthquakes that have occurred during 17 March 2011 to 13 January 2012 in Youngstown area are plotted by circles and denoted by event ids. The deep injection well Northstar 1 (NS#1) is plotted for reference. Events on 17 March 2011 (#1 and #2) are located close to the injection well. Subsequent later events have occurred further away from the injection well and the events on December 2011 to January 2012 are located at the western end of the rupture zone; (b) Cross-section view of the hypocenters. Injection interval of the well between 2504 and 2802 m is indicated by shaded rectangle. Events are clustered in depth ranges 3.5 to 4.0 km, and the seismicity shows gradual migration from the eastern end close to the injection wellbore to the western end of the fault zone. Circle sizes are proportional to the source radius of each event determined by empirical Green's function analysis and circular source model of *Madariaga* [1976]. Dashed lines suggest possible maximum rupture planes based on source model of *Brune* [1970].

fault zone in Japan [*Tadokoro et al.*, 2000, 2005]. *Seeber et al.* [2004] reported a somewhat similar observation in Ashtabula, Ohio where seismicity shifted ~1 km from the point of injection during May 1986 to June 1994.

[39] The seismicity waned after the main shock on 31 December 2011 (which also coincides with the stopping of the injection operation), which is somewhat different from the naturally occurring earthquakes in which most of the aftershocks occur immediately following the main shock. The seismicity plotted in Figure 4 is similar to an earthquake swarm, but in this case, seismicity is spread in time and space due to migrating high fluid pressure front. As such, most events may have occurred as doublets and multiplets.

5.3. Total Injected Volume and Maximum Seismic Moment of the Induced Earthquakes

[40] *McGarr* [1976] reported that annual sums of seismic moments for the Denver earthquakes from 1962 to 1965 agree with the yearly total moment estimated from the volume of fluid injected at the RMA well. He postulated that the seismicity that results from a change in volume ΔV is related to the sum of the seismic moments of the earthquake population, ΣM_0, that is, $\Sigma M_0 \sim \nu\,|\Delta V|$, where ν is the rigidity, and a necessary condition is that the change in volume is accommodated only by seismic failure. *Gibbs et al.* [1973] reported that the number of earthquakes per year appeared to correlate with changes in the quantity of fluid injected per year during 1962–1970 in Rangely, Colorado.

[41] *McGarr* [2012] proposed that the maximum induced earthquake size (moment) scales with total volume of injected fluid. The pore fluid pressure from injection is needed to trigger the earthquakes [*Raleigh et al.*, 1976; *Zoback and Harjes*, 1997], but additionally the total injected volume must be large enough to exert fluid pressure over a sufficiently large area of the preexisting faults, thereby triggering large-sized earthquakes. However, even if this volume is large, it may not be necessary that earthquakes will occur. For example, if a large volume is injected over a long period of time, sufficient to achieve fluid migration, earthquakes may not be triggered. We conclude that although total injected volume is a readily available parameter that may be useful for assessing the propensity for earthquakes to occur, it may need to be interpreted in association with knowledge of the injection rate, and/or an assessment of pressure levels. As in the progressive migration of seismicity, more injected volume would have a better chance to exert pressure to a wider rupture area, thereby increasing the maximum size of the induced earthquakes. Although we do not know the WSW-ENE extent of the fault(s) in the Youngstown area, it is possible that continued injection of fluid at Northstar 1 well could have triggered potentially large and damaging earthquakes.

6. Summary and Conclusions

[42] A total of 167 small earthquakes (M_w 0.0–3.9) were detected during January 2011 to February 2012 in Youngstown, Ohio. These shocks were located close to a deep fluid injection well Northstar 1. Twenty-one accurately located earthquakes are distributed along the pair of en echelon faults striking 265° (ENE-WSW) and dipping steeply to the north (dip = 72°N), consistent with the main shock focal mechanism.

[43] All the well-located earthquakes have occurred at depths ranging from 3.5 to 4.0 km in the Precambrian crystalline basement. Most of the previously known earthquakes associated with the fluid injections in the eastern United States have occurred in Precambrian basement indicating that tectonic strain stored in the crystalline basement is released through the triggered events (e.g., Ashtabula, Ohio [*Seeber et al.*, 2004], and Guy, Arkansas [*Horton*, 2012]). The *P* axis of the main shock mechanism trends

NE-SW and corresponds to horizontal compression (σ_{Hmax}) which is slightly rotated from the ENE-WSW trending broad-scale regional stress field in the northeastern United States [*Du et al.*, 2003; *Zoback and Zoback*, 1991].

[44] The first detected earthquake (M_w 1.2) occurred on 11 January 2011, 13 days after the commencement of injection at Northstar 1 well. At that time, a total of ~700 m^3 of fluid had been injected at a rate of up to 5 m^3/h, and the surface injection pressure was up to 13.5 MPa. Total injection volume was a very small quantity when it started to trigger an earthquake, and the injection pressure was relatively low, and hence, there must have been nearly direct fluid conduits to the ENE-WSW trending fault very close to the injection wellbore, and the subsurface condition at the Precambrian basement may have been near critical for the earthquakes to occur. The cross correlation between the earthquake series and the injection flow rate series indicates that the peak of seismicity follows the peak pressure with approximately five days lag. This short-term response of the injection media at Youngstown is similar to an observation at RMA where about 10 days of time lag in earthquake occurrences was observed following fluid injection [*Healy et al.*, 1968].

[45] We conclude that the recent, 2011–2012, earthquakes in Youngstown, Ohio were induced by the fluid injection at Northstar 1 deep injection well due to increased pore pressure along the preexisting (ENE-WSW trending) faults located close to the wellbore in the Precambrian basement. This is based on the facts that: (1) well-located earthquakes clustered in a narrow zone along the fault trace striking ENE-WSW in the Precambrian basement (Figures 3 and 6); (2) migration of seismicity from the east—close to the injection point, toward the west—away from the wellbore, indicating that the expanding high fluid pressure front increased the pore pressure along its ENE-WSW trending path and progressively triggered the earthquakes; (3) occurrence of earthquakes was generally correlated with the total daily injection volume and injection pressure, and a pair of peaks in the injection parameters appears to be correlated with the occurrence of earthquakes at the early stage of fluid injection when the subsurface hydraulic system started to build up pore pressure; (4) 75% of the minima in surface injection pressure (no pumping operations) appeared to correlate with quiescent intervals of seismicity, which may indicate that the earthquakes were caused by the pressure buildup in the fractured Precambrian basement and stopped when pressure dropped; and (5) a short-term response of the injection media to the fluid injection parameters on the time scale of hours to few days (5+) suggests that the site behaved as a fractured Precambrian reservoir as in the Rocky Mountain Arsenal, Colorado.

[46] **Acknowledgments.** John Armbruster at Lamont-Doherty Earth Observatory of Columbia University (LDEO) led fieldwork in Youngstown, Ohio and processed raw data during January–March 2012. Chris Grope at Youngstown State University participated in the fieldwork and helped in portable station service and data retrieval. Mike Hansen and Tim Leftwitch of the Ohio Division of Geological Survey, Ohio Department of Natural Resources, helped to carry out the fieldwork and supported this study, as well as provided well log data and other material for the study. Jeffrey Dick of Youngstown State University helped us to deploy a NetQuake station, YSLD, at the campus. Larry Smyers of D&L Energy Inc. provided a spreadsheet of injection parameters at Northstar 1 well. Paul Richards and Heather Savage at LDEO provided critical comments that improved the paper. Alberto Malinverno helped to interpret well logging data. I thank Bill Menke for helping me with Poisson distribution. Stephen Holtkamp and Michael Brudzinski of Miami University of Ohio shared their result of regional event detection which helped us to solidify detection of regional events down to M_w ~0.5. Mitchell Gold of LDEO read the manuscript and provided editorial help. Bill Leith of U.S. Geological Survey supported the field work, and Bill Ellsworth and Art McGarr of USGS provided useful comments. The U.S. Geological Survey has provided partial support for this study under contract G10AC00094. This is Lamont-Doherty Earth Observatory contribution 7681.

References

Ake, J., K. Mahrer, D. O'Connell, and L. Block (2005), Deep-injection and closely monitored induced seismicity at Paradox Valley, Colorado, *Bull. Seismol. Soc. Am.*, *95*, 664–683.

Baranoski, M. T. (2002), Structure contour map on the Precambrian unconformity surface in Ohio and related basement features, report, *Div. Geol. Surv. Map PG-23,* scale 1:500,000, Ohio Dep. of Nat.l Resour., Columbus. [Available at http://www.dnr.state.oh.us/Portals/10/pdf/mappg23.pdf.]

Brown, W. A., C. A. Frohlich, W. L. Ellsworth, J. H. Luetgert, and M. R. Brunt (2012), The May 17th, 2012 M4.8 earthquake near Timpson, east Texas: Was it natural or was it induced?, Abstract S53I-06 presented at 2012 Fall Meeting, AGU, San Francisco, Calif., 3–7 Dec.

Brune, J. N. (1970), Tectonic stress and the spectra of seismic shear waves from earthquakes, *J. Geophys. Res.*, *75*, 4997–5009.

Brunt, M. R., W. A. Brown, and C. A. Frohlich (2012), Felt reports and intensity maps for two M4.8 Texas earthquakes: 17 May 2012 near Timpson and 20 October 2011 near Fashing, Abstract S51E-2454 presented at 2012 Fall Meeting, AGU, San Francisco, Calif., 3–7 Dec.

Byerlee, J. D. (1978), Friction of rocks, *Pure Appl. Geophys.*, *116*, 615–626.

Davis, S. D., and W. D. Pennington (1989), Induced seismic deformation in the Cogdell oil field of west Texas, *Bull. Seismol. Soc. Am.*, *79*, 1477–1495.

Du, W.-X., W.-Y. Kim, and L. R. Sykes (2003), Earthquake source parameters and state of stress for northeastern United States and southeastern Canada from analysis of regional seismograms, *Bull. Seismol. Soc. Am.*, *93*, 1633–1648.

Ellsworth, W. L., S. H. Hickman, A. L. Llenos, A. McGarr, A. J. Michael, and J. L. Rubinstein (2012), Are seismicity rate changes in the midcontinent natural or manmade?, paper presented at 2012 Seismological Society of America Annual Meeting, San Diego, Calif.

Frohlich, C., C. Hayward, B. Stump, and E. Potter (2011), The Dallas-Fort Worth earthquake sequence: October 2008 through May 2009, *Bull. Seismol. Soc. Am.*, *101*, 327–340.

Gibbons, S. J., and F. Ringdal (2012), Seismic monitoring of the North Korea nuclear test site using a multichannel correlation detector, *IEEE Trans. Geosci. Remote Sens.*, *50*, 1897–1909, doi:10.1109/TGRS.2011.2170429.

Gibbs, J. F., J. H. Healy, C. B. Raleigh, and J. Coakley (1973), Seismicity in the Rangely, Colorado, area: 1962–1970, *Bull. Seismol. Soc. Am.*, *63*, 1557–1570.

Gomberg, J. S., K. M. Shedlock, and S. W. Roecker (1990), The effect of S-wave arrival times on the accuracy of hypocenter estimation, *Bull. Seismol. Soc. Am.*, *80*, 1605–1628.

Hansen, M. C. (2012), Earthquakes in Ohio, *Educ. Leaflet 9*, Div. of Geol. Surv., Ohio Dep. of Nat. Resour., Columbus. [Available at http://www.dnr.state.oh.us/Portals/10/pdf/EL/el09.pdf.]

Hansen, M. C., and L. J. Ruff (2003), The Ohio seismic network, *Seismol. Res. Lett.*, *74*, 561–564.

Healy, J. T., W. W. Rubey, D. T. Griggs, and C. B. Raleigh (1968), The Denver earthquakes, *Science*, *161*, 1301–1310.

Herrmann, R. B., S.-K. Park, and C.-Y. Wang (1981), The Denver earthquakes of 1967–1968, *Bull. Seismol. Soc. Am.*, *71*, 731–745.

Horton, S. (2012), Disposal of hydrofracking waste fluid by injection into subsurface aquifers triggers earthquake swarm in central Arkansas with potential for damaging earthquake, *Seismol. Res. Lett.*, *83*, 250–260, doi:10.1785/gssrl.83.2.250.

Hsieh, P. A., and J. S. Bredehoeft (1981), A reservoir analysis of the Denver earthquakes—A case study of induced seismicity, *J. Geophys. Res.*, *86*, 903–920.

Hubbert, M. K., and W. W. Rubey (1959), Role of fluid pressure in mechanics of overthrust faulting, *Geol. Soc. Am. Bull.*, *70*, 115–206.

Keranen, K., H. M. Savage, G. Abers, and E. S. Cochran (2013), Potentially induced earthquakes in Oklahoma, USA: Links between wastewater injection and the 2011 M_W 5.7 earthquake sequence, *Geology*, *41*, 699–702, doi:10.1130/G34045.1.

Kim, W.-Y., and M. Chapman (2005), The 9 December 2003 central Virginia earthquake sequence: A compound earthquake in the central Virginia seismic zone, *Bull. Seismol. Soc. Am.*, *95*, 2428–2445.

Klein, F. W. (2007), User's guide to HYPOINVERSE-2000, a Fortran program to solve for earthquake locations and magnitudes, *U.S. Geol. Surv. Open File Rep., 02-171*, 121 pp.

Madariaga, R. (1976), Dynamics of an expanding circular fault, *Bull. Seismol. Soc. Am.*, *66*, 639–666.

McGarr, A. (1976), Seismic moments and volume changes, *J. Geophys. Res.*, *81*, 1487–1494.

McGarr, A. (2012), Factors influencing the seismic hazard of earthquakes induced by fluid injection at depth, paper presented at SPE/SEG Workshop on Injection Induced Seismicity, Soc. of Pet. Eng., Broomfield, Colo, 12–14 Sept. 2012.

McGarr, A., D. Simpson, and L. Seeber (2002), Case histories of induced and triggered seismicity, in *International Handbook of Earthquake and Engineering Seismology*, edited by W. Lee, H. Kanamori, P. Jennings, and C. Kisslinger, chap. 40, pp. 647–664, Academic Press, London.

Meremonte, M. E., J. C. Lahr, A. D. Frankel, J. W. Dewey, A. J. Crone, D. E. Overturf, D. L. Carver, and W. T. Bice (2002), Investigation of an earthquake swarm near Trinidad, Colorado, August–October 2001, *U.S. Geol. Surv. Open File Rep., 02-0073*.

National Academy of Sciences (2012), *Induced Seismicity Potential in Energy Technologies,* 225 pp., Natl. Acad. Press, Washington, D. C.

Nicholson, C., and R. L. Wesson (1992), Triggered earthquakes and deep well activities, *Pure Appl. Geophys.*, *139*, 561–578.

Nicholson, C., E. Roeloffs, and R. L. Wesson (1988), The northeastern Ohio earthquake of 31 January 1986: Was it induced?, *Bull. Seismol. Soc. Am.*, *78*, 188–217.

Ohio Department of Natural Resources (ODNR) (2012), Preliminary report on the Northstar 1 class II injection well and the seismic events in the Youngstown, Ohio, area, report, 23 pp., Columbus, March.

Raleigh, C. B., J. H. Healy, and J. D. Bredehoeft (1976), An experiment in earthquake control at Rangely, Colorado, *Science*, *91*, 1230–1237.

Rubinstein, J. L., W. L. Ellsworth, and A. McGarr (2012), The 2001–present triggered seismicity sequence in the Raton Basin of southern Colorado/northern New Mexico, Abstract S34A-02 presented at 2012 Fall Meeting, AGU, San Francisco, Calif., 3–7 Dec.

Schaff, D. P. (2008), Semiempirical statistics of correlation-detector performance, *Bull. Seismol. Soc. Am.*, *98*, 1495–1507.

Schaff, D. P., and F. Waldhauser (2010), One magnitude unit reduction in detection threshold by cross correlation applied to Parkfield (California) and China seismicity, *Bull. Seismol. Soc. Am.*, *100*, 3224–3238, doi:10.1785/0120100042.

Seeber, L., and J. G. Armbruster (1993), Natural and induced seismicity in the Erie-Ontario region: Reactivation of ancient faults with little neotectonic displacement, *Geogr. Phys. Quat.*, *47*, 363–378.

Seeber, L., J. Armbruster, and W. Y. Kim (2004), A fluid-injection-triggered earthquake sequence in Ashtabula, Ohio: Implications for seismogenesis in stable continental regions, *Bull. Seismol. Soc. Am.*, *94*, 76–87.

Shi, J., P. G. Richards, and W. Y. Kim (2000), Determination of seismic energy from *Lg* waves, *Bull. Seismol. Soc. Am.*, *90*, 483–493.

Stover, C. W., and Coffman, J. L. (1993), Seismicity of the United States, 1568–1989 (Revised), *U.S. Geol. Surv. Prof. Pap., 1527*, 418 pp.

Tadokoro, K., M. Ando, and K. Nishigami (2000), Induced earthquakes accompanying the water injection experiment at the Nojima fault zone, Japan: Seismicity and its migration, *J. Geophys. Res.*, *105*(B3), 6089–6104, doi:10.1029/1999JB900416.

Tadokoro, K., M. Ando, and K. Nishigami (2005), Correction to "Induced earthquakes accompanying the water injection experiment at the Nojima fault zone, Japan: Seismicity and its migration," *J. Geophys. Res.*, *110*, B03305, doi:10.1029/2004JB003602.

Viegas, G., K. Buckingham, A. Baig, and T. Urbancic (2012), Large scale seismicity related to wastewater injection near Trinidad, Colorado, USA, paper presented at GeoConvention 2012, Can. Soc. of Pet. Eng., Calgary, Alberta, Canada.

Waldhauser, F., and W. L. Ellsworth (2000), A double-difference earthquake location algorithm: Method and application to the northern Hayward fault, California, *Bull. Seismol. Soc. Am.*, *90*, 1353–1368.

Yeats, R. S., K. Sieh, and C. R. Allen (1997), *Geology of Earthquakes*, 568 pp., Oxford Univ. Press, New York.

Zhao, L. S., and D. V. Helmberger (1994), Source estimation from broadband regional seismograms, *Bull. Seismol. Soc. Am.*, *84*, 91–104.

Zoback, M. D., and H.-P. Harjes (1997), Injection-induced earthquakes and crustal stress at 9 km depth at the KTB deep drilling site, Germany, *J. Geophys. Res.*, *102*, 18,477–18,491.

Zoback, M. D., and J. H. Healy (1984), In situ stress measurements to 3.5 km depth in the Cajon Pass scientific research borehole: Implications for the mechanics of crustal faulting, *J. Geophys. Res.*, *97*, 5039–5057.

Zoback, M. D., and J. Townend (2001), Implications of hydrostatic pore pressures and high crustal strength for the deformation of intraplate lithosphere, *Tectonophysics*, *336*, 19–30.

Zoback, M. D., and M. L. Zoback (1991), Tectonic stress field of North America and relative plate motions, in *Neotectonics of North America*, edited by Slemmons et al. pp. 339–366, Geol. Soc. of Am., Boulder, Colo.

Zoback, M. L. (1992), Stress field constraints on intra-plate seismicity in eastern North America, *J. Geophys. Res.*, *97*, 11,761–11,782.

Sent: Wednesday, May 09, 2012 2:45 AM
Subject: Couple denied mortgage because of gas drilling

Couple denied mortgage because of gas drilling

Brian Smith lives near Marcellus Shale well in Daisytown

http://www.wtae.com/news/local/investigations/Couple-denied-mortgage-because-of-gas-drilling/-/12023024/12865512/-/ohf26fz/-/index.html#.T6mu842bM44.facebook

----

Ward: Gas company financing is preventing residents from getting mortgages

Published: August 1, 2011

http://thedailyreview.com/news/ward-gas-company-financing-is-preventing-residents-from-getting-mortgages-1.1182565

THESE all below on DamascusCitizens.org - search for MORTGAGES

- See more at: http://www.damascuscitizensforsustainability.org/category/impacts/mortgages/#sthash.PhWpj80a.dpuf

Fracking Boom Gives Banks Mortgage Headaches

November 15, 2013

WHY FRACKING IS A PROBLEM FOR BANKS

BY ANDY PETERS, AMERICAN BANKER, NOVEMBER 12, 2013

An East Coast oil boom has promised potential riches to lucky landowners. But the oil rush may cause big headaches for some unlucky banks.

At least three institutions — Tompkins Financial (TMP) in Ithaca, N.Y., … Continue reading

Filed Under: Mortgages

NYPIRG Urges Cuomo to Reject dSGEIS Due to Conflicts of Interest

April 24, 2013

The New York Public Interest Research Group (NYPIRG) has sent a letter to New York State Governor Cuomo urging him to reject the Revised Draft Supplemental Generic Environmental Impact Statement (dSGEIS) due to a conflict of interest on the part of the consultants who worked on the socio-economic impact section. … Continue reading

Filed Under: Economic, Health, Impacts, Jobs, Mortgages, New York, Political Influence, Regulatory, Rural Economies

You Have to See It to Believe It: What It's Like to Have Fracking in Your Backyard

April 22, 2013

You Have to See It to Believe It: What It's Like to Have Fracking in Your Backyard

Residents in industry-friendly West Virginia share their experiences, photos and videos.
April 15, 2013
From Alternet, by Tara Lohan

Click here for complete article

This article was published in partnership with GlobalPossibilities.org.
Ed … Continue reading

Filed Under: Accidents, Economic, Gas Industry, Health, Impacts, Mortgages, Rural Economies

Gas Drilling, Homeowners Don't Mix

September 21, 2012

IF GAS DRILLING COMES TO THE SOUTHERN TIER, HOMEOWNERS HAVE PROPERTY-RELATED EFFECTS TO CONSIDER, WHETHER THEY HAVE ALREADY SIGNED A GAS LEASE OR ARE STILL CONSIDERING ONE

BY ELISABETH N. RADOW, PRESSCONNECTS.COM, SEPT. 18, 2012

Elisabeth Radow is the managing attorney of Radow Law and chairs the New York State … Continue reading

Filed Under: Experts, Mortgages

Mortgages for Drilling Properties May Face Hurdle

March 18, 2012

BY IAN URBINA, NEW YORK TIMES

The Department of Agriculture is considering requiring an extensive environmental review before issuing mortgages to people who have leased their land for oil and gas drilling.
Last year more than 140,000 families, many of them with low incomes and living in rural areas, received … Continue reading

Filed Under: Mortgages, New York Times

Promises made, but not kept, and it's all legal

December 28, 2011

BY JOSHUA SCHNEYER AND BRIAN GROW, REUTERS

TRAVERSE CITY, Michigan – Late in the summer of 2010, hundreds of farmers in northern Michigan were fuming.

All had signed leases with local brokers permitting drillers to tap natural gas and oil beneath their land. All were demanding thousands of dollars in bonuses … Continue reading

Filed Under: Mortgages, News Stories

Home Mortgages, Homeowner Liability Affected by Gas Drilling

November 10, 2011

NEW YORK STATE BAR ASSOCIATION JOURNAL

NOVEMBER/DECEMBER 2011, VOL. 83, NO. 9, LEAD ARTICLE

". . . issues not often discussed, such as the owner's potential liability and the continued viability of the mortgage."

"Residential fracking carries heavy industrial risks, and the ripple effects could be tremendous. Homeowners can be … Continue reading

Filed Under: Impacts, Mortgages, Reports / Studies Tagged With: gas leases and homeowners liabilities, homeowners gas drilling leases, NYS Bar Association Journal, NYSBA Journal

Rush to Drill for Natural Gas Creates Conflicts With Mortgages

October 19, 2011

BY IAN URBINA, NEW YORK TIMES

As natural gas drilling has spread across the country, energy industry representatives have sat down at kitchen tables in states like Texas, Pennsylvania and New York to offer homeowners leases that give companies the right to drill on their land.

And over the past … Continue reading

Filed Under: Mortgages, New York Times, News Stories Tagged With: energy industry representatives, Ian Urbina, Mortgages, natural gas, Natural Gas Creates Conflicts With Mortgages, real estate executives, Rush to Drill for Natural Gas, toxic wastewater

Houses for Shale

June 5, 2010

NEW MORTGAGES UNAVAILABLE FOR PROPERTIES WITH GAS DRILLING LEASES

BY LINDA FIELDS (PIKE COUNTY COURIER)

NORTHEAST Pa — Property owners may make money from leasing to Marcellus Shale gas drillers, and they may also find their property can't be financed for a new mortgage.

If gas is extracted and sold, … Continue reading

NOVEMBER/DECEMBER 2011
VOL. 83 | NO. 9

NEW YORK STATE BAR ASSOCIATION

Journal

NYSBA

Homeowners and Gas Drilling Leases: Boon or Bust?

By Elisabeth N. Radow

Also in this Issue

POINT OF VIEW

Gas drilling in Dimock, PA

Homeowners and Gas Drilling Leases: Boon or Bust?

By Elisabeth N. Radow

The Conundrum

Gas companies covet the shale gas deposits lying under homes and farms in New York's Marcellus Shale region and are pursuing leasing agreements with area property owners. Many homeowners and farmers in need of cash are inclined to say yes. In making their argument, gas companies reassure property owners that the drilling processes and chemicals used are safe. Yet aside from arguments about the relative safety of the extraction process are issues not often discussed, such as the owner's potential liability and the continued viability of the mortgage. The property owner can be particularly vulnerable when the drilling process involves high-volume, horizontal hydraulic fracturing, or "fracking."

For example, when Ellen Harrison signed a gas lease agreement in 2008, the company representative made no mention of fracking. Harrison received no details, only the chance for a "win-win" with "clean" gas for the locals and royalties for her. Like most Americans, Harrison has a mortgage loan secured by her home. All mortgages, Harrison's included, prohibit hazardous activity and hazardous substances on the property.

Reprinted with permission from the New York State Bar Association *Journal*, November/December 2011, Vol. 83, No. 9, published by the New York State Bar Association, One Elk Street, Albany, New York 12207.

Waste pond at hydro-fracking drill site, Dimock, PA

Elisabeth N. Radow (eradow@cuddyfeder.com) is Special Counsel to the White Plains law firm of Cuddy & Feder LLP. Ms. Radow chairs the Hydraulic Fracturing Committee for the League of Women Voters of New York State. Ms. Radow's Law Note, *Citizen David Tames Gas Goliaths on the Marcellus Shale Stage*, was published in the 2010 Spring issue of the *Cardozo Journal of Conflict Resolution*. This analysis and the assertions made in this article are attributable to the author alone.

Photographs courtesy of J Henry Fair. Mr. Fair's work has appeared in the *New York Times, Vanity Fair, Time and National Geographic*. His new book, *The Day After Tomorrow: Images of Our Earth In Crisis* is a series of essays and startling images. www.industrialscars.com.

Flight services provided by LightHawk http://www.lighthawk.org.

Tanker trucks filling water reservoir at hydo-fracking gas drilling operations near Sopertown, Columbia Township, PA

Overspray of drilling slurry at hydro-fracking drill site, Dimock, PA

Residential fracking carries heavy industrial risks, and the ripple effects could be tremendous. Homeowners can be confronted with uninsurable property damage for activities that they cannot control. And now a growing number of banks won't give new mortgage loans on homes with gas leases because they don't meet secondary mortgage market guidelines. New construction starts, the bellwether of economic recovery, won't budge where residential fracking occurs since construction loans depend on risk-free property and a purchaser. This shift of drilling risks from the gas companies to the housing sector, homeowners and taxpayers creates a perfect storm begging for immediate attention.

> A home represents a family's most valuable asset, financially and otherwise.

The introduction of fracking in homeowners' backyards presents a divergence from typical current land use practice, which separates residential living from heavy industrial activity, and the gas leases allocate rights and risks between the homeowner and gas company-lessee in uncharacteristic ways. Also, New York's compulsory integration law can force neighbors who do not want to lease their land into a drilling pool, which can affect their liability and mortgages as well.

The Marcellus Shale Region

The Marcellus Shale region, located across New York's Southern Tier, represents a portion of one of America's largest underground shale formations, with accessibility to gas deposits ranging from ground surface to more than a mile deep. The decade-old combined use of horizontal drilling and high-volume hydraulic fracturing is the current proposed means of extracting the trapped shale gas. Horizontal drilling, which dates back to 1929, became widely used in the 1980s, with the current technology providing lateral access to mile-deep shale in multiple directions from a single well pad.

To envision what this looks like, imagine one well pad that accommodates eight or more vertical wells with each well engineered to extend a mile or more in depth then turn and drill horizontally in its own direction, up to a mile through shale across residential properties and farms owned by a cluster of neighboring residents. High-volume hydraulic fracturing, first introduced by Halliburton in 1949, mixes millions of gallons of water with sand, brine and any of a number of undisclosed chemicals, which are injected into the well bore at pressure sufficient to rupture open the formation, prop open the mile-deep shale fractures with sand and release the trapped gas back into the well. Fracking-produced wastewater, with concentrated levels of these toxic chemicals, drilling mud, bore clippings and naturally occurring radioactive material, such as uranium, radium 226 and radon, is released from the well into mud pits and holding tanks, then trucked out for waste treatment or reused. Reuse of frack fluid, currently the favored practice because it spares the finite water supply, concentrates the waste toxicity. The Environmental Protection Agency estimates that 20%–40% of the fracking wastewater stays underground. The Marcellus Shale sits amid an intricate network of underground aquifers that supply drinking water in New York and surrounding states via municipal water supplies, private wells and springs. Shallow private wells constitute the primary source of drinking water for the upstate New York residences and farms where fracking for shale gas would take place, posing a cumulative threat to the state's complex matrix of aquifers that source our groundwater.

The Risks

The use of fracking expanded in 2005 when Congress exempted it through statutory amendments from complying with decades-old federal environmental laws governing safe drinking water and clean air. (This exemption is now commonly known as the Halliburton loophole.) Also in 2005, New York changed its compulsory integration law to pave the way for fracking.

According to the 2010 Form 10-Ks of Chesapeake Energy and Range Resources (both doing business in the Marcellus Shale region), natural gas operations are subject to many risks, including well blow-outs, craterings, explosions, pipe failures, fires, uncontrollable flows of natural gas or well fluids, formations with abnormal pressures and other environmental hazards and risks. Drilling operations, according to Chesapeake, involve risks from high pressure and mechanical difficulties such as stuck pipes, collapsed casings and separated cables. If any of these hazards occur it can result in injury or loss of life, severe damage or destruction of property, natural resources and equipment, pollution or other environmental damage and clean-up responsibilities,[1] all in the homeowner's backyard.

American culture traditionally favors land use that keeps heavy industrial activity out of residential neighborhoods. The reasons range from safety to aesthetics. A home represents a family's most valuable asset, financially and otherwise. In legal terms, homeownership or "fee simple absolute title" means a bundle of rights encompassing the air space above and the ground below the land surface. It entitles homeowners to build up and out, pledge the house and land as collateral for a mortgage loan, and lease or sell the property. Part of a home's purchase price pays for this bundle of rights. Another bundle of rights attributable to homeownership

Continued on Page 14

Continued from Page 12

consists of the actual roof over one's head; clean, running water; and access to utilities. A third bundle of rights is attributable to the intangibles that make a house a home, such as peaceful sanctuary, fresh air, and a safe, secure haven for budding children. Residential fracking challenges all of these attributes of home ownership.

Shifting Risk

Gas leases provide the bundle of rights from which gas companies generate financing and operate gas wells. Profitable gas *extraction* benefits from broad rights to access, extract, store and transport the gas, on the company's timetable. Gas leases contain these rights. Profitable gas *investment* benefits from latitude on timing of gas extraction and the latitude not to extract gas at all. Gas leases contain these rights too. The gas company has the sole discretion to drill, or not to drill. Leases provide the currency in trade. The longer the lease term, the more latitude a leaseholder has to manage market fluctuations. With its broad gas storage rights, a leaseholder can store gas from other sources, on-site and wait for the demand curve to peak before executing the most favorable transactions. In August 2011, the U.S. Geologic Survey estimated reserves of "technically recoverable" shale in the Marcellus Shale play at 84 trillion cubic feet, reflecting a significant reduction from DEC's long-standing website estimate of between 168 trillion and 516 trillion cubic feet. Shale gas projections have an inherent value, separate and apart from the extracted gas. People invest capital based on the anticipated reserves. Time will tell how the new estimates change if and where gas companies actually drill in New York. Some regions may be too difficult or expensive to access; others will be off-limits by law. The terms of the gas leases nevertheless entitle the gas lessee to maintain the leasehold, which can facilitate investor activity. The Form 10-K appended to the 2010 Chesapeake Energy Annual Report states,

> Recognizing that better horizontal drilling and completion technologies, when applied to new unconventional plays, would likely create a unique opportunity to capture decades worth of drilling opportunities, we embarked on an aggressive lease acquisition program, which we have referred to as the "gas shale land grab" of 2006 through 2008 and the "unconventional oil land grab" of 2009 and 2010. We believed that the winner of these land grabs would enjoy competitive advantages for decades to come as other companies would be locked out of the best new unconventional resource plays in the U.S. We

Hydro-fracking drill sites, feeder pipelines, and access roads and gravel banks for road building (Dimock, PA)

> believe that we have executed our land acquisition strategy with particular distinction. At December 31, 2010, we held approximately 13.2 million net acres of onshore leasehold in the U.S. and have identified approximately 38,000 drilling opportunities on this leasehold. We believe this extensive backlog of drilling, more than ten years worth at current drilling levels, provides unmistakable evidence of our future growth capabilities.[2]

The broad bundle of rights granted by gas leases enables gas companies to raise capital in the millions or billions of dollars once the up-front per-acre signing bonus is paid to the homeowner. This is beneficial for the drilling investment itself and for maintaining the company's competitive advantage. On the other hand, the effect of the lease encumbering the homeowner's residence can have repercussions for mortgage financing, as will be discussed below.

Getting the Gas

Drilling companies derive the right to drill underneath residential (and non-residential) property in three ways:

- deed to the subsurface rights below the fee estate (a practice not typically used in New York);
- lease agreement with the fee owner; and
- compulsory integration, which involves government action that forces a property owner who wishes no drilling activity below its property into a drilling pool if the lessee otherwise has control of a statutorily prescribed percentage of land (in New York it is 60%).

A drilling application submitted to DEC must show the area (up to 640 aces), known as a spacing unit, assigned to the well. The spacing unit becomes officially established when DEC issues the well permit.

Deed to Subsurface Rights

A deed to the subsurface or mineral rights splits the fee estate between the surface property and the subsurface property, with separate deeds for each estate. Subsurface deeds are common in Western states where drilling is an established practice; it gives the deed holder the full range of rights to the subsurface. As with the surface deed, it is considered a real property interest and is also recorded in the land records against the section, block and lot for the surface property. The rights do not extend above the subsurface and should not, as a legal matter, interfere with the rights of the surface owner. As a practical matter, because of drilling lifecycle hazards, the surface owner may sacrifice some of the attributes of home ownership discussed in this article.

Standard Lease Agreement With Fee Owner

The standard space lease, between a building owner (landlord or lessor) and a tenant (or lessee) grants the right to occupy a specified space in the building for a finite time, in exchange for an agreed upon rent payable in regular installments. If the lease contains a percentage rent (a commercial lease concept based upon tenant revenue), it includes a formula for calculating the percentage rent and gives the landlord the right to inspect the tenant's books to verify that the landlord receives the agreed upon percentage. Except for the space leased to the tenant, the landlord retains all rights of ownership. When the lease expires, the tenant moves out, or the tenancy converts to a month-to-month tenancy. No duration of month-to-month holding over on the tenant's part converts the month-to-month arrangement into a lease for years. To end the relationship, either the landlord or tenant can give 30 days' written notice to the other.[3] To extend beyond the month-to-month relationship, the parties must enter into a new written lease.

In contrast, gas leases function more like a deed with a homeowner indemnity than a space lease – revealed by an assessment of the cumulative impact of the broad bundle of rights granted to the gas company-lessee and the corresponding bundle of rights relinquished by the homeowner. Standard pre-printed gas leases presented to New York homeowners by landmen and signed, *without negotiation*, represent the typical practice (until recently) in our state, and will be used here to illustrate the impact this has on the of rights and responsibilities of the homeowner. Depending upon the DEC's ultimate regulatory framework, homeowners who negotiate gas leases can expect similar impacts given the industrial sized risks involved.

The Use

A gas lease grants the right to extract the gas and a litany of related gas-constituents; it also grants the right to explore, develop, produce, measure and market for production from the leasehold and adjoining lands using methods and techniques which are not restricted to current technology.

The Space

In a standard gas lease, the physical leased space consists of the subsurface area within the property boundaries and undesignated portions of the surface lands

> to set up and store drilling equipment; create a surface right of way to use or install roads, electric power and telephone facilities, construct underground pipelines and so-called "appurtenant facilities," including data acquisition, compression and collection facilities for use in the production and transportation of gas products to, from and across the leased property; and store any kind of gas underground, regardless of the source, including the injecting of gas, protecting and removing gas, among other things.

The lessee's expansive, undesignated, reserved surface rights can result in acres going to support the operation, jeopardize a home mortgage and eliminate the homeowner's ability to build on the surface in areas the lessee determines would interfere with drilling operations. Without limiting the location, size and type of pipeline, the homeowner leaves open the chance of a high-pressure gas line running under the property.

The Term

The lease runs for a five-year primary term (a portion contain a five-year renewal term), which in a standard lease the lessee can unilaterally transform into an indefinite, extended term, without signing a new lease, for any of the following reasons:

> exploration anywhere in the spacing unit, or a well in the spacing unit is deemed "capable of production," or gas from the spacing unit is produced, or the spacing unit is used for underground gas storage, or the prescribed payments are made.

The term "capable of production" is defined broadly enough to include off-site preparatory work. Regardless of the stated lease term, once a well is "capable of production," the rights continue for as long as operations continue, possibly decades.

The Rent

Homeowners receive a signing bonus ranging from dollars to thousands of dollars per acre of leased land. This single payment can potentially tie up the property, indefinitely. References in so-called "paid-up" leases (common in New York) to other potential additional payments (except for the royalty payment) are deemed satisfied by the signing bonus. Absent negotiation, royalties consist of a percentage (typically 1/8 or 12.5%), net of production-related expenses and any loss in gas volume that reduces the revenue received. Late payments or failure to make a royalty payment can "never" result in an automatic lease termination. Homeowners share the royalty with other members of the drilling pool on a pro-rated basis. This is known as correlative rights. The larger the drilling pool, the smaller the royalty. Unlike the percentage rent provision in a commercial lease, a gas lease contains no detailed formula for calculating the net royalty payment, no pro-rata share corollary to calculate the relative percent the homeowner bears to the pool of all other property owners entitled to divide the royalty pie and no right to review the lessee's books and records.

Assignment

Space leases require a tenant to obtain landlord consent for a third-party lease assignment. In contrast, a gas lessee can sell and assign to or finance the gas lease (or any interest) with any party it selects, without providing notice to the homeowner. This continuing right deprives homeowners of control over confirming consistency between the initial lease and the terms of the assigned document – who ends up with the lease, who gets hired and allowed onto the family's private property and the quality of the drilling activity performed in their backyard. As the record title holder, homeowners remain potentially liable for the activity that occurs on their property, if it is not effectively delegated.

Hazardous Activity/Hazardous Substances

Space leases expressly prohibit hazardous activity and the presence or storage of hazardous substances on the property, such as chemicals and flammable or toxic petroleum products. Gas leases permit both the drilling activity and the use of hazardous substances and flammable products, such as the methane gas itself. Gas leases reserve the right to store gas of any kind, indefinitely, underground, regardless of the source, which can create additional risk to the homeowner's personal safety and adversely impact, as will be discussed, a homeowner's responsibility to its lender.

Easements

Gas leases contain grants of easements, which is not typical for a lease. This grant includes the lessee's right, even after surrendering the leasehold, to "reasonable and convenient easements" for the existing wells, pipelines, pole-lines, roadways and other facilities on the surrendered lands. Assuming its enforceability, a driller can surrender a lease and still assert a range of potentially perpetual surface and subsurface rights as superior to those of the fee owner without any further payment and without the obligation for repair, maintenance or resulting damage. However, unless the actual lease containing the easement grant gets recorded against the residential property in the public records, which, apparently is often not the case, the lessee has no assurance the easements will be protected. Even so, leases reserving potentially perpetual, undesignated easements for roads and pipelines raise expensive, long-term liability concerns for homeowners, their lenders and, potentially, fellow taxpayers.

Insurance/Indemnification-Risk Allocation to Homeowner

Space leases typically require the tenant to post a security deposit to cover late rent or property damage. Gas leases do not contain a similar provision. Space leases also require tenants to purchase general liability insurance naming the landlord as an additional named insured with an indemnity covering costs for uninsured damage and other costs occasioned by the tenant and its invitees. Risks associated with typical leasehold property damage belong to tenants since they control the space. Drilling leases typically omit these points. Absent negotiation, gas leases contain no insurance and no indemnification. Even assuming the existence of an indemnification, federal protection via the Halliburton loophole can provide cover. Unless anticipated DEC rules change, New York intends to require disclosure only of fracking chemicals by gas companies. While this represents a step in the right direction, it also gives companies an "out" by merely requiring them to disclose which chemicals they use. It does not necessarily make companies liable for the damage those chemicals cause. Eliminating the right to frack with toxic and carcinogenic chemicals by reinstating the laws amended by the Halliburton loophole would eliminate the shift of financial responsibility away from the gas company as it relates to this aspect of the gas drilling lifecycle. Regulating use of benign fracking additives that can boost risk would be useful as well. For example, radioactivity, a known danger at elevated levels, poses greater risks when it interacts with frack-fluid additives that contain calcium.[4] By not restoring liability to the companies that control drilling operations and coupling it with economic reasons to prevent casualties, a homeowner will have to first experience the property damage or personal injury, then successfully arbitrate or litigate against the gas lessee for reimbursement and remediation, a burden most homeowners can't afford or mentally handle. Even assuming a homeowner's fortitude to sue, focus on damages and remediation misses the fact that residential fracking introduces irreparable risks to homes and the families that live there.

> Assuming its enforceability, a driller can surrender a lease and still assert a range of potentially perpetual surface and subsurface rights as superior to those of the fee owner.

Gas Lease Mortgages

New York law[5] recognizes minerals (before extraction) as real property. In May 2011, a Chesapeake Energy subsidiary, Chesapeake Appalachia, pledged mineral rights on over 1,000 Bradford County, Pennsylvania, mineral leases as collateral for a $5 billion line of credit mortgage loan with Union Bank of California, while in July, 2011, another Chesapeake Energy subsidiary, Appalachia Midstream Services, pledged pipeline rights-of-way on over 2,000 Bradford County properties to access an unspecified line of credit mortgage loan with Wells Fargo. Although the mortgage was properly recorded in the county recorder's office against the section, block and lot of the fee/surface property, the news of a $5 billion loan linked to their property surprised mortgage-seeking homeowners. Legally, Chesapeake's mortgaged interests are distinguishable from the surface owner's, so that shouldn't interfere with a home loan, but residential fracking might. It is worth noting that Wells Fargo, one of Chesapeake's lenders, stands among national lenders that do not grant mortgage loans to homeowners with gas leases.

Homeowner Predicament

Despite DEC website warnings about the potential adverse impacts of gas leases,[6] the government plays no role in the lease process. Contract law favors the rights of private parties to enter into arm's-length transactions without government intervention. Yet, when large numbers of complaining upstate homeowners recount consistent practices employed by the landmen that resulted in pre-printed standard gas leases signed without negotiation, it would be appropriate to involve the New York Attorney General, to examine the facts. In consumer protection contexts, the government (on its own or as a result of litigation) has seen fit to offer protection. Homeowners who signed gas leases do not constitute consumers *per se*, but the analogy supports Attorney General involvement to restore to the landowner the bulk of rights attributable to fee ownership and, by extension, the property's value. Paradoxically, for example, gas leases reciting "good faith negotiations" between the parties lock in homeowners with lessee-favored termination clauses. Unlike space leases that terminate on a stated expiration date, gas leases give lessees latitude to extend a stated lease term, indefinitely, by asserting it is "capable of production" or "paid up" or otherwise, subject to "force majeure," asserting New York's de facto drilling moratorium as the event beyond their control. "Force majeure" litigation is now on the dockets across New York's Southern Tier.

Municipal Backlash; Indefinite Leases

Municipalities within the 28 counties sitting on top of New York's Marcellus Shale differ on the benefits of fracking. Municipalities in favor of fracking focus on local economic growth.[7] Municipalities opposing fracking take into consideration competing established economies, such as agriculture and tourism. By asserting home rule, municipalities have enacted moratoria, amended master plans or codes to prohibit heavy industry, including gas drilling, and banned drilling on public land or altogether.[8] In September 2011, Anschutz Exploration Corp. filed a lawsuit against the Town of Dryden asserting the supremacy of the state to issue a drilling permit over the right of the municipality to amend its zoning law to prohibit drilling or storage of natural gas.[9] The outcome of this case will have significant ripple effects throughout the state.

When municipalities favor fracking, homeowners with questions or concerns are on their own. Residents who do not wish to renew and residents who are committed to leasing but want to renegotiate terms when their lease expires, as with an expired space lease, are meeting some resistance from the gas companies, who are using General Obligations Law § 15-304 (GOL) to reinstate expired leases. That statute states that before a recorded drilling lease expires by its own terms, the owner "may" serve a cancellation notice to the lessee triggering a lessee right to file an affidavit affirming that the lease is in full force and effect. Then, more papers get filed to confirm and preserve that right. Unlike the space lease which terminates on a certain date, GOL § 15-304 gives drillers a second chance which (so long as the driller has recorded the full lease) can tie an unwilling homeowner indefinitely to a gas lease the homeowner no longer wants. Homeowners electing not to give the statutory notice live in limbo, uncertain as to where they stand.

If a lessee decides to drill for gas but lacks the total acreage it needs, the lease provides the statutorily required leverage to form a so-called "spacing unit" by forcing unwilling property owners surrounding the voluntarily leased property into a drilling pool, a process called compulsory integration.

Compulsory Integration

Involuntary compulsory integration represents the most controversial method drilling companies use to access gas. Compulsory integration (or forced pooling) exists by statute in 39 states.[10] It replaced the common law rule of "capture" which allowed Person A to legitimately collect and own gas from Person B's supply if it flowed into Person A's well. To capture gas before a neighbor did, surface wells proliferated in close proximity to one another, causing the overall gas pressure to drop and making gas extraction inefficient for all involved. It also blighted the surface lands. Today, Environmental Conservation Law § 23-0901 (ECL) deputizes a driller, subject to a DEC hearing, to force an unwilling property owner into a spacing unit if the drilling company otherwise controls 60% or more of the acreage in the spacing unit either by lease, deed or voluntary integration,[11] which itself involves lease swaps among leaseholders to form the spacing unit.

Proponents assert that forced pooling makes the drilling infrastructure investment more cost efficient by maximizing access to gas while also maintaining the surface landscape and fairly compensating the noncontributing "integrated" homeowner with a shared net 12.5% royalty. Opponents consider it a form of eminent domain. The constitutionality of forced pooling under a predecessor statute was confirmed in dicta by the New York Court of Appeals in *Sylvania v. Kilborne*, itself citing the United States Supreme Court, which held that "a state has constitutional power to regulate production of oil and gas so as to prevent waste and to secure equitable apportionment among landholders of migratory gas and oil underlying their land fairly distributing among them the costs of production and the apportionment."[12]

Yet, the updated statute's effect eliminates the homeowner's right to control the homestead, creates financial risk for the driller's acts by not expressly holding the driller responsible, and jeopardizes access to a mortgage or the ability to sell the property. The ECL permits objection by a homeowner to the forced pooling within prescribed guidelines (having a scientific basis) none of which includes asserting a conflict with other (existing or intended) contract obligations, such as a mortgage. ECL § 23-0503, empowers DEC to schedule an adjudicatory hearing if it determines that "substantial and significant issues have been raised in a timely manner." Whether a driller's rights of involuntary compulsory integration come after, or trump, sanctity of contract between a homeowner and its mortgage lender needs clarification.

$6.7 Trillion Secondary Mortgage Market

The Federal Housing Finance Agency (FHFA) was created in July 2008 on the heels of the mortgage crisis, to provide supervision, regulation and housing mission oversight of Fannie Mae and Freddie Mac and the Federal Home Loan Banks (FHLB) and to support a stable and liquid mortgage market. As of September 2010, according to FHFA, the combined debt obligations of these government-sponsored entities totaled $6.7 trillion, with Fannie Mae and Freddie Mac purchasing or guarantying 65% of new mortgage originations. FHFA, as conservator of the secondary mortgage market, has a fiduciary responsibility to promote the soundness and safety of the secondary mortgage market. It is in FHFA's interest to limit mortgage defaults.

Most American homeowners hold a mortgage loan and 90% of all residential mortgage loans are sold into the secondary mortgage market (exceptions exist for million dollar homes which do not get sold by the lending bank). It is assumed that most upstate New Yorkers who signed gas leases have a mortgage, will want one in the future or want that right for a future purchaser. Mortgage lending favors low-risk activity on its mortgaged properties. Fannie Mae, Freddie Mac and the FHLB establish lending guidelines for appraisers and underwriters that dictate whether a home is a worthy investment. This helps to facilitate their combined mission to attract investors, such as pension funds, who provide liquidity in the secondary mortgage market. Primary lenders, in turn, rely on their borrowers' compliance with mortgage covenants mirroring these lending guidelines for the life of the loan.

Assuming 10% of the existing secondary mortgage market portfolio includes residential properties subject to drilling activity, this amounts to $670 billion of secondary mortgage market debt; assuming the number is only 1%, this amounts to $67 billion. Eventually, gas drilling may span up to 34 of the lower 48 states, including densely populated cities such as Fort Worth, Texas. If so, a substantial portion of the secondary residential mortgage market portfolio may be at risk from residential fracking.

Loan Underwriting Reveals Collateral Flaws With Residential Fracking

Home Appraisal

All mortgage loans require a property appraisal, title insurance covering the lender or its assignees and homeowner's insurance. Home and land appraisals are based upon like-properties, similarly situated, and are used to determine market value, the loan-to-value ratio and the maximum loan amount. Reliable appraisals of properties subject to gas leases are difficult to obtain and potentially prohibitively expensive; it would require a comprehensive title search of area properties encumbered by gas leases. Often a memorandum of the gas lease and not the lease itself is recorded, and a read-through of the entire gas lease is required to make a fair comparison between lease-encumbered properties. Underwriters need to evaluate the risks and know who pays for them; without the full lease in hand, they can't make such an evaluation.[13]

Evaluating the driller's identity can be another underwriting challenge; with unrecorded lease assignments, lenders don't know who is performing the heavy industrial activity on their residential collateral. Federal Housing Authority guidelines for federally insured mortgage loans, which make up a portion of the secondary mortgage market debt, require that a site be rejected "if property is subject to hazards, environmental contaminants, noxious odors, offensive sights or excessive noise to the point of endangering the physical improvements or affecting the livability of the property, its marketability or the health and safety of its occupants,"[14] all of which are potential characteristics of residential fracking.

Flare at hydro-fracking gas drilling operations near Sopertown, Columbia Township, PA

Lender's Title Insurance

A lender's title policy insures the mortgage lien, as of the date of the policy (up to the loan amount), against loss or damage if title is vested in someone other than the homeowner. Gas leases signed after the policy date are not covered by the policy. Gas leases in effect when the policy is issued will be listed as a title exception. Coverage won't include the gas lease or any claims arising out of it. Title endorsements don't eliminate this exception to coverage. Underwriters consider these exceptions a red flag, sufficient to jeopardize the loan. Lenders financing properties subject to compulsory integration won't discover the title encumbrance from a title search because ECL § 23-0901 makes no apparent reference to recording the DEC determination of compulsory integration in the land records. New York title policies expressly exclude from coverage loss or claims relating to any permit regulating land use. It remains unclear whether a gas drilling permit which includes forced pooled property would fall within this exclusion. Either the Legislature will clarify the statute or the ambiguity will be a source of future litigation. Rating agencies and secondary mortgage market investors should be apprised if a loan portfolio which they have rated or in which they have invested, as the case may be, contains gas leases or forced pooled properties, since both add new risk.

Homeowner's Insurance

All residential mortgage lenders require homeowner's insurance from their borrowers. Even the most comprehensive homeowner's coverage, known as "broad risk form" or "special form" insurance excludes the types of property damage associated with the drilling lifecycle, such as air pollution, well-water contamination, earth movement and other risky commercial activity performed on residential property.

POINT OF VIEW

The Mortgage: No Hazardous Activity/Substances, No Gas/Gas Storage, No Radioactive Material

Residential mortgages prohibit borrowers from committing waste, damage or destruction or causing substantial change to the mortgaged property or allowing a third party to do so. This includes operations for gas drilling. Standard residential mortgages prohibit borrowers from causing or permitting the presence, use, disposal, storage, or release of any "hazardous substances" on, under or about the mortgaged property. In mortgages, "hazardous substances" include gasoline, kerosene, other flammable or toxic petroleum products, volatile solvents, toxic pesticides and herbicides, materials containing asbestos or formaldehyde and radioactive materials. Borrowers are also prohibited from allowing anyone to do anything affecting the mortgaged property that violates any "environmental law." "Environmental law" means federal, state and local law that relates to health, safety and environmental protection. Mortgages obligate borrowers to give lenders written notice of any release, or threat of release, of any hazardous substances and any condition involving a hazardous substance which adversely affects the value of the mortgaged property.

Mortgages prohibit the activities gas leases permit to preserve the property's marketability. For example, shallow water wells and springs, typical in the northeast, represent the home's drinking water source; they become susceptible to contamination from drill site spills and leaks or flooding from frack wastewater. Frack fluid chemicals, pollutants and naturally occurring radioactivity in the waste have been reported to far exceed levels considered safe for drinking water. A contaminated well cannot be easily remediated, if at all. A home or a farm without on-site potable water may not sell. Migrating methane gas from the drilling process risks explosions both inside and outside of the home.

Because water and migrating methane gas each defy boundaries, following minimal underwriting setback requirements between the home and the drill site may prove inadequate to protect a water well from irreparable contamination or a home from explosion. A bank can consider these factors when approving a mortgage loan, and once financed, when declaring a mortgage loan in default.

Homeowner and Lender Vulnerability

The 2010 Form 10-K issued by Chesapeake states:

> There is inherent risk of incurring significant environmental costs and liabilities in our operation due to our generation, handling and disposal of materials, including waste and petroleum hydrocarbons. We may incur joint and several liability, strict liability under applicable U.S. federal and state environmental laws in connection with releases of petroleum hydrocarbons and other hazardous substances at, on, under or from our leasehold or owned properties, some of which have been used for natural gas and oil exploration and production activities for a number of years, often by third parties not under our control. For our non-operated properties, we are dependent upon the operator for operational and regulatory compliance. While we maintain insurance against some, but not all risks described above, our insurance may not be adequate to cover casualty losses or liabilities, and our insurance does not cover penalties or fines that may be assessed by a governmental authority. Also, in the future we may not be able to obtain insurance at premium levels that justify the purchase.[15]

In the Form 10-K appended to its 2010 Annual Report, Range Resources adds:

> We have experienced substantial increases in premiums, especially in areas affected by hurricanes and tropical storms. Insurers have imposed revised limits affecting how much the insurer will pay on actual storm claims plus the cost to re-drill wells where substantial damage has been incurred. Insurers are also requiring us to retain larger deductibles and reducing the scope of what insurable losses will include.[16]

Signing a gas lease without lender consent is likely to constitute a mortgage default. At any time before or after the drilling begins, a lender can demand the borrower to either terminate the lease or pay off the loan. Since the gas companies have pledged the gas leases as collateral for loans or brought in investors based upon the potential income the gas lease can produce, facilitating a lease termination may require protracted litigation. Further, it is not likely that most homeowner-borrowers will have the ready cash to repay the loan. This places the lender in an untenable position.

Residential fracking, perpetual unfunded easements and long-term gas storage beneath mortgaged homes create a cumulative threat to the repayment of mortgage loans tranched in secondary mortgage market portfolios. Homeowners suffering irreparable property damage, such as well water contamination, structural damage or casualty from a gas explosion, won't have coverage from homeowner's insurance and may have no recourse against the gas company holding the lease. This is so even if homeowners sue and succeed in court since the gas companies' own disclosure statements state they are underinsured. New York State Comptroller Thomas Di Napoli has proposed an up-front gas company–funded emergency fund to remediate those emergencies that can be fixed. As of yet, the gas industry, the Governor, the state Senate and the Assembly have not offered support for such a fund. The Form 10-K for Chesapeake Energy and Range Resources, for example, cite the risks attendant to gas drilling. They do not indicate the source of funding to support the numerous risks from the drilling activity. Unless this source of funding can be identified, the secondary mortgage market, as holder of 90% of the nation's home mortgages, may be left with the clean-up bill. Ultimately, financial responsibility could fall on the taxpayers.

New York homeowners who signed gas leases without the facts about this unconventional drilling claim they did not know the risks involved. These homeowners did not know that they violated their mortgage by entering into the gas lease or have potentially no insurance coverage in case of a drilling loss. Impacted homeowners can write to New York's Attorney General to (1) document their experience; (2) request a reprieve from a mortgage loan default; and (3) institute a "no gas drilling" policy until it is determined that the mortgaged collateral won't be at risk from the driller's plans. To achieve this, gas leases should be revised to modify or omit the risky clauses, such as gas storage, surface rights and undesignated, unfunded easements. In the alternative, the gas leases can be terminated. Homeowners need help before gas permitting begins, in order to spare the homestead and the home mortgage market too.

New Mortgages for Homeowners With Gas Leases and New Construction[18]

Even before the drilling commences, many upstate New York homeowners with gas leases cannot obtain mortgages. Bank of America, Wells Fargo, Provident Funding, GMAC, FNCB, Fidelity and First Liberty, First Place Bank, Solvay Bank, Tompkins Trust Company, CFCU Community Credit Union and others[17] are either imposing large buffer zones (too large for many borrowers) around the home as a condition to the loan or not granting a mortgage at all.

Once lenders connect the "no hazardous activity" clause in the mortgage with the mounting uptick in uninsurable events from residential fracking, this policy can be expected to expand. Originating lenders with gas industry business relationships may decide to assume the risk, make mortgage loans to homeowners with gas leases and keep the non-conforming loans in their own loan portfolio. However, there is a limit to what an originating bank can keep in its own loan portfolio. Eventually, cash infusions from the secondary mortgage market will become a necessity; and secondary mortgage market lending guidelines will be a reality. If homeowners with gas leases can't mortgage their property, they probably can't sell their property either (this assumes the purchaser will need mortgage financing to fund the purchase). The inability to sell one's home may represent the most pervasive adverse impact of residential fracking.

Real estate developers and contractors rely on construction financing and financeable homeowners to stimulate construction starts. New York's upstate construction future depends upon the ability to sell what one builds. Washington County, Pennsylvania, for example, reported improved home sales servicing the gas industry in 2010, but apparently not of properties built on drill sites.

The Conundrum Revisited

The energy and housing sectors both rely on investor dollars to fund their future. Pension funds and other money sources that still invest in housing but now consider natural gas the preferred investment raise a potential paradox: Will individuals' retirement funds expand as their homeownership rights fade away? The conundrum to consider: how can a nation with $6.7 trillion in residential secondary mortgage market debt that measures economic recovery by construction starts and new mortgage loans also accommodate risky and underinsured residential fracking involving a still-unknown quantity of this residential mortgage collateral? Before New York embraces fracking as a new frontier, it would be wise for our corporate and government leaders focused on the vitality of our housing and energy sectors to address and resolve this conundrum. ■

1. Chesapeake Energy Corp., *10-K: Annual Report Pursuant to Section 13 and 15(d)* 27 (2011) (Chesapeake Energy 10-K: Annual Report); Range Resources, Uncovering Tomorrow's Energy: 2010 Annual Report 13 (2010) (Range Resources 2010 Annual Report).

2. Chesapeake Energy 10-K: Annual Report 4.

3. N.Y. Real Property Law § 232-b.

4. Mark Greenblatt, *Texas drinking water makes pipes and plumbing radioactive*, KHOU.com (May 18, 2011) at http://www.khou.com/home/-I-Team-Texas-drinking-water-makes-pipes-and-plumbing-radioactive-1221408194.html.

5. N.Y. Jurisprudence, Mines § 7; *see* N.Y. Uniform Commercial Code § 9-102.

6. Div. of Mineral Res., A Landowner's Guide to Oil & Gas Leasing, Dep't of Envtl. Conservation (2008), http://www.dec.gov/docs/materials_minerals_pdf/brochure.pdf.

7. Cornell University Professor Susan Christopherson cautions against boom-bust impacts. *See* Susan Christopherson, *Marcellus Gas Drilling*, Cornell Univ. 2011, http://www.greenchoices.cornell.edu/development/marcellus.

8. Joe Hoff, *Moratoria, Bans, Resolutions Opposed to Hydrofracking: A Local and Global Sampling*, R-Cause (Sept. 20, 2011) www.r-cause.net/bans-moratoria.

9. *Anschutz Exploration Corp. v. Town of Dryden & Town of Dryden Town Bd.*, Supreme Court, Tompkins County; N.Y. Environmental Conservation Law § 23-0303(2) (ECL).

10. ECL § 23-0901; Marie C. Baca, *State Law Can Compel Landowners to Accept Gas and Oil Drilling*, Pro Publica (May 19, 2011), http://projects.propublica.org/tables/forced-pooling.

11. ECL § 23-0901.

12. *Sylvania Corp. v. Kilborne*, 28 N.Y.2d 427 (1971) (quoting *Hunter Co. v. McHugh*, 320 U.S. 222 (1943)).

13. *See* Greg May, VP, residential lending, *Gas and Oil Leases Impact on Residential Lending*,Tompkins Trust Co., White Paper,(Mar. 24, 2011), http://www.tompkins-co.org/tccog/Gas_Drilling/Focus_Groups/Assessment%20Documents/White%20Paper.pdf

14. Dep't of Hous. & Urban Dev., *Valuation Analysis for Single Family One-to-Four Unit Dwellings* (4150.2) (2011).

15. Chesapeake Energy 10-K: Annual Report 29, *supra* note 1.

16. Range Resources 2010 Annual Report 13, *supra* note 1.

17. Greg May, VP, residential lending Tompkins County Trust, telephonic update of white paper, *supra* note 13, and Joseph Heath, Esq.

18. *See* Ian Urbina, *Rush to Drill for Natural Gas Creates Conflicts With Mortgages*, N.Y. Times, Oct. 20, 2011, p. 1. Mr. Urbina's article used Elisabeth Radow's August 11, 2011, letter to Freddie Mac and the federal agency that oversees Freddie Mac, warning the agencies about potential conflicts in the mortgage market, as a documentary source for his piece. The letter may be viewed at http://www.nytimes.com/interactive/us/drilling-down-documents-8.html#document/p12/a33448.

Testimony Submitted to the Delaware River Basin Commission. September 11, 2013
By Elisabeth N. Radow, Esq. enradow@radowlaw.com; www.radowlaw.com

My name is Elisabeth Radow. I am grateful for the opportunity to submit testimony to Executive Director Carol Collier on behalf of the Delaware River Basin Commission (DRBC). I am a lifelong New Yorker, the managing attorney of Radow Law PLLC and a mother. I chair the Committee on Energy Agriculture and the Environment for the League of Women Voters of New York. The League of Women Voters of New York, New Jersey, Pennsylvania and Delaware have submitted joint testimony to the DRBC previously. Today I submit testimony on my own behalf. My work has been sourced and cited in national publications such as the New York Times, Huffington Post and MORE Magazine and has been published in several law journals. My law practice includes real estate development, real estate finance and increasingly, the effects of gas drilling operations on property ownership.

The basis for my testimony today comes from my research identifying the impacts of unconventional shale gas drilling on property value, risk allocation between the gas drilling company and the homeowner and the increasing inability of homeowners to obtain and maintain a mortgage and homeowners insurance in the presence of gas drilling.

The majestic Delaware River provides drinking water to 15 million people. The responsibility of the DRBC as stewards of this water supply for so many Americans is an awesome one. What I wish to stress is that how the DRBC discharges that obligation will also profoundly and permanently affect the ability of all citizens living in the Delaware River Basin states to have a safe place to call home. Across America, in shale rich-states, property ownership is being revolutionized by the proliferation of the multi-step, heavy industrial drilling operations on the land surface and subsurface of private homes and farms.

Home represents a family’s most valuable asset, financially, spiritually and otherwise. From a property value standpoint, think of home as a bundle of rights: the right to construct, obtain a mortgage loan, lease and sell the property; the right to clean running water, electricity, a roof over ones’ head; a safe place to raise children, crops or cattle, or all of the above. Americans pay for these rights when we purchase our property, and expect these rights to continue until we sell. We want the property value to increase. So does the state. Our tax base depends upon it. Now there is mounting evidence that banks will not extend mortgage loans and insurance companies will not renew homeowners’ insurance policies for homeowners with gas leases and in some cases their neighbors without gas leases. These trends have potentially grave implications for community vitality and personal wealth in areas with fracking and must be examined and clearly understood by policy makers such as the DRBC.

What about unconventional shale gas drilling is producing these threats to homeowner and community wealth and security? Up to now, home has represented the one place people have control of the destiny of their economic assets. Standard gas leases grab homeowner control of property use by giving the gas company the right to establish surface operations, create perpetual, unfunded, road and utility easements, and the right to store gas underground from any source. The standard leases do not require the gas company to fund or perform the maintenance, repair and ultimate restoration of the easements and other surface uses. So that expense stays with the property owner. They give the gas company the free right to sell the lease or take in investors without homeowner consent. This means the homeowner has no control over who comes onto their private property to drill, or the quality of the work they perform.

Gas drilling introduces hazardous activity and hazardous substances, practices which are expressly prohibited by standard mortgages. Consider that while the mortgage lender expects the home to retain its value for the 30 year life of the loan, a gas driller, and by extension its investors, on that very same property, cares more about extracting the most gas for the least expense and least regulation.

Publicly traded gas company 10-K's filed with the Securities and Exchange Commission characterize the drilling lifecycle as subject to many risks. The list of hazards includes: blow-outs, explosions, pipe failures and uncontrollable flows of natural gas, or well fluids. The same public disclosure documents report that the gas drillers are not fully insured for their operations and fail to state that they have available cash reserves to pay for uninsured casualties, property damage and environmental pollution resulting from their operations.

Well-water contamination can occur at one or more points in the drilling process, including from leaks, spills and cracked well casings and the inappropriate road spreading, disposal and treatment of the toxic, radioactive hydraulic fracturing waste. A recently released EPA power point presentation of its Dimock PA water analysis reflects an apparent nexus between gas drilling operations and contaminated water. http://desmogblog.com/2013/08/05/censored-epa-pennsylvania-fracking-water-contamination-presentation-published-first-time. As is currently happening, properties without potable water will lose substantial value and farms without potable water will fail causing personal economic catastrophe. If this impact continues, it could have major ripple effects on the tax base.

While water contamination from gas drilling operations is the most discussed and most obvious adverse impact to a home's use and value, structural damage to the residence represents another cause for concern. Gas drilling operations involve seismic testing which causes vibrations, moving earth, use of explosives, drilling wells and fracturing shale using extreme high pressure and deep well injection of the toxic waste, where permitted. For example, the Youngstown, Ohio region logged more than 100 earthquakes in 2011 which have been linked to deep well injection of hydraulic fracturing waste. http://www.nbcnews.com/science/fracking-practices-blame-ohio-earthquakes-8C11073601?ocid=msnhp&pos=4 According to the US Geological Survey, "the number of earthquakes has increased dramatically over the past few years within the central and eastern United States. More than 300 earthquakes above a magnitude 3.0 occurred in the three years from 2010-2012, compared with an average rate of 21 events per year observed from 1967-2000. USGS scientists have found that at some locations the increase in seismicity coincides with the injection of wastewater in deep disposal wells."
http://www.usgs.gov/blogs/features/usgs_top_story/man-made-earthquakes/

Any of these invasive gas drilling operations can cause a home's foundation to falter and walls to crack making the residence unsafe to inhabit. For example, recently, two couples in Johnson County, Texas filed a lawsuit for property damage allegedly resulting from fracking-related earthquakes.

While there is no government sponsored registry of gas drilling related impacts to homeowners, these accounts abound. Many are reflected on the FrackTracker Internet database. I am providing the link so the DRBC can review and confirm the mounting accounts. http://www.fractracker.org/2013/03/pacwas-list-of-the-harmed-now-mapped-by-fractracker/

Standard gas leases fail to mention insurance. Homeowners remain potentially liable for the activity that occurs on their property, if it is not effectively delegated to the gas company in the lease or effectively addressed by the gas driller. Homeowners insurance excludes from coverage industrial activity and leaves homeowners vulnerable to losing their insurance coverage. This was confirmed in a July 2012 press release by Nationwide Mutual Insurance Company stating that:

> Nationwide's personal and commercial lines insurance policies were not designed to provide coverage for any fracking-related risks.…. From an underwriting standpoint, we do not have a comfort level with the unique risks associated with the fracking process to provide coverage at a reasonable price. Insurance is a contract and it is designed to cover certain risks. Risks like natural gas and oil drilling are not part of our contracts, and this is common across the industry**.**
> (http://www.nationwide.com/newsroom/071312-FrackingStatement.jsp)**.**

This fact was reconfirmed in a March 2013 news report which stated: Fracking-related damage, insurance industry insiders say, is not covered under a standard homeowner's insurance policy. Neither is damage caused by floods, earthquakes or earth movement, which insurers call exclusions. "(Fracking is) deemed an exclusion in the same way earthquake or earth movement is," according to the Insurance Information Institute, a nonprofit institute funded by the insurance industry. According to State Farm Insurance, the insurance underwriter does not have a fracking endorsement for private residences. While State Farm does have earthquake, earth-movement and sinkhole endorsements available in most areas, the endorsement may not cover fracking related impacts. http://m.shalereporter.com/industry/article_2cbf4e02-4f96-52cb-9264e169b706b05a.html

In August 2013, Lebanon, New York's town supervisor Jim Goldstein disclosed in an open letter that a constituent had their homeowner's insurance renewal for their home and farm in Lebanon denied because there is a gas well on their property. Mr. Goldstein confirmed through the insurance agent, who writes a lot of policies in southern Madison County, that this is a new trend and will come up as property owners fill out renewal applications. The property owner reported no history of payment problems or incidents on the property**.**

90% of all mortgage loans are sold into the secondary mortgage market. The standard mortgage used in the secondary mortgage market prohibits the transfer of an interest in the real property (which includes entering into a gas lease) without lender consent; and the presence of hazardous materials and hazardous activity consistent with the practices characterized by unconventional gas drilling operations. People with mortgage loans who signed gas leases without lender consent violated their mortgage; yet, as long as the borrower pays the loan, the lender may not become aware of the default. However, a mortgaged residence without homeowner's insurance constitutes an incurable mortgage default. If the homeowner/borrower cannot obtain replacement coverage in the marketplace, he or she would have to pay the substantially more expensive "forced insurance" premiums arranged through the originating bank or loan servicer (which coverage inures only to the benefit of the bank, not the homeowner), or risk losing the mortgage loan altogether and face foreclosure.

What if a homeowner doesn't have a mortgage yet, but wants one? Because most loans are sold by the originating lender into the secondary mortgage market, mortgage loans are underwritten based upon guidelines issued by the secondary mortgage market. These guidelines have restrictions which could put the originating bank on the hook for buying back the loan if a homeowner allows gas drilling after obtaining a mortgage and the gas drilling results in well water contamination, structural damage or other property damage, or the home becomes uninsured. In recognition of the risks, some national banks are taking precautions when asked to loan on properties with gas leases; others are just saying "no" to residential mortgage loans with residential fracking. Because the property's conformity to secondary market standards will be questioned, an originating lender who elects to make a mortgage loan is more likely to keep the loan in its private loan portfolio and not sell it into the secondary mortgage market. With finite reserves, originating banks can make only a limited number of portfolio loans.

One national bank is taking charge of borrowers who sign a gas lease while also having an outstanding mortgage: Sovereign Bank, N.A., now requires borrowers to sign and record a mineral, oil and gas rights rider to the mortgage which stays in effect for the duration of the mortgage. It prohibits leasing the surface and subsurface of the property for minerals, oil or gas extraction; and requires the borrower to take affirmative steps to prevent renewal or expansion of rights under any existing lease or similar prior grant. The covenant restricting this use entitles the bank to bring the property back into conformity and requires the borrower to pay all bank and attorneys' fees incurred as a result.

Key Bank's Mortgage Group has lending guidelines which provide:

> No mortgages will be written on properties that have a gas well.
> Key Bank can deny a mortgage to homeowners whose properties are within 600 feet of a gas well.
> No mortgages will be written on properties with a gas lease. .
> Property owners with gas leases and gas companies can be held liable for damages.
> http://neogap.org/neogap/

In another case, JPMorgan Chase refused to amend the terms of an existing borrower's refinancing agreement to permit a gas lease with BP. Chase's spokeswoman stated: "It's becoming wide-spread across the industry. Servicers and lenders are becoming more unwilling to approve a loan on these properties," "At the end of the day, we may not even own the loan." http://www.vindy.com/news/2013/mar/10/banks-build-roadblocks-to-riches-from-dr/?print

If a person cannot obtain a mortgage loan or keep a mortgage loan because of the risks associated with gas drilling operations, the house will be difficult to hold onto or sell. Where does that leave the homeowner? Either vulnerable to foreclosure, trapped in the home or forced to abandon it. If current trends continue, homeowners living in gas drilling regions, even those who elect not to sign a gas lease but who are compelled through compulsory integration or forced pooling to join a spacing unit; or other people living in close proximity to homeowners with gas drilling on their property, may find themselves swept into the same net facing bankers and insurance underwriters electing not to loan or renew homeowners insurance because of the migrating risks, such as water contamination and seismic activity, associated unconventional gas drilling. What effect would this have on the home value of people who do not even support the gas drilling? Does the DRBC or a DRBC State open itself up to litigation for forcing a property owner against their will into a spacing unit if that homeowner is subsequently turned down for a mortgage loan or homeowners' insurance? How will the ripple effects of this affect the tax base?

New concerns regarding the ability to mortgage and insure a home are also arising out of the proliferation of retooled older pipelines and newer ones crisscrossing under residences throughout the Country. For example, on May 29, 2013 Exxon owned Pegasus pipeline burst open spilling at least hundreds of thousands of gallons of tar sands crude oil into the residential neighborhood of Mayflower, Arkansas requiring dozens of families to evacuate. In August, 2013 two unrelated pipeline explosions occurred in Illinois, one in Erie which required 80 families to temporarily evacuate their homes, another in Van Buren County which killed a man, destroyed his home and caused the temporary evacuation of 25 homes, affecting 35-40 people. What would such spills do to the Delaware River Basin and its residents? Time will tell whether mortgage lenders and insurance underwriters will revise their underwriting standards to exclude coverage for homes located in close proximity to high pressure pipelines.
http://www.bloomberg.com/news/print/2013-09-02/decades-of-ruptures-from-defect-show-perils-of-old-pipe.html
http://www.arktimes.com/arkansas/ArticleArchives?tag=Pegasus%20pipeline%7C%7CExxonMobil
http://thinkprogress.org/climate/2013/08/13/2457691/cornfield-explosion-in-western-illinois
http://thesouthern.com/news/local/natural-gas-caused-deadly-house-explosion/article_06a3d02e-06bc-11e3-969a-0019bb2963f4.

Because of the connection to water contamination from the multi-phase drilling and fracking process and the vulnerability of homes to structural damage, what will happen to the property investment of families living across the Delaware River Basin if the DRBC elects to proceed with drilling in this water rich region? Where will these people go if their property is harmed? Who will buy the affected homes? For what price? Again, what will happen to the tax base?

The assertion by the oil and gas industry that unconventional shale gas drilling using current technology can be performed safely lacks credibility. Industry public disclosure documents, risk assessment by the insurance industry and regular reports of property damage and environmental impacts affecting homes across the nation support a contrary conclusion. Indeed, the growing reluctance of the mortgage and insurance industries to handle fracking affected properties, a reluctance driven by the long tradition of objective calculation of risk in both of these industries, presents an irrefutable answer to the claims of the oil and gas industry that unconventional gas drilling can be performed safely.

I urge the Delaware River Basin Commission not to endorse unconventional gas drilling in light of the expensive, uninsured risks it poses to homeowners and the potential it has for inflicting enormous economic losses, potentially in the many millions of dollars on homeowners and communities in the Delaware River Basin. The oil and gas industry asks that we consider the benefits of unconventional shale gas drilling. I ask that you consider the costs, including the potential financial devastation of hundreds, if not thousands or more, of innocent homeowners and just say “No” to fracking. Thank you.

7D

ADVANTAGE ENGINEERS
telecommunications | environmental | geotechnical

Evaluation of Risk to Brockway Borough Municipal Authority Surface Water and Groundwater Sources from Flatirons Development, LLC Gas Drilling Operations

Jefferson and Elk County, Pennsylvania

PREPARED BY:

Advantage Engineers, LLC
910 Century Drive
Mechanicsburg, PA 17055

DECEMBER 2011

Respectfully Submitted:

Steven R. Read, P.G.
Senior Hydrogeologist

Edward L. Balsavage, P.E.
Managing Engineer

Advantage Project Number: 1001594.01

TABLE OF CONTENTS

1.0 INTRODUCTION

1.1 Project Summary

This document provides the findings of Advantage Engineers, LLC (Advantage) evaluation of the potential for adverse impact from gas drilling operations to the water resources of Brockway Borough Municipal Authority (BBMA). The evaluation involved review of Flatirons Development, LLC (Flatirons) Well Pad 6 operations and their potential effects to Rattlesnake Reservoir and Rattlesnake Run. In addition to Pad 6, Flatirons has begun development, and/or proposed additional facilities, in the Rattlesnake Creek watershed and the contiguous Whetstone Branch watershed. The risk evaluation considered all of BBMA's land holdings where they have developed reservoirs and supply wells for potable water production. The attached Figures 1 and 2 show the approximate extent of BBMA's land holdings, and Flatirons existing and proposed facilities on USGS topographic mapping and recent aerial photography.

1.2 Documents Reviewed

The following documents were reviewed as part of this evaluation:

- *Draft*, Brockway Borough Municipal Authority, Well #5 Protection Plan, Flatirons Development, LLC, March 8, 2011, Rev. March 21, 2011.
- Responses to Advantage Engineers Review of Plan, August 2, 2011.
- Field Preparedness, Prevention, & Contingency Plan (PPC), Flatirons Development, LLC, 10-6-2011 (Revision Date).
- Erosion and Sedimentation General Permit (ESCGP-1) Application for the Flatirons Development, LLC, Dannic ESCGP-1 #4 Project, Horton Township, Elk County and Snyder Township, Jefferson County, Pennsylvania, October 2010, W.J. Young & Associates.
- Erosion, Sediment and Stormwater Control Plan for Oil and Gas Operations, Dannic ESCGP-1 #3A, Snyder and Horton Townships, Jefferson and Elk Counties, for Flatirons Development, LLC, prepared by Botsford Surveying, Inc. Marion Center, PA.
- Post Construction Stormwater and Site Restoration Plan for: Dannic ESCGP-1 #3A, Snyder, Horton Township, Jefferson, Elk County, Pennsylvania, July 2010, prepared by Botsford Surveying, Marion Center, PA.
- Material Safety Data Sheets for: CI-100 Acid Corrosion Inhibitor, CS 500 SI (scale inhibitor), FE-100L Iron Chelator, Shale Surf 1000, NE 100, ICI-3240 (biocide), Dupont Oust® XP Herbicide, Monsanto Roundup Pro® Herbicide, Genesis Xtra Drench (antiparasitic for sheep), CI 150 (acid corrosion inhibitor), B317 (scale inhibitor), HO15 (hydrochloric acid 15%), HO36 (hydrochloric acid 36%), J609 (friction reducer), L058 (iron stabilizer), and Diesel Fuel – High Sulfur.

1.3 Project Area Hydrologic Setting and Description

BBMA owns over 2,000 acres of environmentally-sensitive and unique land area in Elk and Jefferson Counties. Dating to the 1930's, these lands have been relied on to produce and store all potable water for the BBMA water system. The water supply sources found on BBMA lands include the following:

- Rattlesnake Reservoir
- Groundwater supply Well 5 located in the Rattlesnake Creek watershed
- Whetstone Branch Reservoirs Nos. 1 and 2
- Groundwater supply Wells 1 and 2 located in the Whetstone Branch watershed.

Given the heavily forested, undeveloped, and "pristine" condition of BBMA's lands, the water quality from the reservoirs and wells is exceedingly high, and requires minimal treatment prior to potable use.

The water sourced from these lands includes surface water from the streams that is stored in the reservoirs, spring water that discharges to the reservoirs and streams, and groundwater supply wells. The water from the streams and springs is sufficient to meet BBMA's average day demand of nearly 1,000,000 gallons per day (gpd) for most of the year. During the drier summer periods the artesian flow from wells 1, 2, and 5 are needed to supplement the supply.

The baseflow to the streams within the BBMA property is supplied from groundwater and spring flow which originates as infiltrating precipitation to the nearby lands. Some of this precipitation water infiltrates to shallow depths through only the soil mantle and discharges to springs and streams within hours to days. Water that drains further downward and into the bedrock aquifer will have a longer residence time in the subsurface prior to discharging to springs and the streams. Because of this interconnection between the springs and streams, and the nearby lands, both the Whetstone Branch and Rattlesnake Creek are susceptible to even small releases of contaminants from nearby areas, including sediment releases from construction. Some of the baseflow to the streams is also anticipated to originate from precipitation water that recharges the more distant uplands to the east at Boone Mountain.

Regarding Rattlesnake Creek and Whetstone Branch, Pennsylvania Department of Environmental Protection (PADEP) has classified the designated use for both streams as Cold Water Fishery (CWF). This classification refers to protected uses, and is the basis for development of water quality criteria for purposes such as determining appropriate land use in the watershed, and determining acceptable stream impact from proposed development. PA Code Title 25, Chapter 93 defines this classification as follows:

> *CWF - Maintenance or propagation, or both, of fish species including the family Salmonidae and additional flora and fauna which are indigenous to a cold water habitat.*

These streams are further protected by PADEP as High Quality, Cold Water Fishery (HQ-CWF,) from their headwaters to the Rattlesnake reservoir dam, and Whetstone Dam No. 1, respectively. This classification is special recognition of excellent water quality and habitat conditions that meet the following criteria (as excerpted from Chapter 93 regulations):

(a) Qualifying as a High Quality Water.
A surface water that meets one or more of the following conditions is a High Quality Water.
(1) Chemistry.
(i) The water has long-term water quality, based on at least 1 year of data which exceeds levels necessary to support the propagation of fish, shellfish and wildlife and recreation in and on the water by being better than the water quality criteria in § 93.7, Table 3 (relating to specific water quality criteria) or otherwise authorized by § 93.8a(b) (relating to toxic substances), at least 99% of the time for the following parameters:

dissolved oxygen	*aluminum*
iron	*dissolved nickel*
dissolved copper	*dissolved cadmium*
temperature	*pH*
dissolved arsenic	*ammonia nitrogen*
dissolved lead	*dissolved zinc*

(ii) The Department may consider additional chemical and toxicity information, which characterizes or indicates the quality of a water, in making its determination.
(2) Biology. One or more of the following shall exist:
(i) Biological assessment qualifier.
(A) The surface water supports a high quality aquatic community based upon information gathered using peer-reviewed biological assessment procedures that consider physical habitat, benthic macroinvertebrates or fishes based on Rapid Bioassessment Protocols for Use in Streams and Rivers: Benthic Macroinvertebrates and Fish, Plafkin, et al., (EPA/444/4-89-001), as updated and amended. The surface water is compared to a reference stream or watershed, and an integrated benthic macroinvertebrate score of at least 83% shall be attained by the referenced stream or watershed.
(B) The surface water supports a high quality aquatic community based upon information gathered using other widely accepted and published peer-reviewed biological assessment procedures that the Department may approve to determine the condition of the aquatic community of a surface water.
(C) The Department may consider additional biological information which characterizes or indicates the quality of a water in making its determination.

It is also noteworthy that prior to Flatirons gas drilling operations, BBMA's lands were heavily forested land with no development except for BBMA's water system facilities. BBMA operates two (2) sand filtration plants to filter surface water from the reservoirs, but these operations do not involve the use of any large volumes of hazardous chemicals or ongoing land disturbance.

In summary, the streams located on BBMA lands are closely connected and vulnerable to the land uses of the nearby areas. These lands until recently were heavily forested with no development, except for BBMA's water sources and associated facilities. The streams provide all water used by BBMA, except for some groundwater from their wells that augment supplies during dry weather periods. These streams have been classified as CWF and HQ-CWF in recognition of their excellent water quality and habitat conditions, which make these streams uniquely sensitive to disturbance and contaminants. Impacts to streams of this quality are normally irreparable.

2.0 EVALUATION OF FLATIRONS OPERATIONS

2.1 Pad 6

Flatirons constructed drilling Pad 6 in 2010 and has drilled one well to date. During drilling of the top hole for gas well DU-3-6-1H the artesian flow at BBMA's well 5 ceased and later returned. Based on these operations the gas well top hole is clearly in hydraulic communication with the fresh water bedrock aquifer, including well 5. The extent of this connection has not been determined by Flatirons. Following this event Flatirons prepared a Well 5 Protection Plan, but this plan did not adequately investigate the nature and extent of the fresh water bedrock aquifer in the area of Pad 6 and well 5. This condition is further discussed in Section 3.2 of this report.

The gas well was subsequently completed, and fracking was performed in November 2011. A pipeline is proposed to transfer gas from Pad 6 to an existing compressor station located about 3,000 feet to the east. Pad 6 lies directly north and within 1,000 feet of BBMA's Rattlesnake Reservoir. Surface water run-off from Pad 6 flows to a wetland area near BBMA's treatment building, and is subsequently conveyed to a location below the Rattlesnake Reservoir dam. The run-off from the proposed pipeline would intersect the reservoir and upstream areas of Rattlesnake Creek.

2.2 Possible Sources of Contamination at Pad 6 and Associated Operations

The following are recognized as sources/events that present a risk to the surface and subsurface/fresh water aquifer in the BBMA watershed.

<u>Gas Well Drilling and Construction</u>

Advancement of the borehole creates a potential connection (i.e., pathway) between the fresh water aquifer, and the lower intervals that contain saline/formation water and other objectionable water quality issues. **A clear hydrogeologic connection has already been established between Pad 6 and Well 5, and therefore any breach in the casing or grout seal places Well 5 and/or Rattlesnake Reservoir at risk.** In addition to a casing/grout seal breach, the presence of vertical fracturing intersected by the gas well may also serve as a possible pathway for saline water/fracking fluids to migrate into fresh water zones.

In addition to saline water, hydraulic fracturing (fracking) fluids, a.k.a. slickwater, include additional contaminants with various human health risks (ingestion, dermal contact, and inhalation) and ecological toxicity. Return water includes not only the slickwater chemicals added to facilitate stimulation of gas-producing zones, but also formation water which typically is very saline with very high dissolved solids (known to exceed 30% by weight), and elevated naturally occurring radioactive materials (NORM). A casing and/or grout breach could enable fluids under pressure to leak directly into the fresh water bedrock aquifer, and/or the unconsolidated overburden. Such a breach might also result in leakage to the surface either directly or via subsurface. Given the interconnected nature of the groundwater system and surface water, both sources would be at risk of contamination. Depending on the volume of the release, the receiving surface and/or groundwater may be rendered unfit for potable use.

Drill cuttings are produced during drilling. When in contact with water these materials may produce run-off water with the same constituents as formation water, i.e., salinity and NORM.

There may be air born migration of unwanted chemicals from the pad site due to wind. These chemicals could be in the form of dust, vapors, or mists. Downwind transport and subsequent deposition directly into a water way, or onto the ground surface for later transport in run-off water, may adversely affect water quality and/or flora and fauna.

Hazardous/Toxic Fluids Handling

The large volume of aqueous-based fluids with hazardous/toxic chemical constituents represents a significant risk to surface waters and shallow groundwater. It can be expected that one (1) million gallons or more of brine water and fracking water will be stored, transferred, pumped, and transported during the course of operations. At these points of contact there is risk for spillage of relatively small volumes which is not of special concern; however, some operations involve risk of a large volume release, such as pressurized hose/pipe failure, sudden tank rupture, hidden leak that occurs over time, and transport tanker accident. Because fluid transfer to and from Pad 6 is performed with transport tankers, it is expected that there will be many hundreds, if not one (1) thousand or more individual trips. These trips generally occur over unpaved roadways constructed in mostly steep terrain, where a vehicle accident could result in rollover and sudden tank breach and subsequent release of 5,000 or more gallons of aqueous waste. Due to the steepness of the area, such a release could reach surface water as run-off, and with infiltration to shallow groundwater interflow water. Such a release could potentially result in a chronic source of contamination to surface and groundwater, since even very low concentrations of some of the known constituents in the fluids are known to be a risk to human health and the environment.

Liquid transport tanker routes are assumed to proceed further west of Pad 6 to the compressor station. Areas west of Pad 6 lie upgradient of the Rattlesnake Reservoir dam, and thus within the HQ-CWF designated use section of Rattlesnake Creek. As such, this area is considered especially sensitive to a large release of aqueous waste.

3.0 RISK EVALUATION AT PAD 6

3.1 Water Quality Impacts

It is our opinion that the identified exposure pathways described above require 1) increased safeguards by Flatirons, and 2) further effort to characterize the potential for a completed pathway to determine whether additional safeguards are needed. The following should be addressed:

- Tanker transport represents a significant risk for a large hazardous materials spill given the anticipated large number of tanker trips that will occur. There does not appear to be sufficient attention to planning for such an event, especially with regards to prevention. There must be plans in place to address operations (or cessation thereof) during inclement weather, as well as regular road inspections to ensure that road surfaces are stable. Some locations may require a barrier or fencing to preclude a tanker from leaving the road or rolling. Overall, there must be a specific response plan in place to address the potential release scenarios, which includes personnel-specific training.

- A subsurface release of fluids from the gas well, or possibly directly from the lower borehole interval via existing vertical fracturing, has the potential to serve as a long-term but possibly undiscovered contaminant source. The water resources of BBMA remain at risk until sufficient information is provided to document that these pathways are not complete, that such migration would not reasonably occur, or that a system is in place that would quickly detect such a release to allow time to prevent significant impact. A monitoring program is necessary to enable early detection of this condition.

The Field Preparedness, Prevention, & Contingency Plan (PPCP) prepared by Flatirons should be modified and expanded to address the issues described above.

3.2 Groundwater Impacts

As previously stated, the hydrogeologic conditions that resulted in the loss of artesian flow at well 5 during top hole drilling at Pad 6 were not fully characterized. Supplemental information to the Well 5 Protection Plan was provided by Flatirons as requested; however, no conclusions or assessment of the interconnectivity between the Flatiron and #5 wells were provided. There are also questions regarding the volume of groundwater removed during top hole drilling, grouting of the top hole, and the pre- and post drilling Well 5 water quality analyses based on review of the Protection Plan.

It is understood that an aquifer test and analysis will be conducted for Well #5. This test will provide additional data, provided that groundwater is monitored at the Flatiron pad site. The aquifer testing plan should be submitted to BBMA prior to testing for their review.

The following are specific items that should be addressed as part of the aquifer testing and as follow-up investigation to the Protection Plan:

1. Clearly define the interconnectivity between the Flatirons gas well top hole and Well #5, including but not limited to:
   a. Horizontal hydraulic gradient between Well # 5 and Flatiron top-hole well
   b. Specific dip angle and attitude in top hole well
   c. Vertical hydraulic gradient between Well #5 and Flatiron top-hole well
   d. Groundwater contour map based on site specific and area static water levels

2. Either the rate of discharge or total volume removed from top-hole during drilling activities should be provided. The information provided is in inches of water stream, which does not allow calculation of the total water volume or flow rates.

3. A distance drawdown analysis between Well #5 and the Flatiron top-hole well is recommended in order to define the magnitude of interconnectivity. It is understood that the proposed aquifer pumping test would provide this information. This data would also aid in determining the potential zone of influence for similar activity in other nearby areas.

4. The pre- and post-drilling Well 5 water quality parameters were not consistent and therefore a direct comparison could not be made for all parameters. Of concern was the turbidity increase from 0.27 nephalometric turbidity units (NTU) before the top hole was drilled, to 1.39 NTU afterwards.

5. It was noted that a 50% excess cement volume was used when the 11 3/4 inch surface casing was grouted, and that no return flow was observed. The impact of injecting grout within the formation should be reviewed, especially within the fresh water aquifer, to ensure that potential water bearing zones are not grouted shut and that area groundwater flow is not adversely impacted. Additionally, an alternative method should be employed during grouting of the top-hole to minimize the introduction of grout into the formation.

6. Cross sections were provided for review; however, no cross section from the Flatiron pad site to Well 5 was included. This cross section, with groundwater gradients and structural features, would help conceptualize the subsurface model being developed.

The information from the above work should be evaluated prior to expansion of gas drilling activities that are in proximity to BBMA supply wells.

4.0 RISK EVALUATION AT OTHER FLATIRON OPERATIONS

Flatirons has proposed other drilling pads, roads, a freshwater impoundment, and pipelines within the Rattlesnake Creek and Whetstone Branch watersheds. As previously stated, the additional facilities proposed for Rattlesnake Creek watershed are within the drainage area designated as HQ-CWF, which requires an additional level of evaluation for risk to water quality, and may require some additional level of permitting beyond a general permit. For the most part, all of the possible contaminants and exposure pathways described for Pad 6 are also applicable to the other operations and should be addressed.

The proposed operations at other locations may also pose additional risk to BBMA wells 1 and 2, depending on proximity. Insufficient investigation has been performed to adequately understand the bedrock aquifer hydraulics.

5.0 COMMENTS REGARDING FLATIRONS PLANS AND PERMIT APPLICATIONS

Comments regarding the erosion and sedimentation control, stormwater control, and post construction stormwater and site restoration plans and general permit applications are provided below:

Pad 6 Erosion, Sediment & Stormwater Control Plan

1. There should be additional plans with details of all the proposed E&S controls.
2. There are cross culverts shown on the construction entrance but no information provided for riprap at the discharges (stone size, pad dimensions, etc.).
3. There should be silt fence/ silt soxx on the down slope side of the topsoil stockpiles.
4. The Erosion, Sediment and Stormwater Control Plan for Oil and Gas Operations in section 5.c. and d. states there is no increase in runoff, but there is a change in cover condition. There is no discussion/demonstration in defense of the statement that the pre- and post-development runoff volume is equal.
5. The E&S Report does not contain any site specific information regarding the BMP's that are proposed. These should be completed by the plan designer and should not be left for a contractor to select and design at the time of construction.
6. Minimal information is provided for the infiltration trench, e.g., whether it is to be lined with geotextile fabric, how much cover, etc.
7. Overall limits of disturbance should be shown to delineate areas of disturbance.
8. Further information should be provided regarding how sediment is prevented from entering the infiltration trenches.
9. Further information should be provided regarding the permanency of infiltration trenches, and these should be shown on the restoration plan.
10. No construction sequence is provided.
11. The application states 14.8 acres of disturbance. The amount of disturbance required on the plans shown appears significantly less. The proposed areas to be disturbed should be clearly shown.

These questions and comments should be addressed in order to adequately describe the proposed development(s), and ensure that impacts from erosion and sedimentation are minimized, and appropriately managed for this CWF and HQ-CWF setting.

Other Locations

- Rattlesnake Creek upstream from the dam is designated HQ-CWF, so this includes the entire reservoir area. This water body is also classified by PFBC as a naturally reproducing trout stream. These classifications must be accounted for in any plan/permit application for facilities within this portion of the watershed. This may necessitate in some instances the requirement to obtain individual instead of general permits, and also meet antidegradation standards.

6.0 SUMMARY OF FINDINGS

Based on the excellent water quality and habitat conditions, and location(s) of recharge area, the Rattlesnake Creek and Whetstone Branch watersheds are especially vulnerable to degradation from development activities that have potential to introduce contaminants to the ground surface and fresh water bedrock aquifer. The drilling at Pads 5 and 6, and associated activities at other locations within these watersheds **clearly** have the potential to adversely impact the sensitive surface water and groundwater supplies relied on by BBMA to serve their water system. Prior to further gas well drilling and development activities it is recommended that the following be completed:

1. The Preparedness, Prevention, & Contingency Plan prepared by Flatirons should be modified to address all aspects of hazardous fluid storage, and tanker transport of fluids, inclement weather operations, road inspections, and the need for roadside barriers to prevent a tanker roll and/or sudden tanker breach.

2. Flatirons should provide sufficient information to document that a subsurface release of fluids from a gas well will not affect the fresh water aquifer and/or surface water in the area. A monitoring program is necessary to enable early detection of this condition.

3. Aquifer testing should be completed at Pad 6 in order to adequately characterize the interconnection between the gas well top hole and BBMA well 5. The use of excess grout and the groundwater turbidity increase should be investigated

4. All plans and permits should be modified to address the operations proposed for the HQ-CWF designated areas of Rattlesnake Creek and Whetstone Branch.

5. The Pad 6 E&S and Stormwater plans require clarification and/or additional information in order to adequately describe the proposed development(s), and ensure that impacts from erosion and sedimentation are minimized, and appropriately managed for this CWF and HQ-CWF setting.

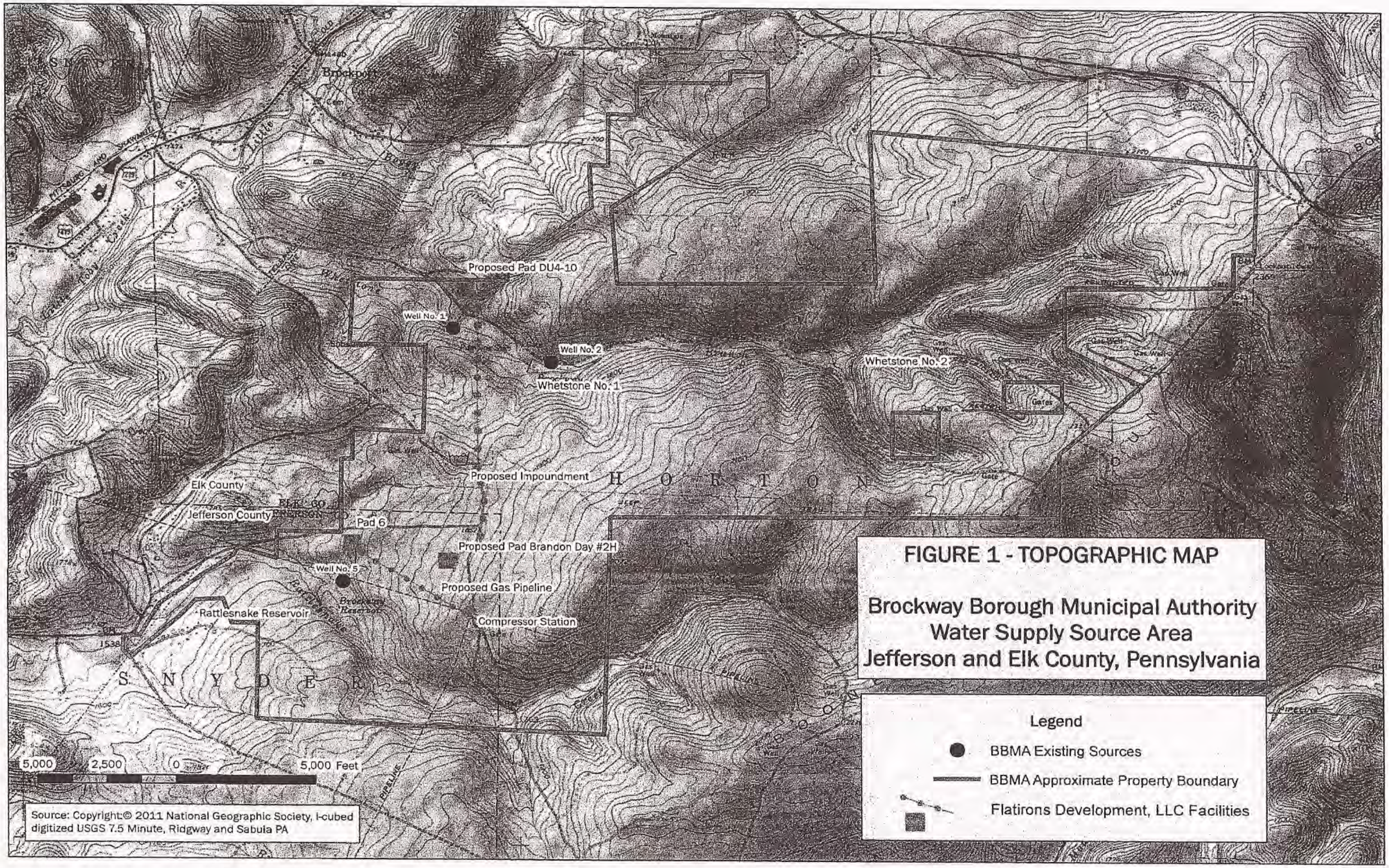
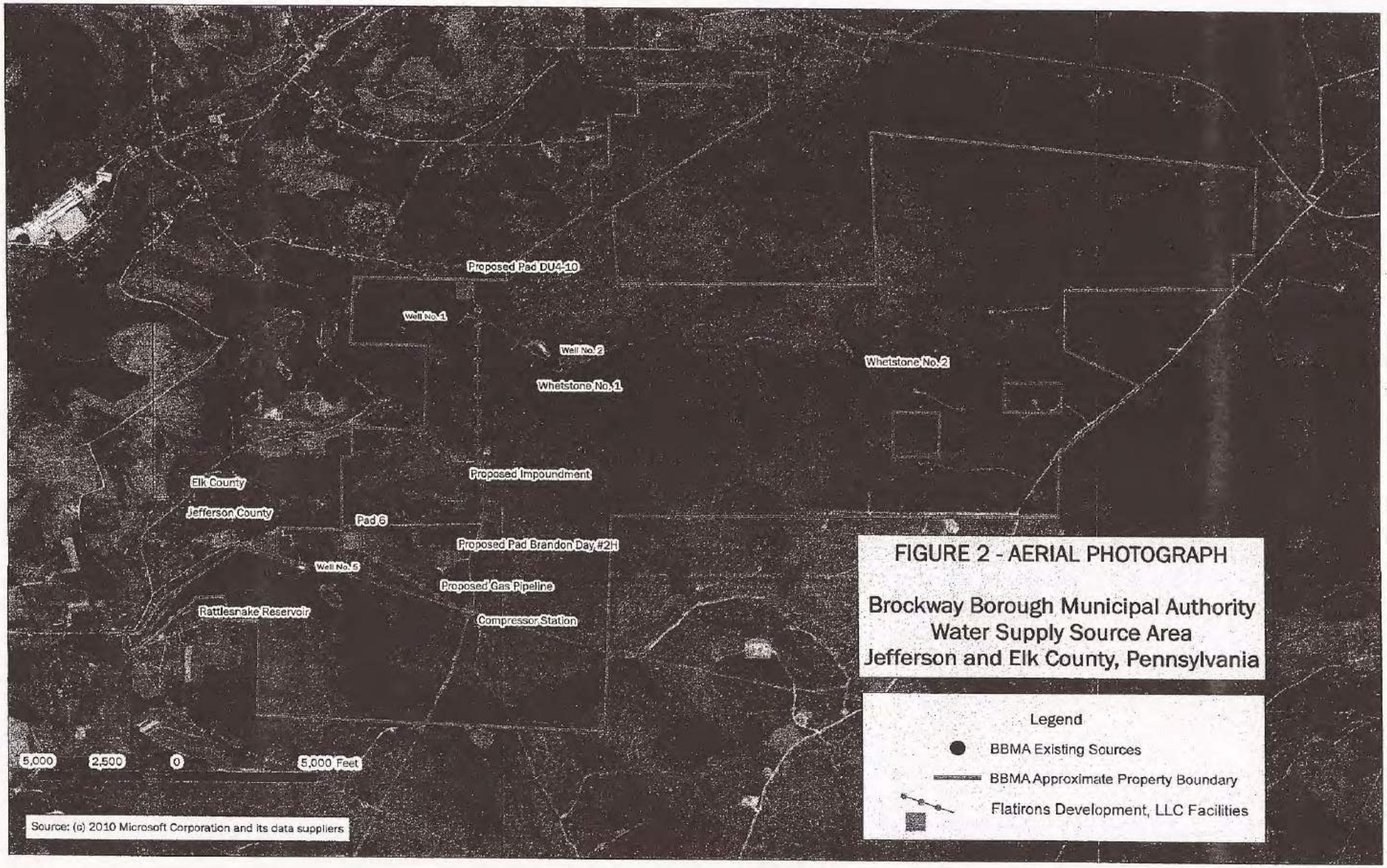


FIGURE 1 - TOPOGRAPHIC MAP
Brockway Borough Municipal Authority
Water Supply Source Area
Jefferson and Elk County, Pennsylvania
Legend
BBMA Existing Sources
BBMA Approximate Property Boundary
Flatirons Development, LLC Facilities
Proposed Pad DU4-10
Well No. 1
Well No. 2
Whetstone No. 1
Whetstone No. 2
Proposed Impoundment
Pad 6
Proposed Pad Brandon Day #2H
Well No. 5
Proposed Gas Pipeline
Compressor Station
Rattlesnake Reservoir
Elk County
Jefferson County
H O R T O N
S N Y D E R
Brockport
5,000
2,500
0
5,000 Feet
Source: Copyright © 2011 National Geographic Society, i-cubed
digitized USGS 7.5 Minute, Ridgway and Sabula PA


Proposed Pad DU4-10
Well No. 1
Well No. 2
Whetstone No. 1
Whetstone No. 2
Proposed Impoundment
Elk County
Jefferson County
Pad 6
Proposed Pad Brandon Day #2H
Well No. 5
Proposed Gas Pipeline
Rattlesnake Reservoir
Compressor Station
5,000
2,500
0
5,000 Feet
Source: (c) 2010 Microsoft Corporation and its data suppliers
FIGURE 2 - AERIAL PHOTOGRAPH
Brockway Borough Municipal Authority
Water Supply Source Area
Jefferson and Elk County, Pennsylvania
Legend
BBMA Existing Sources
BBMA Approximate Property Boundary
Flatirons Development, LLC Facilities

HALLSTEAD - GREAT BEND
JOINT SEWER AUTHORITY
P.O. BOX 747
GREAT BEND, PA 18821-0747
Phone (570)879-2994
Fax (570)879-8093

11 September 2013

Delaware River Basin Commission
Commission Secretary
P.O. Box 7360
25 State Police Drive
West Trenton, NJ 08628
paula.schmitt@drbc.state.nj.us

Impacts of Natural Gas Drilling Operations

Due to the duties of work, overseeing the remediation of a school closed for asbestos contamination, I cannot attend today's hearing.

Over the last few years the Hallstead Great Bend Joint Sewer Authority has had some issues with natural gas development. Some of these include use of seismic trucks conducting tests on public roads vibrating the sewer infrastructure, failure to call PA-1-CALL before excavating roads with sewer collection lines for installation of a natural gas gathering system, and reports from customers about discolored water coming from their water wells. Even with these events Hallstead Great Bend Joint Sewer Authority is not the only municipal authority to be affected.

The reports of discolored water from customers have happened during two different time periods. The first was during the boring under the Susquehanna River for the Laser pipeline, a natural gas gathering system, in June and July of 2011. The second was boring the Laser Pipeline under Route 11 and Interstate 81 in Great Bend Township in July and August of 2011. The final event was when two natural gas wells were drilled in August 2012 on the Coyle well pad in Liberty Township, feet from the Great Bend Township line by WPX Energy.

During the summer of 2011 residents on both sides of the Susquehanna River in Great Bend Township experienced brown colored water during the both boring operations, except for residents serviced by PA American Water Company. Some people installed filters, some people were provided with limited water from the Laser Pipeline for a very short duration. One statement made by the Laser Pipeline was that they were using water and bentinite. The one problem I had with that was, the bentonite had a high aluminum content and due to being trained as a HAZWOPER (hazardous waste operations and emergency response), I am trained on how to look up what other compounds are being used at the sites, by the markings on the containers. During this time compounds within the drilling mud were entering residents private drinking water wells and through them these compounds were entering the Hallstead Great Bend Joint Sewer Authority waste water collections system and treated at the waste water treatment plant.

In August 2012 there were complaints received by the authority about water being discolored again, but this time black. The plant operator checked the sewer collection system for flow to verify that area did not have a broken sewer line causing the black colored water. At this same time Ryan Klemish of DEP Oil and Gas was investigating reports of black colored water from residents on the west side of the Susquehanna River in Great Bend Township on New York Ave. and Baptist Hill Road. Then later in the month after the 20th the water also turned black in color again. Again the sewer authority received complaints for black colored water and had to inform these residents that the sewer lines were not broken. This prompted residents to call DEP and Jeff Hartman from DEP water quality to visit the sewer authority on 24 August 2012. In September this second instance of black colored water ended. During this time on the Coyle well pad the instances of black colored water mirrored the dates when WPX was drilling the natural gas wells through an open bore or no casings were present. There is also the issue of the directional drilling company recovering the Max Gel, for reuse, from the drilling mud, by dumping the drilling mud in to a hay bale box lined with black fabric feet from Trowbridge Creek. One of these boxes was found while inspecting the sewer line along Trowbrigde Creek after flooding in September 2011. A second was found on the Stevens Property in Silver Lake Township two months earlier and he was able to obtain a sample of the Max Gel that spilled into his forested area. In March 2013 I also discovered that a few homes on Route 7A in the Town of Conklin, New York were also affected by black colored water and diminishment in August of 2012 and two of the properties had to have new water wells drilled.

These events could have affected the treatment process at the waste water treatment plant, but during the boring of the Laser pipeline in 2011 we were starting the interm-treatment system for our plant upgrade. In 2012 our final treatment system was put online days before the first gas well was drilled on the Coyle well pad, so we cannot validate data for these periods. What is interesting is that during these events our treatment system was outside of permit limits and on 27 June 2013 other members of the Hallstead Great Bend Joint Sewer Authority had a meeting with DEP over these periods. The authority is responsible to discharging effluent within the permit limits, even if there are affected water wells from gas drilling operations. After asking the question about affected water wells discharging compounds into our system, one representative from the DEP remarked to get an inflow sensor to detect it. If there is residence or group of residences that are affected and the water has enough contamination in it to affect the treatment process the authority has a responsibility and duty to physically disconnect them from the sewer system until the water meets standards that can be treated by our treatment process. Generally the DEP wants to fine the sewer authority due to the negative effects from the entire drilling operations.

Then there is the Brockway Borough Municipal Authority and the problems that they have encountered with drilling operations. In November 2010 they sued to stop wells from being

drilled near one of the reservoirs that they own. In January 2011 they came to an agreement with the drilling company and drilling began a few weeks later. Then during drilling operations one of the artesian wells supplying the Rattlesnake Reservoir stopped discharging water. This was the day after the BBMA issued the position statement. There was a new well permit issued for this well pad in May 2013 with hearings being conducted, even after the BBMA had a study conducted to assess the risks to the drinking water reservoirs. This report is titled, Evaluation of Risk to Brockway Borough Municipal Authority Surface Water and Groundwater Sources form Flatirons Development, LLC Gas Drilling Operations can be found at: http://brockwaycleanwater.wikispaces.com/file/view/Advantage%20Engineers%20Evaluation%201.pdf/297346184/Advantage%20Engineers%20Evaluation%201.pdf
This report does identify possible pathways for gas drilling operations to affect the waters that supply the reservoirs.

The affects from drilling operations can be many and hard to identify, but when a municipality has its drinking water damaged or a sewer treatment plant affected, the DEP will not protect them, but issue notices of violation to these water or waste water authorities. There is one place to turn when this happens, the 2002 Bio-Terrorism Act through the Department of Homeland Security, since the DEP is in the business of issuing permits, not protection. One USGS Scientific Investigations Report, number 2012–5282 does describe what type of effects drilling will have on a watershed. It is named: Hydrogeology of Selected Valley-Fill Aquifers in the Marcellus Shale Gas-Play Area in the Southern Tier of New York State.
Heisig, P.M., 2012, Hydrogeology of the Susquehanna River valley-fill aquifer system and adjacent areas in eastern Broome and southeastern Chenango Counties, New York: U.S. Geological Survey Scientific Investigations Report 2012–5282, 19 p., at http://pubs.usgs.gov/sir/2012/5282.
What I have mentioned with in this letter is from past experiences of municipal authorities in the Commonwealth of Pennsylvannia.

Attachments:
1. E-mail between Bret Jennings and Jeff Hartman 24 August 2012
2. Letter Bret Jennings to Mayor, City of Binghamton 27 August 2012
3. Position statement of Brockway Borough Municipal Authority.

Bret Jennings
Councillor, Great Bend Borough
Chairman, Hallstead Great Bend Joint Sewer Authority
brett76544@hotmail.com

Attatchment 1

Water issues around the HGBJSA collection area.

From: bret jennings (brett76544@hotmail.com)
Sent: Fri 8/24/12 2:36 PM
To: jefhartman@pa.gov

Mr. Hartman
I have heard of issues of black water from my Grandfather on the west side of the Susquehanna river north of Hallstead since the 12 August 2012 and then that cleared up on 15 August 2012. On 23 August 2012 and on today the water was black or brown at my grand fathers trailer on the hill side. At the same time one of the other directors for the Hallstead Great Bend Joint Sewer Authority had his well water go black and he lives next to Trowbridge Creek across the creek from pumping state #1 on Orchard Road. He also uses 2 micron filters for his drinking water and they turned black and had to be replaced. These two sites are separated by the river and about 1100 feet. The well on the hillside west is drilled into bedrock according to the Well drillers log from the DCNR and I did not find the log for the one on Orchard road, but it is in the glacial till of the valley, not the bed rock. Both well stop within 1 to 2 feet of each other after removing the differing elevations for the top of each well. Earlier this week I was in at the sewer plant with Steve and the Chairman of the authority and there were calls to the sewer plant wondering if there was a problem since peoples water went black that have water wells and are connected to the sewer. Today I learned that you had visited the plant, when talking to Steve.
I have also contacted PA American Water over this issue and other than the water main repairs done early this month that resulted in air being expelled from the system, they have not had reports of Black water.

Other than the issues with the repair of the water main, there are other thing that could have caused this
problems outside of the water distribution system:
1. the Sewer collection system leaking
2. The Coyle well pad that started drilling in Liberty Township by WPX. (one mile away from the well on Orchard Road and 4100 ft from my Grand fathers water well.) The two properties are in a straight line with the well pad on Google earth.
3. The water line that Williams is installing from the water withdrawal site on the susquehanna River up to the Coyle well pad and water impoundment southwest of Mingo lake. I saw one or two people from the SRBC walking down the road today at this site while driving to work this morning.

4. The sink hole on the Parker property in the Laser Pipeline right of way, that was discovered by another DEP representative. Possible bacteria growth in the hole has been presented as a problem to my Grandfather. This hole has orange snow fence around it with weeds growing through it. Would the directional drilling for the gas pipeline cause a conductive pathway under the river for affected water to travel?
5. Illegal/illicit discharges.
6. Past history when the Laser Pipeline was drilling under the Susquehanna to the west and under route 11, I 81 and the railroad tracks to the north both wells described were affected.

Ryan Klemish of the DEP is investigating the problem around my Grandfathers water well. 570-346-5530

My Grandfather did not have Ryan's card or I would have copied this e-mail to him.
I also just returned a call from Mike ODonnel 570- 346-5536. I included your and Ryan's name in the message. Since this area with affected water wells from some source is in Zone A for a source water assessment for the City Of Binghamton the Mayor has been informed and will receive a formal letter from me. I am planning on walking to see where the limits of this affected water ends in and around the sewer system Saturday since we have received complaints by phone.

Bret Jennings
Councillor, Great Bend Borough
Director, Hallstead Great Bend Joint Sewer Authority
cell 607-372-4959
home 570-879-4158

Attachment 2

Matthew T. Ryan
Mayor, the City of Binghamton
38 Hawley Street, 4th Floor
Binghamton, NY 13901
Office: 607.772.7001
mayor@cityofbinghamton.com

Bret A. Jennings
PO Box 73
590 Main Street
Great Bend, PA 18821
Cell: 607.372.4959
Home: 570.879.4158
brett76544@hotmail.com

27 August 2012

Water wells affected within the five hour time of travel to the water intake in Binghamton.

Mayor Ryan,

In a letter dated 9 August 2012 I informed you of an incident where water has been affected within Zone A of a source water assessment area for the City of Binghamton÷s drinking water intake. Now there are multiple incidences of water wells being affected on both sides of the Susquehanna River. This is a serious development and has lead to complaints to the Hallstead Great Bend Joint Sewer Authority and two branches of the PA DEP acting independently from each other. One is from the Oil and Gas and the other is for Water Quality. Let me show you the events that I have seen that to show you what has happened:

- Drilling started in the beginning of August 2012 at the Coyle well pad in Liberty Township by WPX Energy.
- My Grandfathers water well went black from 5 to 8 August 2012 when it cleared up. His water well is about 4100 ft from the well pad.
- On 17 August 2012 I checked the WPX website and noticed that they have cut drilling time down 35% to 18 days. Now that is very interesting, so what parts were altered and what effect will this have on the long term operation of the well?
- Prior to 20 August 2012 a DEP oil and gas representative investigated the area around my Grandfathers complaint.
- On 20 August 2012 I visited another director on the sewer authority board due to a canceled meeting and his water filters had been clogged with a black substance that stained his carpet and concrete from tracking it in on his shoes. He had some brown 'stuff' form on top of the heated water when he was preparing some pasta on 19 August 2012. He uses a 2 Micron Filter on his water supply and it was replaced prior to when I talked with him. He is about 5200 ft from the well and on the other side of the Susquehanna River. The bottom of this well and my grandfathers differ by about two feet when looking at what elevation they end at. One is about 127 feet deep, but 110 higher than the river level and the other one is 30 feet deep, but 15 feet higher than the river level. So 15 to 17 feet below the top of the river. That means about 10 feet separates where the black water is compared to the bottom of the river. It is a likely point of communication that should affected water quality in the Susquehanna River.
- On 22 August 2012 I learned of multiple complaints called into the Hallstead Great Bend Joint Sewer Authority over the last two weeks for Black water, but only from people on water wells. They thought that we had some problems with our sewer lines.
- PA American water Co. only had complaints due to a water main break in the Hallstead/ Great Bend area and none for black water.
- On 23 August 2012 I learned that the DEP oil and gas representative that walked the hill side and found a sink hole along the path of the Laser Pipeline that had orange snow fence around it with grass and weeds growing up through it. At this location the pipeline was bored under the Susquehanna River and had not yet

returned to the surface to be emplaced in a ditch. This he declared without testing or knowledge of the issues on the other side of the river, to be the cause of the black water in my Grandfathers water well. This is due to the possibility with it pooling in the bottom and the bacteria turning it black.

- On 23 August 2012 my Grandfathers water was affected again.
- On 24 August 2012 the DEP water quality section visited the sewer plant for complaints from residents due to black water coming from their water wells. These residents believed that there were broken sewer lines affecting their well. I also looked at the sink hole. I could not smell the bacteria or see the water, but it is directly over the 20 inch gas pipeline. I also talked to the head of the Oil and Gas section for NERO (northeast regional office) about what was happening up here and that the water section was also investigating due to a perceived problem of the sewer lines failing and turning the resident÷s well water black. The water quality section representative was also contacted.

Now the question is will the DEP do its job? I cannot expect that due to a law suit where the jury awarded the plaintiff 6.5 million dollars against four DEP workers personally from the Northeast Regional Office, including an assistant regional counsel for NERO. Due to this lawsuit, I have seen a change in the DEP and I am convinced that MFS, Inc. V. Thomas A. DiLazaro, et al. has had a negative effect on the employee÷s of the DEP. Why would a DEP employee make a decision where the people or corporation that is harmed by that decision can file a civil rights case against you personally without the protection of sovereign or limited government immunity. There is a link to an article on the case: http://pabrownfieldsenvironmentallaw.foxrothschild.com/2010/03/articles/bombshell-decision-holds-dep-staffers-personally-liable-for-civil-rights-violations/

Then 16 February 2011 the case was over turned by the Pa eastern district: http://scholar.google.com/scholar_case?case=11348538898640049244&q=MFS,+Inc.+v.+Thomas+A.+DiLazaro,+et+al.&hl=en&as_sdt=2,39

The appeal to the 3rd Circuit was issued on 26 April 2012 were the PA Eastern District ruling was upheld: http://docs.justia.com/cases/federal/appellate-courts/ca3/11-1690/11-1690-2012-04-26.pdf

Even with these rulings in favor of the DEP employee÷s under sovereign immunity, one still has to wonder if this case has had a lasting effect on the performance of the DEP.

For the Hallstead Great Bend Joint Sewer Authority waste water treatment plant we do have decisions to make now. Since there was no sewer collection line failures that caused the discoloration of the residents well water and that this discoloration was present on the other side of the river, there is only one conclusion, the sewer system did not cause the discoloration. The only issues that could have caused it are the sink hole with bacteria in it and the drilling operations at the Coyle well pad. If the discharges from these residences are affecting the treatment system right now we would not be able to identify it due to changing our system over from the interim treatment system to our current treatment system and generating a new biomass in the different treatment zones. If in the future these residences on water wells have enough contaminates to affect the operations of the treatment system then two options would have to be implemented. Removing the affected water supply from the sewage collection system or have to build and operate a treatment system to protect the present treatment system. Both of these options increases costs for the other users and will require a new National Pollution Discharge Elimination Permit for the sewer treatment plant due to a change in waste characteristic coming into the sewer treatment plant.

For the City of Binghamton, this affected water that is likely entering the Susquehanna River through the river bottom that is about 13 miles from the water intake near Broome Street and may affect the water quality. This is just one well pad in the Commonwealth of Pennsylvania that is over 11% of the watershed above the drinking water intake. There is also the issue of what about the Elmira and Corning area that does have watersheds upstream from them in the Commonwealth of Pennsylvania. There is far more drilling operations in areas of the Commonwealth of Pennsylvania, upstream from the City of Elmira.

What I see is that a new source of contamination has developed just across the NY/PA state line from the City of Binghamton that could be temporary or permanent. The DEP may be compromised due to a recent lawsuit that may have a lasting effect on the employee÷s performance. There is one instance in western PA where a resident, Beth, has sued the DEP to perform its job and the court on appeal agreed. I cannot say actions will not be taken in PA, but it is not likely or will have to have overwhelming evidence for the DEP to take action. At this point the only action I can say will happen is monitoring of the sewer system for monitoring of the biological process, changes in laboratory results from the discharge and the solid waste leaving the sewer treatment plant.

Bret A. Jennings
Councillor, Great Bend Borough
Director, Hallstead Great Bend Joint Sewer Authority

Attachment 3

Brockway Borough Municipal Authority

501 Main Street
Brockway, PA. 15824

Office of the Borough Manager
Phone (814)268-6565x103 Fax (814) 265-1300

To: Senate President Pro Tempore Joe Scarnati, Speaker of the House Sam Smith; State Representative Matt Gabler

BBMA Position on Gas Development on the Watershed's Serving as Public Drinking Waters Sources

February 15, 2011

This letter is to provide a clear statement of the position of the Brockway Borough Municipal Authority (BBMA) relative to natural gas development on the watersheds supplying drinking water to thousands of people in the Brockway area.

We, (BBMA) believe that Rattlesnake and Whetstone Run watersheds provide drinking water of unparalleled quality in our state. In that regard, we view this natural resources and forested environment that protects it as invaluable and irreplaceable.

We in turn view the current gas development activities on the watersheds as a potential threat to these resources as the processes employed are unconventional and to new to predict and understand the environmental impacts and consequences associated with those activities.

We believe that the Pennsylvania Department of Environmental Protection (DEP) is the primary entity charged with protecting the water resources in Pennsylvania. And that a failure by DEP to act in a prudent manner constitutes negligence by that agency.

We recognize that current oil and gas regulations may be less than adequate relative to providing explicit safeguards for our watershed; however, we also believe that DEP has authority prescribed in the Clean Stream Law and other acts which empowers DEP to limit or eliminate the activities on these watersheds to minimize the potential environmental degradation.

We recognize, as public water suppliers, we are often held to design-standards which are much more stringent than the standards applied to gas developers. We view this disparity as inappropriate and continue to lobby legislatures to change such standards.

We welcome the economic benefits that gas development creates in our region; however, also understand the true costs of this development may be more widely distributed across the population, less tangible and more difficult to assess than those benefits.

We believe air pollution from the gas development is likely to impact the quality of our water.

We believe liquid pollution from the frac water, associated chemicals, fuel, lubricants, and production water are likely to impact the quality of our water.

We believe that truck traffic, surface disturbance and equipment operating on our watershed are likely to impact the quality of our water.

We believe that the physical disturbance associated with drilling and fracking are likely to impact the quantity and quality of our water.

We have learned that surface landowners are subservient to the interests of oil and gas owners. And that water rights and ownership are recognized by few people when conflicting with industrial interests.

We entered into a surface damage agreement with a gas developer as the alternative was their continued unauthorized development as we struggled to try to control the damages inflicted by their activities. We entered this agreement with the developers to protect our customers should the gas development cause damage to the water resources which they threaten.

We have discovered that the PA constitution contains guarantees of the citizens' rights against the effects of gas development; however, no agency is enforcing these provisions.

We believe that the technologies currently employed for gas development would allow for gas extraction beneath our watersheds by using lands outside of the watersheds. However, as our watersheds are undeveloped, it is simply more convenient to mine the gas using sensitive watersheds rather than procuring alternate development tracts.

We have been forced, to cut timber that is not mature at a time when timber prices are low, to agree to accommodate industrial development on lands which are not suited for such, and endure the anxiety which comes from the uncertainty associated with the potential impacts of this gas development.

We remain opposed to any gas development on our watershed as it jeopardizes a water resource which, if impacted, has no viable replacement.

We believe that gas development on these sensitive watersheds is 'unreasonable' and may result in 'irrefutable harm'.

We recognize that a group of citizens are organized in an effort to protect the water resources from the impacts associated with gas development activities.

We have requested and maintain hopes that the DEP will provide technical assistance to develop watershed management plans as they advocated in local press articles.

We have spent significant monies on water monitoring, legal actions and engineering reviews to protect our rights to clean water.

Under current regulatory conditions, we see no practical end to this matter, and encourage anyone, so inclined, and willing to act within legal standards, to become involved in an effort to minimize the development and associated impacts on the Rattlesnake and Whetstone watersheds.

Cc: Bob Reisinger
R Ed Ferraro
Robert P Ging
Brockway Borough Council
Brockway Area Clean Water Alliance
Files - BBMA

πIMPORTANT INFORMATION ABOUT YOUR DRINKING WATER

Este informe contiene informacion muy importante sobre su agua de beber.
Traduzcalo o hable con alguien que lo entienda bien.

Beaver Falls Municipal Authority Has Levels of Total Trihalomethanes (TTHMs) Above Drinking Water Standards

Our water system recently violated a drinking water standard. Although this incident was not an emergency, as our customers, you have a right to know what happened and what we are doing to correct this situation.

We routinely monitor for drinking water contaminants. After receiving our latest test results for the 3rd quarter of 2010, it shows that our system exceeded the standard or maximum contaminant level (MCL) for total trihalomethanes (TTHMs). The MCL for TTHMs is a Running Annual Average (RAA) of 0.080 mg/l, which is comprised of an average of the four (4) most recent quarterly samples. The RAA for TTHMs over the last year ending in the 3rd quarter of 2010 is 0.0857mg/l. The highest level detected was 0.1154 mg/l and the lowest level detected was 0.0733 mg/l.

What should I do?

You do not need to use an alternative (e.g., bottled) water supply. However, if you have specific health concerns, consult your doctor.

What does this mean?

This is not an immediate risk. If it had been, you would have been notified immediately. However, **some people who drink water containing trihalomethanes in excess of the MCL over many years may experience problems with their liver, kidneys, or central nervous system, and may have an increased risk of getting cancer.**

What happened? What was done?

Disinfectants can combine with organic and inorganic matter present in water to form chemicals called disinfection byproducts (DBPs), which includes TTHMs. These byproducts are produced by every public water system that uses disinfectants. The Beaver Falls Municipal Authority changed our disinfecting treatment process to include chloramines in September. Preliminary testing indicates that this has already reduced the TTHM levels in our system and should bring us into compliance with DEP regulations by the end of this year.

For more information, please contact our office at 724-846-2400 X231.

Please share this information with all the other people who drink this water, especially those who may not have received this notice directly (for example, people in apartments, nursing homes, schools, and businesses). You can do this by posting this notice in a public place or distributing copies by hand or mail.

This notice is being sent to you by Beaver Falls Municipal Authority.

PWS ID#: 5040012 Date distributed: 11/10

September 10, 2013

Jeff Zimmerman
Zimmerman & Associates
13508 Maidstone Lane
Potomac, MD 20854

RE: Beaver Falls Municipal Authority

Atty. Zimmerman,

The Beaver Falls Municipal Authority (BFMA) is public drinking water system that pulls water from the Beaver River in Beaver Falls, PA, which is formed by the confluence of the Mahoning and Shenango Rivers near New Castle, PA. BFMA began experiencing elevated Brominated levels in 2009. These elevated levels caused BFMA to exceed the EPA's Maximum Contaminant Level (MCL) for Total Trihalomethanes (TTHM'S) for the first 3 quarters of 2010. The MCL for TTHM's is a running annual average (RAA) of .08mg/l, which is comprised of an average of the four most recent quarterly samples. The RAA for the first quarter of 2010 was .087mg/l, for the second quarter of 2010 was.097mg/l, and for the third quarter of 2010 was .0857mg/l. Each of these occurrences required BFMA to publically notify all of our 18,000 customers that we were in violation of an EPA drinking water standard. Beginning in September 2010 BFMA began using chloramines as its primary disinfectant over chlorine which had been used by BFMA for over 50 years. The main reason for this change was that chloramines produce lower levels of TTHM's. This change will also enable BFMA reduce TTHM levels in our drinking water and remain in compliance with EPA's drinking water standards. BFMA expended over $25,000 in capital for this conversion. Chloramine disinfection has been used for over 80 years but can cause problems to people on dialysis machines if not removed prior to dialysis. Chloramines may also be toxic to fish.

Over the past 4 years there have been at least 3 instances where individuals or companies have been prosecuted for illegally dumping frack water into the Mahoning, Shenango, or Beaver River. Unfortunately in every instance BFMA was not notified until a few days after each episode and are unsure if any of the frack water made it to our intake. While it has been documented many places that frack water has elevated levels of brominated disinfection byproducts, which are precursors to TTHM formation no correlation was traced back to any legal or illegal discharges up stream of our intake.

If you have any questions, please feel free to contact me at (724) 846-2400 Extension 231.

Sincerely,

James Riggio
General Manager

LINK to available Determination Letters as of September, 2013:
https://www.dropbox.com/sh/4czu1lpfw91yc72/AAChowVf2H9bEcCwqa0IYn6Ga?dl=0

Damascus Citizens for Sustainability would like to present the DRBC Commissioners and staff over 100 Determination Letters from the Pennsylvania Department of Environmental Protection, sent to home and business owners whose water was affected by nearby gas well drilling. As there is both a time frame after the well is completed and a distance requirement that the home or business has to be from the well to have a challengeable presumption of responsibility by the gas drilling company apply, all of these cases are in both required limits. These limits were changed recently from 6 months to one year and from 1,000 feet to 2,500 feet but the older cases will not be revisited. There would be many more receiving a positive determination of impact with even this small widening of the two requirements. A positive determination means that the DEP has to do additional investigation and drilling company has to replace the water supply in some fashion satisfactory to the DEP.

The letters are from the years 2008 through 2012. They were obtained via a Right To Know request and a lawsuit filed by the Scranton Times, taking a year and a half to acquire them. They show that the Department's investigations indicate that the home or business owners' water supplies were impacted by gas well drilling with changes in either water quantity or quality based on testing done before drilling and after. The details in the letters show what these changes are including diminished quantity and increases in minerals, salts, changes in pH and clarity of the water and gasses, often methane, moving with the water.

In addition to these letters to individual home and business owners, there are on the supplied disc about 30 investigations and consent orders covering wide areas,whole neighborhoods with multiple homes and businesses. One of these was spoken of by my colleague and has 6 maps of impacted areas each covering about 24 square miles - that's number 161 on the disc - areas where there we know the damage continues.

These letters are, at long last, proof that the hydraulic fracturing horizontal drilling process DOES impact water supplies and is doing so in Pennsylvania and that therefore, drilling should not be allowed in the Delaware River Basin.

Geologic Methane Leakage in Wyalusing PA Area and Well Failure Rates Reported by PADEP Presenter – Barbara Arrindell

First let's start with well failure rates - these are based on Pennsylvania DEP reports of wells drilled, violations and failures as assembled by Prof. Ingraffea of Cornell University.

1,609 wells drilled in 2010. 97 well failures. 6% rate of failure.

1,972 wells drilled in 2011. 140 well failures. 7.1% rate of failure.

1,346 wells drilled in 2012 120 well failures. 8.9% rate of failure.

Consistent with previous industry data, and not improving

I would like to stress that these mistakes,errors, failures result in permanent damage that impacts real places and real communities and real people and their lives and hopes and families...to say nothing of their property values. And these are only the initial failures - as the drilling proceeds, though there are nine listed types of violations possible, for many more wells, " The inspection reports indicate that many failed wells were not issued violations." according to Dr. Ingraffea's research. To pretend that allowing drilling in the Delaware Basin would produce different results is foolish.

So now to look at one of those real places certified as an impacted area by PA DEP. This is along the Susquehanna River in Bradford County where PA DEP fined Chesapeake Appalachia, LLC $900,000. for causing "stray gas" conditions, impacting the area and contaminating water supplies. DCS sent GasSafetyUSA with a Picarro CRDS machine to record the methane levels from public roads where there were reports of bubbling in the Susquehanna River and in ponds, puddles and in residents drinking water sources. Though it is harder to record methane any distance away from it's source we found elevated methane levels, as shown in figure which combines the roads covered in the June GasSafety run with two of the impact area maps in the "Consent Order" of May 16, 2011. Blue and orange markers indicate the Paradise Road and Sugar Run methane migration impact areas(4 mile radius each) mapped in that Consent Order and show about double the surrounding local methane baseline levels. There is definitely an ongoing methane leakage situation here and contamination of drinking water sources that has continued since September, 2010 through the GasSafety methane survey in June, 2013.

IN OTHER WORDS THE AREA IS STILL IMPACTED AND THE WATER SOURCES ARE STILL CONTAMINATED FROM DRILLING.

The Conclusion from the September, 2013, GasSafety Wyalusing Report

"Methane from any source rapidly diffuses and rises in the air. Consequently, detection of possible methane sources from any distance away requires extremely sensitive measurement capabilities. The GSI survey approach takes advantage of extremely sensitive measurement instrumentation to detect small increases in ambient air methane levels as an indication of probable methane emissions sources in a given area. Based on the data collected using that equipment, we conclude that the Towanda-Wyalusing area is probably substantially impacted by methane emissions from shale gas wells both within and beyond the survey area. The coincidence of two DEP methane migration impact areas, Paradise Road and Sugar Run, and the most marked elevated ambient air methane levels suggests there are still gas control problems associated with the shale gas wells there, as well as in another documented impact area in Leroy Township also cursorily measured following the main survey. A rapid water test in the Leroy area confirmed the water in that area is still contaminated with methane. These survey results suggest measures taken by gas well operators with regard to methane migration problems that have occurred in these three areas have likely been only partially effective."

IN OTHER WORDS THE AREA IS STILL IMPACTED AND THE WATER SOURCES ARE STILL CONTAMINATED FROM DRILLING.

The figure is from the GasSafety Report on these Wyalusing area measurements - found on the disc and here:

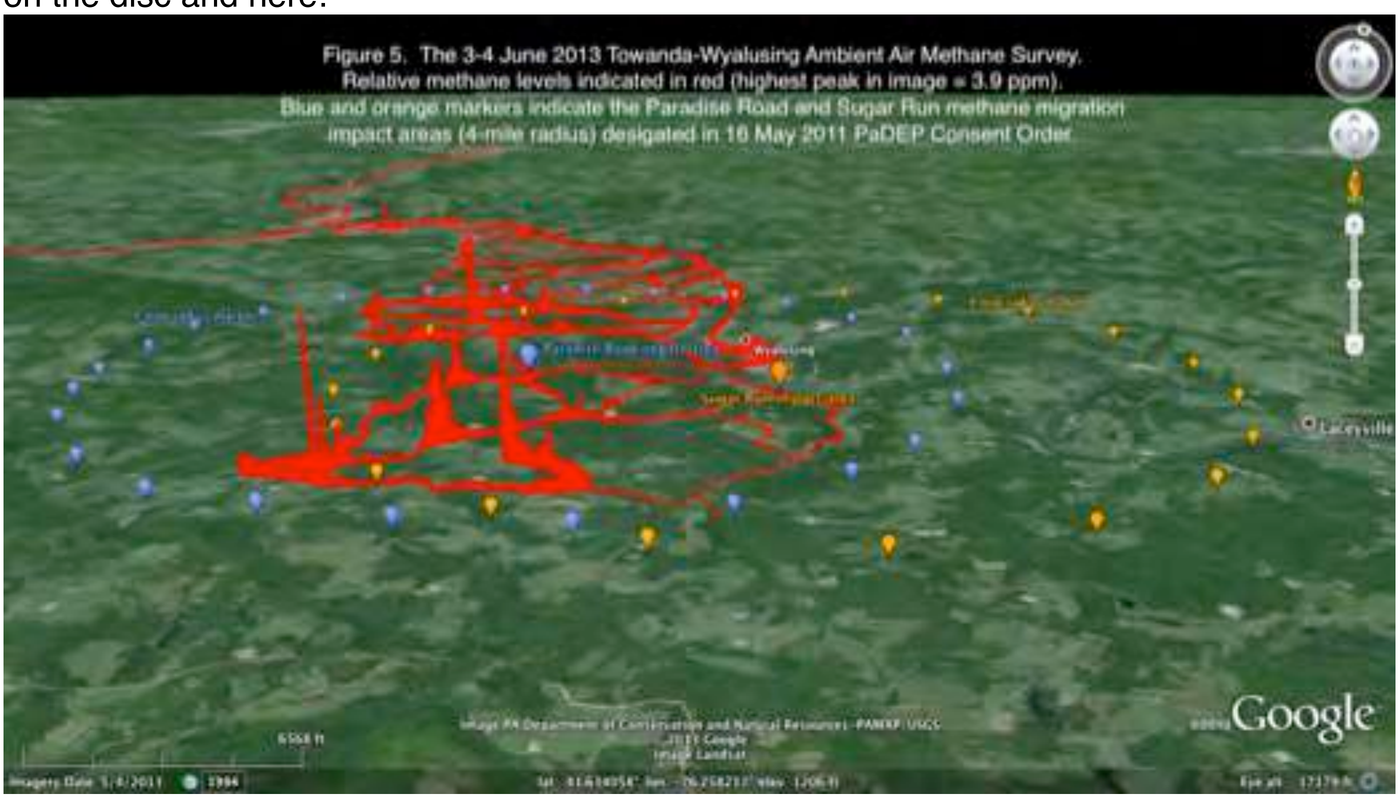


Figure 5. The 3-4 June 2013 Towanda-Wyalusing Ambient Air Methane Survey. Relative methane levels indicated in red (highest peak in image = 3.9 ppm). Blue and orange markers indicate the Paradise Road and Sugar Run methane migration impact areas (4-mile radius) desigated in 16 May 2011 PaDEP Consent Order.

"Stray Gas" Definition • A gaseous material that is from an undetermined source that is located in area that may become hazardous. • Hazardous conditions can be flammable, toxic, or oxygen reducing that could cause suffocation. http://pa.water.usgs.gov/projects/energy/stray_gas/presentations/3_840_Graeser.pdf
-----
$900,000. fine - http://www.businessweek.com/ap/financialnews/D9N9C7981.htm
Consent order referenced here is #161 in this Determination letters folder on the disc and at this link: https://www.dropbox.com/s/ndgx7fe2hg8f2dg/161%20Consent%20Agreem%20Susquehana%20River.pdf

CRDS http://www.picarro.com/technology/cavity_ring_down_spectroscopy

http://www.damascuscitizensforsustainability.org/wp-content/uploads/2012/11/PSECementFailureCausesRateAnalysisIngraffea.pdf
Table 1. Violation Codes Used to Identify Wells with Violations for Figure 7.
78.73A - Operator shall prevent gas and other ‡uids from lower formations from entering fresh groundwater.
78.81D2 - Failure to case and cement properly through storage reservoir or storage horizon
78.83A - Diameter of bore hole not 1 inch greater than casing/casing collar diameter
78.73B - Excessive casing seat pressure
78.83GRNDWTR - Improper casing to protect fresh groundwater
78.83COALCSG - Improper coal protective casing and cementing procedures
78.85 - Inadequate, insufficient, and/or improperly installed cement
78.86 - Failure to report defective, insufficient, or improperly cemented casing
207B - Failure to case and cement to prevent migrations into fresh groundwater

THIS BELOW IS RECENT DATA OBTAINED with a Picarro CRDS machine - very accurate to 1/2 ppm and the area picture is detaied in the May 16 PA DEP Consent Order (it is item #161) in "PA DEP determination yes" FOLDER This is information we will be publishing, but felt it must be taken into account today by those concerned about the Delaware Basin, It shows the geological leakage in an the area covered by the Consent order issued by PA DEP and Chesapeake was fined $900,000.   At least one lawsuit was settled also there for $1.6 million. and there are many more filed.
This is not on the disc or in the dropbox folder

From: "Payne, Bryce" <bryce.payne@wilkes.edu>
Date: July 26, 2013 10:43:40 AM EDT
To: "B. Arrindell" <glassart@FortyFrogFarm.com>, Bob Ackley <bobackley@gassafetyusa.com>
Subject: **Wyalusing report images and ?**

Barbara, Bob,

Have a look at two attached images of methane levels during second Wyalusing run. The two images are same data from different directions and altitudes.

In the "Wya regional SW view.jpg" file Wyalusing survey area is apparent on left, Leroy gas leak area in right background, with reference travel to/from runs on highways plotted to provide reference methane levels in image.

In the other image view is closer to Wyalusing from south. Leroy leak area is apparent in far left background, and reference methane level areas plotted in immediate foreground and far background.

These images work for you guys? Do we know if there is nat gas service in the surveyed area? I am presuming not -- not enough houses in sufficiently close proximity, but need to know for sure before concluding that the fairly widespread methane elevations are due to fracking/transmission lines and not distribution lines.

Bryce

Wellbore Integrity: Recent Operator Performance in Pennsylvania

1,609 wells drilled in 2010.
97 well failures.
6% rate of failure.

1,972 wells drilled in 2011.
140 well failures.
7.1% rate of failure.

1346 wells drilled in 2012
120 well failures.
8.9% rate of failure.

Consistent with previous industry data, and not improving.

Figure 7. Preliminary results of survey of leaking wells in the Pennsylvania Marcellus play based on violations issued by the DEP. Violations data from http://www.depreportingservices.state.pa.us/ReportServer/Pages/ReportViewer.aspx?/Oil_Gas/OG_Compliance

"Should New York State and/or Starkey Township Allow High Volume Shale Gas Extraction?"

Anthony R. Ingraffea, Ph.D., P.E. (NYS No. 081309-0)
Dwight C. Baum Professor of Engineering
Cornell University
and
President
Physicians, Scientists, and Engineers for Healthy Energy, Inc.
January 23, 2013

No.

Why? I Will Focus on Two Important Reasons, Using Quotes from

“Where the science of fracking is concerned, engineer **Tony Ingraffea** and geologist **Terry Engelder** agree on almost everything except this:

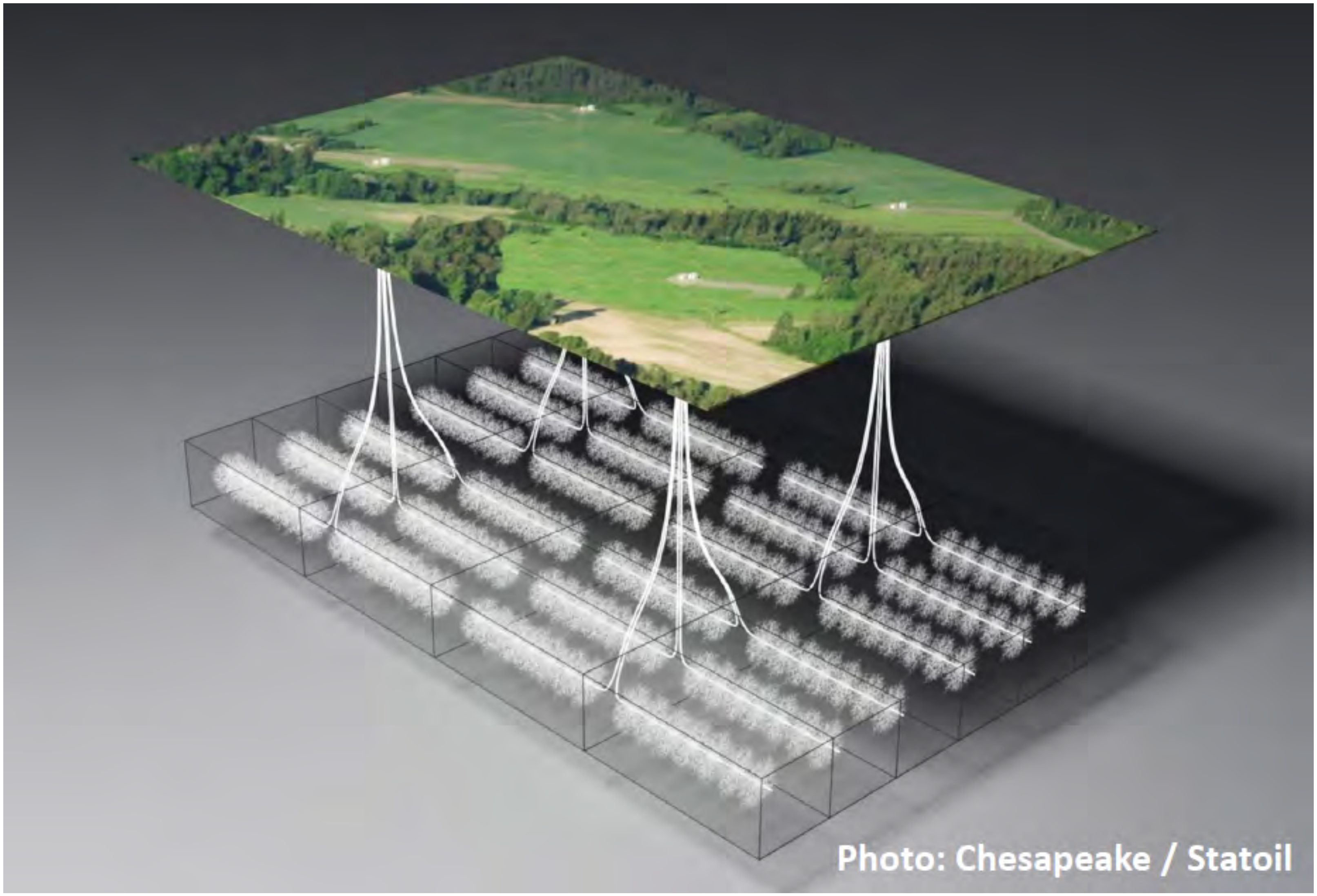
"Tony thinks fracking should stop, and I don't," says Engelder… **"I believe that economic health has to come before environmental health is worked out. Tony is arguing for environmental health at any cost**.“”

http://www.villagevoice.com/2012-09-19/news/boom-or-doom-fracking-environment/3/

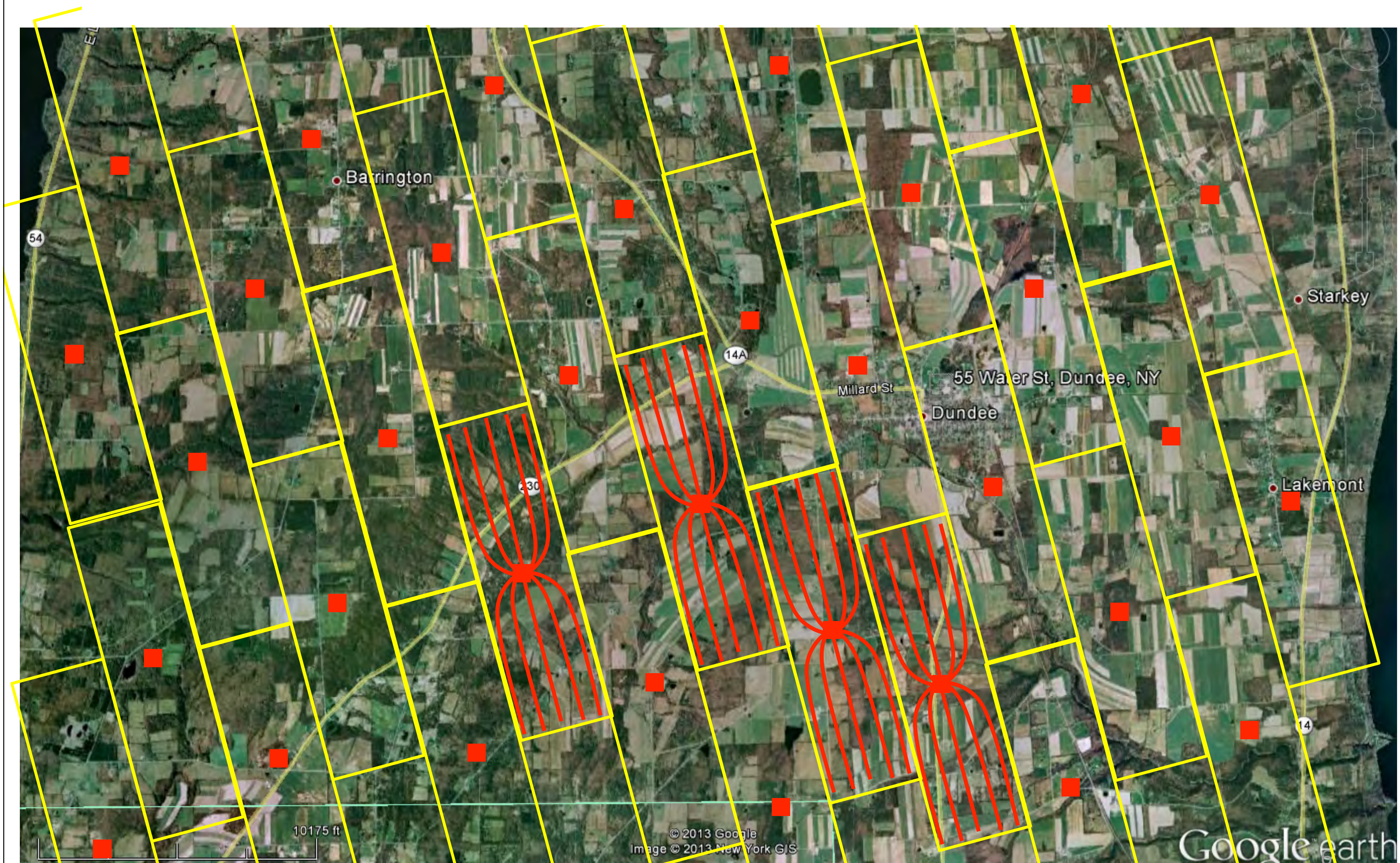
Reason #1:

Yup. Because that

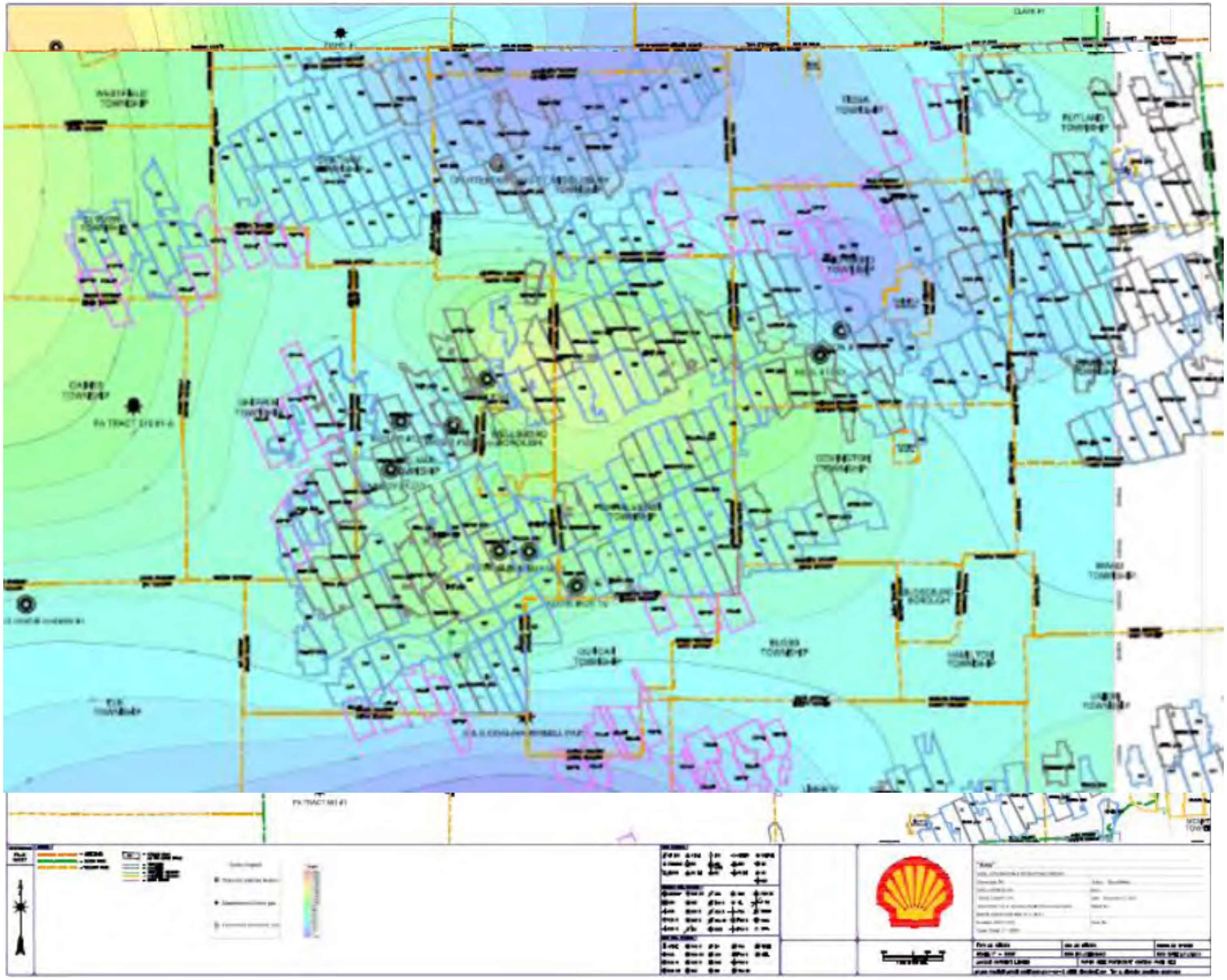
Shale Gas Production Must Use Clustered, Multi-Well Pads and High-Volume Long Laterals



An Industrial-Ideal Pad/Well Buildout Scenario



Clustering of Pads in Tioga County, PA



In the large U.S plays, shale gas development has only just begun, and it requires a large number of large, multi-well, clustered pads and significant ancillary infrastructure

Shale Gas Production Requires 100's of Thousands of New Wells

With an Unacceptable Rate of Failure to Contain Hydrocarbon Migration

Wellbore Integrity: Recent Operator Performance in the Pennsylvania Marcellus Play

1,609 wells drilled in 2010.
97 well failures.
6% rate of failure.

1,972 wells drilled in 2011.

~100,000 Marcellus and Utica Wells in NYS:
You Do The Math

1346 wells drilled in 2012
120 well failures.
8.9% rate of failure.

Consistent with previous industry data, and not improving.

What Are the Implications of

Each leaking well has the potential for contamination of one or more private or public water sources, and will leak volatile organic compounds into the atmosphere.

High Volume Hydraulic Fracturing Proposed Regulations
6 NYCRR Parts 550-556, 560
Among My Comments and Recommendations

Recommendation: As a minimum, DEC should perform and publish its own statistical analysis of documented incidents of hydrocarbon migration into underground sources of drinking water in the Marcellus play in Pennsylvania, and develop its own prediction of immediate and long-term rate of well failures for shale gas development in New York.

Recommendation: It is not possible to perform a rational cost-benefit analysis of shale gas development in New York without a science-based, probabilistic estimate of the number of expected well contamination incidents due to faulty wells. DEC should estimate the cost associated with mitigation of such contamination in its economic analysis of shale gas development. Each leaking well will, unless completely stopped from leaking natural gas, contribute to methane emissions and exacerbation of climate change. DEC should estimate the impact of such emissions on NYS goals for reduction of CO_{2eq} .

Why? I Will Focus on Two Important Reasons, Using Quotes from Prof. Engelder for Motivation

“These renewable have a huge upside”, Engelder said. “In my view, the subsidies are really very appropriate”.

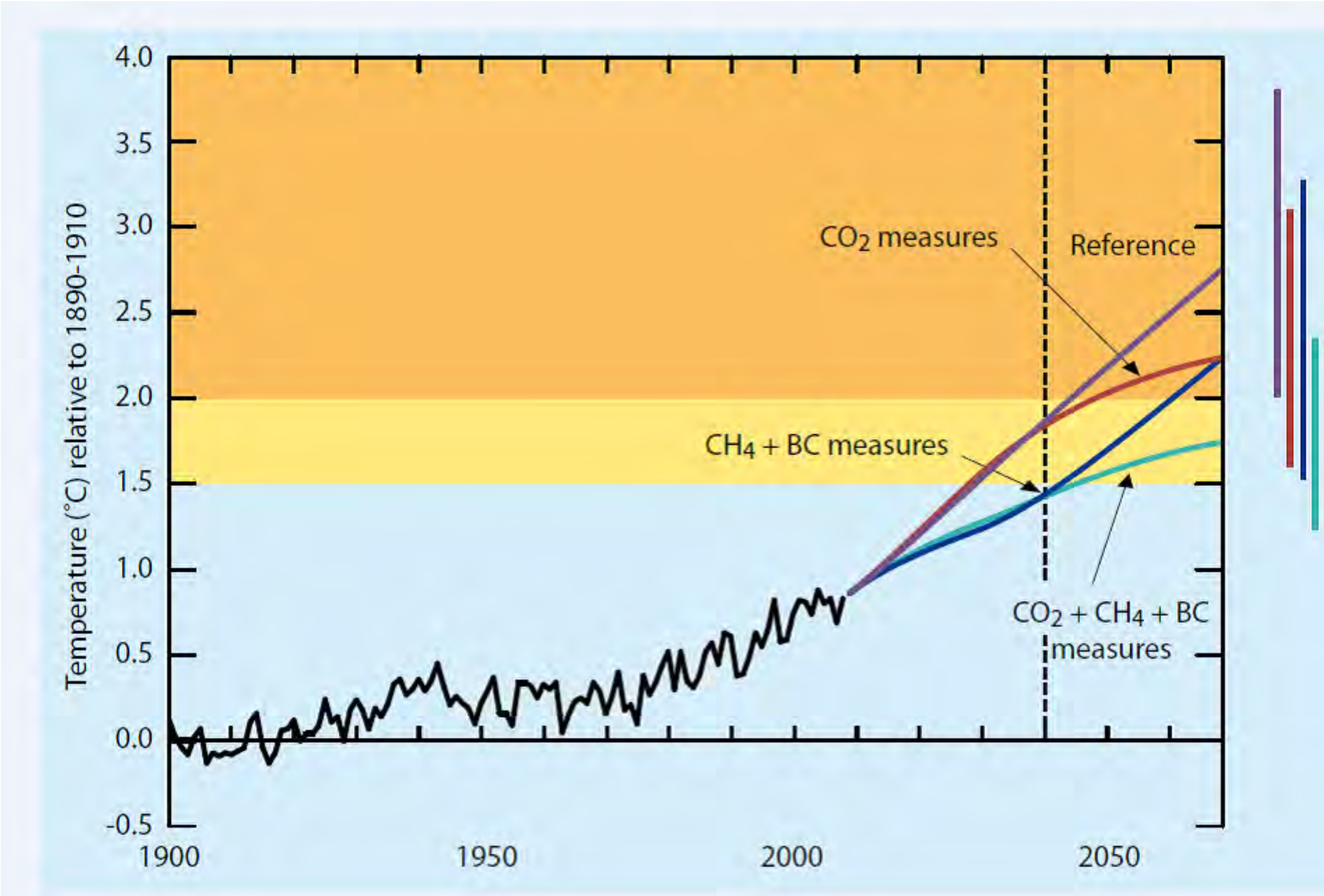
Engelder, who’s been both praised and criticized for his support of gas drilling, said he is sure that research and technology will ultimately deliver innovations that make renewable a major force.

“There’s no doubt about it’, he said, adding that **“the payout might not happen until 2042”.**

Reason #2:

2042 is too late!!

Why Is Controlling Methane (CH_4) Emission So Important?



Shindell, *et al. Science* ***335, 183 (2012)***

Methane Is a Much More Potent Greenhouse Gas Than Carbon Dioxide

- 33 times more potent over 100 years*
- 105 times more potent over 20 years*
- Therefore, even small leakage rates important:

Each 1% lifetime production leakage from a well produces about the same climate impact as burning the methane twice.

*Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, and Bauer SE (2009). Improved attribution of climate forcing to emissions. *Science* 326: 716-718.

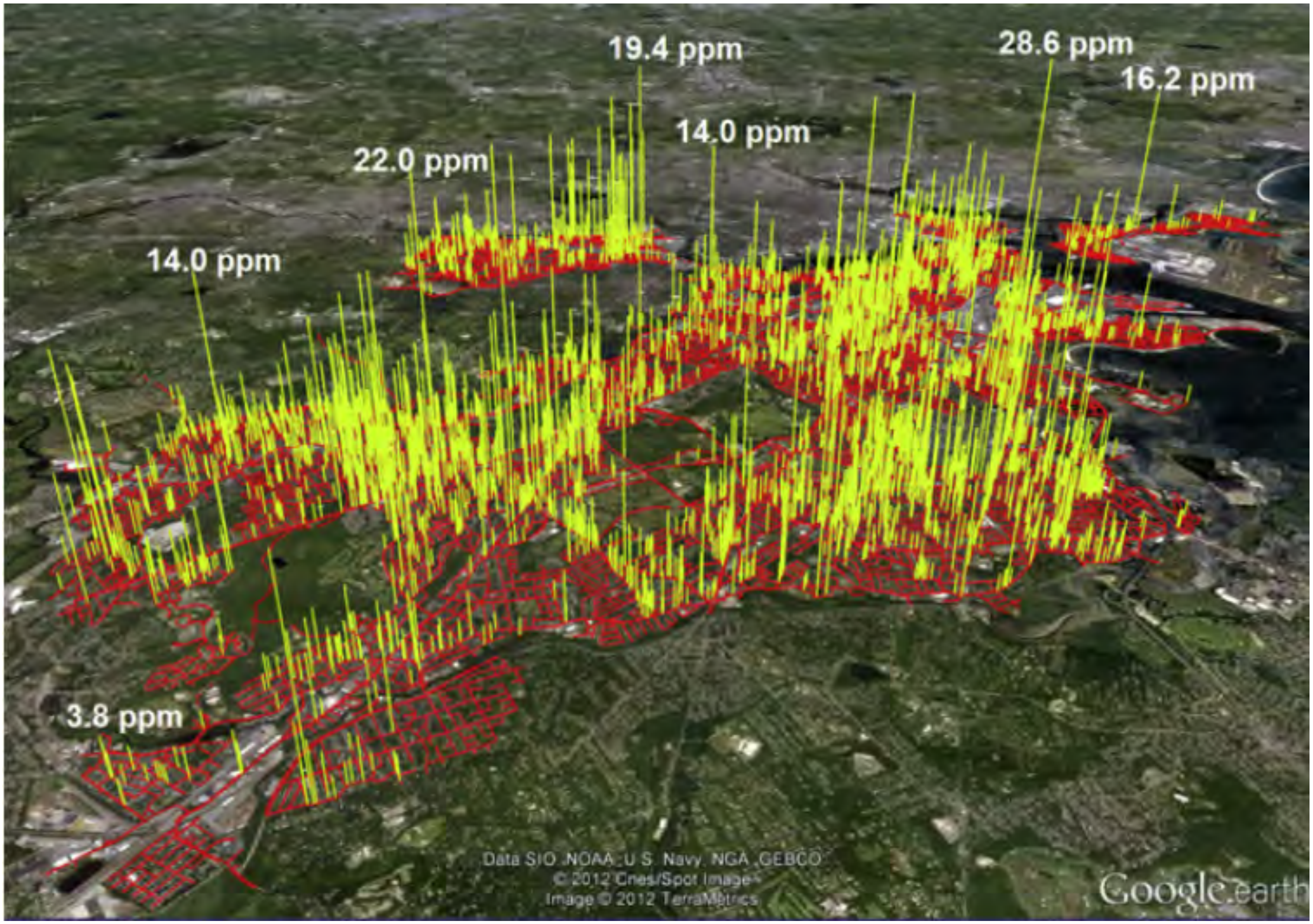
<u>Upstream/Midstream</u> Methane Emission Measurements are Coming in Very High

Uinta Basin, Utah:
Up to 9% of total production
Nature 493, 12 (03 January 2013) doi:10.1038/493012a

Denver–Julesburg Basin, Colorado:
2.3% to 7% of total production
Pétron, G. *et al*. J. Geophys. Res. 117, D04304 (2012)

Note: Howarth, Santoro, Ingraffea predicted
TOTAL (UPSTREAM/MIDSTREAM/DOWNSTREAM) emission range of 3.6% to 7.9%.
Climatic Change Letters, 2011

Downstream Methane Leakage from Aging Urban Distribution Pipelines: Boston MA



N.G. Phillips et al. / Environmental Pollution 173 (2013) 1–4

NO to HVHF, YES to a Much Better Plan

Convert New York State's (NYS's) all-purpose -- electricity, transportation, heating/cooling, industry -- energy infrastructure to one derived entirely from wind, water, and sunlight (WWS).

We the people own the sun. We own the wind. We own the water. Those fuel costs are $0.00.

Or, we can have 50,000 to 100,000 Marcellus and Utica Wells;
8,000 to 16,000 pads;
500 to 1,000 compressor stations;
Thousands of miles of new pipelines;
Thousands of incidents of well water contamination;
Increase New York's contribution to global warming;
Sequester forever twice the tonnage of the US Navy in non-recyclable steel casing.

1% tidal (2600 1-MW turbines)
5.5% hydroelectric (6.6 1300-MW plants, of which 89% exist).

NO to HVHF, YES to a Much Better Plan

The plan would:

- Reduce NYS's end-use power demand ~37%.

- Stabilize energy prices since fuel costs would be zero.

- Create more jobs than lost because nearly all NYS energy would now be produced in-state, ~58,000 <u>new, permanent, full-time</u> jobs by 2025.

- Reduce NYS air pollution mortality and its costs by ~4000/yr, and ~$33 billion/yr (3% of 2010 NYS GDP), respectively, repaying the 271 GW installed power needed within ~17 y.

- NYS's own emission decreases would reduce 2050 U.S. climate costs by ~$3.2 billion/yr.

We Own the Wind, the Sun, the Water: Their Fuel Cost is Zero.

Wind, water and solar energy will provide a stable, renewable source of electric power not subject to the same fuel supply limitations as fossil fuels and nuclear power. Due to the eventual depletion of coal, oil, natural gas, and uranium resources, their prices will continue to rise.

We Own the Wind, the Sun, the Water: They Make Us Energy Secure and Independent

"Should New York State and/or

No.

Thank you !

PSE
Physicians Scientists & Engineers for Healthy Energy

CORNELL UNIVERSITY FOUNDED A.D. 1865

Projected Unit Costs of Selected Conventional Fossil Fuels Over the Period 2009-2030 in NYS.

Fuel Type	**Projected Changes in Fuel Cost, 2009-2030**		
	2009	**2030**	**Percent Change**
Gasoline – all grades	$19.30	$40.39	109%
Natural Gas - Electric	$6.30	$10.14	27%
Natural Gas – Commercial	$10.29	$15.00	[illegible]
Natural Gas – Industrial	$8.73	$11.98	37%

Source: NYSEPB (2009), Energy Price and Demand Long-Term Forecast (2009-2028). Annual growth rate factors provided in reference document have been extrapolated for the period 2029-2030.

Externality Costs for Fossil Fuel Generation

The hidden costs of:

- Air pollution morbidity and mortality
- Water pollution costs
- Global warming damage. e.g. coastline loss, agricultural and fish losses, human heat stress mortality, increases in severe weather and air pollution
- Worker health

Approximate fully annualized generation and short-distance transmission costs for WWS and new conventional power (2007 U.S. cents/kWh-delivered), including externality costs.

Energy Technology	2005-2012*	2020-2030*
Wind Onshore	4[a] -10.5[b]	<4[a]
Wind Offshore	11.3[c] -16.5[b]	7[b]-10.9[c]
Wave	>11.0[a]	4-11[a]
Geothermal	9.9-15.2[b]	5.5 -8.8[g]
Hydroelectric	4.0-6.0[d]	4[a]
CSP	14.1-22.6[b]	7 -8[a]
Solar PV (Utility)	11.1-15.9[b]	5.5[g]
Solar PV (Commercial	14.9-20.4[b]	7.1-7.4[h]
Solar PV (Residential	16.5-22.7[e]	7.9-8.2[h]
Tidal	>11.0[a]	5-7[a]
New conventional (plus externalities)[f]	**9.6-9.8 (+5.3) =**	**12.1-15.0 (+5.7) = 17.8-20.7**

Approximate fully annualized generation and short-distance transmission costs for WWS power (2007 U.S. cents/kWh-delivered), including externality costs. Also shown are generation costs and externality costs (from Table 4) of new conventional fuels. Actual costs in California will depend on how the overall system design is optimized as well as how energy technology costs change over time.

*$0.01/kWh for transmission was added to all technologies as in Delucchi and Jacobson (2011) except for distributed generation projects (i.e. commercial and residential solar PV)

a)Delucchi and Jacobson (2011)
c) Levitt et al. (2011)
d) REN21 (2010)
e) SEIA (2012). Residential LCOE: Calculated by multiplying the Lazard (2012) Commercial LCOE by the ratio of the Residential PV $/Watt to the Commercial PV $/Watt = $.149*($5.73/$5.16) - $.204($5.73/$5.16)
f) The current levelized cost of conventional fuels in NYS is calculated by multiplying The electric power generation by conventional source in NYS (EIA, 2012b) by the Levelized cost of energy for each source (Lazard, 2012 for low estimate; EIA, 2012c for high estimate)and dividing by the total generation. The future estimate assumes a 26.5% increase in electricity costs by 2020 (the mean increase in electricity prices in NYS from 2003-2011, EIA, 2012d), and twice this mean increase by 2030. Externality costs are from Table 4.
g) Google (2011), 2020 projection
h) The ratio of present-day utility PV to present-day commercial and residential PV multiplied by the projected LCOE of utility PV

Not Much Respect from EXXON Mobil CEO

"Now, with these new technologies that evolve always come a lot of questions. Ours is an industry that is built on technology, it's built on science, it's built on engineering, and because ***we have a society that by and large is illiterate in these areas, science, math and engineering, what we do is a mystery to them and they find it scary.*** And because of that, it creates easy opportunities for opponents of development, activist organizations, to manufacture fear."

Rex W. Tillerson, Chairman and CEO,
Exxon Mobil Corporation
June 27, 2012
Council on Foreign Relations

Easy for Him to Say

"…And as long as we as an industry follow good engineering practices and standards, these risks are entirely manageable. And the consequences of a misstep by any member of our industry -- and I'm speaking again about the shale revolution -- ***the consequences of a misstep in a well, while large to the immediate people that live around that well, in the great scheme of things are pretty small,*** and even to the immediate people around the well, they could be mitigated."

Rex W. Tillerson, Chairman and CEO,
Exxon Mobil Corporation
June 27, 2012
Council on Foreign Relations

EXXON Mobil CEO on Global Warming

"…And as human beings as a -- as a -- as a species, that's why we're all still here. We have spent our entire existence adapting, OK? ***So we will adapt to this. Changes to weather patterns that move crop production areas around -- we'll adapt to that. It's an engineering problem, and it has engineering solutions.*** And so I don't -- the fear factor that people want to throw out there to say we just have to stop this, I do not accept. I do believe we have to -- we have to be efficient and we have to manage it, but we also need to look at the other side of the engineering solution, which is how are we going to adapt to it. And there are solutions. It's not a problem that we can't solve."

Rex W. Tillerson, Chairman and CEO,
Exxon Mobil Corporation
June 27, 2012
Council on Foreign Relations

EXXON Mobil CEO on Journalists

"…But this is an ongoing dialogue I've been having with people in your profession now for some time; that for whatever reason, ***a large number of people in the journalism profession simply are unwilling to do their work. They're unwilling to do the homework.*** And so they get something delivered to them from the manufacturers of fear; it makes a great story. I mean, it – I mean, it does. It makes a great story. People love that kind of stuff. The consuming public loves it, because it goes to what, you know, their fears are."

Rex W. Tillerson, Chairman and CEO,
Exxon Mobil Corporation
June 27, 2012
Council on Foreign Relations

Farmer Joe Is a Liar

"…There are a lot of sources of science-based information. There are a lot of sources that can debunk claims that are made specific -- you know, specific examples. ***Farmer Joe lit his faucet on fire, and that's because there was gas drilling going on, you know, in his back porch. And we can go out there and we can prove with science that that is biogenic gas; it's been in the water table for millions of years; it finally made its way Farmer Jones' faucet, it had nothing to do with any oil and gas activities.*** And part of when you're dealing with the subsurface strata is you've got to -- you got to understand that Mother Nature has done a lot of things in the subsurface that have nothing to do with anything man has done. And it changes. It moves around all the time. So what once was will change."

Rex W. Tillerson, Chairman and CEO,
Exxon Mobil Corporation
June 27, 2012
Council on Foreign Relations

EXXON Mobil CEO Correct on Shale Gas Economics

"…And what I can tell you is the cost to supply is not $2.50. We are all losing our shirts today. You know, we're making no money. It's all in the red."

"The higher volumes are not only the result of drilling in the higher Btu area, **but are also the result of drilling longer laterals and completing them with more frac stages**. **We've also experimented with reduced cluster spacing, decreasing the frac interval from 300 feet to 150 to 200 feet, all of this looks very promising.** Once we extract ethane beginning late next year, this will further enhance the economics."

Range Resources earnings call Q4 2011

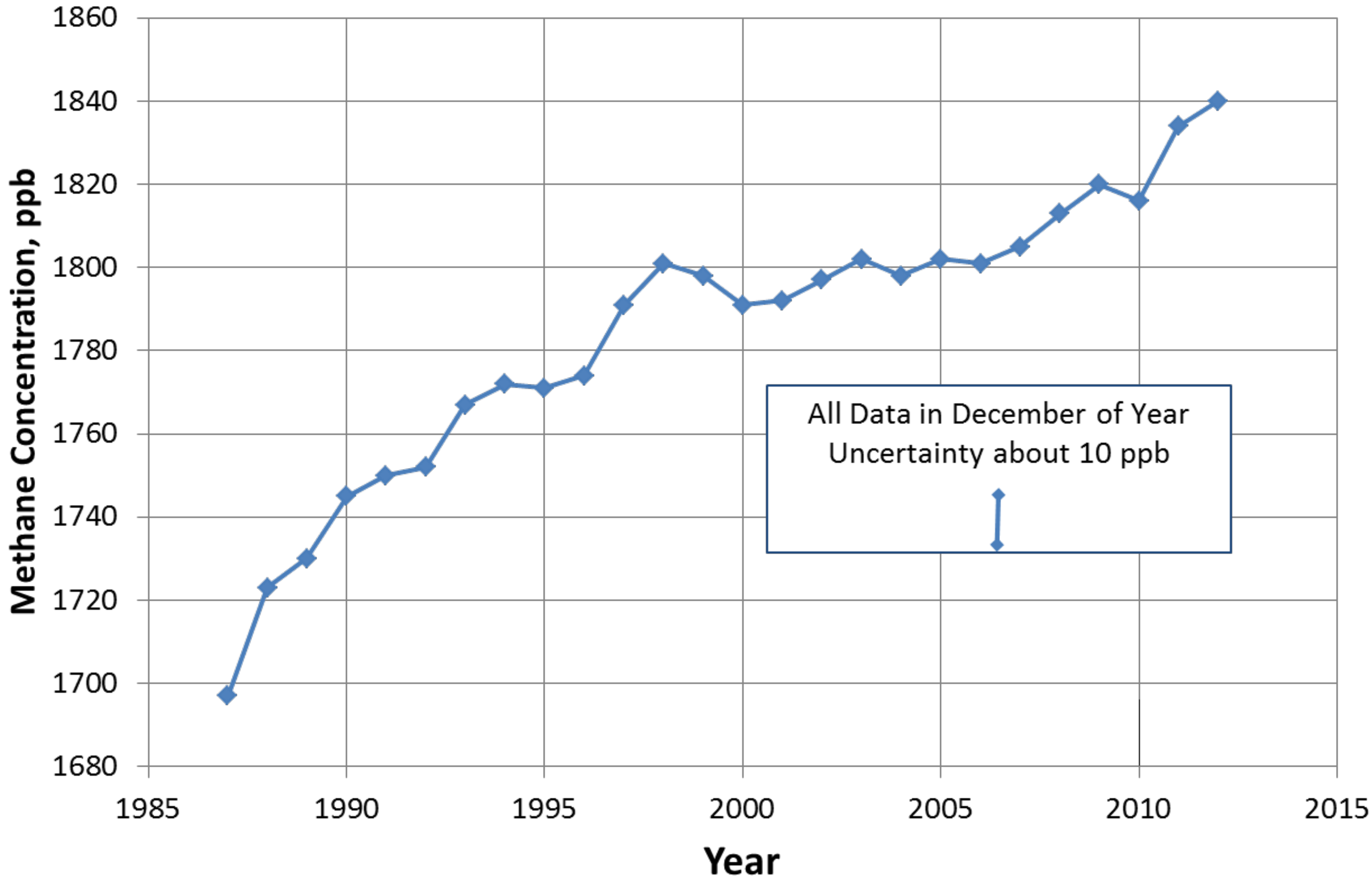
Last year's earnings:
Q2 2011 was $51,293,000.
Q3 2011 was $34,755,000.
Q4 2011 was a loss of -$2,989,000.
Q1 2012 was a loss of -$41,800,000.

78.73A - Operator shall prevent gas and other fluids from lower formations from entering fresh
78.81D2 - Failure to case and cement properly
78.83A - Diameter of bore hole not 1 inch greater
78.73B - Excessive casing seat pressure
78.83 GRNDWTR - Improper casing to protect fresh
78.83 COALCSG - Improper coal protective casing
78.85 - Inadequate, insufficient, and/or improperly
78.86 - Failure to report defective, insufficient, or
207B - Failure to case and cement to prevent

Additional Counts of Wells with

2010	64 wells with violations, 47 additional wells with loss of integrity noted in Inspection Comments
2011	97 wells with violations, 45 additional wells with loss of integrity noted in Inspection Comments
2012	44 wells with violations, 76 additional wells with loss of integrity noted in Inspection Comments

Measured Methane Concentration in the Atmosphere



DATA FROM NOAA: http://www.esrl.noaa.gov/gmd/dv/iadv/graph.php?code=MLO&program=ccgg&type=ts

2012 International Energy Agency Report on Fossil Fuels and Climate Change

“On the November 2012 International Energy Agency report, spokesperson Michael Levi said,

"The report confirms that, given the current policies, we will blow past every safe target for emissions. This should put to rest the idea that the boom in natural gas will save us from that.” “

(http://www.nytimes.com/2012/11/13/business/energy-environment/report sees-us-as-top-oil-producer-in 5years.html?_r=1&adxnnl=1&adxnnlx=1354623973-G4+SBz4O1YBFWAJS7XpkXA&)

Germany Sets New Solar Record By Meeting Nearly Half of Country's Weekend Power Demand

by Timon Singh, 05/31/12

"Germany fed a whopping 22 gigawatts of solar power per hour into the national grid
last weekend, setting a new record by meeting nearly half of the country's weekend power demand. The Renewable Energy Industry (IWR) in Muenster announced that Saturday's solar energy generation met nearly 50 percent of the nation's midday electricity needs and was equal to 20 nuclear power stations at full capacity."

NYS Doing Quite Well WITHOUT Shale Gas

NO NEW TAXES

Plan seeks to close $1.3B deficit, help municipalities

New York Gov. Andrew Cuomo presents his 2013-14 executive budget address Tuesday in Albany. His $136 billion state budget would increase spending about 2 percent without tax increases, but New Yorkers would feel some fee hikes. ASSOCIATED PRESS

1.9%
spending hike

BUDGET HIGHLIGHTS

DEFICIT REDUCTION
Closes a $1.3 billion budget gap without new taxes or fees.

PENSION RELIEF
Starts program to help local governments fund growing pension costs.

MINIMUM WAGE
Raises from $7.25 to $8.75 an hour.

EDUCATION AID
Boosts by $889 million, or by 4.4 percent, including $75 million in competitive grants.

ECONOMIC DEVELOPMENT
Creates tax-free zones for job growth and continues $220 million for regional development councils.

By Joseph Spector
jspector@gannett.com

ALBANY — Gov. Andrew Cuomo offered a budget proposal Tuesday that seeks to increase the minimum wage and offer tax breaks to businesses, while increasing aid to schools and closing two prisons.

The $136 billion budget plan would increase state spending by 1.9 percent and close a $1.3 billion deficit for the 2013-14 fiscal year, which starts April 1. It includes no broad-based tax increases.

The budget also includes an additional $6 billion that Cuomo expects to receive from the federal government to pay for the Affordable Care Act and Superstorm Sandy recovery.

Cuomo said the nearly $143 billion package would boost the state's struggling economy, rebuild after the storm and increase education aid by 4.4 percent.

"We're going to take this moment in time and moment in history, and we will pledge ourselves to build this state back

See BUDGET, Page 5A

$8.75
min. wage

'We will pledge ourselves to build this state back to a level that it's never reached.'

GOV. ANDREW CUOMO

ON THE WEB
See video of reaction from state Sen. Tom O'Mara, R-Big Flats, with this story at **theithacajournal.com.**

INSIDE

» Plan for regional "hot spots." **Page 3A**
» Help for local governments. **Page 4A**
» More aid for education. **Page 4A**
» Lifton: Proposal not enough. **Page 5A**

1.9%
spending hike

BUDGET HIGHLIGHTS

DEFICIT REDUCTION
Closes a $1.3 billion budget gap without new taxes or fees.

PENSION RELIEF
Starts program to help local governments fund growing pension costs.

MINIMUM WAGE
Raises from $7.25 to $8.75 an hour.

EDUCATION AID
Boosts by $889 million, or by 4.4 percent, including $75 million in competitive grants.

ECONOMIC DEVELOPMENT
Creates tax-free zones for job growth and continues $220 million for regional development councils.

Ithaca Journal, 1/23/13

PA Having Economic Problems WITH Shale Gas

Tuesday, January 22, 2013
Stunning Fact: PA Unemployment Rate Rises During Last 12 Months Even As National Rate Declines

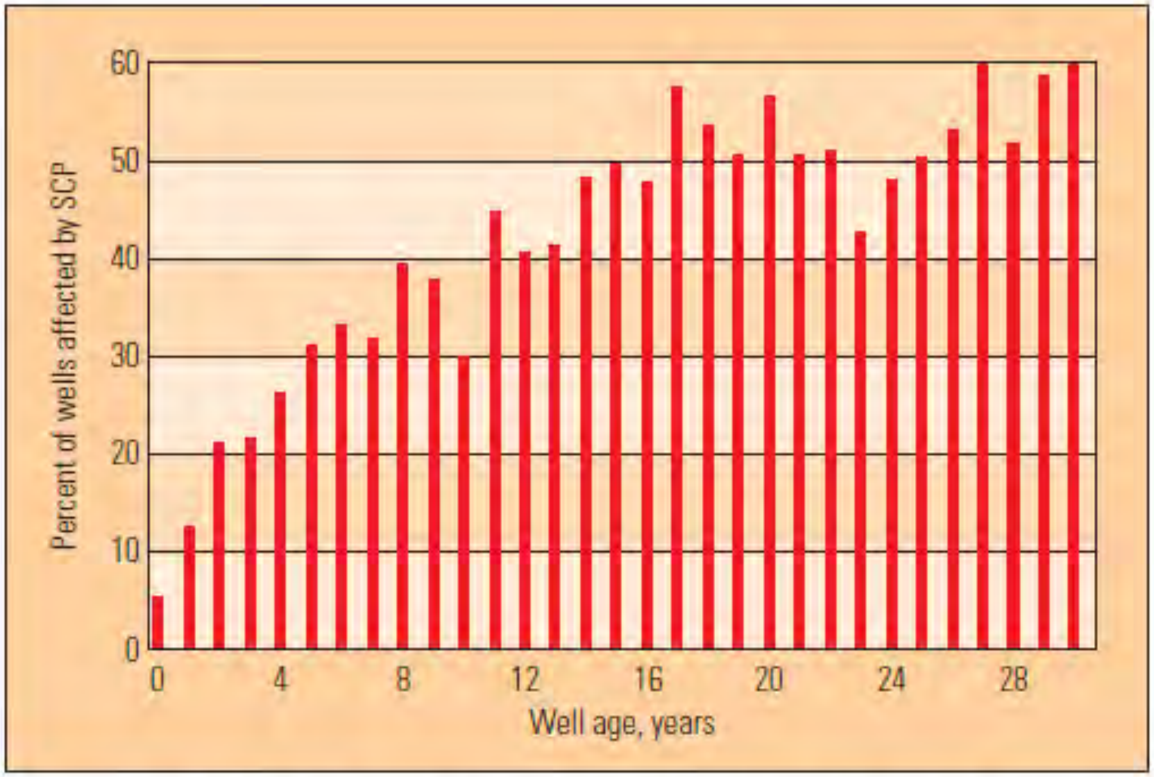
Pennsylvania is among the few states to have a higher unemployment rate in December 2012 than in December 2011. The facts are that Pennsylvania's unemployment rate was 7.9% in December 2012 and is up from 7.7% in December 2011.

Pennsylvania's economy is headed in the wrong direction, even as the national unemployment rate fell from 8.2% to 7.8%, and even as Pennsylvania becomes the third largest producer of natural gas in the country….

These are ugly facts that indict the economic development and budget policies of the Corbett Administration. Corbett's failure is rooted in an assault on public education, including our state universities, that has destroyed at least 19,000 jobs. His failure is also rooted in a mistaken belief that gas drilling and gas production alone can bring Pennsylvania a broad prosperity.

http://johnhanger.blogspot.com/2013/01/stunning-fact-pa-unemployment-rate.html

"Since the earliest gas wells, uncontrolled migration of hydrocarbons to the surface has challenged the oil and gas industry."



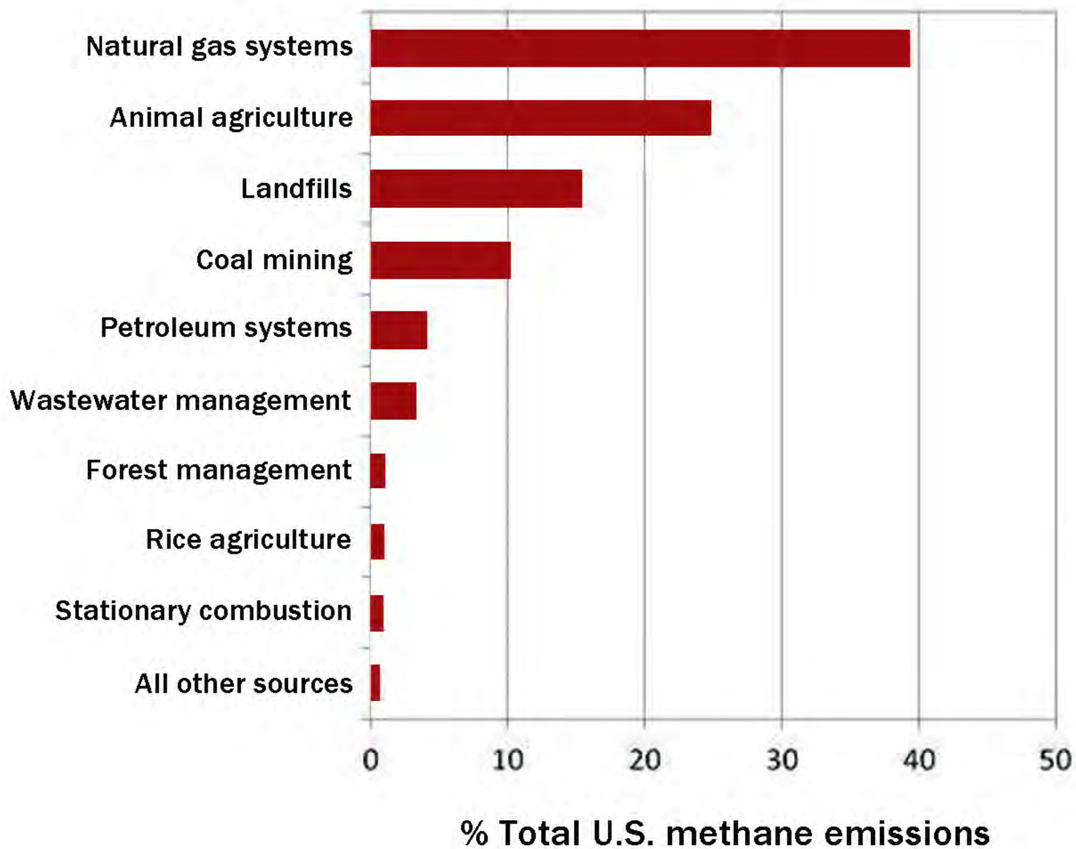
^ Wells with SCP by age. Statistics from the United States Mineral Management Service (MMS) show the percentage of wells with SCP for wells in the outer continental shelf (OCS) area of the Gulf of Mexico, grouped by age of the wells. These data do not include wells in state waters or land locations.

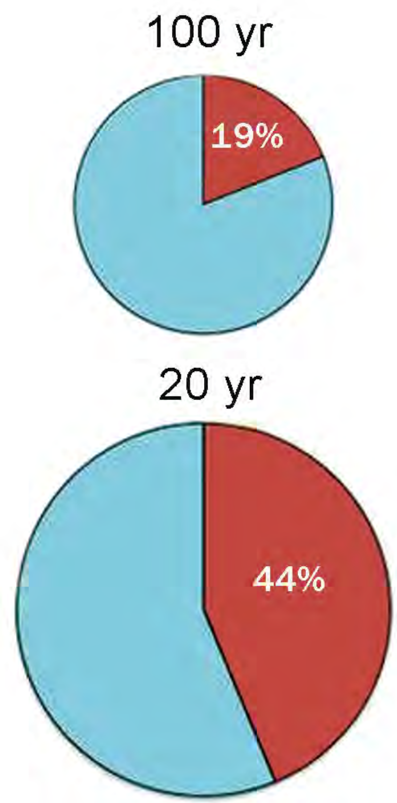
SCP=Sustained Casing Pressure. Also called sustained annular pressure in one or more of the casing annuli.

- About 5% of wells fail soon
- More fail with age
- Most fail by maturity

Brufatto *et al.*, *Oilfield Review*, Schlumberger, Autumn, 2003

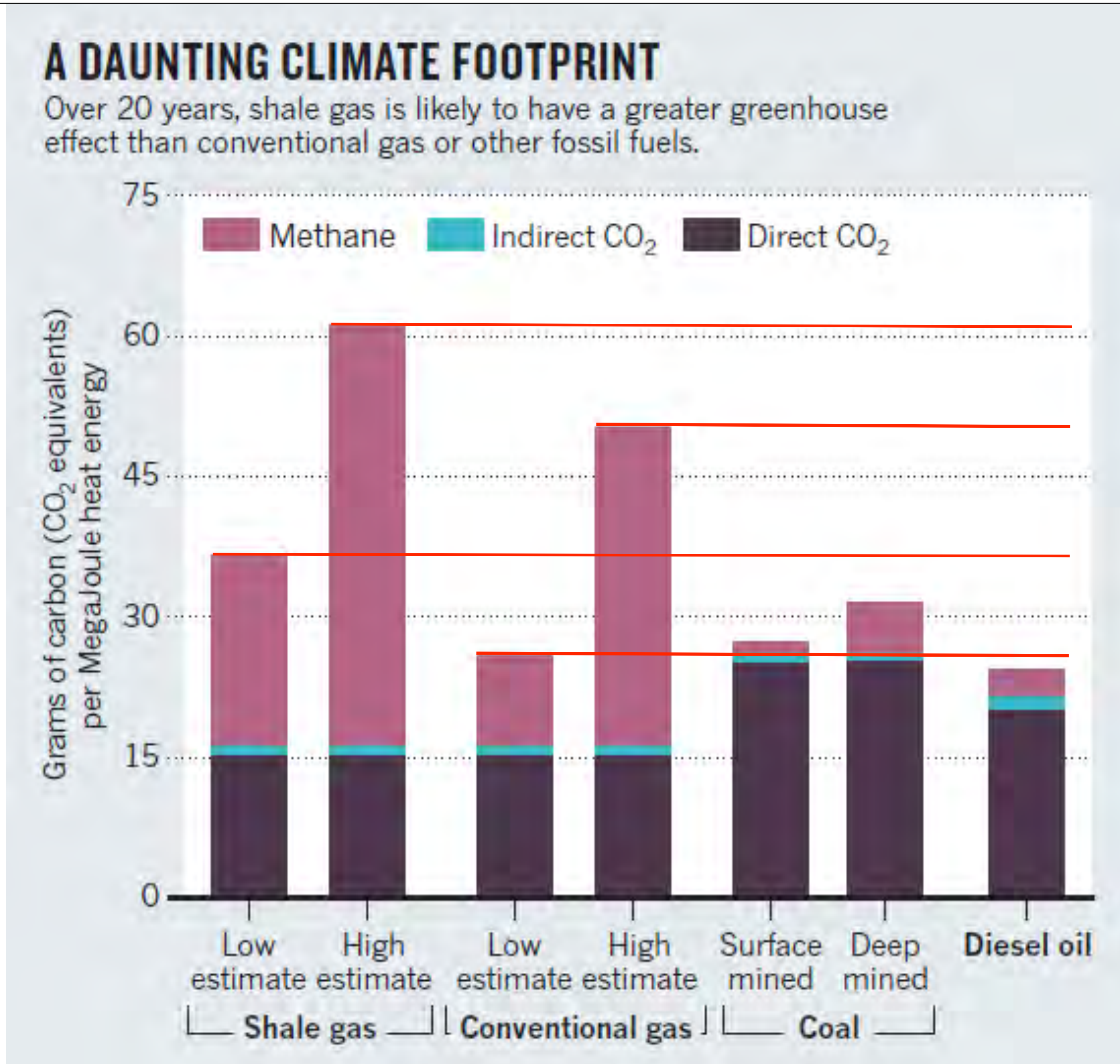
Natural Gas Systems Now Produce 39% of Total U.S. Methane Emissions





Methane contribution to entire greenhouse gas inventory

(Howarth et al. 2012, based on 2011 EPA data for 2009)



Howarth & Ingraffea, *Nature*, 15 September 2011

Aubrey McClendon, CEO of Chesapeake Gas on Climate Change

Mr. McClendon promotes natural gas as a carbon-light fuel, but that doesn't mean he's convinced that man is really changing the climate. "There have been times in the past on this planet where it's been hotter but CO2 levels have been lower. And there have been times when CO2 levels have been higher and the climate's been cooler. . . Would people cheat on climate science? Sure. Because all it is a model into which there are 2,000 variables and if I want this outcome I nudge that one up a little and down a little bit and there you go."

Wall Street Journal, April 27, 2012

OIL&GAS JOURNAL

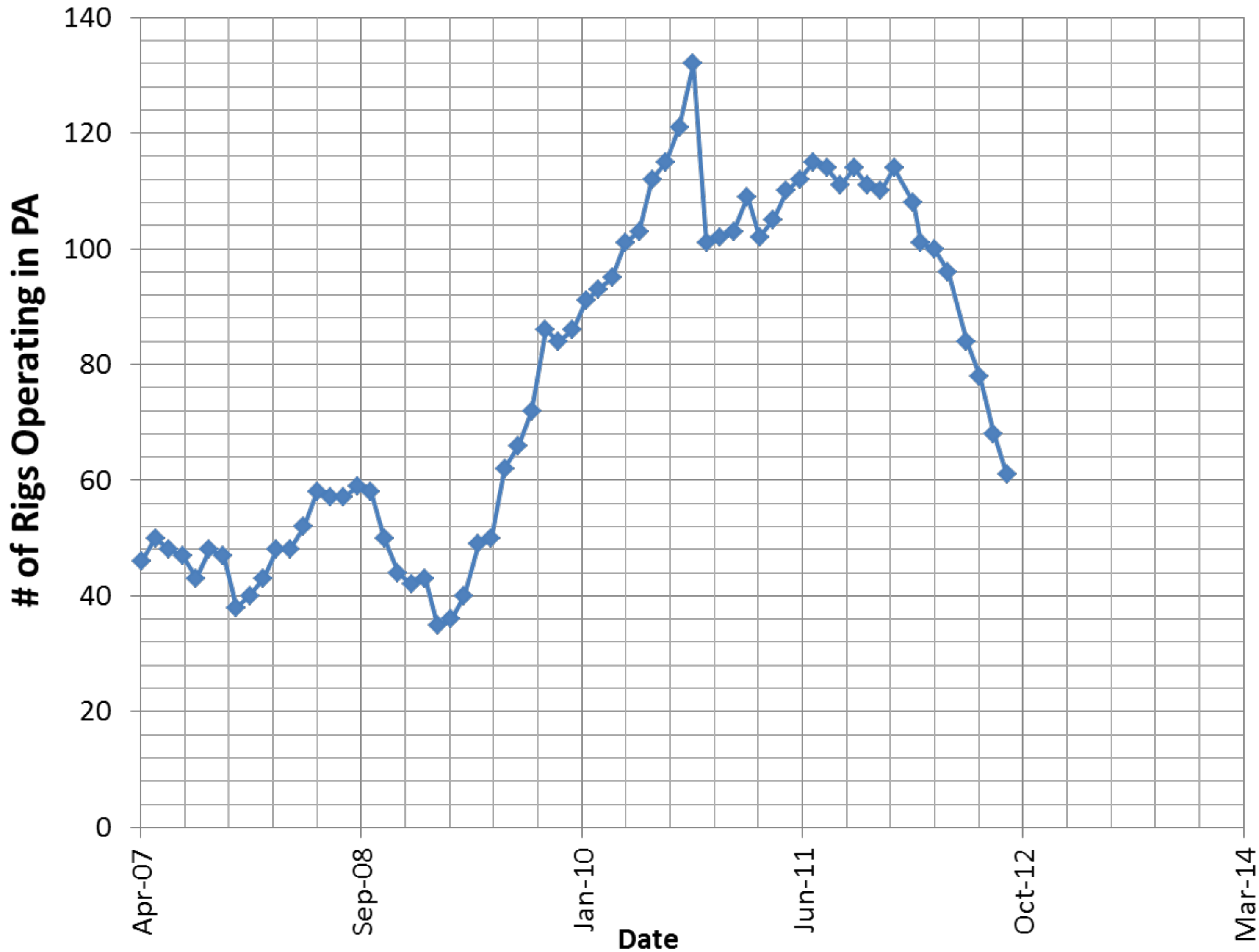
ERCB: Alberta frac job leak caused by insufficient spacing

HOUSTON, Dec. 14
12/14/2012
By OGJ editors

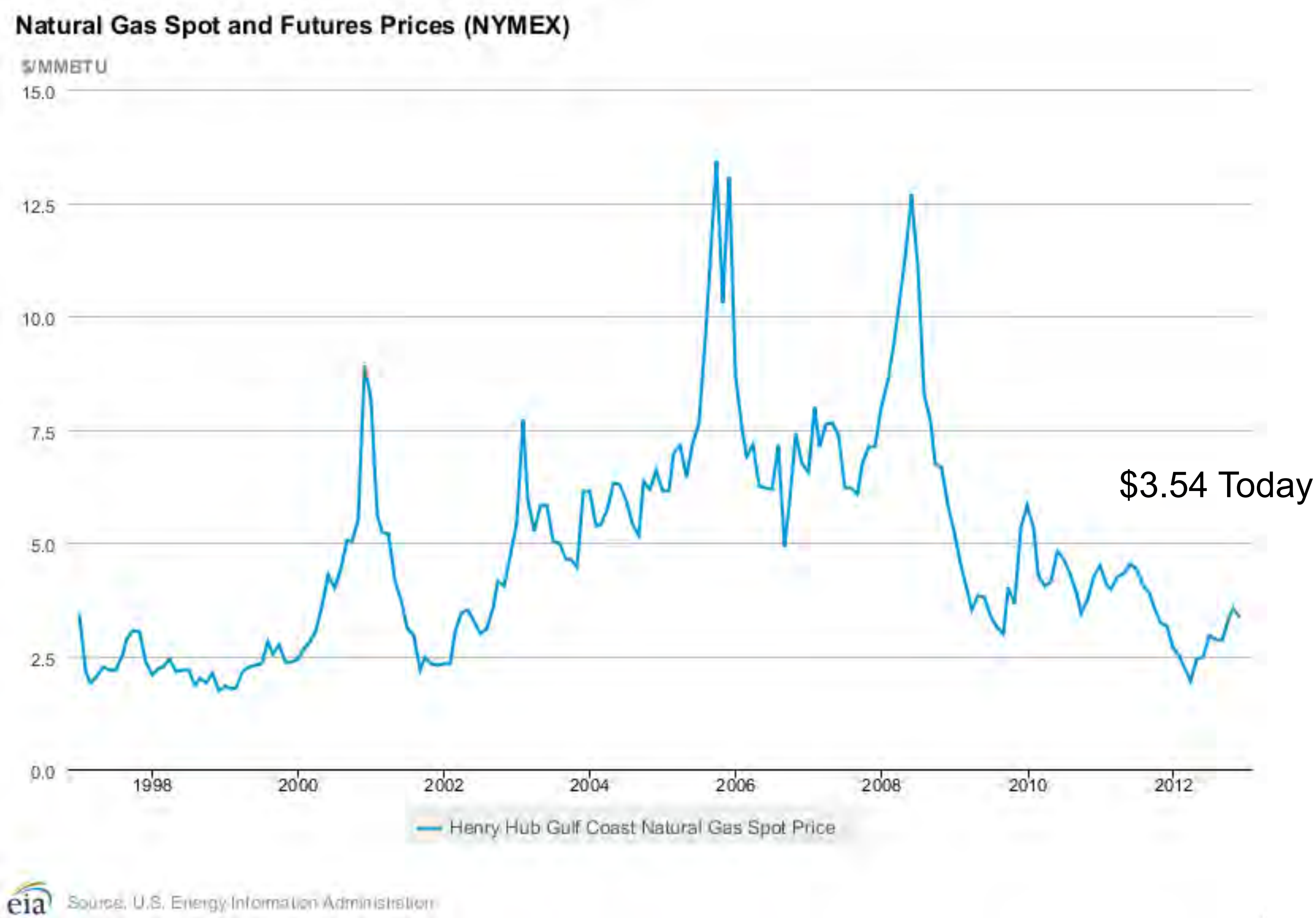
Insufficient distance between wellbores caused a vertical oil well to leak fluids after hydraulic fracturing of a nearby horizontal well last January in Red Deer County, Alta., an investigation by the Alberta Energy Resources Conservation Board has determined.

The agency said communication between wells didn't occur until about 1 hr and 45 min after the frac job, so no significant decrease in pressure was observed at the Midway well during the operation. Increased pressure and flow rates in the Wild Stream vertical well caused surface components, which weren't rated for hydraulic fracturing, to fail.

Trends in Drilling Rig Count in PA



Natural Gas Price is Volatile



UNEP

UNEP Global Environmental Alert Service (GEAS)

Taking the pulse of the planet; connecting science with policy

Website: www.unep.org/geas E-mail: geas@unep.org

November 2012

Home Subscribe Archive Contact

Thematic Focus: Resource Efficiency, Harmful Substances and Hazardous Waste

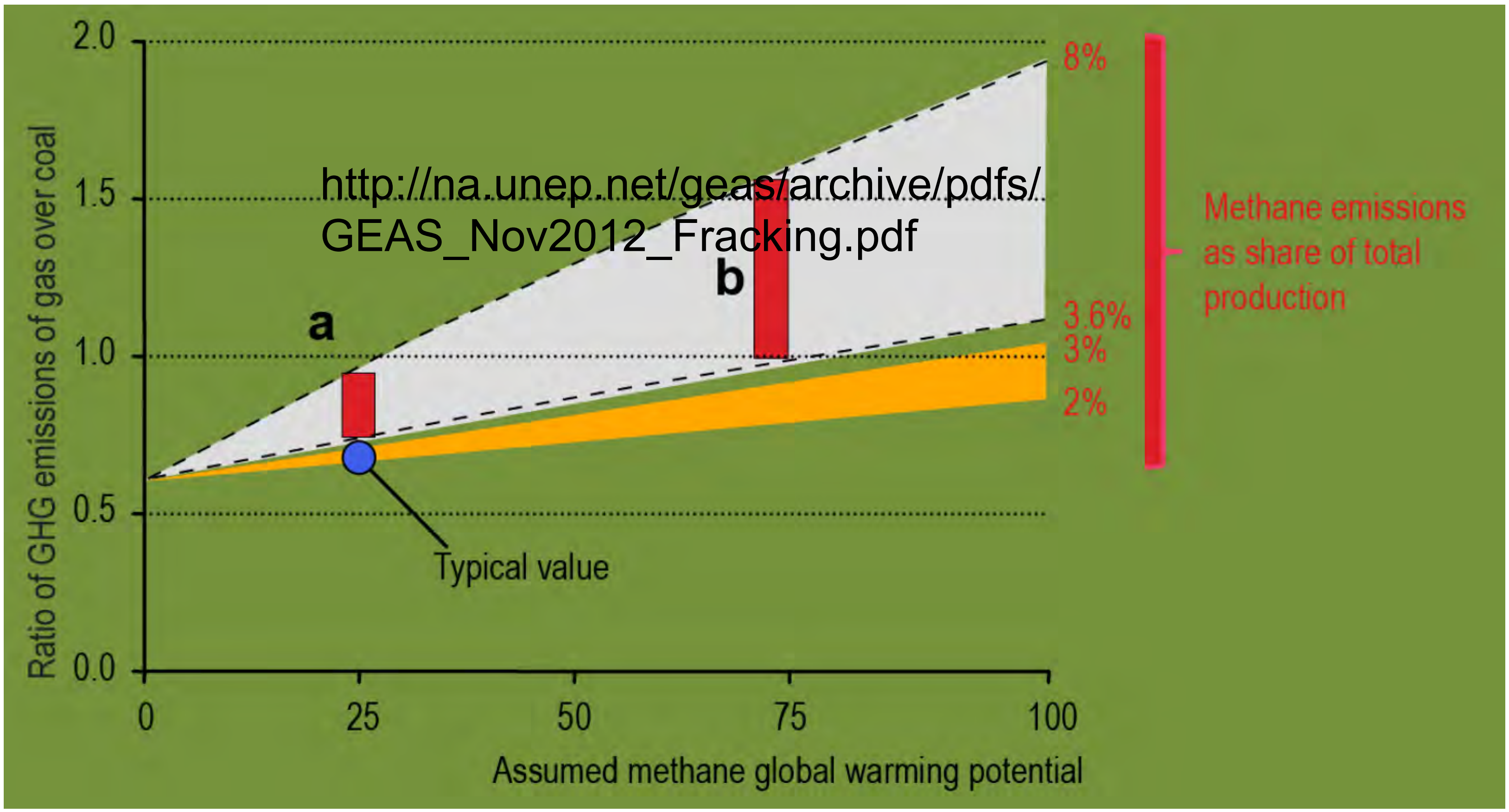
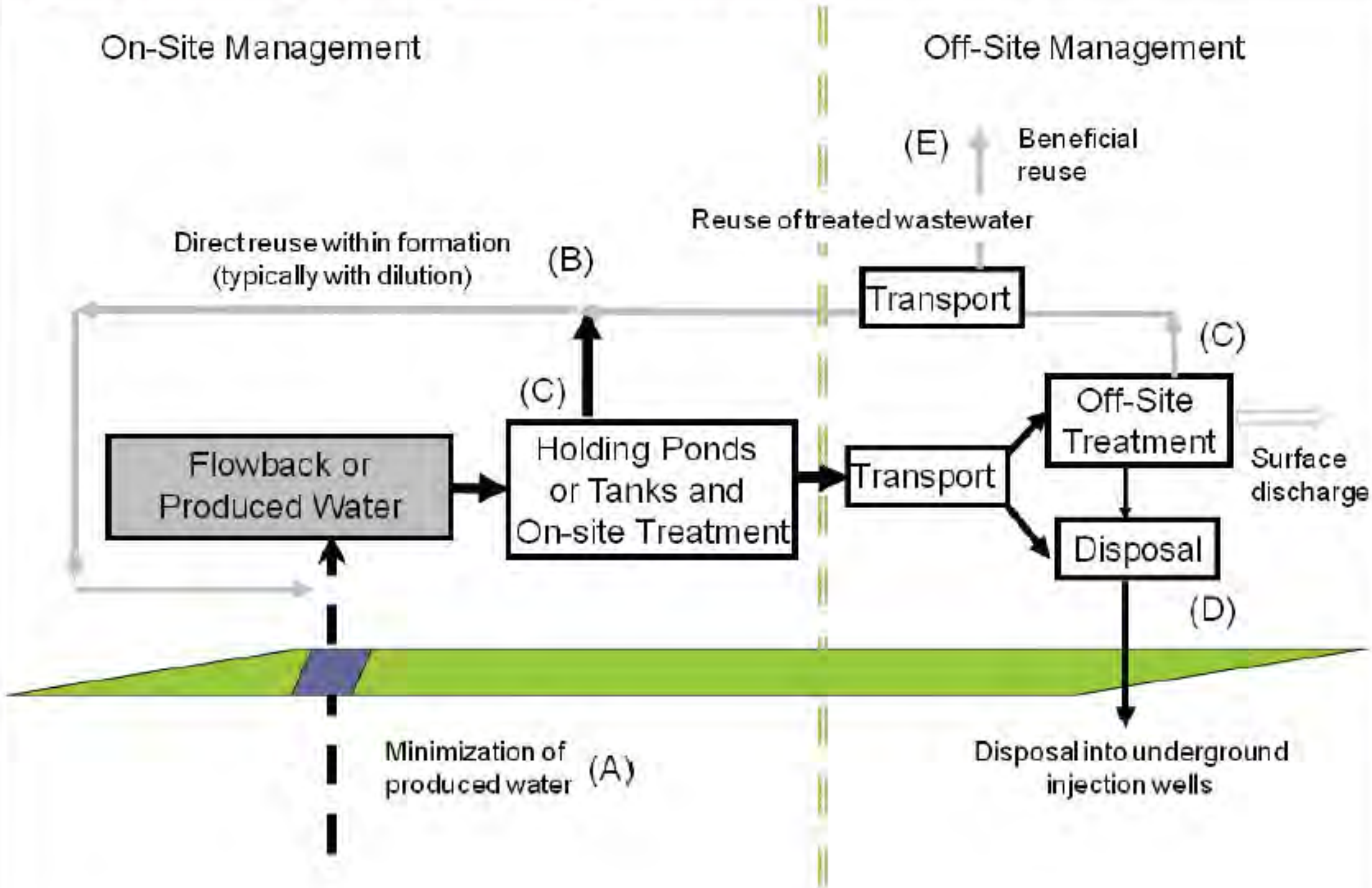


Figure 1. Summary of Management Options for Shale Gas Wastewater



NRDC document
May 2012 D:12-05-A

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

IN THE MATTER OF:

Chesapeake Appalachia, LLC Tuscarora, Terry, Monroe, Towanda, and Wilmot Townships Bradford County	: Violations of The Oil and Gas Act, : and The Clean Streams Law : :

CONSENT ORDER AND AGREEMENT

This Consent Order and Agreement is entered into this 16th day of May, 2011, by and between the Commonwealth of Pennsylvania, Department of Environmental Protection (hereinafter "Department"), and Chesapeake Appalachia, LLC (hereinafter "Chesapeake").

The Department has found and determined the following:

A. The Department is the agency with the duty and authority to administer and enforce the Oil and Gas Act, Act of December 19, 1984, P.L. 1140, as amended, 58 P.S. §§ 601.101-601.605 ("Oil and Gas Act"); The Clean Streams Law, Act of June 22, 1937, P.L. 1987, as amended, 35 P.S. §§ 691.1-691.1001 ("Clean Streams Law"); Section 1917-A of the Administrative Code of 1929, Act of April 9, 1929, P.L. 177, as amended, 71 P.S. §§ 510-17 ("Administrative Code"); and the rules and regulations promulgated thereunder (hereinafter "Regulations").

B. Chesapeake Appalachia, LLC (hereinafter "Chesapeake") is an Oklahoma Limited Liability Company authorized to do business in Pennsylvania which maintains a business address of P.O. Box 18496, Oklahoma City, OK 73154-0496.

C. Chesapeake constitutes a "person" as that term is defined by Section 103 of the Oil and Gas Act, 58 P.S. § 601.103, and by Section 1 of the Clean Streams Law, 35 P.S. § 691.1.

D. Chesapeake is the "owner" and "operator," as those terms are defined by Section 103 of the Oil and Gas Act, 58 P.S. §601.103, of certain gas wells within the areas defined by the Department as follows: the area of Towanda Township, Bradford County (hereinafter " Area"); the area in Tuscarora Township, Bradford County (hereinafter " Area"); the Paradise Road area of Terry Township, Bradford County (hereinafter "Paradise Road Area"); the area in Monroe Township, Bradford County (hereinafter " Area"); the Sugar Run area of Wilmot Township, Bradford County (hereinafter "Sugar Run Area"); the Spring Hill Road area of Tuscarora Township, Bradford County (hereinafter "Spring Hill Road Area"); and the residence. Maps of the Area, Area, Paradise Road Area, Area, Sugar Run Area, Spring Hill Road Area, and Area, are attached as Exhibit A and incorporated herein.

<u>Area</u>

E. In February of 2010, contacted Chesapeake to complain about his water supply well producing black water and "churning."

F. Chesapeake responded and provided with temporary replacement water.

G. On February 26, 2010, Chesapeake contacted the Department about the water well and the actions Chesapeake intended to take in response to complaint.

H. The Department reviewed Chesapeake's planned tasks and asked that additional measures be taken, including on-site gas screening of residences, low lying areas, and springs/streams; and that the annulus pressures at the Miller, Farr and Kent well pads be checked.

I. Chesapeake carried out the additional measures requested by the Department.

J. On March 1, 2010, informed Chesapeake that a pond on his property was bubbling.

K. On March 3, 2010, Chesapeake installed a PVC riser pipe (vent stack) on the water well. An elevated concentration of methane was detected in the well headspace. Methane also was detected at low levels in the basement and upstairs of the residence.

L. On March 4, 2010, Chesapeake installed a methane monitor in the basement of the residence.

M. On March 24, 2010, a second landowner, , contacted Chesapeake about problems with his water well. Chesapeake responded and notified the Department.

N. Chesapeake installed methane monitoring equipment in a total of five residential locations in the area.

O. On March 29, 2010, with the approval of the Department, Chesapeake began remedial work at the Miller gas wells.

P. On April 13, 2010, the Department issued Chesapeake a Notice of Violation for the failure to prevent the migration of gas into sources of fresh groundwater and for defective casing or cementing of the Miller gas wells.

Q. By approximately April 20, 2010, visible water disturbance had subsided in the pond. Chesapeake drilled a new water well for the residence in May, 2010.

Area

R. On June 25, 2010, the Department received a complaint of bubbling in a beaver pond in Tuscarora Township, Bradford County.

S. The nearest gas wells to the beaver pond are operated by Chesapeake. Chesapeake's Sivers well pad is 1,700 feet from the pond and Chesapeake's Mowry 2 well pad is 3,600 feet from the beaver pond.

T. The Department notified Chesapeake of this complaint on June 30, 2010 and Chesapeake initiated an investigation.

U. On July 26, 2010, Chesapeake provided the Department with a summary of its investigation relating to the Sivers well pad, including an isotopic analysis of the gas emitted from the beaver pond and of gas found in the annular space of the surface casing of Chesapeake's wells on three surrounding pads. A plan of action was also submitted that called for modifying the wellbore construction, particularly with respect to cementing; additional testing; and implementing a 3-string casing design.

V. On August 6, 2010, the Department issued Chesapeake a Notice of Violation for the unpermitted discharge of polluting substances and failure to prevent the migration of gas into sources of fresh groundwater for the Sivers area.

W. On August 7, 2010, Chesapeake instituted a monitoring plan which included inspections of the beaver pond, private residences, and gas wells in the Sivers area.

X. Gas emitted from the beaver pond had similar characteristics to gas found in the annular space of the surface casing of Chesapeake's Mowry 2 gas well.

Y. Bubbling at the beaver pond continued from June 25, 2010, in diminishing amounts, to August 26, 2010.

Z. Chesapeake completed remedial work on their nearby gas wells between August 18, 2010, and August 30, 2010.

AA. Since August 26, 2010 to the present, no bubbling has been observed at the beaver pond.

Paradise Road Area

AB. On July 13, 2010, the Department became aware of water supply complaints by and ı, who reside on Paradise Road, Terry Township, Bradford County.

AC. On July 15, 2010, the Department investigated the complaints and collected groundwater samples at the] residences.

AD. On July 21, 2010, the Department became aware of a water supply complaint by also on Paradise Road, Terry Township, Bradford County. The Department investigated and collected samples of the well on the same day.

AE. On August 2 and 3, 2010, Chesapeake collected water samples and installed methane alarm systems at the residences.

AF. On August 6, 2010, the Department issued Chesapeake a Notice of Violation for the unpermitted discharge of polluting substances and failure to prevent the migration of gas into sources of fresh groundwater for the Paradise Road Area.

AG. Chesapeake has provided temporary replacement water, installed water well vent stacks, drilled replacement wells, and installed water treatment systems at the residences.

AH. Isotopic analyses of gas from a residence and water wells in the Paradise Road Area indicate that the gas at the homes is not microbial in origin and is consistent with isotopic analyses of gas found in the annular space of surface casing of Chesapeake's Welles gas wells.

Area

AI. On August 4, 2010, Chesapeake responded to a landowner complaint of possible methane intrusion in a water supply at a home on Brockton Road, Monroe Township, Bradford

County. Chesapeake responded and, that same day, notified the Department that methane was detected in three private water supplies and one home along Brockton Road.

AJ. On August 6, 2010, the Department confirmed the presence of methane in the headspace of the three home water wells along Brockton Road.

AK. On August 6, 2010, Chesapeake instituted a monitoring plan of certain residences in the area of Chesapeake's Dan Ellis well pad, which is located approximately 4,700 feet to the South.

AL. On August 6, 2010, the Department issued Chesapeake a Notice of Violation for the unpermitted discharge of polluting substances and the failure to prevent the migration of gas into sources of fresh groundwater for the Dan Ellis area.

Sugar Run Area

AM. On September 2, 2010, the Department received information of bubbling in the Susquehanna River near the community of Sugar Run, in Wilmot Township, Bradford County.

AN. On September 3, 2010, the Department inspected the Sugar Run Area and found gas bubbling at numerous locations in the Susquehanna River. A sample of the gas was collected and sent to an independent laboratory to be analyzed. In addition, the Department inspected numerous residential dwellings in the Sugar Run Area and found methane in several water supply wells.

AO. On September 3, 2010, Chesapeake began screening the locations of bubbling in the river, certain residential water wells, and soils in the Sugar Run Area.

AP. On September 7, 2010, the Department collected water samples from the potentially impacted water wells in the Sugar Run Area.

AQ. Chesapeake installed vent stacks on water supply wells at residences in the Sugar Run Area owned or occupied by and . Chesapeake also provided temporary replacement water for

AR. On September 9, 2010, the Department issued Chesapeake a Notice of Violation for the unpermitted discharge of polluting substances and the failure to prevent the migration of gas into sources of fresh groundwater for the Sugar Run Area.

Spring Hill Road Area

AS. On September 16, 2010, Chesapeake notified the Department that methane gas was detected in a water supply located along Spring Hill Road in Tuscarora Township, Bradford County.

AT. The nearest drilled Marcellus well, Chesapeake's Champdale well, is approximately 880 feet from the water supply referenced in paragraph AT, above.

AU. On September 24, 2010, the Department issued Chesapeake a Notice of Violation for the unpermitted discharge of polluting substances and the failure to prevent the migration of gas into sources of fresh groundwater for the Spring Hill Road Area, and for defective casing or cementing of the Champdale/Champluvier gas wells.

Residence

AV. On or about June 24, 2010, contacted Chesapeake with a complaint about their water at in Granville Township, Bradford County. Chesapeake initiated an investigation and determined that an elevated concentration of methane gas was present in the well headspace.

AW. A water sample collected from the water supply on June 26, 2010, indicated an elevated level of methane.

AX. On July 8, 2011, filed a complaint with the Department alleging her water supply had been impacted by gas drilling activity.

AY. On July 14, 2010, methane was detected in the headspace of the water well.

AZ. On September 15, 2010, the Department issued Chesapeake a Notice of Violation for the unpermitted discharge of polluting substances and the failure to prevent the migration of gas into sources of fresh groundwater.

Additional Investigations

AAA. Since August of 2010, the Department has inspected various Chesapeake gas wells in the Sivers, Dan Ellis, Paradise Road, Sugar Run, and Spring Hill Road Areas. As a follow-up and precaution, Chesapeake has perforated and squeezed additional cement behind the casing in a number of its gas wells in the subject areas.

AAB. In the course of its investigation, the Department has collected water samples from drinking water wells at residences in the Paradise Road, Dan Ellis, Sugar Run, and Spring Hill Road Areas. The Department also has collected isotopic gas samples to compare the gas from various gas wells drilled by Chesapeake to gas from various locations.

Determination of Discharge of Natural Gas into the Groundwater

AAC. Chesapeake has caused or allowed the unpermitted discharge of natural gas, a polluting substance, into the groundwater, which constitutes a "water of the Commonwealth" as that term is defined in 35 P.S. §691.1, in violation of Section 401 of the Clean Streams Law, 35 P.S. §691.401.

AAD. As of the date of this Consent Order and Agreement, Chesapeake has taken certain actions approved by the Department to prevent the ongoing, unpermitted discharge of natural gas into the waters of the Commonwealth.

Determination of Gas Migration Violations

AAE. Chesapeake failed to properly case and cement the gas wells and to prevent the migration of gas into sources of fresh groundwater in violation 25 Pa. Code §§ 78.73(a), 78.81(a), and 78.86, as in effect prior to February 5, 2011.

AAF. The violations described in Paragraphs AAC through AAE, above constitute unlawful conduct under the laws and regulations administered by the Department, including Section 509, of the Oil and Gas Act, 58 P.S. § 601.509 and Section 611 of the Clean Streams Law, 35 P.S. § 691.611; constitute a public nuisance under Section 502 of the Oil and Gas Act, 58 P.S. § 601, and Section 401 of the Clean Streams Law, 35 P.S. § 691.401; require restoration or replacement of certain water supplies pursuant to Section 208 of the Oil and Gas Act, 58 P.S. § 601.208 and 25 Pa. Code § 78.51; and subject Chesapeake to civil penalty liability under Section 506, of the Oil and Gas Act, 58 P.S. § 601.506 and Section 605 of the Clean Streams Law, 35 P.S. §§ 691.605.

Order

After full and complete negotiation of all matters set forth in this Consent Order and Agreement, and upon mutual exchange of the covenants contained herein, the parties desiring to avoid litigation and intending to be legally bound, it is hereby ORDERED by the Department and AGREED to by Chesapeake as follows:

1. **Authority.** This Consent Order and Agreement is an Order of the Department authorized and issued pursuant to Section 503, of the Oil and Gas Act, 58 P.S. § 601.503; Section 5 of the Clean Streams Law, 35 P.S. § 691.5; and Section 1917-A of the Administrative Code, supra.

2. **Findings.**

a. Chesapeake agrees that the findings in Paragraphs A through AAB above are true and correct and, in any matter or proceeding involving Chesapeake and the Department, Chesapeake shall not challenge the accuracy or validity of these findings.

b. The parties do not authorize any other persons to use the findings in this Consent Order and Agreement in any matter or proceeding.

c. Chesapeake disagrees with the determinations stated in Paragraphs AAC through AAF above.

3. **Corrective Actions.**

a. Within fourteen (14) days after the date of this Consent Order and Agreement, Chesapeake shall submit to the Department, for review and approval, a plan which:

1) includes a list of all gas wells drilled by or on behalf of Chesapeake in the areas depicted on Exhibit A and identifies the number of casings used in each well and the depth to which the strings of casing are set;

2) includes the defined logging protocol (hereinafter "wellbore evaluations") which Chesapeake shall employ to evaluate the integrity of wells appearing on the list submitted pursuant to Paragraph 3.a.1), identification of a hierarchy of the wells that will be so evaluated, and an explanation of the rationale for selecting the hierarchy of such wells, above;

3) includes an implementation schedule not to exceed six (6) months which sets forth, at a minimum, the date on which Chesapeake shall commence the wellbore evaluation on the wells identified for evaluation pursuant to Paragraph 3.a.2), above; and

4) identifies the actions Chesapeake shall take to analyze each and every gas well identified for evaluation pursuant to Paragraph 3.a.2), above, and recommendations for the rehabilitation work necessary to control and mitigate shut-in surface casing pressure and stray gas from those wells;

b. Within five (5) days of approval by the Department, Chesapeake shall implement the plan submitted pursuant to Paragraph 3.a., above, as approved by the Department;

c. Within seven (7) days of the date of the approval of the plan submitted pursuant to Paragraph 3.a, above, Chesapeake shall begin pressure testing of each accessible annuli on each of the gas wells identified for evaluation pursuant to Paragraph 3.a.2), above. Chesapeake shall pressure test each annuli for forty-eight (48) consecutive hours, and shall provide the test results for each tested well within five (5) days of completion of the pressure test on each respective well. At least twenty-four (24) hours before Chesapeake begins pressure testing in accordance with this Paragraph, Chesapeake shall provide the Department written notice of the gas well to be tested, and the date and approximate time that Chesapeake shall begin such pressure test.

d. Within sixty (60) days of the date of the approval of the plan submitted pursuant to Paragraph 3.a, above, in all cases Chesapeake shall have completed the 48-hour pressure test of the annuli on all of the gas wells identified pursuant to Paragraph 3.a.2), above, and shall provide the Department with the results of the pressure tests for all of those wells.

e. Every other Monday following the approval of the plan submitted pursuant to Paragraph 3.a., above, Chesapeake shall submit a report containing the following information for each well identified pursuant to Paragraph 3.a.2):

1) the status of the work at each well (i.e., 'Deemed Finished,' 'In Progress,' or 'Scheduled');

2) Chesapeake's analysis of each well's logs and recommended actions to be taken based on all of the information available to Chesapeake.

3) For wells In Progress:

i. the date logged; date or dates on which cement was squeezed; depth of squeezes; date and time the 48-hour casing pressure build-up test was started, supported by information in the form of a chart or digital recording;

ii. a daily well work activity summary, separate from any monitoring report, that includes a brief description of that work and of the wellhead's status; and

iii. Chesapeake's daily completion reports, including all of the days of work on each well.

f. Chesapeake's obligation to submit the weekly reports required in Paragraph 3.e. shall terminate when the Department determines in writing that Chesapeake has eliminated the unpermitted discharge of natural gas into the waters of the Commonwealth from any well owned and/or operated by Chesapeake within the areas of Bradford County identified in Paragraph D, above, in this Consent Order and Agreement.

4. **Specifications of New Wells.** All gas wells drilled by or on behalf of Chesapeake in the areas identified in Paragraph D, above on or after the date of this Consent Order and Agreement shall be cased and cemented in a manner consistent with the specifications and practices described in Exhibit D unless, based on conditions observed in advance of or at the time of drilling, Chesapeake determines that alternate specifications or practices are warranted.

In the event that Chesapeake determines that alternate specifications or practices are warranted, Chesapeake shall notify the Department of the alternate specifications or practices utilized.

5. **Installation of Pressure Gauges.** Within ninety (90) days after the date of this Consent Order and Agreement, Chesapeake shall install pressure gauges on all existing wells within the areas described in Paragraph D, above, at the surface and intermediate casing ports in a manner allowing pressures to be inspected at any time by the Department. Chesapeake shall install such gauges on all wells drilled by or on behalf of Chesapeake within the areas described in Paragraph D, above, on or after the date of this Consent Order and Agreement.

6. **Reporting Water Supply Complaints.** Attached as Exhibit B is a Protocol For Reporting Water Supply Complaints identifying (i) the procedures Chesapeake shall implement within the areas identified in Paragraph D, above, to report to the Department water supply complaints within twenty four (24) hours after Chesapeake receives any such complaint, in accordance with 25 Pa. Code § 78.51(h) (effective February 5, 2011); (ii) the actions Chesapeake shall take to investigate any such complaint; (iii) the information to be reported to the Department based on such investigation; and (iv) the timing and form of such reports. Chesapeake shall implement the plan for any future complaint within the areas identified in Paragraph D, above.

7. **Remediation of Water Supplies.**

a. Beginning upon execution of this Consent Order and Agreement, with respect to the water supplies listed on Exhibit C, Chesapeake shall:

1) at least once every two weeks, screen the well at each water supply listed in Exhibit C for percentage of free combustible gas, and sample the well at each of those water supplies, provided the landowner consents to such screening and sampling;

2) for each water sample collected at a water supply listed in Exhibit C, Chesapeake shall have the water sample analyzed in a Pennsylvania-accredited laboratory for dissolved methane, dissolved ethane, and dissolved propane;

3) Chesapeake shall continue to conduct the screening and sampling under Paragraph 7.a.1), above, once every two weeks at each water supply listed in Exhibit C, provided the landowner consents, until the results of the screenings and sampling done by the Department or by Chesapeake under Paragraph 7.a.1), above, show (A) that either no combustible free gas is present at the water supply's wellhead, or, that such levels of combustible free gas, if properly vented pursuant to applicable regulations and Department practice, do not pose a danger to persons or property *and* (B) that the concentration of dissolved methane is below 7 milligrams/liter. However, Chesapeake may petition the Department, based on information obtained in accordance with this Paragraph for a determination that the concentration of methane in the water supply is at background levels for the aquifer that supplies the water supply. Chesapeake may further petition the Department for a determination that the concentration of combustible free gas at the wellhead is at levels that do not present a danger to persons or property if properly vented according to applicable regulations and Department practice;

4) for each water supply that meets the standards under Paragraph 7.a.3), above, or for which a plan has been submitted and approved pursuant to Paragraph 7.b and 7.c, Chesapeake shall continue to screen each such water supply for free combustible gas and shall sample each such water supply at least once per quarter, and shall have the water sample analyzed in a Pennsylvania-

accredited laboratory for the parameters listed in Exhibit E, provided the landowner consents to such screening and sampling; and

5) unless the Department determines that the concentration of methane in the water supply is at background levels for the aquifer that supplies the water supply, Chesapeake shall continue such screenings and sampling under paragraph 7.a.4), above, for each quarter until the results of the screenings and sampling done by the Department and by Chesapeake under this Paragraph 7 show that, for eight consecutive quarters, seventy-five percent (75%) of the water samples within each monitoring point over time contain seven (7) milligrams per liter or less of dissolved methane (or meets the standard then prescribed by applicable regulations), and no individual water sample exceeds two times this standard.

b. If after 60 days beyond the date of this Consent Order and Agreement, the dissolved methane is equal to or greater than 7 mg/l, or the measured free gas in the headspace is greater than 25% of the L.E.L., then Chesapeake shall submit to the Department for review and approval a plan and schedule to address each water supply listed on Exhibit C, including such remedial actions as Chesapeake may already have implemented. The quality of a restored or replaced water supply will be deemed adequate if it meets the standards established under the Pennsylvania Safe Drinking Water Act (35 P.S. §§ 721.1—721.17), or is comparable to the quality of the water supply before it was affected if that water supply did not meet these standards. Despite the filing of such a plan, Chesapeake shall remain obligated to monitor and screen such water supplies as required by this Paragraph 7.

c. Within fourteen (14) days of the Department's approval of any plan submitted pursuant to Paragraph 7.b., above, Chesapeake shall fully implement that plan as approved by the Department, subject to any determination by the Department that the concentration of methane in the water supply is at background or otherwise acceptable levels for the aquifer that supplies the water supply and the concentration of combustible free gas at the wellhead is at levels that do not present a danger to persons or property if properly vented according to applicable regulations and Department practice.

d. In the event that the owner of a residence identified in Exhibit C does not allow Chesapeake to fully implement the plan approved by the Department pursuant to Paragraph 7.d., above, then for each such residence Chesapeake shall establish an escrow account, or a common account for all such residences, in an amount approved by the Department to be used for the exclusive purpose of funding all of the expenses associated with providing either a treatment system or a replacement permanent water supply to the residence(s).

e. Chesapeake shall be responsible for paying any fees, charges, or taxes associated with every required escrow account or any common account.

f. Chesapeake shall maintain each escrow account, or the common account, until such time as the occupants of the residence(s) for which the account has been established notify Chesapeake in writing that installation of a treatment system or a replacement permanent water supply either has occurred at the residence owner's expense, or the funds in the escrow account may be used to install a permanent water supply at the residence.

g. Within thirty (30) days of the Department's receipt of notice that the funds in an escrow account may be used to install a treatment system or a replacement permanent water supply at a residence, Chesapeake shall make all necessary arrangements with any necessary vendors or contractors for the purchase and installation of a treatment system or replacement permanent water supply at the residence at issue. Chesapeake shall provide copies of the paid invoice(s) from the vendors or contractors to the Department.

h. Within fourteen (14) days of receiving the paid invoice(s) for the purchase and installation of the treatment system or replacement permanent water supply, the Department shall draw on the appropriate escrow account, or the common account, in the amount necessary to reimburse Chesapeake for the payments to the vendors or contractors for such.

i. Following the purchase and installation of any system or water supply using funds drawn against an escrow account, Chesapeake shall maintain the escrow account to secure the long term operation and maintenance expenses of such systems or supply.

j. In the absence of any notification referenced in Paragraph 7.g., Chesapeake shall maintain each escrow account, or the common account, until such time as other arrangements for disposition of the escrow account are made by the Department.

8. **Sampling Protocol.** All water samples gathered and analyzed by or on behalf of Chesapeake, and submitted to the Department pursuant to this Consent Order and Agreement, shall be collected in accordance with the following protocol, or other method approved by the Department:

After purging the well, fill the 5 gallon bucket with water. Attach a nozzle and 12" length of ¼ inch diameter tubing to the end of the 5/8 inch hose connected to a faucet. Make sure that the flow rates through the tubing are low. Remove the cap of the 1 L bottle (or vial) and fill it with water. Once the bottle filled, immerse it in the 5 gallon bucket full of water, keeping the tubing at the bottom of the bottle. Place the bottle at the bottom of the bucket under a head of water, and keep water flowing at a low rate until another 2 volumes of water have been displaced from the bottle. Then slowly lift the tubing out of the bottle and immediately cap it under water. No air should be allowed into the 1 L bottle. When finished, tape the cap to the bottle around the neck, pack the bottle upside down in ice, and ship it overnight.

9. **Submission of Documents.** With regard to any document that Chesapeake is required to submit pursuant to this Consent Order and Agreement, the Department will review Chesapeake's document and will approve, modify or disapprove the document, or a portion thereof, in writing. If the document, or any portion of the document, is found to be deficient by the Department, within 14 days of receipt of the deficiencies, Chesapeake shall submit a revised document to the Department that addresses the Department's concerns. The Department will approve, modify or disapprove the revised document in writing. Upon approval by the Department, the document, and any schedule therein, shall become a part of this Consent Order and Agreement for all purposes and shall be enforceable as such.

10. **Civil Penalty Settlement.** In settlement of any claim for civil penalties which the Department is authorized to pursue under law, including Section 506 of the Oil and Gas Act, 58 P.S. § 601.506, and Section 605 of the Clean Streams Law, 35 P.S. §§ 691.605, the Department hereby assesses a civil penalty of Seven Hundred Thousand Dollars ($700,000) for the violations set forth in the Findings, above. The payment shall be made by corporate check or the like, made payable to the "Commonwealth of Pennsylvania," and forwarded to the Department pursuant to Paragraph 17, below, or by an alternate method approved by the Department, within five days of execution of the Consent Order and Agreement.

11. **Donation to Well Plugging Fund.** Chesapeake agrees to donate Two Hundred Thousand Dollars ($200,000) to the Department's Well Plugging Fund. Chesapeake shall make such payment in the manner described in Paragraph 10, within five days of execution of the Consent Order and Agreement.

12. **Stipulated Civil Penalties.**

a. **If Chesapeake fails to comply with any provision of this Consent Order and Agreement, Chesapeake shall be in violation of this Consent Order and Agreement and, in addition to other applicable remedies, shall pay a civil penalty as follows:** If Chesapeake fails to comply with any obligation imposed upon it pursuant to this Consent Order and Agreement, Chesapeake shall be in violation of this Consent order and Agreement, and, in addition to other applicable remedies, shall pay a civil penalty in the amount of One Thousand Dollars ($1000) per day for each day, or any portion thereof, that Chesapeake fails to comply with its obligation.

b. Stipulated civil penalties shall be due automatically without further notice on or before the 15th day of each succeeding month, shall be made by corporate check or the like made payable to "Commonwealth of Pennsylvania," and shall be sent to the Department at the address set forth in Paragraph 17, below.

c. Any payment under this Paragraph shall neither waive Chesapeake's duty to meet its obligations under this Consent Order and Agreement, nor preclude the Department from commencing an action to compel Chesapeake's compliance with the terms and conditions of this Consent Order and Agreement for which payment is made.

13. **Additional Remedies.**

a. In the event Chesapeake fails to comply with any provision of this Consent Order and Agreement, the Department may, in addition to the remedies prescribed herein, pursue any remedy available for a violation of an order of the Department.

b. The remedies provided by this paragraph and Paragraph 12 (Stipulated Civil Penalties) are cumulative and the exercise of one does not preclude the exercise of any other. The failure of the Department to pursue any remedy shall not be deemed to be a waiver of that remedy. The payment of a stipulated civil penalty, however, shall preclude any further assessment of civil penalties for the violation for which the stipulated civil penalty is paid.

14. **Reservation of Rights.** The Department reserves the right to require additional measures to achieve compliance with applicable law. Chesapeake reserves the right to challenge any action which the Department may take to require those measures.

15. **Liability of Chesapeake.** Chesapeake shall be liable for any violations of the Consent Order and Agreement, including those caused by, contributed to, or allowed by its officers, directors, agents, employees, contractors, successors, and assigns.

16. **Transfer of Gas Wells.**

a. Chesapeake's duties and obligations under this Consent Order and Agreement shall not be modified, diminished, terminated or otherwise altered by the transfer of any legal or equitable interest in any of the gas wells identified on the list submitted pursuant to paragraph 3.a.1), above, or any other Chesapeake gas wells covered hereby.

b. If before the termination of this Consent Order and Agreement, Chesapeake intends to transfer any legal or equitable interest in any of the gas wells on the list submitted pursuant to paragraph 3.a.1), above, Chesapeake shall provide a copy of this Consent Order and Agreement to the prospective transferee at least thirty (30) days prior to the contemplated transfer and shall simultaneously inform the Department of such intent at the address set forth in Paragraph 17, below.

c. The Department, in its discretion, may agree to modify or terminate Chesapeake's duties and obligations under this Consent Order and Agreement and may agree to a transfer upon determination that Chesapeake is in full compliance with this Consent Order and Agreement, including payment of any stipulated penalties owed, and upon the transferee entering into a Consent Order and Agreement with the Department concerning the gas wells at issue. Chesapeake agrees to waive any right that it may have to challenge the department's decision in this regard.

17. **Correspondence with Department.** All correspondence with the Department concerning this Consent Order and Agreement shall be addressed to:

Jennifer W. Means
Environmental Program Manager
Eastern Region Oil and Gas Management
Department of Environmental Protection
208 West Third Street – Suite 101
Williamsport, PA 17701-6448
Phone (business hours): (570) 321-6557
Phone (non-business hours): (570)327-3636
e-Mail: jenmeans@state.pa.us

18. **Correspondence with Chesapeake.** All correspondence with Chesapeake concerning this Consent Order and Agreement shall be addressed to:

Tal Oden
Regulatory Manager North, East Division
Chesapeake Energy Corporation
P.O. Box 18496
Oklahoma City, OK 73154
Phone: (405) 935-4073
e-Mail: tal.oden@chk.com

Chesapeake shall notify the Department whenever there is a change in the contact person's name, title, or address. Service of any notice or any legal process for any purpose under this

Consent Order and Agreement, including its enforcement, may be made by mailing a copy by first class mail to the above address.

19. **Severability.** The paragraphs of this Consent Order and Agreement shall be severable and should any part hereof be declared invalid or unenforceable, the remainder shall continue in full force and effect between the parties.

20. **Entire Agreement.** This Consent Order and Agreement shall constitute the entire integrated agreement of the parties. No prior or contemporaneous communications or prior drafts shall be relevant or admissible for purposes of determining the meaning or intent of any provisions herein in any litigation or any other proceeding.

21. **Attorneys Fees.** The parties shall bear their respective attorney fees, expenses and other costs in the prosecution or defense of this matter or any related matters, arising prior to execution of this Consent Order and Agreement.

22. **Modifications.** No changes, additions, modifications, or amendments of this Consent Order and Agreement shall be effective unless they are set out in writing and signed by the parties hereto.

23. **Titles.** A title used at the beginning of any paragraph of this Consent Order and Agreement may be used to aid in the construction of that paragraph, but shall not be treated as controlling.

24. **Decisions under Consent Order and Agreement.** Except for Paragraph 16.c., above, any decision which the Department makes under the provisions of this Consent Order and Agreement, including a notice that stipulated civil penalties are due, is intended to be neither a final action under 25 Pa. Code § 1021.2, nor an adjudication under 2 Pa. C.S. § 101. Any objection which Chesapeake may have to the decision will be preserved until the Department enforces this Consent Order and Agreement.

25. **Termination.** Chesapeake's obligations, but not the Findings, of this Consent Order and Agreement shall terminate when the Department provides written notice that Chesapeake has completed all of the requirements of this Consent Order and Agreement, and has paid any outstanding stipulated civil penalties due under Paragraph 12, above.

26. **Execution of Agreement.** This Consent Order and Agreement may be signed in counterparts, each of which shall be deemed to be an original and all of which together shall constitute one and the same instrument. Facsimile signatures shall be valid and effective.

IN WITNESS WHEREOF, the parties hereto have caused this Consent Order and Agreement to be executed by their duly authorized representatives. The undersigned representatives of Chesapeake certify under penalty of law, as provided by 18 Pa. C.S. § 4904, that they are authorized to execute this Consent Order and Agreement on behalf of Chesapeake; that Chesapeake consents to the entry of this Consent Order and Agreement as a final Order of the Department; and that Chesapeake hereby knowingly waives its rights to appeal this Consent Order and Agreement and to challenge its content or validity, which rights may be available under Section 4 of the Environmental Hearing Board, the Act of July 13, 1988, P.L. 530, No. 1988-94, 35 P.S. § 7514; the Administrative Agency Law, 2 Pa. C.S. § 103(a) and Chapters 5A and 7A; or any other provision of law.

Signature by Chesapeake's attorney certifies only that the agreement has been signed after consulting with counsel.

FOR CHESAPEAKE APPALACHIA, L.L.C.:

13MAY11

John K. Reinhart (Date)
Vice President, Operations-Eastern Division

5-13-11

Craig P. Wilson, Esq. (Date)
Attorney for Chesapeake Appalachia, L.L.C.

FOR THE COMMONWEALTH OF PENNSYLVANIA, DEPARTMENT OF ENVIRONMENTAL PROTECTION:

5/13/11

Jennifer W. Means (Date)
Environmental Program Manager
East Region Oil & Gas Management

5/13/2011

Geoffrey J. Ayers (Date)
Regional Counsel
Northcentral Region

5/16/11

David J. Raphael (Date)
Chief Counsel
Department of Environmental Protection

Exhibit A

Maps of:

Miller/ Area

Sivers Area

Paradise Road Area

Dan Ellis Area

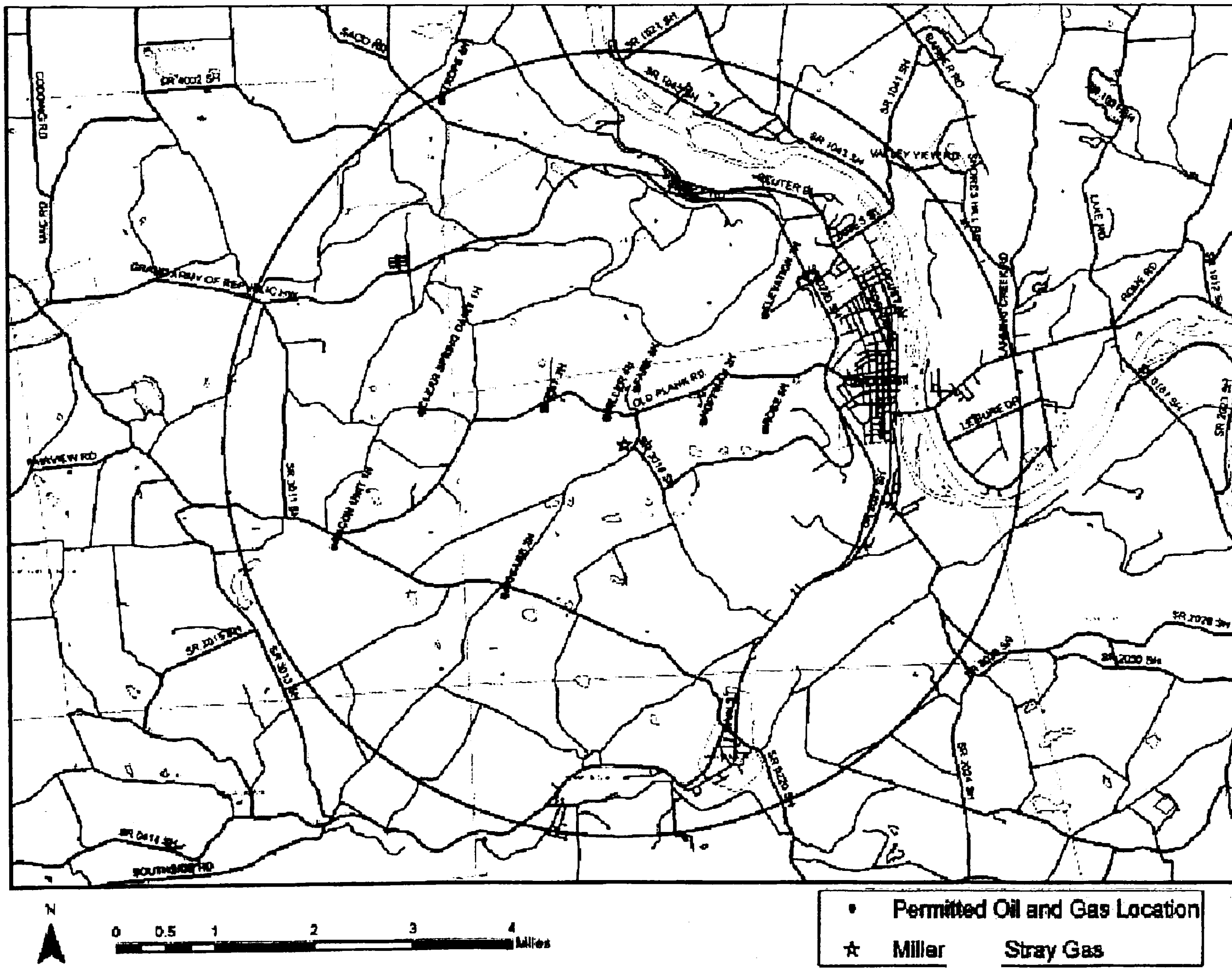
Sugar Run Area

Spring Hill Area

Area

9/27/2010

Miller / Stray Gas Area - 4 Mile Radius

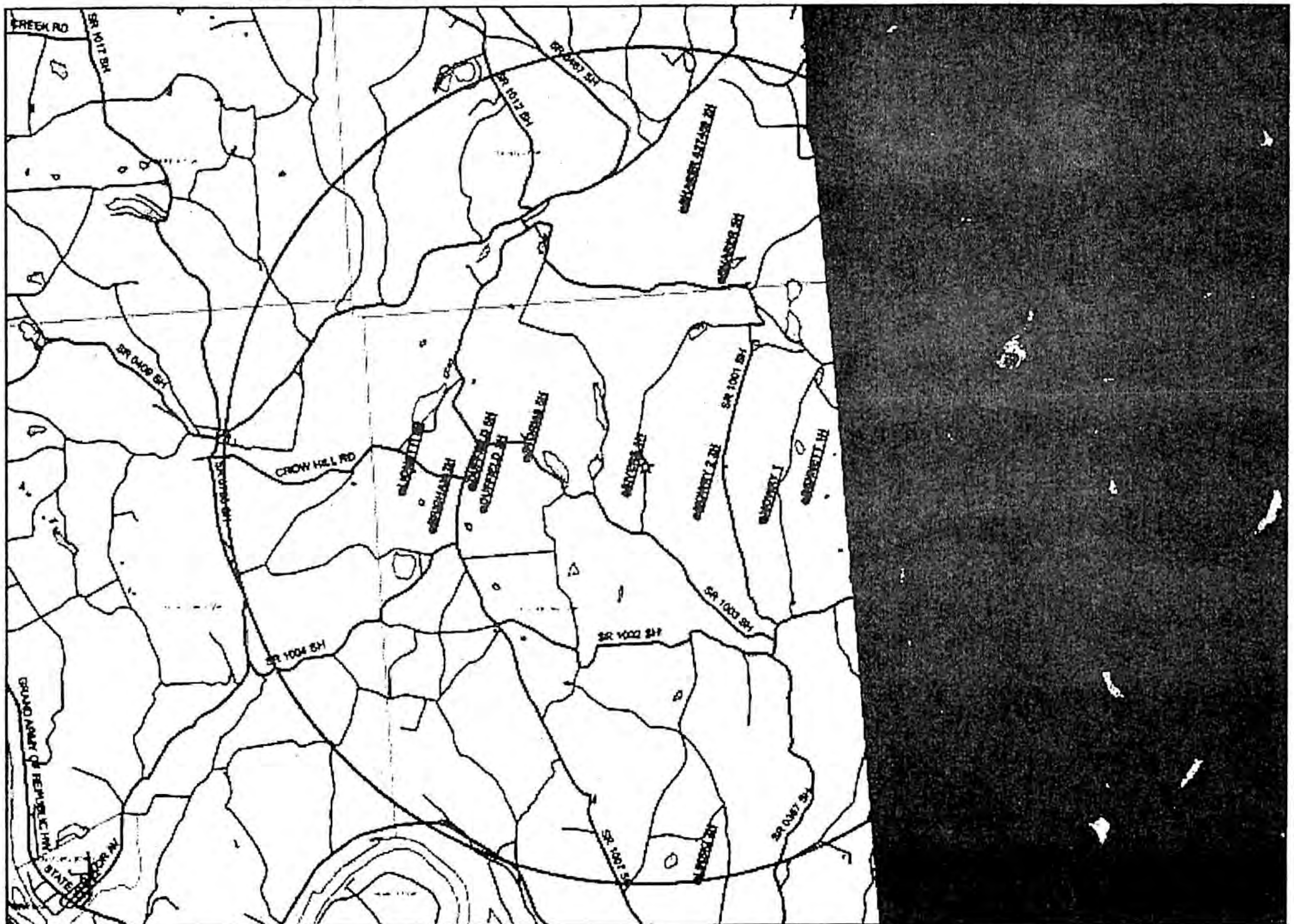


•	Permitted Oil and Gas Location
☆	Miller Stray Gas

*Permitted Oil and Gas Locations may contain multiple wells per location. Refer to attached table.

9/27/2010

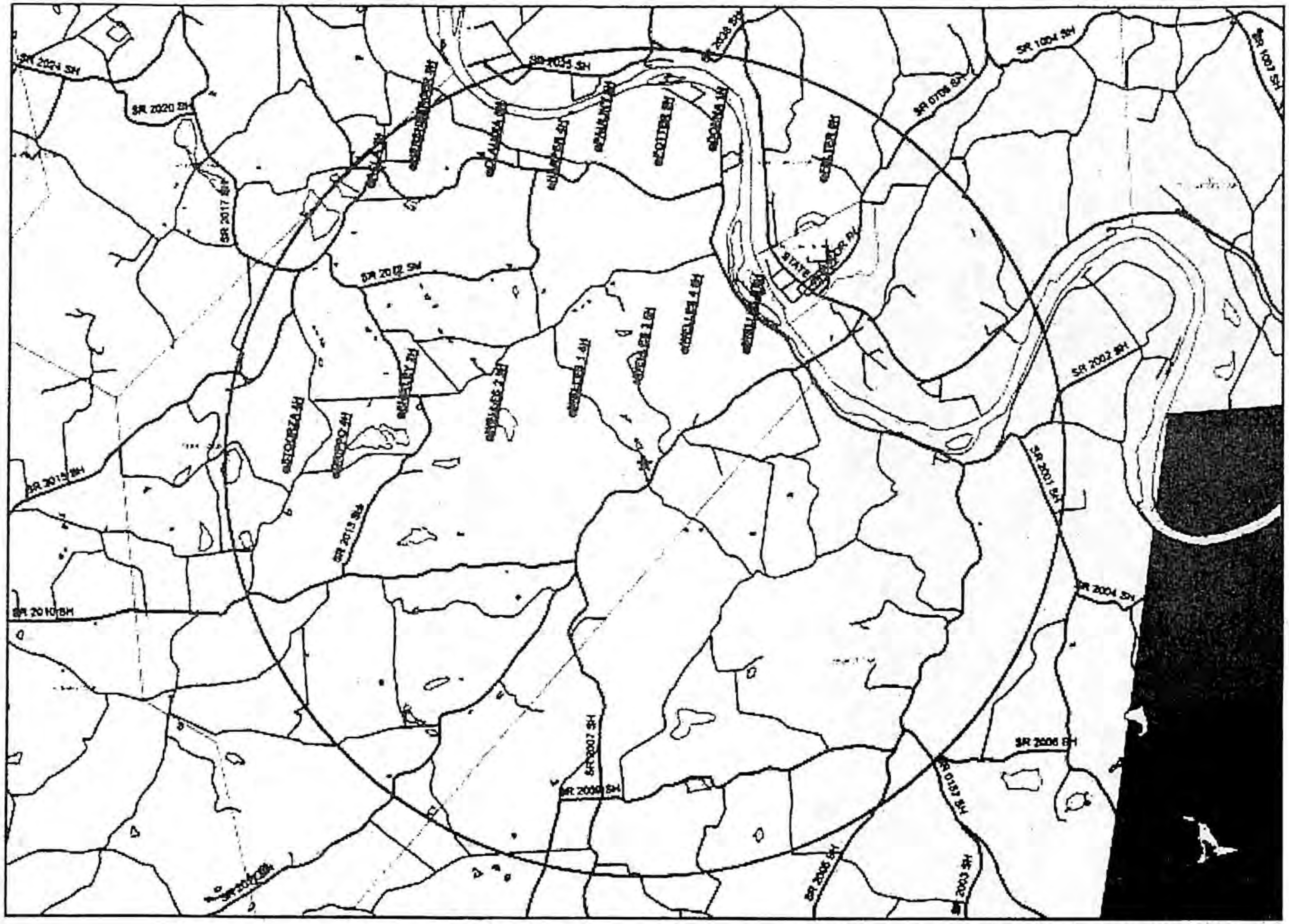
Sivers Beaver Pond Stray Gas Area - 4 Mile Radius



☆	Sivers Beaver Pond Stray Gas
•	Permitted Oil and Gas Wells

*Permitted Oil and Gas Locations mat contain multiple wells per location. Refer to attached table.

Paradise Rd Stray Gas Area - 4 Mile Radius



N

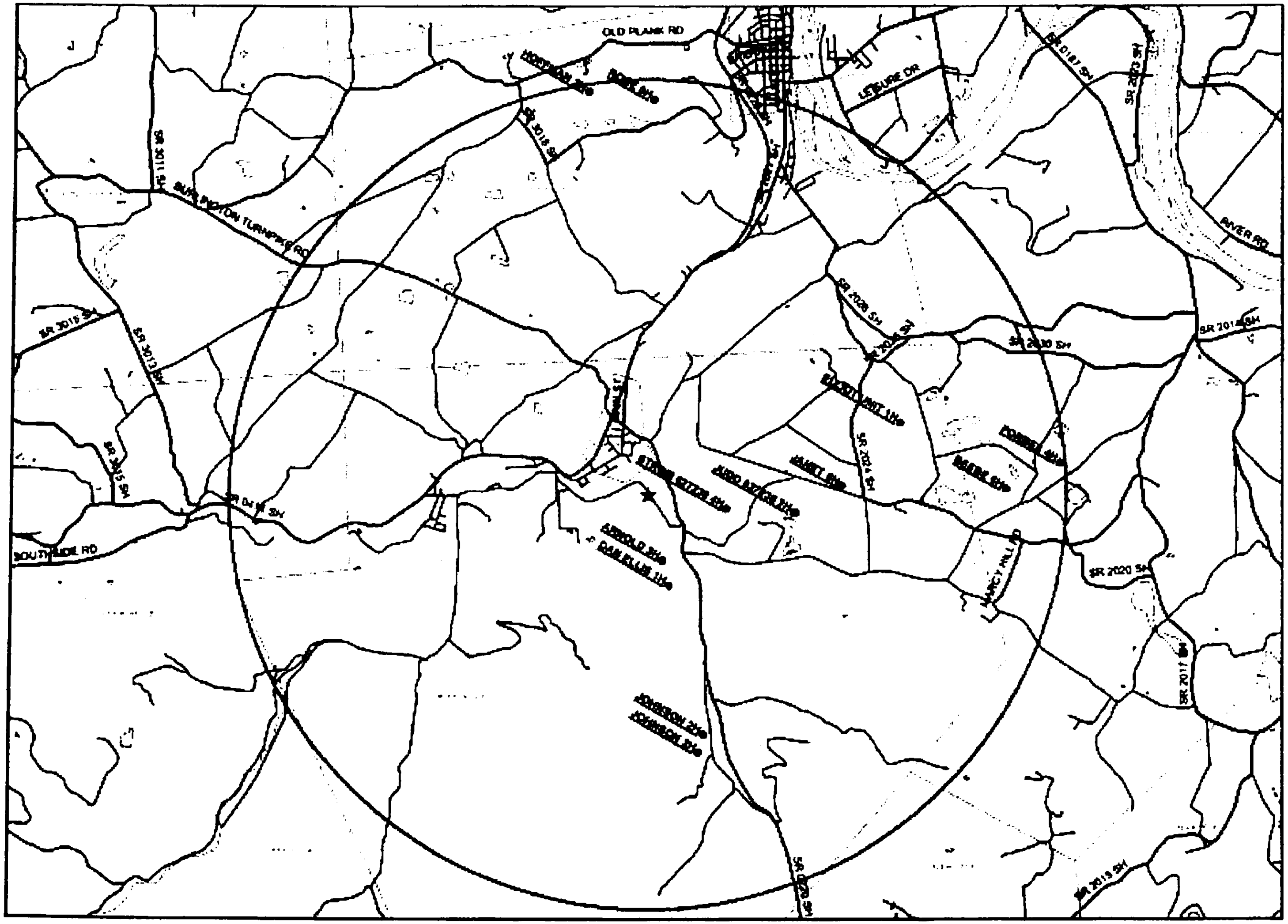
0 0.5 1 2 3 4 Miles

- • Permitted Oil and Gas Location
- ★ Paradise Rd Stray Gas

*Permitted Oil and Gas Locations may contain multiple wells per location. Refer to attached table

9/27/2010

Dan Ellis / Brocktown Rd Stray Gas Area - 4 Mile Radius



N

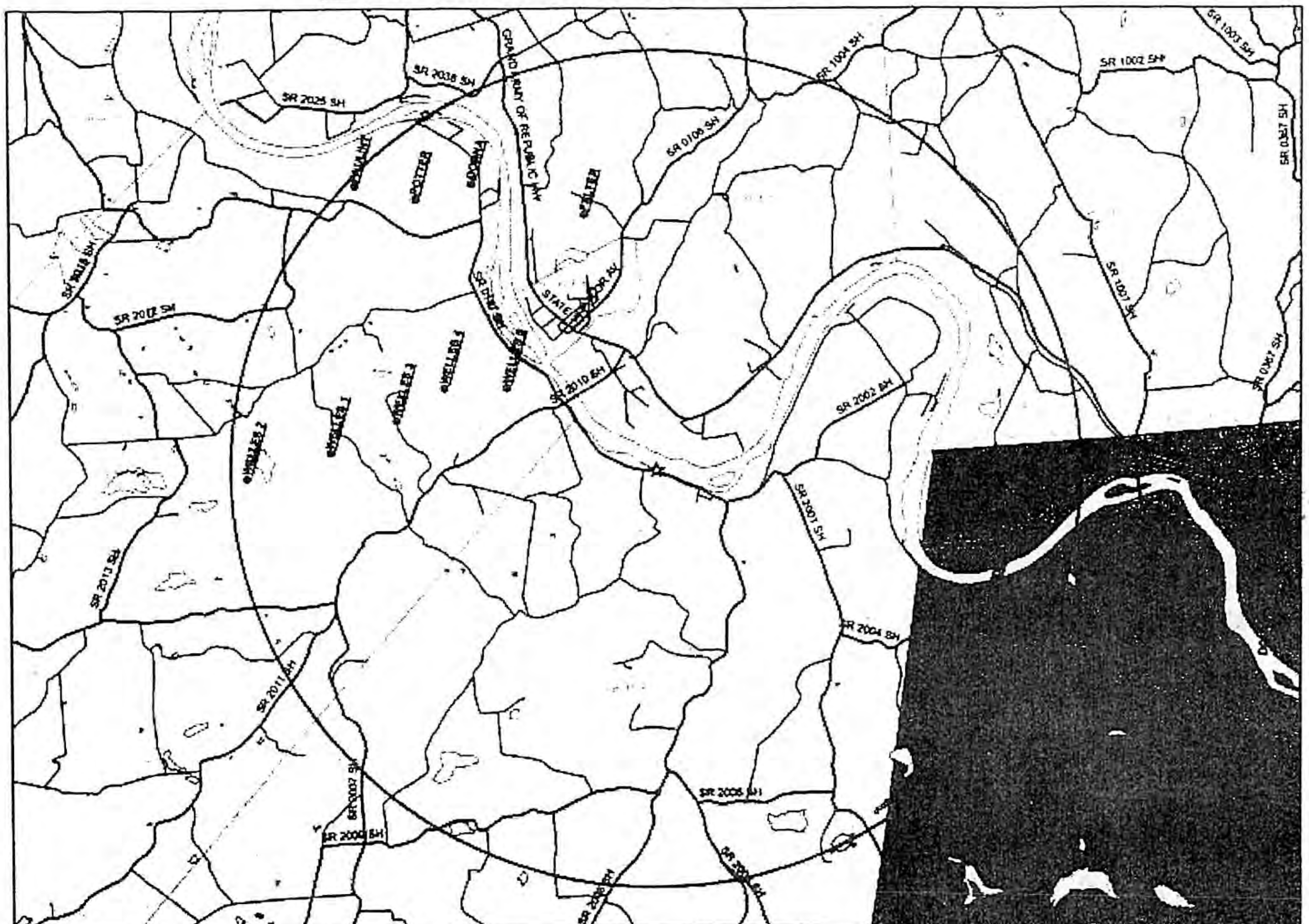
0 0.5 1 2 3 4 Miles

- • Permitted Oil and Gas Locations
- ★ Dan Ellis Brocktown Stray Gas

*Permitted Oil and Gas Locations mat contain multiple wells per location. Refer to attached table.

9/27/2010

Sugar Run Stray Gas Area - 4 Mile Radius



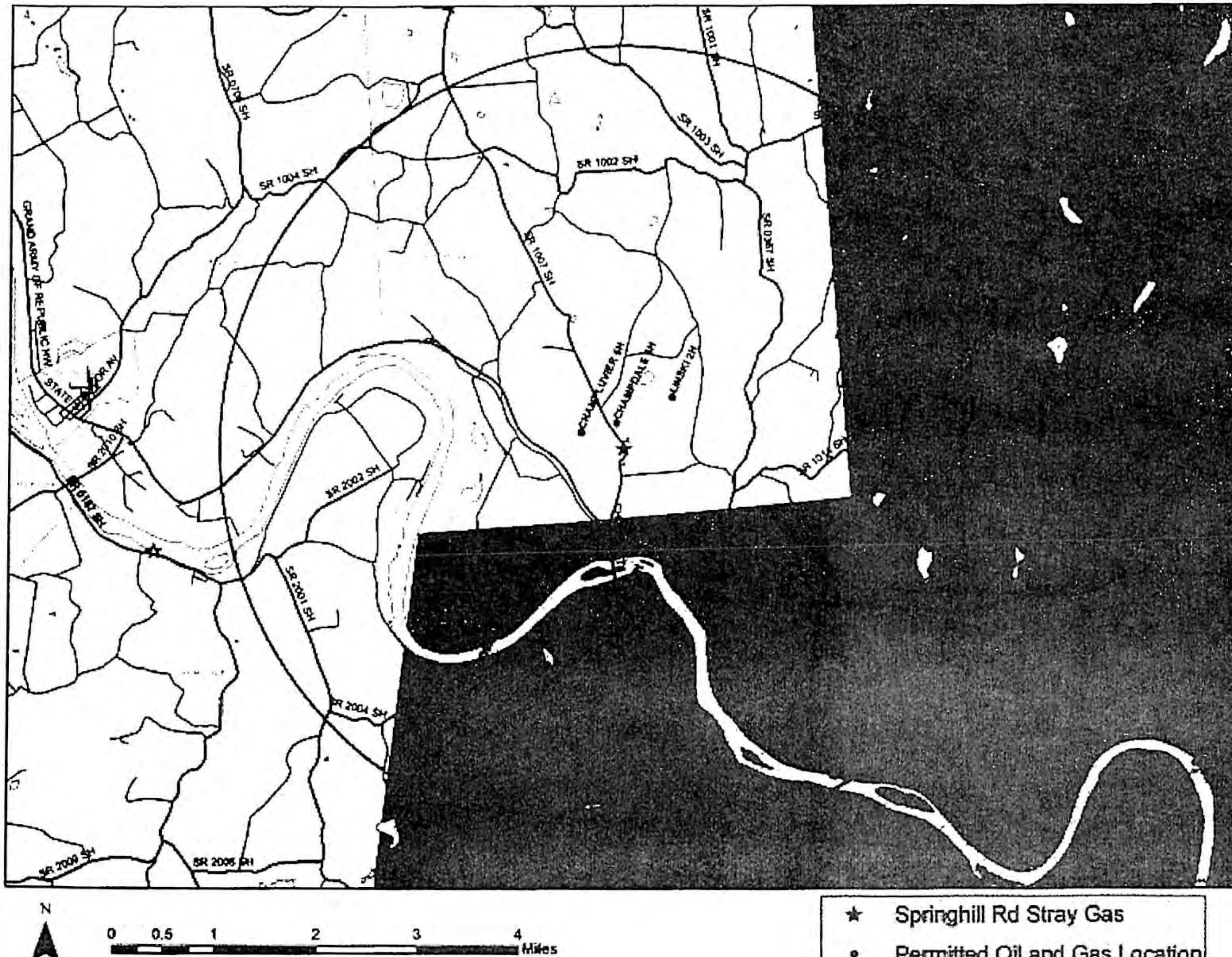
☆ Sugar Run Stray Gas

• Permitted Oil and Gas Location

*Permitted Oil and Gas Locations mat contain multiple wells per location. Refer to attached table.

9/27/2010

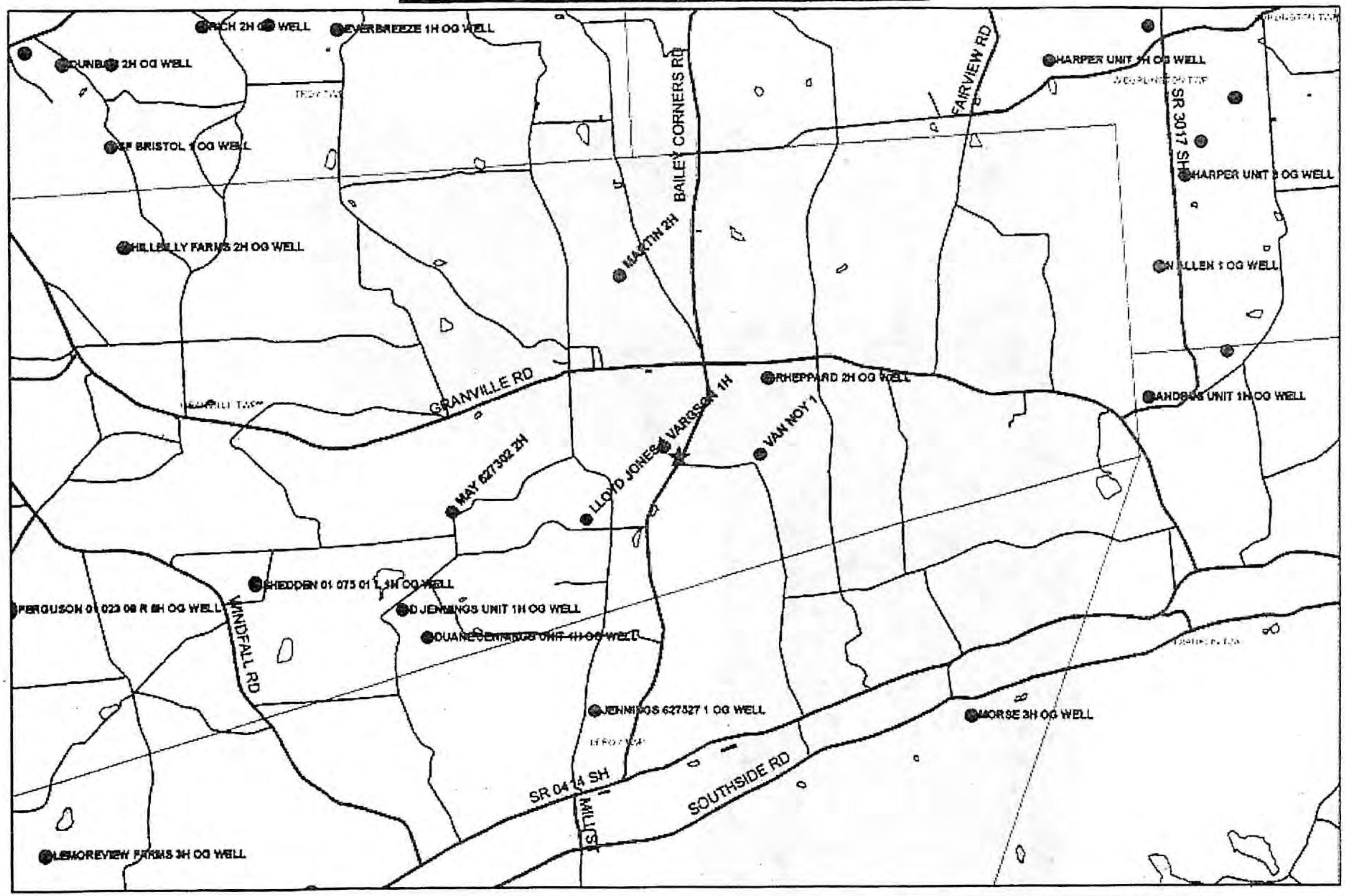
Springhill Rd Stray Gas Area - 4 Mile Radius



★	Springhill Rd Stray Gas
•	Permitted Oil and Gas Location

*Permitted Oil and Gas Locations mat contain multiple wells per location. Refer to attached table.

Granville Twp., Bradford County



0 0.5 1 2 3 4 Miles

N

- Investigated Gas Wells
- Oil and Gas Well
- Water Supply

4/12/2011

EXHIBIT B

PROTOCOL FOR REPORTING WATER SUPPLY COMPLAINTS

(1) Reporting of water supply complaints – combustible gas detected = 10 % LEL

If combustible gas is detected inside a building or structure at a concentration equal to or greater than 10 % LEL, then (A) immediate notification shall be made to the Department, (B) a report shall be filed with the Department by phone and email within 24 hours after the interview with the complainant and field survey of the extent of natural gas, and (C) weekly reports shall be provided to the Department in accordance with (3) and (4) below.

(2) Investigating water supply complaints

All investigations of potential gas migration incidents shall be conducted in accordance with 25 Pa. Code § 78.89, or as subsequently prescribed by applicable regulation.

(3) Information to be reported to the Department

Weekly reports required by (1)(C) above shall include, in addition to what is required pursuant to 25 Pa. Code § 78.89, the following:

(A) The location and type of all gas monitoring equipment installed;

(B) Results of methane readings, if any, in tabular form and including % of methane by volume and % of LEL, from each potentially affected location (water wells, headspace, surface water);

(C) Results of water chemistry data from water well samples and surface water samples, when available, including the location of each sampling point; and

(D) An explanation of any corrective actions undertaken, including a description of any equipment installed.

The first weekly report submitted in connection with any investigation shall identify the nearest Chesapeake gas well and include the following well construction information: well depth, number of casings, length of each casing string, wellbore evaluation results, caliper logs, and cement returns.

The first weekly report submitted in connection with any investigation also shall identify the latitude and longitude and street address of each home, business, farm, water well, surface water body, and structure implicated by the complaint, and the owner or occupier of such.

(4) Timing and form of reports

Weekly reports required by (1)(C) above shall bc submitted each Monday, beginning one week after the 24-hour report has been made to the Department in accordance with (1)(B) above. The obligation to submit weekly reports shall continue until a final report is submitted for the incident.

EXHIBIT C

List of Water Supplies

Determination letters pursuant to Section 208(b) of the Oil and Gas Act

Sugar Run

Sugar Run, PA	18846
Sugar Run, PA	18846
Sugar Run, PA	18846
Sugar Run, PA	18846
Sugar Run, PA	18846
Sugar Run, PA	18846
Gettysburg, PA	17325

Paradise Rd

Wyalusing, PA	18853
Wyalusing, PA	18853
Wyalusing, PA	18853

Brocktown/Dan Ellis

Monroeton, PA	18832
Monroeton, PA	18832
Monroeton, PA	18832

Springhill Rd

Laceyville, PA	18623
Laceyville, PA	18623

Vargson

Granville Summitt, PA	16926

No determination letter

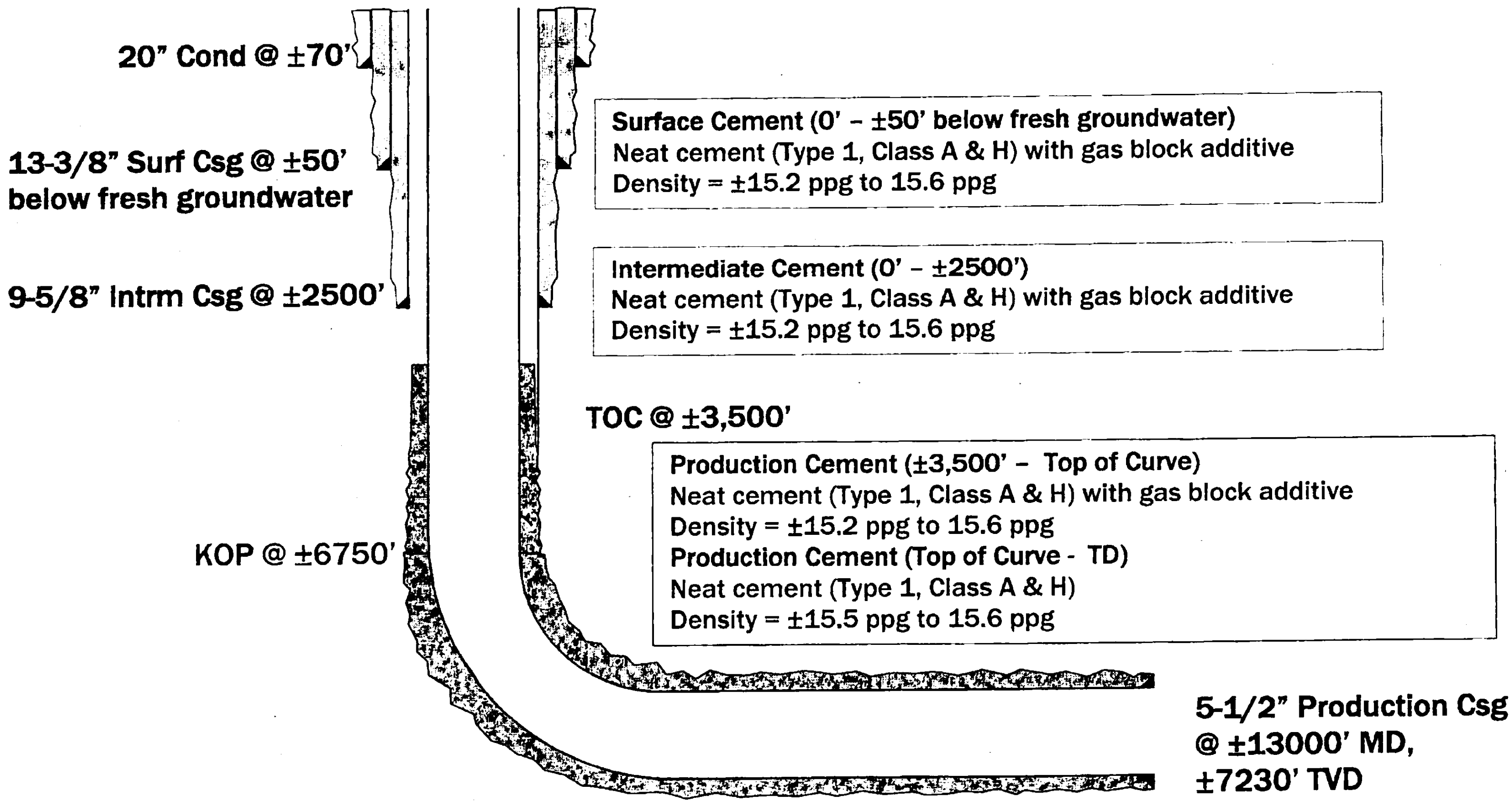
Sugar Run

Sugar Run, PA	18846

EXHIBIT D

SPECIFICATIONS AND PRACTICES FOR CASING AND CEMENTING

Well Casing and Cement Illustration



Cementing Practices

Conductor

- 26" Hole to minimum depth of ±70'.
- 20" Conductor to be cemented with High Density Cement.
- Record all fresh ground water encountered in the Driller's Log Book.

Surface Section

- 17-1/2" hole to be drilled to minimum of ±50' below base of fresh ground water. In the absence of other data, the depth of fresh ground water is determined primarily by using the known depths of surrounding water wells within a ±2500' radius, and correcting for elevation differences.
- Record all fresh ground water encountered in the Driller's Log Book.
- Circulate and condition hole.
- Run new string of 13-3/8" surface casing.
- Run centralizers in the middle and top of the first joint, top of third joint, and every third to surface.
- Pump ±35 bbls of gelled spacer, ±100 bbls of fresh water, drop bottom plug.
- Pump High Density Cement with gas block additive.
- Drop top plug and displace with water at maximum rate.
- Record volume of cement to surface in the Driller's Log Book.
- Wait on cement for 8 hrs.
- Performing FIT to 15 ppg EMW on surface casing (squeeze shoe if less than 15 ppg EMW).

Cementing Practices (continued)

Intermediate Section

- 12-1/4" hole to be drilled to intermediate casing depth. Intermediate depth is typically at a minimum of ±2000', but is well specific and is based on various data sources and geologic interpretation.
- Circulate and condition hole.
- Run new string of 9-5/8" intermediate casing.
- Run centralizers in the middle and top of the first joint, top of third joint, and every third to surface.
- Reciprocate casing throughout the cement job.
- Pump ±35 bbls of gelled spacer, ±100 bbls of fresh water, drop bottom plug.
- Pump High Density Cement with gas block additive.
- Drop top plug and displace with water at maximum rate.
- Record volume of cement to surface in the Driller's Log Book.
- Wait on cement for 8 hrs.
- Performing FIT to 16 ppg EMW on intermediate casing (squeeze shoe if less than 16 ppg EMW).

Cementing Practices (continued)

Production Section

- 8-3/4", 8-1/2", or 7-7/8" hole to be drilled to casing depth.
- Run new string of 5-1/2" production casing.
- Run centralizers at least from end of curve to TOC on every second joint.
- Prior to cementing, circulate at least three bottoms up annular volumes.
- If possible, reciprocate and rotate casing throughout the cement job.
- Pump minimum of ±50 bbls of weighted chem wash at ±14.0 ppg.
- Drop bottom plug.
- Pump High Density Cement with gas block additive from above curve to TOC.
- Drop top plug and displace with water at maximum rate.
- Wait on cement for 8 hrs and attempt to hold 250 psi on annulus.

EXHIBIT E

STANDARD ANALYSIS CODE 942 LIST OF PARAMETERS

SPECIFIC CONDUCTIVITY @ 25.0 C
pH, LAB (ELECTROMETRIC)
ALKALINITY TOTAL AS CACO3 (TITRIMETRIC)
TOTAL DISSOLVED SOLIDS (TDS)
HARDNESS TOTAL (Calculated)
CALCIUM, TOTAL BY TRACE ELEMENTS IN WATERS & WASTES
MAGNESIUM, TOTAL BY TRACE ELEMENTS IN WATERS &
SODIUM, TOTAL BY TRACE ELEMENTS IN WATERS & WASTES
POTASSIUM, TOTAL BY TRACE ELEMENTS IN WATERS &
CHLORIDE, TOTAL
BARIUM, TOTAL BY TRACE ELEMENTS IN WATERS & WASTES
IRON, TOTAL BY TRACE ELEMENTS IN WATERS & WASTES BY
MANGANESE, TOTAL BY TRACE ELEMENTS IN WATERS &
STRONTIUM, TOTAL BY TRACE ELEMENTS IN WATERS &
TURBIDITY
METHANE
ETHANE
PROPANE

Gas Safety Incorporated
16 Brook Lane
Southborough, Massachusetts 01772
774-922-4626 www.gassafetyusa.com

Report to

Damascus Citizens for Sustainability
25 Main Street
Narrowsburg, New York 12764

Report on a Survey of Ground-Level Ambient Methane Levels in the Vicinity of Wyalusing, Bradford County, Pennsylvania

November 2013

by

Bryce F. Payne Jr.[1] and Robert Ackley[2]

[This report is subject to revision.]

NOTE: Figures follow text.

There have been numerous reports of methane emissions related to shale gas development in the vicinity of Wyalusing, Bradford County, Pennsylvania. In the interest of furthering the understanding of those fugitive methane events Damascus Citizens for Sustainability engaged Gas Safety, Inc. to survey ambient air methane levels in the vicinity of Wyalusing, PA. The survey covered parts of 9 townships on both sides of the Susquehanna River (Figure 1 –

[1] Consulting and research in environmental science since 1992. Associate Research Professor, Dept. Environmental Engineering and Earth Sciences, Wilkes University, Wilkes-Barre, PA and Senior Fellow of the Wake Forest University Center for Energy, Environment, and Sustainability, Winston-Salem, NC. bryce.payne@wilkes.edu

[2] President of Gas Safety, Inc. with 30 years experience in gas leak detection and measurement, related regulatory compliance, and training. bobackley@gassafetyusa.com

following text) from Towanda on the northwest to Wyalusing on the central eastern side. Survey coverage was restricted to readily identifiable public roadways. Consequently, the survey was most intense from the Susquehanna River west to Pennsylvania Route 187.

Though the survey results do not prove a relationship between ambient air methane contamination and groundwater contamination, it is clearly suggestive. Further, it also suggests shale gas well operations in that area still did not have control of the gas that has been developed there. In fact, as will be discussed, survey data indicates there may be gas control problems in about 10% of the survey area resulting in elevated methane levels in most of the area.

In addition, detection of any level of methane above normal background for an area indicates only two possible conditions: diffuse, non-point emissions are occurring over some portion of the area, or, one or more point sources are active within the area.

Conditions during the Survey

The survey effort involved two separate survey field work efforts, one on 31 January and the other 3-4 June 2013. Weather conditions at the time of the January survey were not ideal. Winds were from the west at speeds consistently near 20 miles per hour (29 feet per second). Under these conditions methane emissions from any source disperse rapidly. Consequently, elevated methane levels due to such emissions are more difficult to detect than under more favorable wind conditions. Functionally this means that, during a road survey, detection of elevated methane levels requires the sources be larger or more intense and in closer proximity to the survey vehicle path than under more favorable wind conditions. However, such wind conditions do cause methane emissions to be swept along the ground surface farther and faster. Consequently, methane emissions appear as a general elevation of methane levels over a wider area, instead of localized markedly elevated peaks.

During the 3-4 June field work weather conditions were more favorable. The wind was from the north-northwest at an average speed of 5 miles per hour (around 8 feet per second). Under these conditions methane emissions would be expected to be detectable as low concentration plumes extending for an appreciable distance to the south-southeast of the source. Mixing layer structure and height was not estimated during the survey, but conditions should have favored typical lower atmospheric mixing patterns in which most methane emissions diffuse rapidly upward.

Results of the January Survey

As anticipated due to the wind conditions the methane levels were moderately elevated widely over the survey area. Typical methane level observed during the survey was low. The average methane level was 1.86 ppm, with a minimum of 1.79 ppm, 90% were below 1.91 ppm, and 99% below 2.08 ppm.[3] Under such high wind conditions, the layer of the atmosphere that normally forms next to the land surface[4] is swept away by air that would normally move at altitudes of a few hundred to a few thousand feet above. Under gentler wind conditions gases released into the air tend to accumulate in plumes as they dissipate into the turbulent but lower-wind-speed layer of air next to the land surface. Under sustained high wind conditions the air from the higher layer sweeps down and across the land surface rapidly sweeping any released gases across the land surface and up into the atmosphere.

Figure 2 shows an oblique westward view of the survey area in which the data was processed to remove values lower than 2.2 ppm and vertically exaggerate those over 2.2 ppm by a factor of 1000. In effect, this approach visually defines methane levels above 2.2 ppm as elevated methane levels (EMLs). This graphical rendering shows around 18 locations with elevations above 2.2 ppm. There also appear to be many locations with EMLs near 2.2 ppm. This, however, is an artifact of the low resolution of this image and the high resolution of the survey data set. When this image is examined at higher resolution most of the apparent near-2.2-ppm EMLs disappear.

To allow examination of smaller EMLs another image of data was prepared with the methane data processed to remove values below 1.9 ppm and vertically exaggerate values >1.9 ppm by a factor of 100. The lower 1.9-ppm cutoff and vertical exaggeration preserved EMLs that were not apparent upon high resolution examination of Figure 2, as illustrated by Figures 3 and 4. The >1.9-ppm image is not shown as it is visually nearly flat at the resolution that can be rendered on a single page of this report. In the >1.9-ppm image 57 EMLs were indentified as sufficiently clear to merit further examination (see Appendix B for a listing of those EMLs by location). Of those 57 EMLs, 43 were in proximity to and nearly-downwind of gas pipelines, gas well pads, farms, industrial facilities with apparent waste water treatment ponds or lagoons.

---

[3] During survey runs the vehicle has to make stops. The CRDS methane instrument collects data continuously. Consequently, geographically disproportionate amounts of data accumulate whenever the vehicle stops. Geographically disproportionate data accumulations are removed from the data set before statistical analysis. Images are generated using the full raw data sets.

[4] Planetary boundary layer or mixing layer. See Manhattan extended report for more detailed discussion.NEED LINK HERE

Further identification of the methane sources causing the other 14 EMLs was beyond the scope of the survey work.

Despite the strong wind conditions a relatively large methane plume was detected. The plume was detected over an area running from Wysox 2.5 miles southward along the river and up to 3.6 miles to the east. The plume was not present on a later pass through the same area. The extent and consistency of this plume over such a large area under such windy conditions, and its relatively sudden disappearance suggest a sizeable release of methane upwind of the plume area that ended sometime during the survey. Identification of a likely source was beyond the scope of the survey work. It is noteworthy that this plume was again present during the June survey. The plume may have been related to a number of gas wells generally north of Wysox.

Conclusions from 31 January Survey

The strong wind conditions during the methane survey caused rapid mixing and lateral dispersal of methane from any sources in or near the survey area. Under such conditions detection of elevated methane levels is limited to those resulting from larger emissions or those from sources in close proximity to the roadway. The rapid mixing and lateral dispersal causes methane levels in the area to appear more uniformly elevated than would be the case under less windy conditions. This was indicated by the slightly elevated mean (1.86 ppm) and narrow range of methane levels (1.79-1.91 ppm) that accounted for the 90% of the data (further discussed in comparison to the June data follows below). All the other 10% of the data indicating methane levels above 1.91 ppm occurred at less than 60 locations. Among those locations, 43 were in the vicinity of candidate potential methane sources, in most cases gas pipelines or gas well pads. At 14 locations with elevated methane levels candidate potential methane sources were not readily apparent.

Results of the 3-4 June Survey

As expected under the more favorable wind conditions on 3-4 June, methane plumes were detectable over much larger areas than during the extreme wind conditions of the 31 January survey. Elevated methane levels occurred over much of the survey area. Additionally the methane instrument (cavity ring down spectrometer[5]) was run during travel from the survey area and during a brief observational trip to the Leroy Township area. Those two legs of the

[5] http://www.picarro.com/technology/cavity_ring_down_spectroscopy

survey trip provided methane measurements in geographically and geologically adjacent areas that can be reasonably regarded as comparable areas with limited or no shale gas well activity. That area is referred to as the Reference Area in the remainder of this report. It includes data from valleys, along a river, and two town/city areas. Hence, the Reference Area can be reasonably considered to have all likely natural and human-caused methane sources typical for the geographical/geological area, but with minimal large-scale agricultural, industrial or shale gas sources. Also, of some interest is recognition that the methane survey work included parts of two areas under Pennsylvania Department of Environmental Protection Consent Orders. An image displaying the results of the June survey is provided in Figure 5.

It should be borne in mind that the survey work was limited to publicly accessible roads. The survey, therefore, measures the impacts of methane emissions sources at considerable distances from those sources. Consequently, seemingly minor changes, in the tenths or hundredths of a part per million, in ambient air methane levels are of considerable importance in locating methane emissions sources and assessing their broader area impacts.

The June survey average methane level was 1.83 ppm, with a minimum of 1.75 ppm, 90% were below 1.88 ppm, and 99% below 2.05 ppm.[3] Given the difference in wind conditions, these levels were quite similar to those seen in the January survey. For comparison, in the Reference Area the average methane level was 1.78 ppm, with a minimum of 1.76 ppm, 90% were below 1.79 ppm, and 99% below 1.81 ppm.[3] Since much of the survey area is affected by the same type and frequency of methane sources that occur in the Reference Area, one would expect that much of the survey area data would be similar. This was, in fact, found to be the case. It can be seen in Figure 6 that in the Reference Area 97% of the methane levels were below 1.8 ppm, while in the survey area in June, 37% were, but in the survey area in January less than 1% were below 1.8 ppm. These results suggest that methane emissions in about 37% of the survey area are effectively similar to the Reference Area. The strong winds during the January compared to the June survey were probably the cause of the apparent reduction in total area with readings below 1.8 ppm (37% of the area in June compared to <1% in January), Emissions that on 3-4 June were rising into the air more normally, whereas on 31 January emissions were being rapidly mixed and swept over the land surface by the strong winds.

Looking at another methane value of interest, the maximum methane level measured in the Reference Area was 1.88 ppm. In the survey area on 3-4 June 10% of the measurements exceeded the Reference Area maximum, and on 31 January 16%. Consequently, it is reasonable to conclude that at least 10% of the survey area is impacted by methane sources that do not occur in the Reference Area. As previously mentioned, these are agricultural and industrial sources. Field observations and examination of satellite imagery allowed determination that some of the methane sources causing the elevated methane were agricultural or industrial, other than shale gas development. The plumes of the ag/industrial sources appeared less extensive than the plumes of the sources associated with shale gas development. Most of the shale gas methane emissions sources appeared likely to be well pads and pipelines.

With regard to the relationship between ambient air methane surveys and locations of methane sources potentially impacting an area, it is interesting to consider the survey covered parts of the areas under two PaDEP Consent Orders. Those two Orders were between the PaDEP and Chesapeake Appalachia, LLC, dated 16 May 2011[6]. The two Orders were designated for impact areas referred to by PaDEP as Paradise Road and Sugar Run. It should be borne in mind that at the time of the survey, the Consent Order impact areas were not specifically known to GSI and were not specifically targeted. The general outline of the survey area was selected by DCS based on reports in the media and from residents. The specific area was determined by the operational conditions GSI encountered in the field. Consequently, the survey covered the Consent Orders impact areas only coincidentally. Still the survey did include about 2/3 of the Paradise Road and ½ of the Sugar Run Consent Order impact areas. It can be readily observed in Figure 5 that elevated methane levels were concentrated within the Paradise Road impact area compared to the remainder of the survey. There were elevated methane levels in other parts of the survey area but the concentration in the central part of the Paradise Road impact area is distinct. **Though this does not prove a relationship between ambient air methane contamination and groundwater contamination, it is clearly suggestive. Further, it also suggests shale gas well operations in that area still did not have control of the gas that has been developed there. In fact, as already mentioned, the survey data indicates there may be gas control problems in about 10% of the survey area resulting in elevated methane levels over 60-90% of the area.**

In addition, detection of any level of methane above normal background for an area indicates only two possible conditions: diffuse, non-point emissions are occurring over some portion of the area, or, one or more point sources are active within the area. Non-point sources are difficult to assess, precisely because they are diffuse. As mentioned previously, at the end of the survey work reported here a cursory evaluation run was made to the area of a previously documented shale gas well impact in Leroy Township. NEED LINK HERE That site is of interest in this discussion because on the land surface methane emissions occur as a non-point source, with gas emerging from many points over a area of uncertain extent. During the earlier evaluation of that site

---

[6] This PA DEP Consent Order available HERE: https://www.dropbox.com/s/3r34e3ggb88qxbo/161%20Consent%20Agreem%20Susquehana%20River.pdf

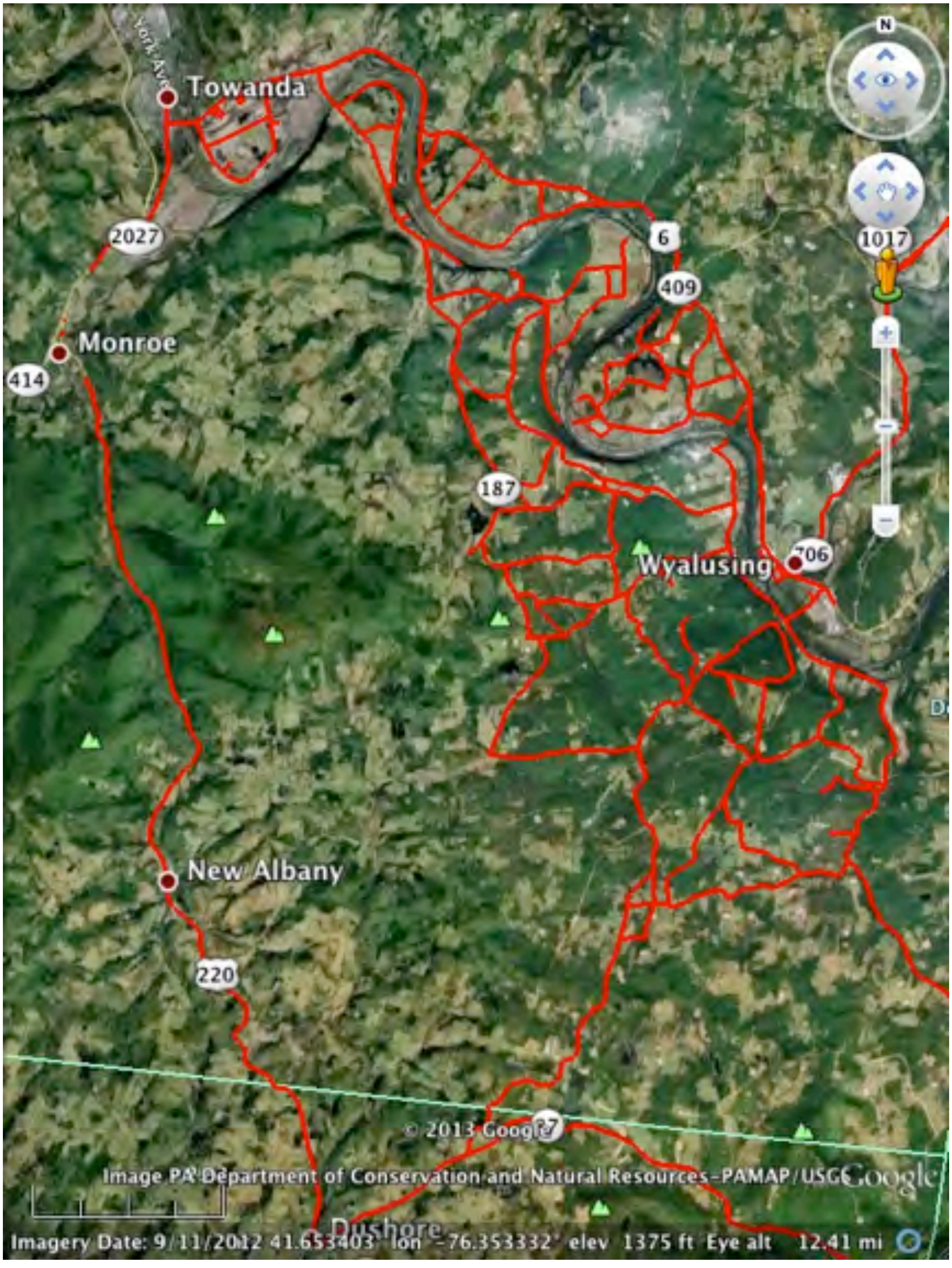
nearly pure natural gas was encountered within inches of the soil surface, but on the nearest road, about 100 yards away, and downwind at the time, only a few ppm of methane were detected. Despite gas well remediation measures, the 4 June run along the same roads confirmed methane levels remain in the range of a few ppm, suggesting the methane migration problem still exists. A cursory water sample test also indicated water in the area still has very high methane levels. Methane contamination was prevalent in the area during the prior evaluation. The Leroy Township situation is troubling with regard to health and safety, and discouraging with regard to the capability of industry to effectively correct gas well problems when they occur.

Point sources of methane present a slightly different set of concerns. A substantial amount of methane is necessary to raise methane levels even slightly over an extensive area, as measured from our survey over public roads. If that amount of methane is being emitted at one or a few point sources, then the concentration of methane in the vicinity of those sources will likely be hazardous with respect to explosion or asphyxiation. Consequently, the methane levels measured during the survey indicate there likely are point sources associated with some shale gas wells in the area that do give rise to hazardous conditions. Those point sources need not necessarily be at the gas well itself, as the gas may find underground pathways to emerge in water wells, homes or other structures, as occurred in Leroy Township, and the Paradise Road and Sugar Run impact areas.

Conclusions

Methane from any source rapidly diffuses and rises in the air. Consequently, detection of possible methane sources from any distance away requires extremely sensitive measurement capabilities. The GSI survey approach takes advantage of extremely sensitive measurement instrumentation to detect small increases in ambient air methane levels as an indication of probable methane emissions sources in a given area. Based on the data collected using that equipment, we conclude that the Towanda-Wyalusing area is probably substantially impacted by methane emissions from shale gas wells both within and beyond the survey area, depending on wind conditions. The coincidence of two DEP methane migration impact areas, Paradise Road and Sugar Road, and the most marked ambient air methane levels suggests there are still gas control problems associated with the shale gas wells there, as well as in another documented impact area in Leroy Township also cursorily measured following the main survey. A rapid water test in the Leroy area confirmed the water in that area is still contaminated with methane. These survey results suggest methane contamination continues and measures taken by gas well operators with regard to methane migration problems that have occurred in these three areas have likely been only partially effective.

Figure 1. Overhead image of roads traveled during the survey of ambient air methane levels in the vicinity of Wyalusing, PA on 31 January 2013 (Google Earth).



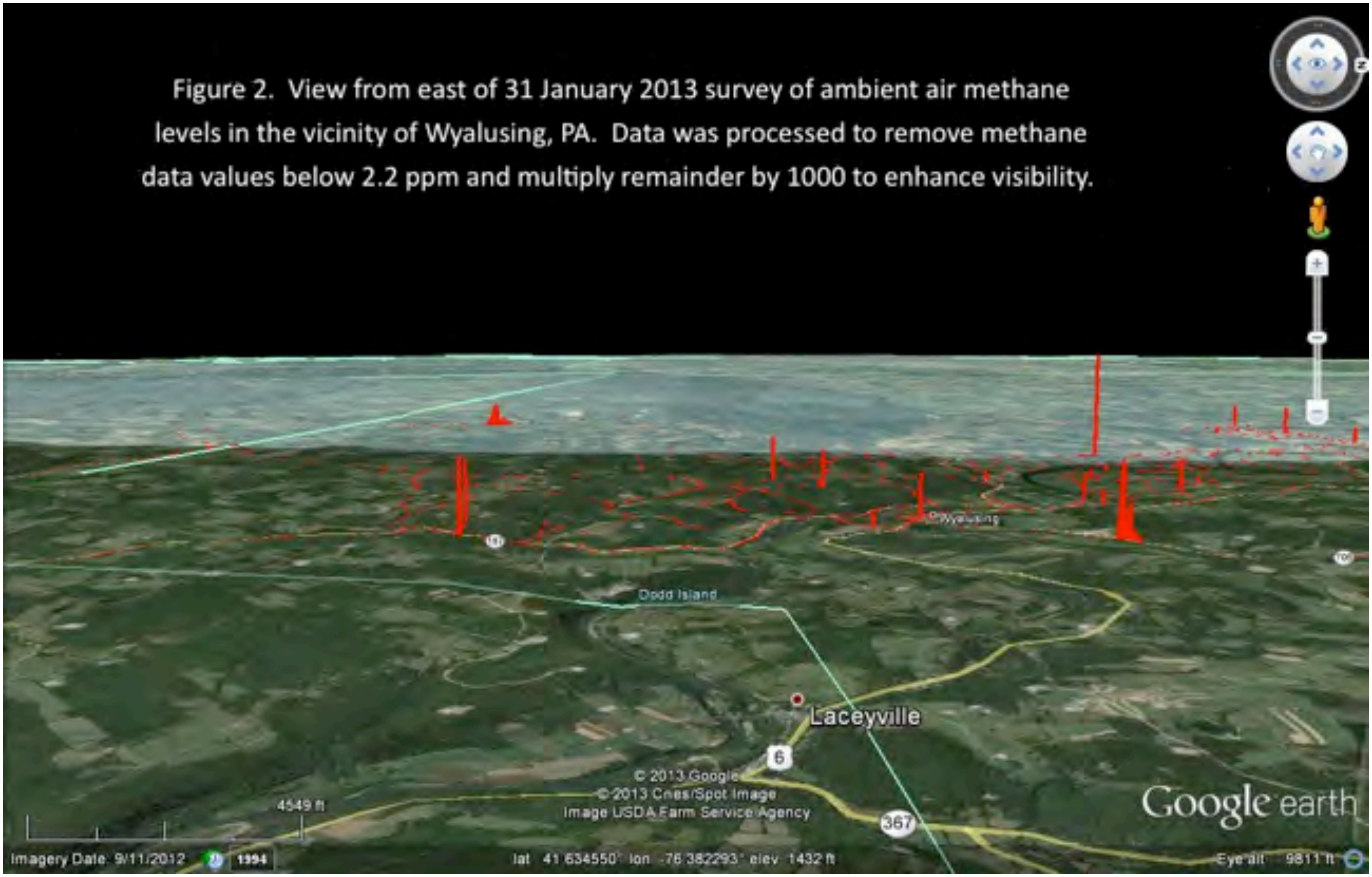


Figure 2. View from east of 31 January 2013 survey of ambient air methane levels in the vicinity of Wyalusing, PA. Data was processed to remove methane data values below 2.2 ppm and multiply remainder by 1000 to enhance visibility.

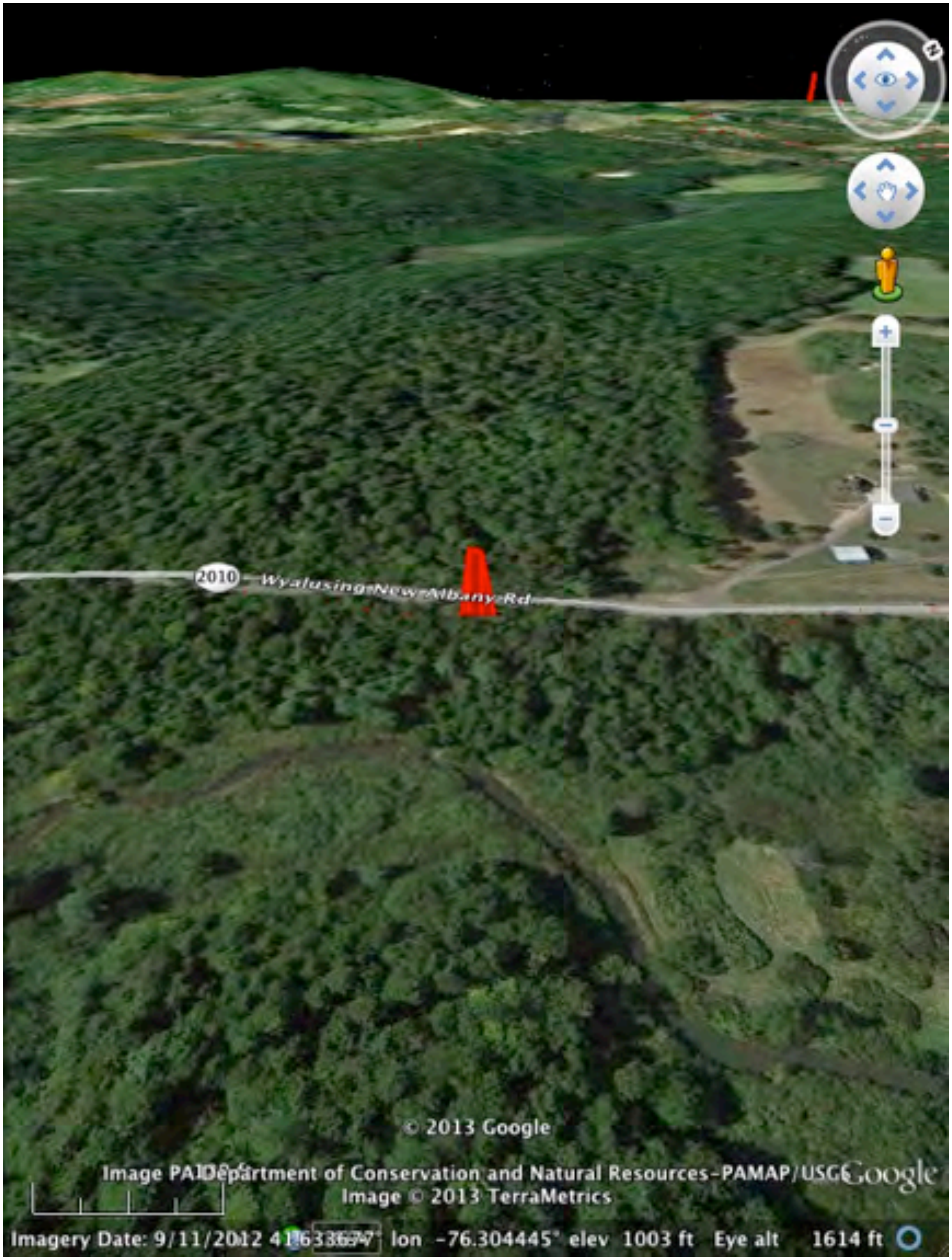


Figure 3. An elevated methane level as rendered by processing of the Wyalusing 31 January 2013 methane survey data to remove values <2.2ppm and multiply remainder by 1000. Compare to same elevated methane location in Figure 4.

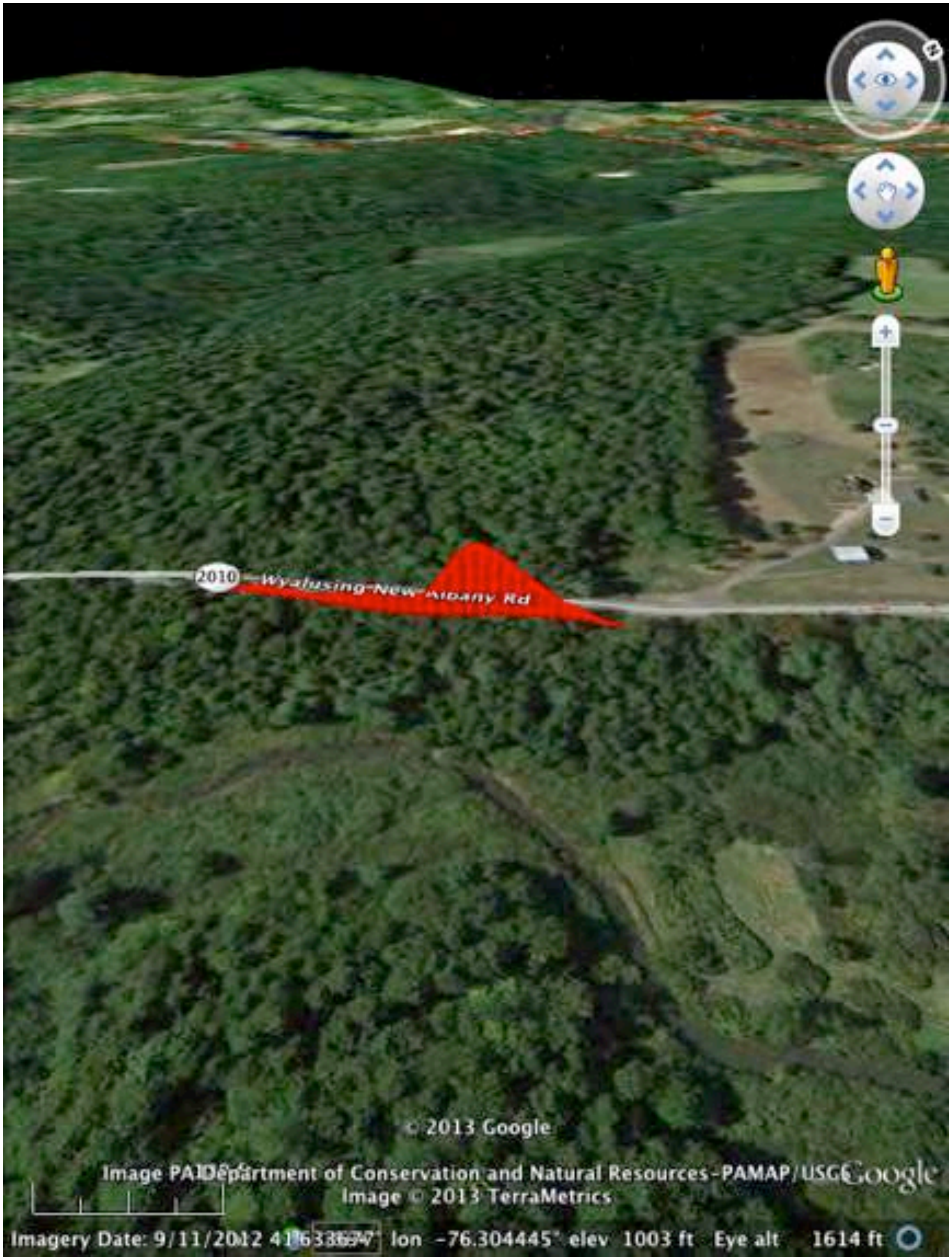


Figure 4. An elevated methane level as rendered by processing of the Wyalusing 31 January 2013 methane survey data to remove values <1.9ppm and multiply remainder by 100. Compare to same elevated methane location in Figure 3.

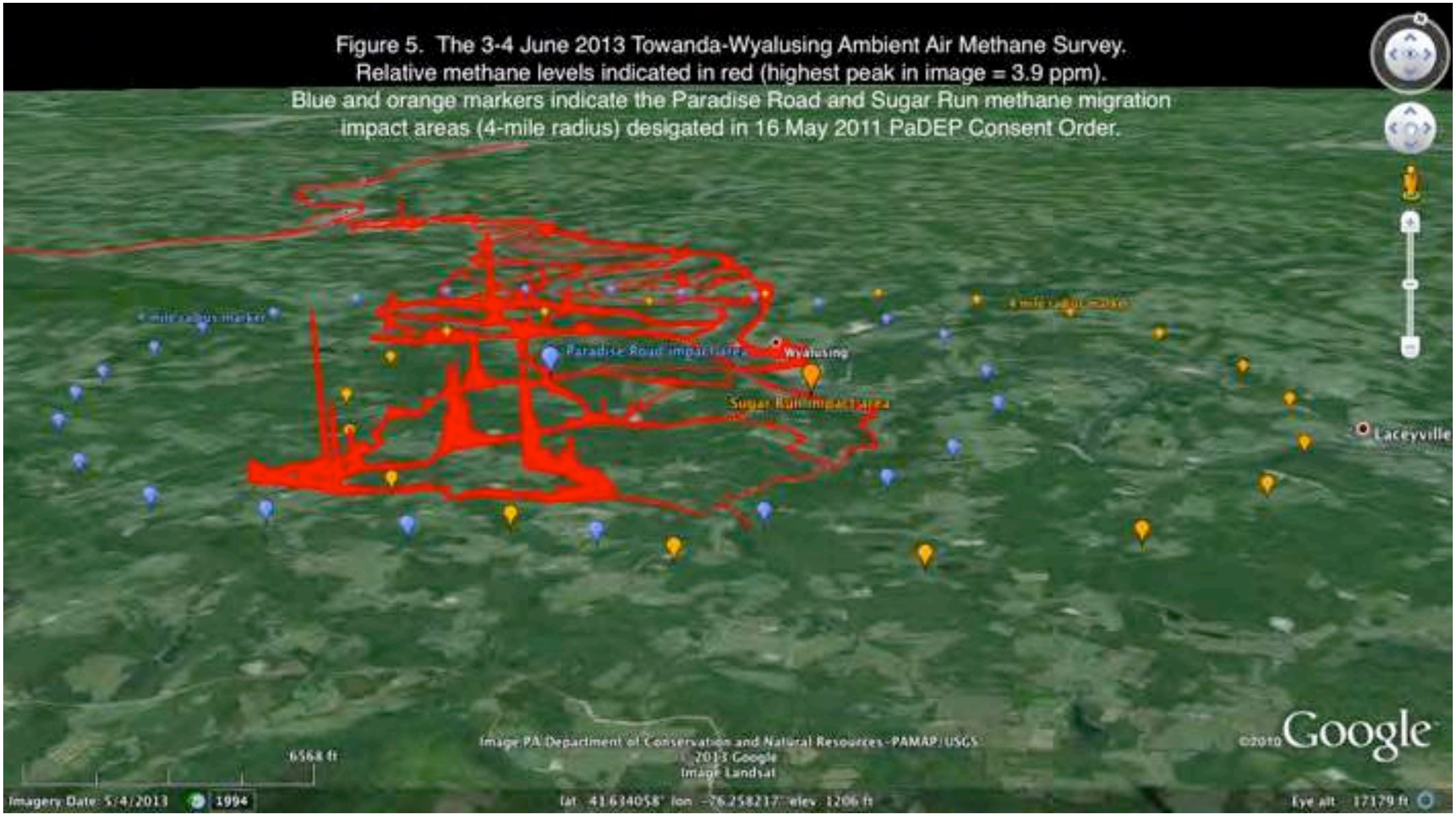


Figure 5. The 3-4 June 2013 Towanda-Wyalusing Ambient Air Methane Survey.
Relative methane levels indicated in red (highest peak in image = 3.9 ppm).
Blue and orange markers indicate the Paradise Road and Sugar Run methane migration impact areas (4-mile radius) desigated in 16 May 2011 PaDEP Consent Order.

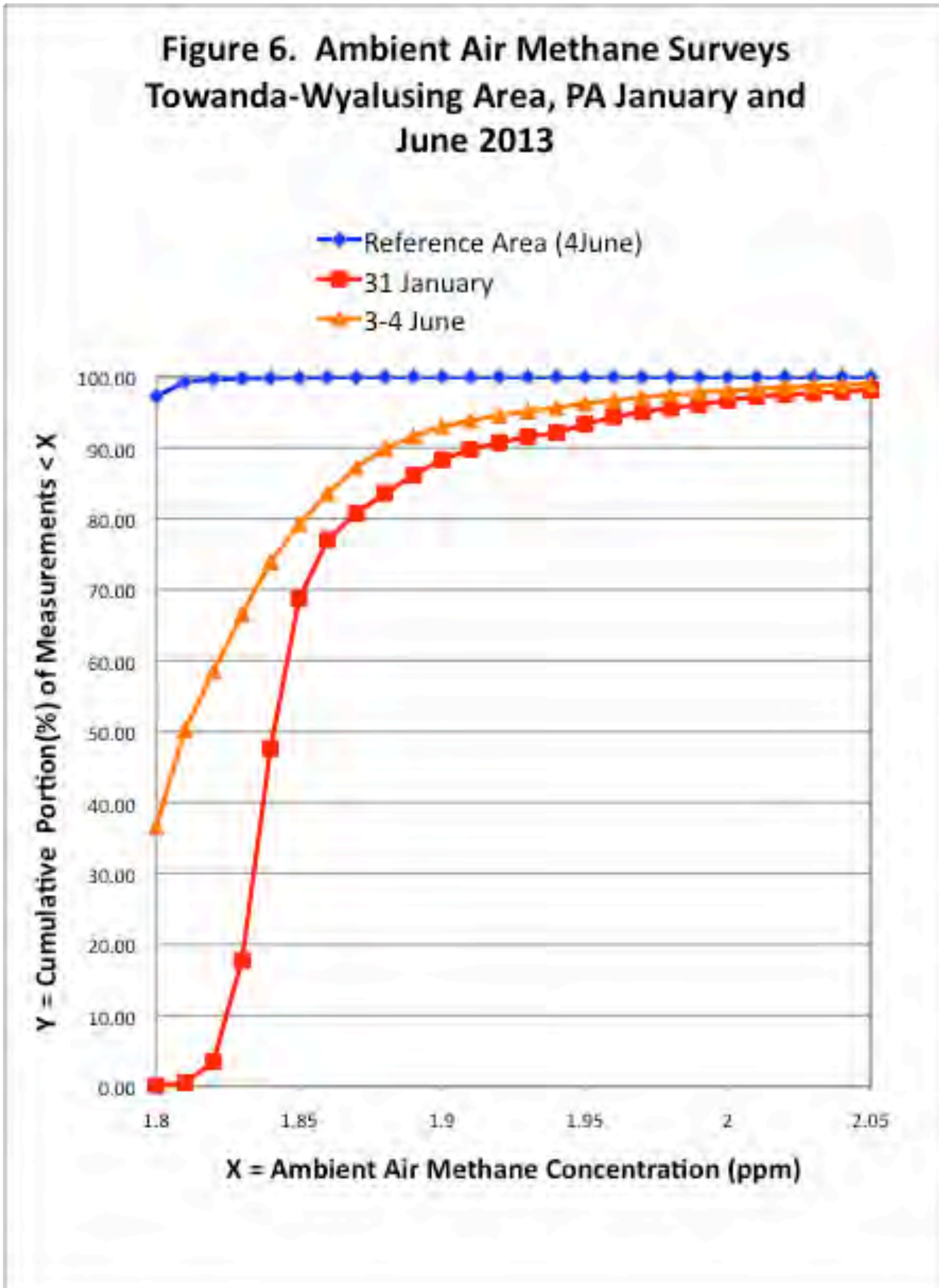


Figure 6. Ambient Air Methane Surveys Towanda-Wyalusing Area, PA January and June 2013
Reference Area (4June)
31 January
3-4 June
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Y = Cumulative Portion(%) of Measurements < X
1.8
1.85
1.9
1.95
2
2.05
X = Ambient Air Methane Concentration (ppm)