The Development of Shale Gas in the United States

Daniel J. Soeder

Research Scientist, Geology
and Environmental Systems

May 9, 2013

U.S. DEPARTMENT OF
ENERGY | National Energy
Technology Laboratory

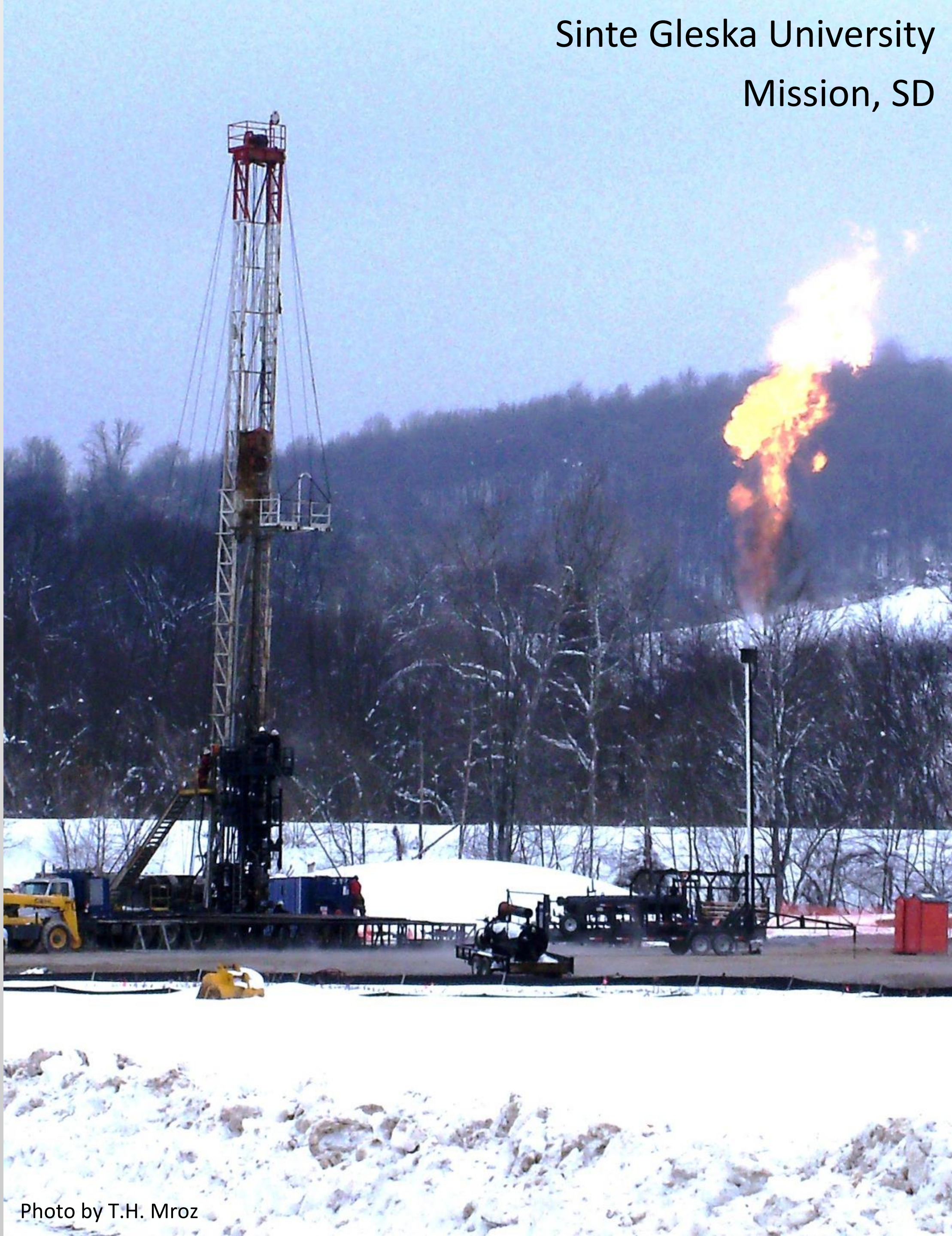
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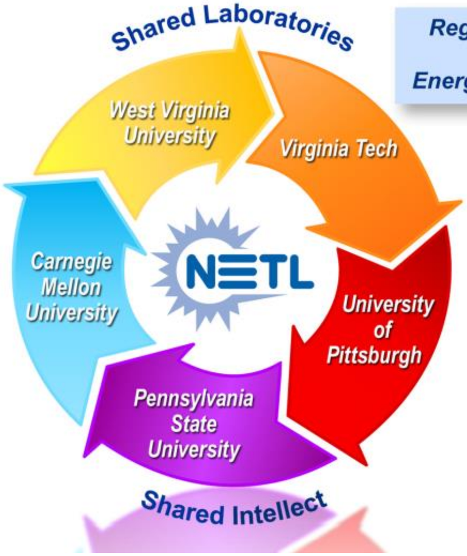
Photo by T.H. Mroz

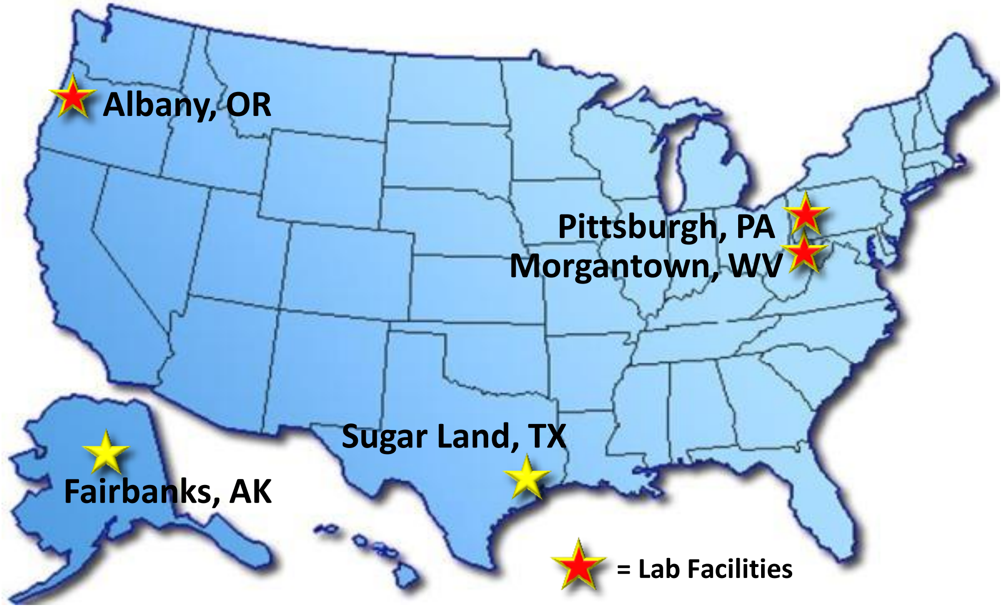
DOE National Energy Technology Laboratory



Regional University Alliance for Energy Technology Innovation

Energy Technology Solutions

- *Energy System Dynamics*
- *Geological and Environmental Systems*
- *Computational and Basic Sciences*
- *Material Science and Engineering*



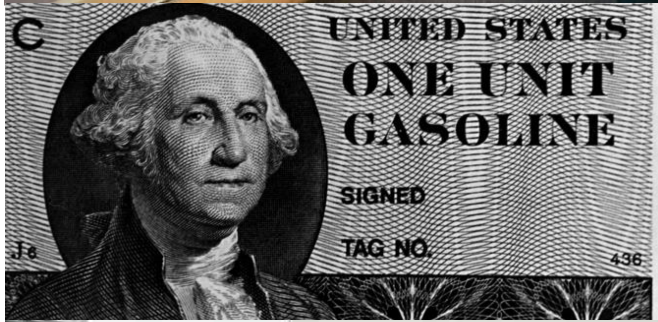
- U.S. DOE Office of Fossil Energy National Laboratory; 5 sites with ~1200 employees
- Onsite research (ORD), and extramural R&D (Strategic Centers)
- Fundamental science to technology demonstration of cutting-edge fossil energy technologies for a secure, affordable, and low-carbon energy future.
- Technology advances though partnerships with industry and other governments.
- International collaboration for fossil energy technology needed by the entire world.
- Collaboration benefits knowledge sharing, human capital development, and financing.
- Fossil fuels are still expected to supply about 80% of world’s energy in 2035

This Presentation

- History of U.S. shale gas research
- Shale geology and resources (including Niobrara in SD)
- Production technology for shale gas
- Concepts of environmental risk
- Risk assessment process for shale gas
- Risk assessment status and plans
- Questions and discussion

Why Shale Gas?

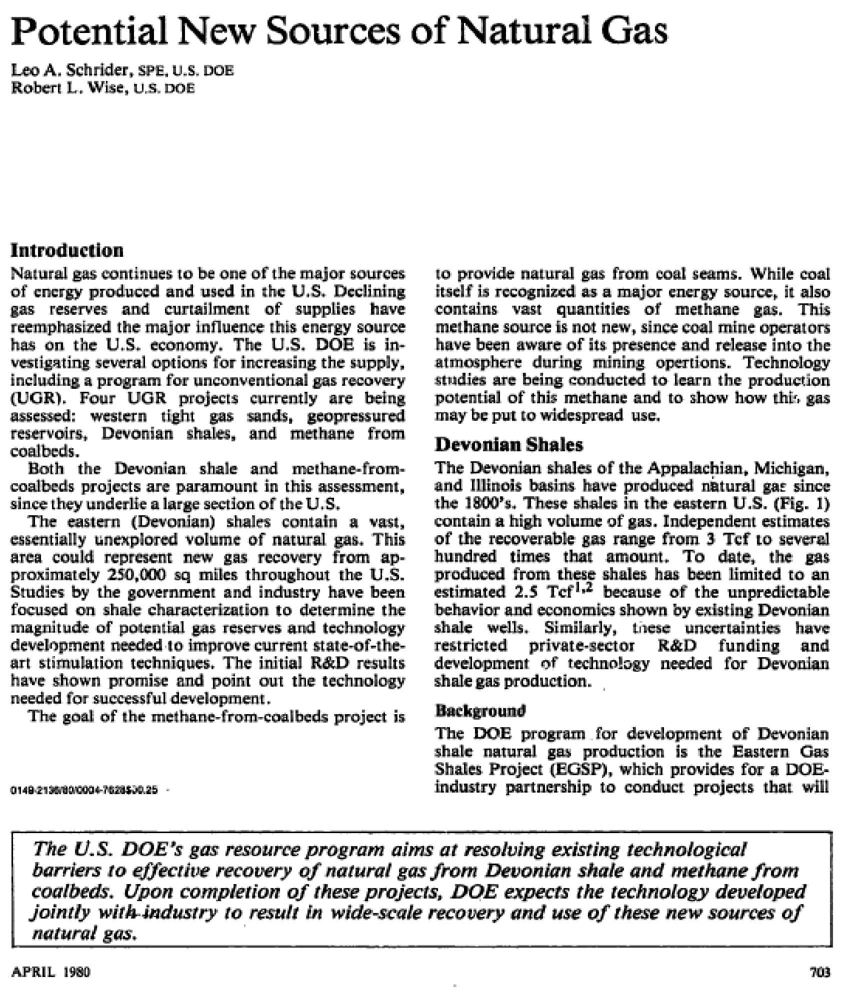
- **October 20, 1973 to Spring 1974: OPEC oil embargo against United States**
  - Gasoline was in short supply
  - Price of gasoline quadrupled ($0.40-$1.60)
- **It is hard to overstate how traumatic this was to both the citizens and government**
  - Car-dependent suburban lifestyles
  - Not too long after the turbulent 1960s
- **U.S. Department of Energy formed by Carter Administration on August 4, 1977**
- **A number of fossil energy research and demonstration projects were funded by DOE in the 1980s, including shale gas.**
  - Resource characterization/data transfer
  - Improved technology and engineering
- **Objective: Encourage development of <u>domestic</u> sources of oil and gas**



New Sources of Natural Gas

SPE 7628

- **Resources were known but not economical to produce.**
  - Dunkirk Shale in NY (1821)
  - Huron Shale in KY (early 1900s)
  - Coal seam gas
  - Tight gas sands
- **DOE funded natural gas R&D projects to increase domestic energy supplies:**
  - Eastern Gas Shales
  - Western Tight Gas Sands
  - Coal Bed Methane
  - Geopressured Aquifers
- **Later projects (1990s)**
  - Methane hydrates
  - Ultra deep gas



Potential New Sources of Natural Gas

Leo A. Schrider, SPE, U.S. DOE
Robert L. Wise, U.S. DOE

Introduction

Natural gas continues to be one of the major sources of energy produced and used in the U.S. Declining gas reserves and curtailment of supplies have reemphasized the major influence this energy source has on the U.S. economy. The U.S. DOE is investigating several options for increasing the supply, including a program for unconventional gas recovery (UGR). Four UGR projects currently are being assessed: western tight gas sands, geopressured reservoirs, Devonian shales, and methane from coalbeds.

Both the Devonian shale and methane-from-coalbeds projects are paramount in this assessment, since they underlie a large section of the U.S.

The eastern (Devonian) shales contain a vast, essentially unexplored volume of natural gas. This area could represent new gas recovery from approximately 250,000 sq miles throughout the U.S. Studies by the government and industry have been focused on shale characterization to determine the magnitude of potential gas reserves and technology development needed to improve current state-of-the-art stimulation techniques. The initial R&D results have shown promise and point out the technology needed for successful development.

The goal of the methane-from-coalbeds project is to provide natural gas from coal seams. While coal itself is recognized as a major energy source, it also contains vast quantities of methane gas. This methane source is not new, since coal mine operators have been aware of its presence and release into the atmosphere during mining opertions. Technology studies are being conducted to learn the production potential of this methane and to show how this gas may be put to widespread use.

Devonian Shales

The Devonian shales of the Appalachian, Michigan, and Illinois basins have produced natural gas since the 1800's. These shales in the eastern U.S. (Fig. 1) contain a high volume of gas. Independent estimates of the recoverable gas range from 3 Tcf to several hundred times that amount. To date, the gas produced from these shales has been limited to an estimated 2.5 Tcf[1,2] because of the unpredictable behavior and economics shown by existing Devonian shale wells. Similarly, these uncertainties have restricted private-sector R&D funding and development of technology needed for Devonian shale gas production.

Background

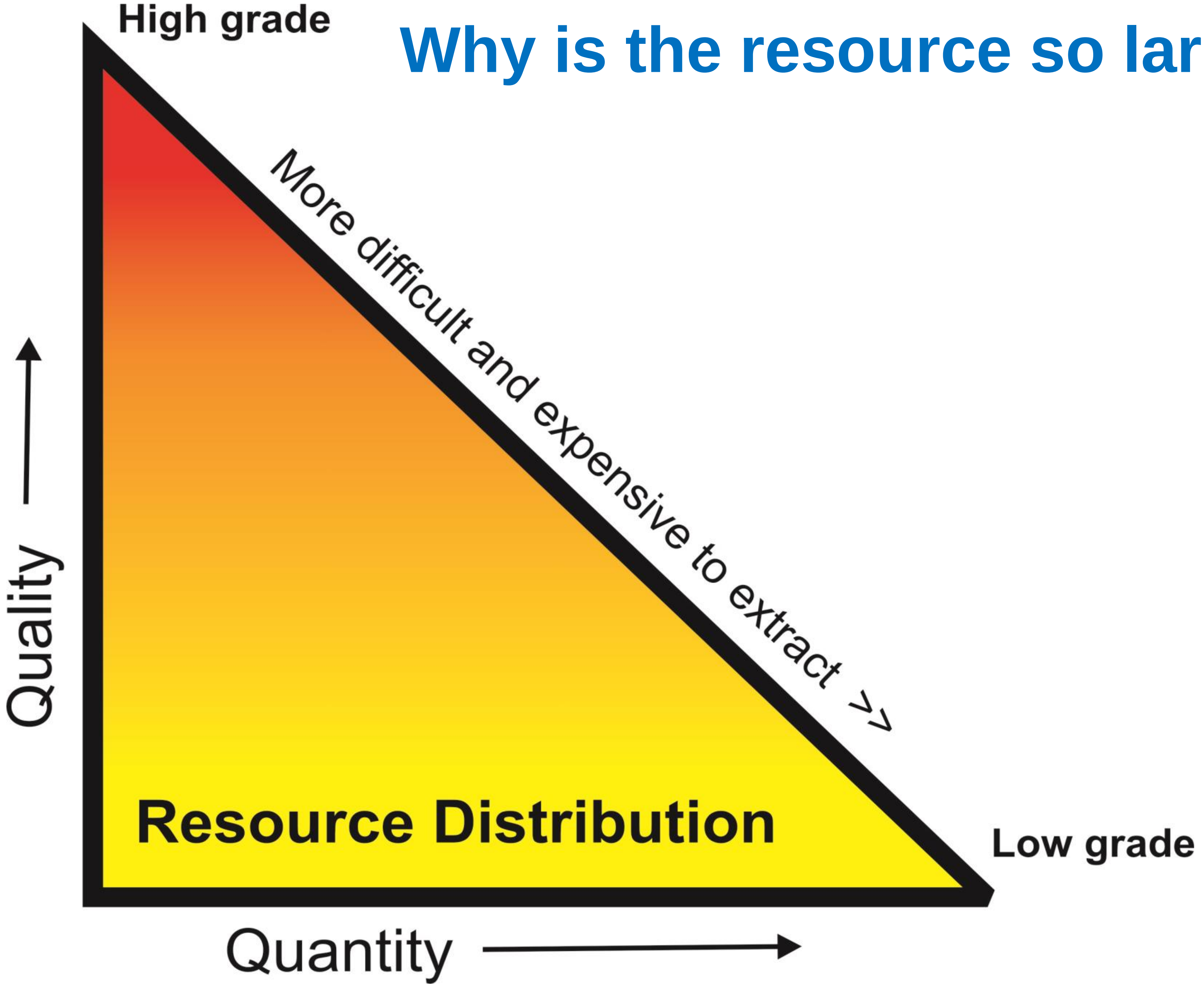
The DOE program for development of Devonian shale natural gas production is the Eastern Gas Shales Project (EGSP), which provides for a DOE-industry partnership to conduct projects that will

0149-2136/80/0004-7628$00.25

> *The U.S. DOE's gas resource program aims at resolving existing technological barriers to effective recovery of natural gas from Devonian shale and methane from coalbeds. Upon completion of these projects, DOE expects the technology developed jointly with industry to result in wide-scale recovery and use of these new sources of natural gas.*

Schrider, L. A. and R.L. Wise, 1980, Potential new sources of natural gas: Journal of Petroleum Technology, April 1980, p. 703-716.

Why is the resource so large?



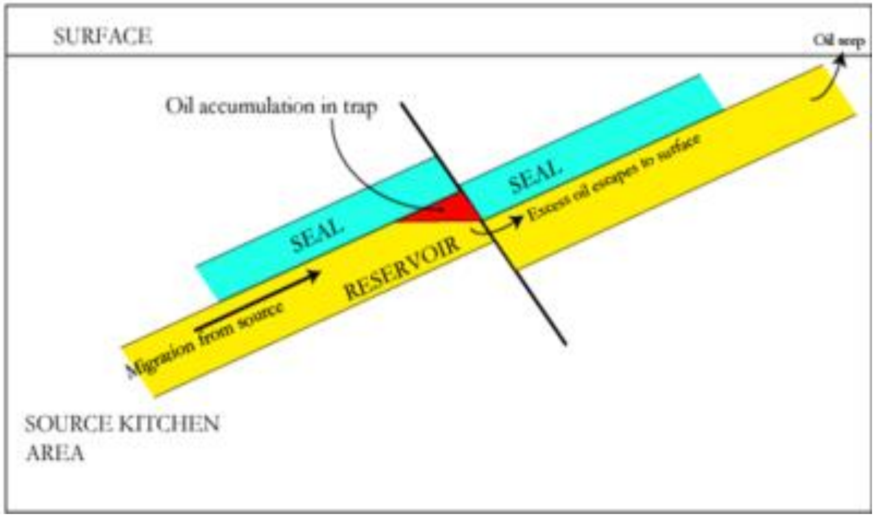
Petroleum Geology Review

Conventional Reservoir: concentrated deposit of recoverable oil and/or gas.

NEED:

1. Source rock: 1-2% organics (kerogen)
   a. Types I and II kerogen (petroleum + gas)
   b. Type III kerogen (coal + gas)
2. Thermal maturity
3. Reservoir rock
4. Trap and Seal
5. Migration pathway

If any one of these is missing,
no production.



Shale gas is "unconventional": produced directly from thermally-mature high-organic content source rock. No reservoir, trap or seal needed.

USGS calls this a “continuous resource,” producible essentially anywhere.

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, 2011: USGS Fact Sheet 2011–3092, U.S. Geological Survey, Reston, VA, 2 p. (http://pubs.er.usgs.gov/publication/fs20113092)

Gas Shale Geology

- Fine-grained, clastic mudrock, composed of clay, quartz, carbonate, organic matter, and other minerals.

- Shale is organic-rich (black: >2% carbon), or organic lean (gray or red), and commonly fissile.

- Shale porosity (ϕ) ~ 10%
- Shale permeability (k) µd to nd.

- Small grains = small pores; ϕ can be intergranular, intragranular, and intra-organic.

- Gas occurs in fractures, in pores and adsorbed or dissolved onto organic materials and clays.

Photo by D. Soeder

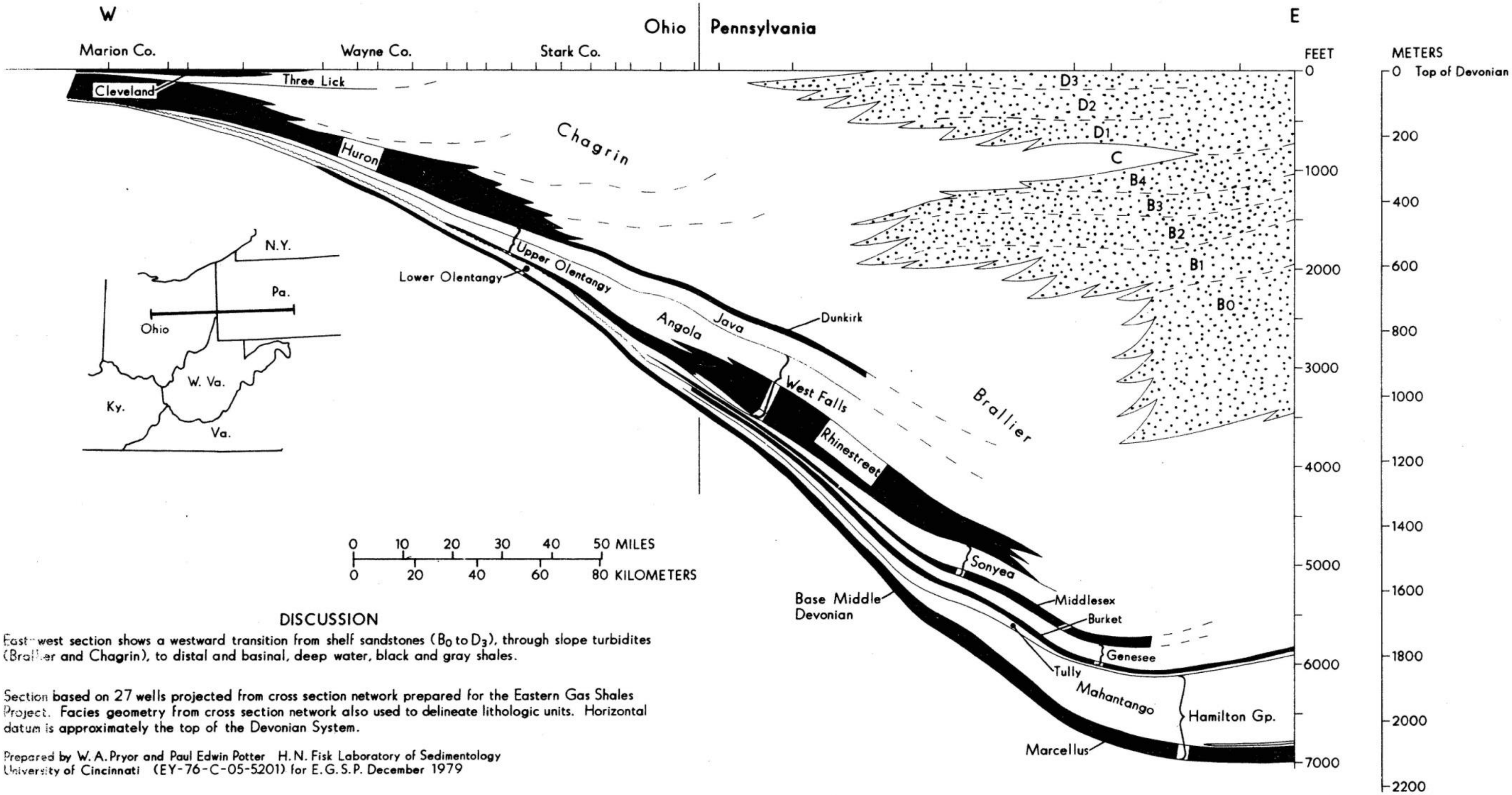
Soeder, D. J., 1988, Porosity and permeability of eastern Devonian gas shale: SPE Formation Evaluation, Vol. 3, No. 2, p. 116-124, DOI 10.2118/15213-PA.

DOE Eastern Gas Shales Project 1976-1992

All photos, DOE

Bolyard, T.H., 1981, A summary and evaluation of the eastern gas shales program cored wells in the Appalachian Basin: Report prepared for U.S. Department of Energy under contract DE-AM21-78MC08216, by Science Applications, Inc., Morgantown, WV, September 1981, 32 p.

Appalachian Basin Stratigraphy



DISCUSSION

East-west section shows a westward transition from shelf sandstones (B_0 to D_3), through slope turbidites (Brallier and Chagrin), to distal and basinal, deep water, black and gray shales.

Section based on 27 wells projected from cross section network prepared for the Eastern Gas Shales Project. Facies geometry from cross section network also used to delineate lithologic units. Horizontal datum is approximately the top of the Devonian System.

Prepared by W. A. Pryor and Paul Edwin Potter H. N. Fisk Laboratory of Sedimentology
University of Cincinnati (EY-76-C-05-5201) for E. G. S. P. December 1979

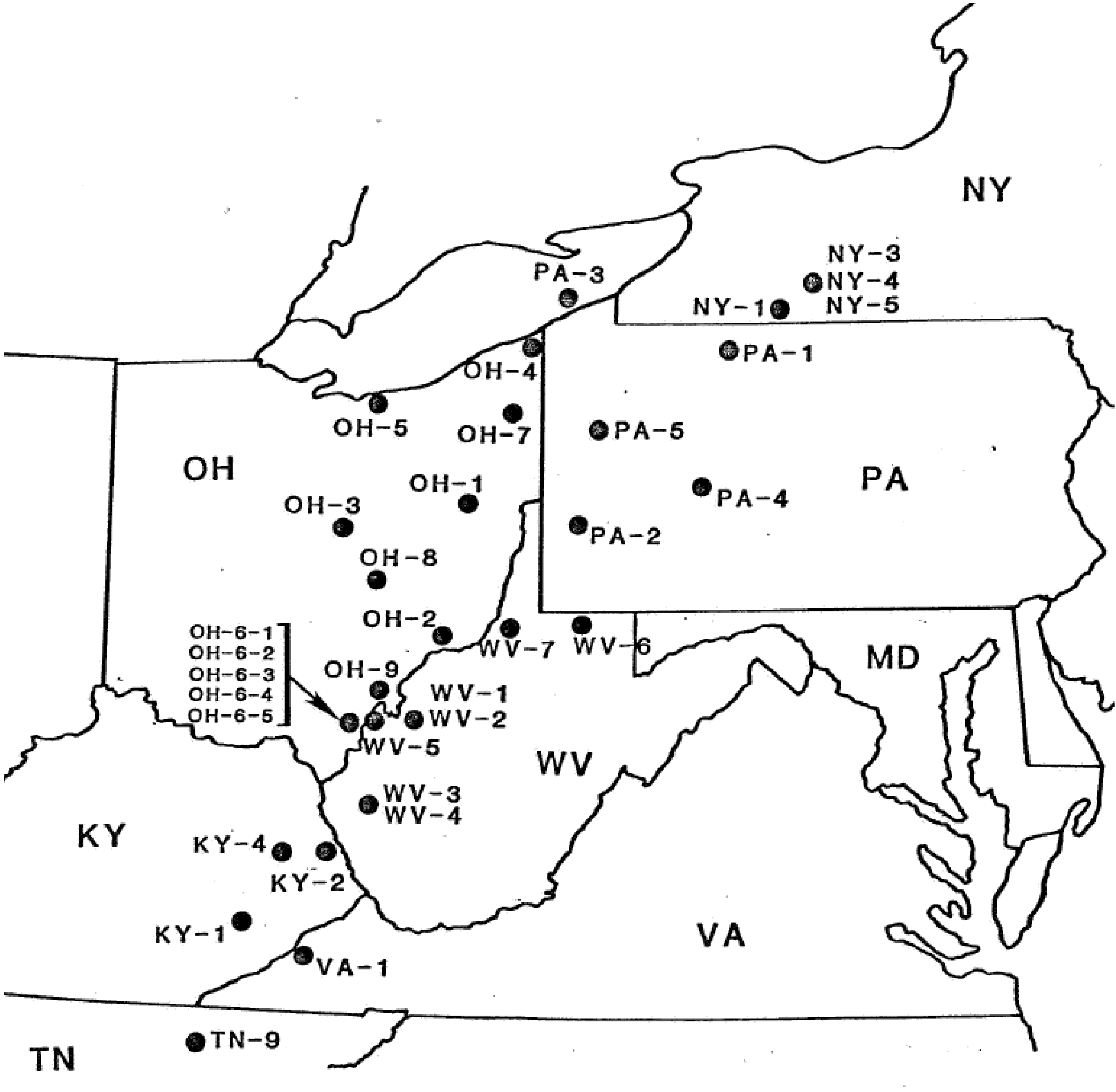
Potter, P.E., B. Maynard, and W.A. Pryor, 1980, Final report of special geological, geochemical, and petrological studies of the Devonian shales of the Appalachian Basin: report prepared for U.S. Department of Energy under contract EY-76-C-05-5201, by University of Cincinnati, OH, January 1980, 94 p.

EGSP Cored Well Locations

44 cores total

- 34 wells in the Appalachian Basin
  - Most Upper Devonian
  - Only 9 wells to Marcellus Shale
    - WV-6, WV-7
    - OH-4, OH-7, OH-8
    - PA-1, PA-2, PA-4, PA-5
    - None deeper
- 3 wells in Michigan Basin (Antrim Shale)
- 7 wells in the Illinois Basin (New Albany Shale)

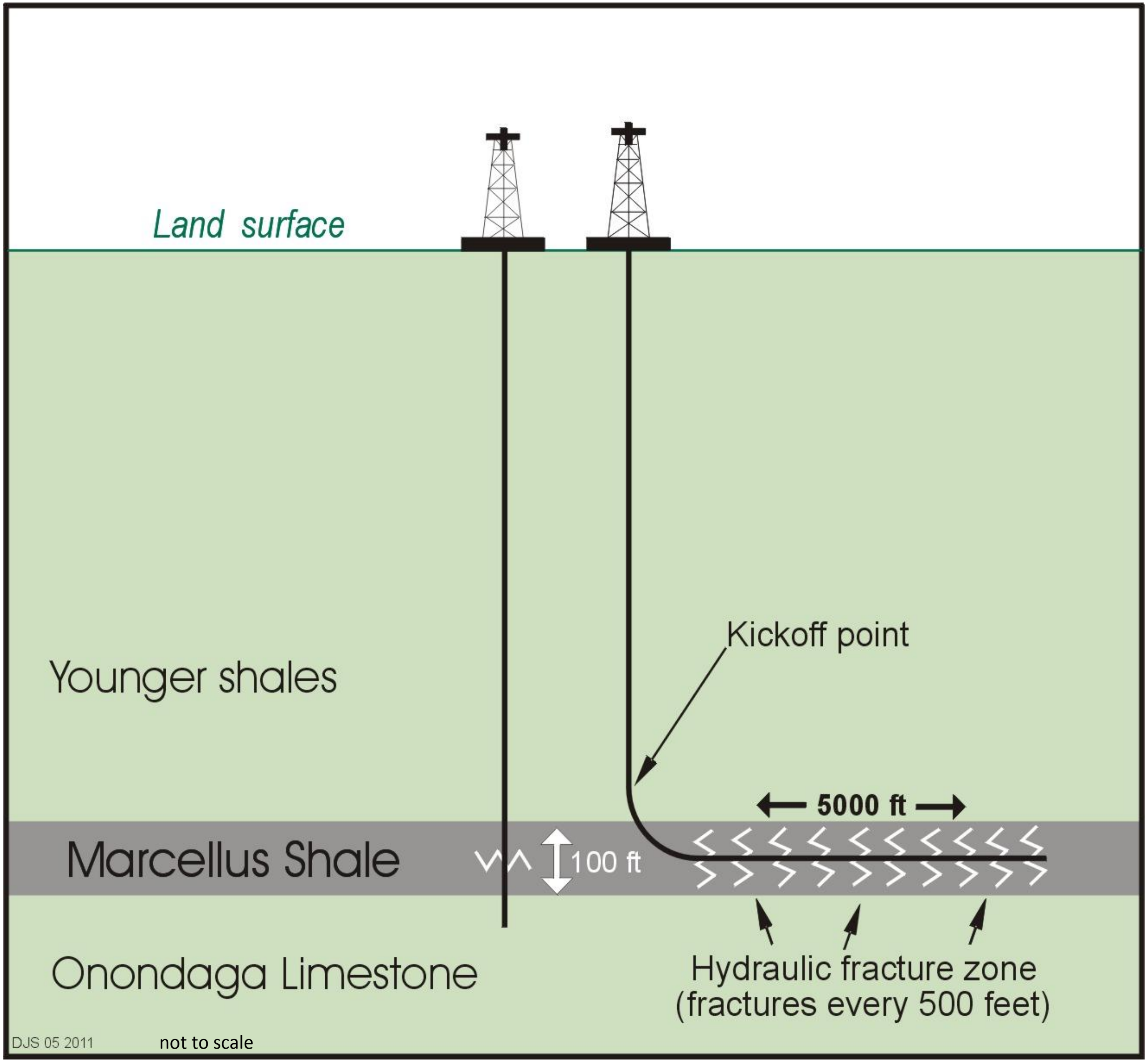
- "Stimulation alone is insufficient to achieve commercial shale gas production." - Horton, 1981



Horton, Andrea I. , 1981, A comparative analysis of stimulations in the eastern gas shales: Report DOE/METC 145, U.S. Department of Energy, Morgantown Energy Technology Center, Morgantown, WV, 120 p.

Looming Conventional Gas Shortages

- The United States was facing significant shortfalls of conventional natural gas production in the late 1990s
- Conventional fields in the Gulf Coast had watered out and no new gas fields were being developed.
- The Mackenzie Delta in Canada was being assessed for gas resources, as was the North Slope.
- Distributors constructed import terminals for LNG, like Dominion's at Cove Point on the Chesapeake Bay (photo).
- Wellhead prices for natural gas were near $11.00 MCF in 2008.



Deepwater tension leg platforms drove the technology.
High gas prices drove the economics.

Directional drilling

- Downhole hydraulic motors
- Geosteering:
- Measurement while drilling
- Inertial navigation
- Telemetry: better electronics
- 5,000+ ft laterals

Staged hydraulic fracturing

- Slickwater frac to reduce friction loss
- Light sand frac for less proppant

Shale Gas Production History

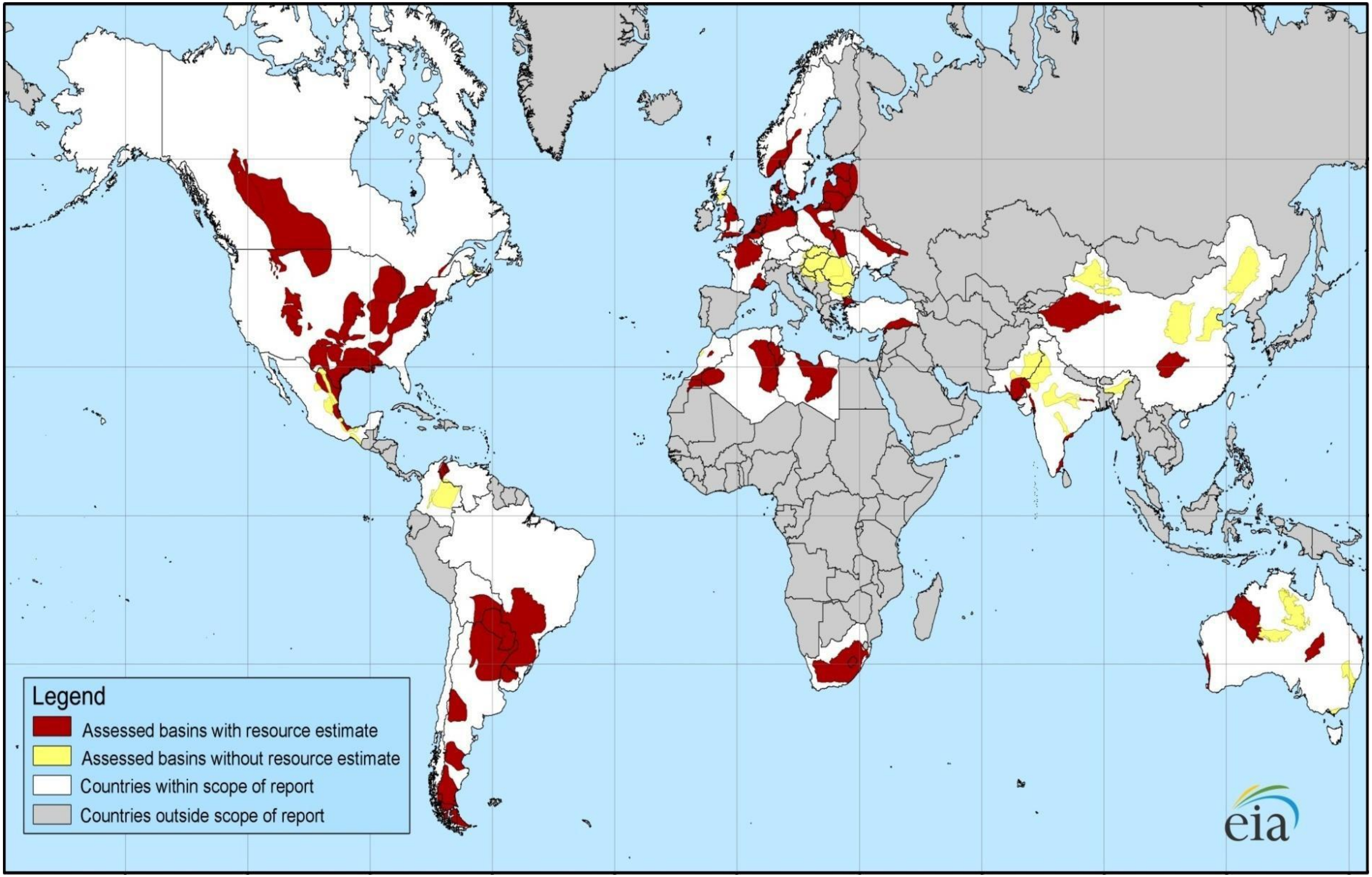
- **EGSP Data:** Many different completion and stimulation technologies were tested, horizontal drilling was prototyped in 1986.
- **Barnett Shale**, Ft. Worth Basin, Texas: Mitchell Energy adapted directional drilling technology and achieved economic production of shale gas in 1997.
- **Fayetteville Shale**: 2004, Southwestern Energy, northern Arkansas
- **Haynesville Shale**: Same period, Chesapeake Energy, ArkLaTex region
- **Marcellus Shale**: Range Resources, Rentz #1 vertical well to deeper target in 2005; nonproductive, recompleted in Marcellus Shale
  - Range Resources, Gulla #9 “discovery” well drilled in 2007; IP 4.9 MMCFD
- **Bakken Shale:** Williston Basin, North Dakota; primarily oil, estimated recoverable 7.5 billion barrels, ND is now 3rd largest oil producer in U.S.
- **New targets:** Woodford Shale (Arkoma Basin), Utica Shale (Appalachian Basin), Eagle Ford Shale (Texas Gulf Coast/Maverick Basin), Niobrara Shale, Mancos Shale and Mowry Shale (Colorado and Wyoming), and even shales in the Triassic Rift Basins on the Atlantic Piedmont.
- **Energy value of U.S. natural gas may be double the remaining oil in Saudi Arabia** (A. McLendon, former Chesapeake CEO).

http://www.doi.gov/news/pressreleases/usgs-releases-new-oil-and-gas-assessment-for-bakken-and-three-forks-formations.cfm

North American shale plays (as of May 2011)

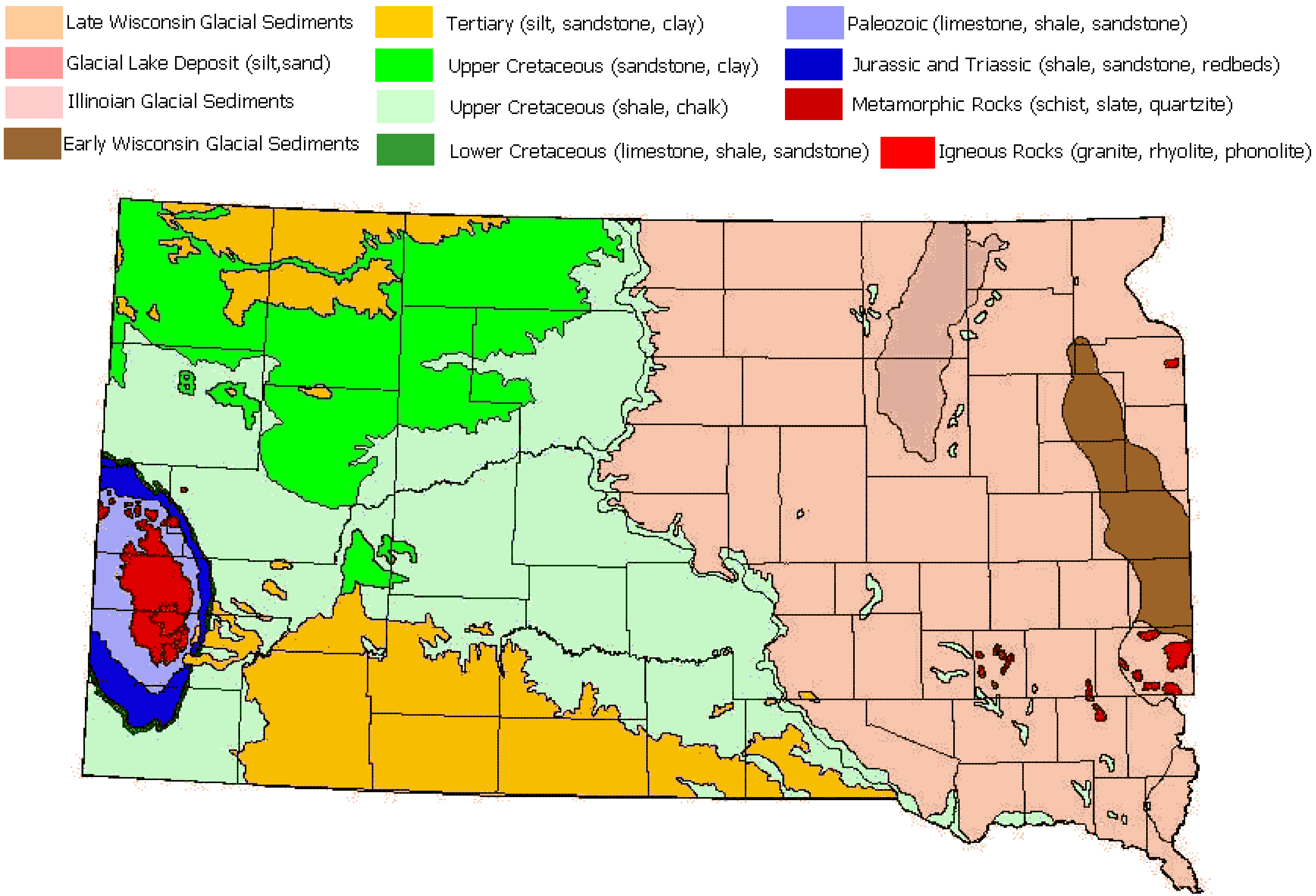
Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Shale Gas Worldwide



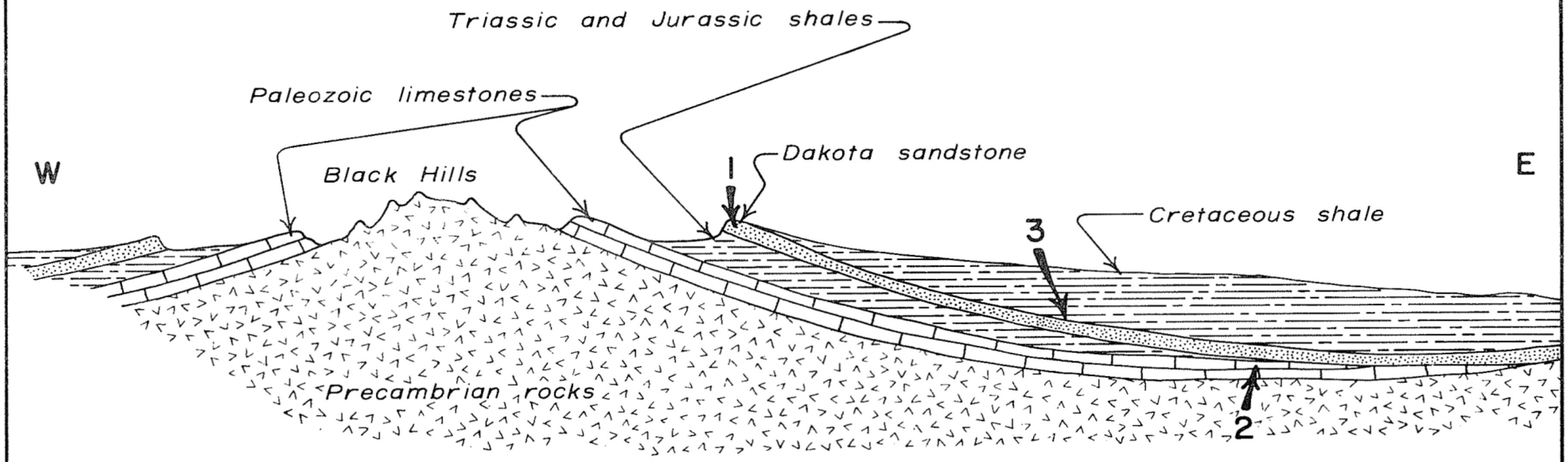
Source: U.S. Energy Information Administration

South Dakota Geology



http://www.sdgs.usd.edu/publications/maps/geo/generalgeo.html

Generalized Cross Section



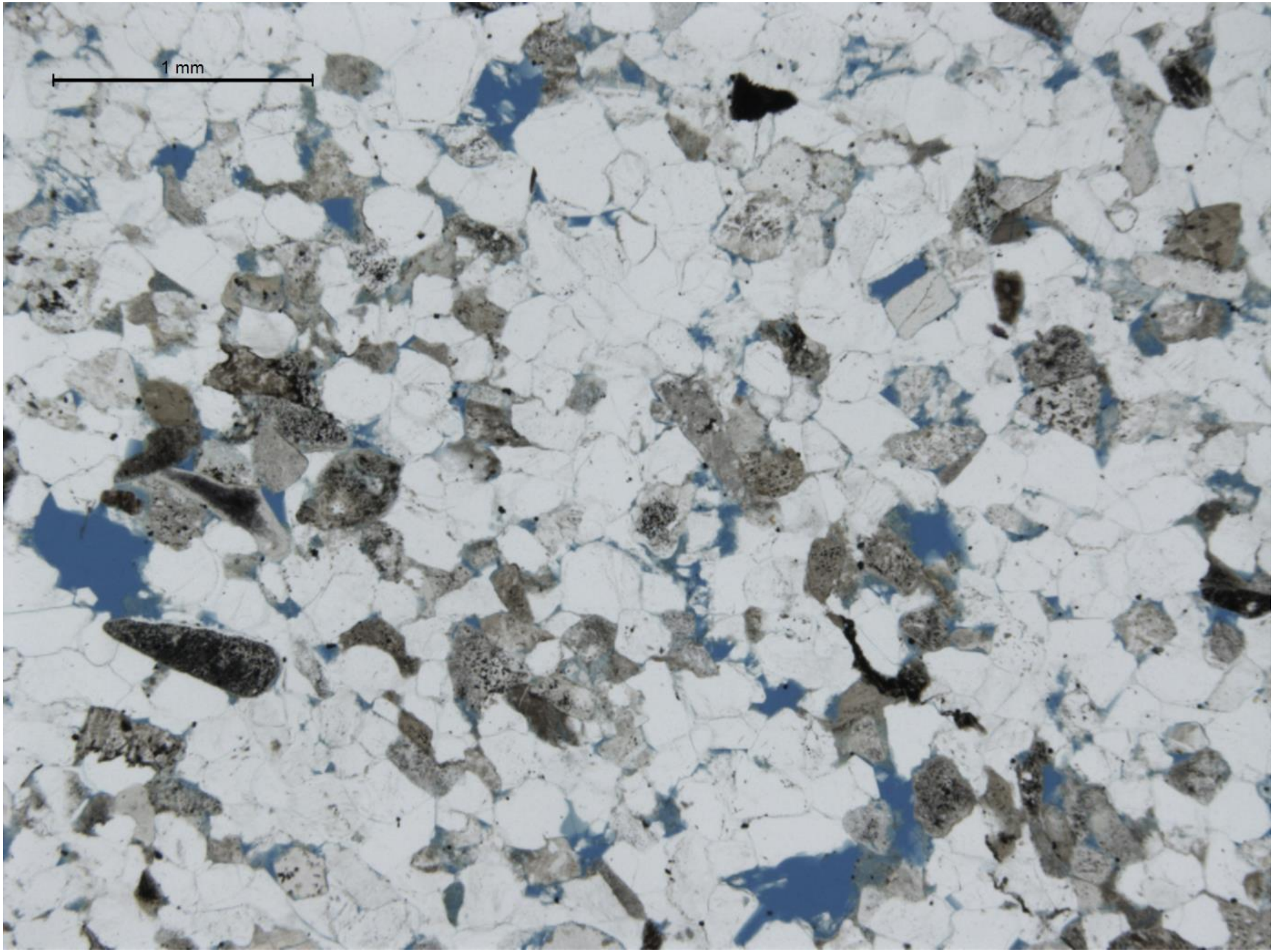
not shown to scale
see text for explanation

Figure 1. Three theories for steady-state recharge to the Dakota sandstones.

dj

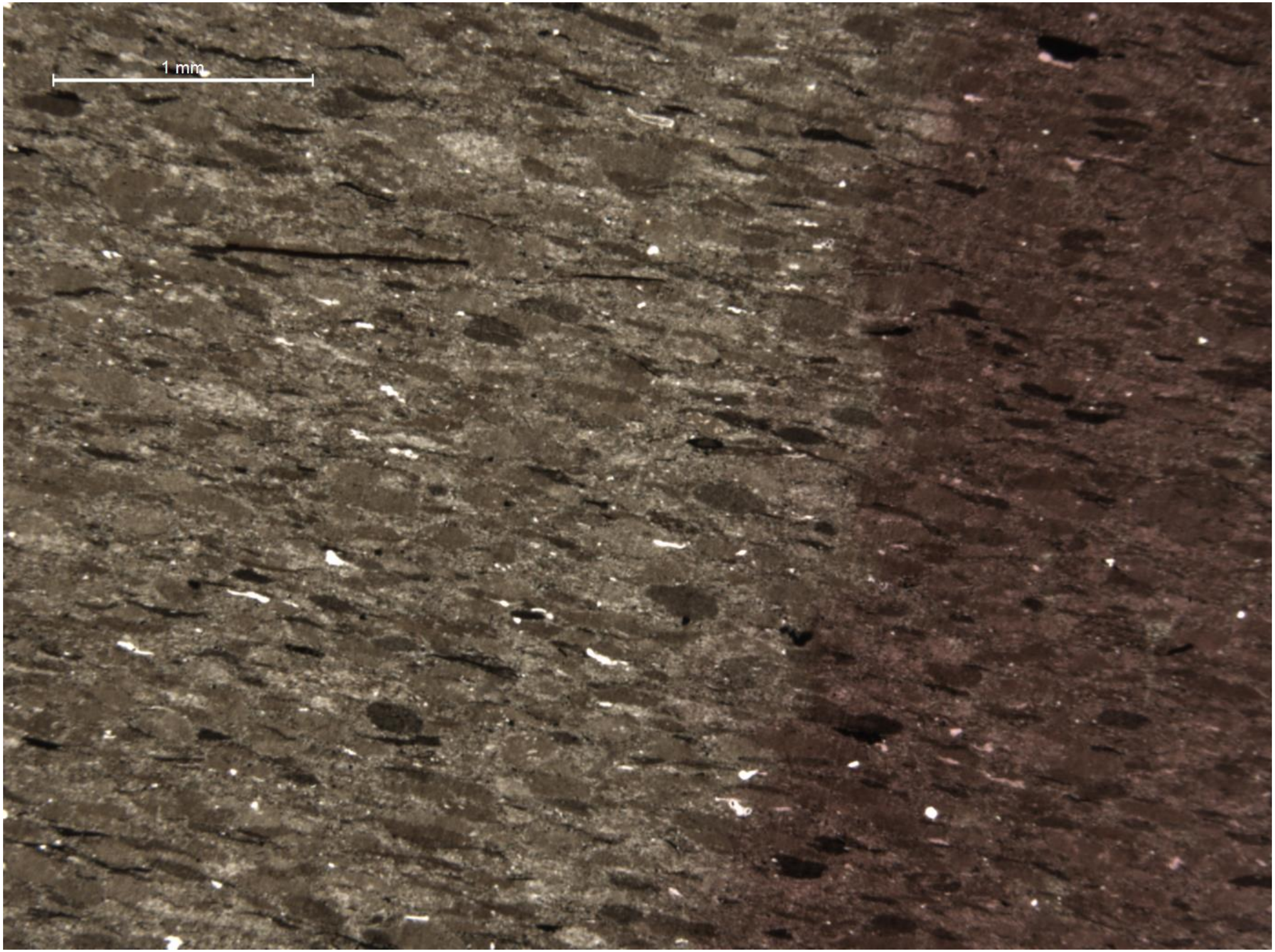
Gries, J.P, P.H. Rahn, and R.K. Baker, 1976, A pump test in the Dakota Sandstone at Wall, SD, South Dakota Geological survey, circular 43, 11 p.

Frontier Sandstone



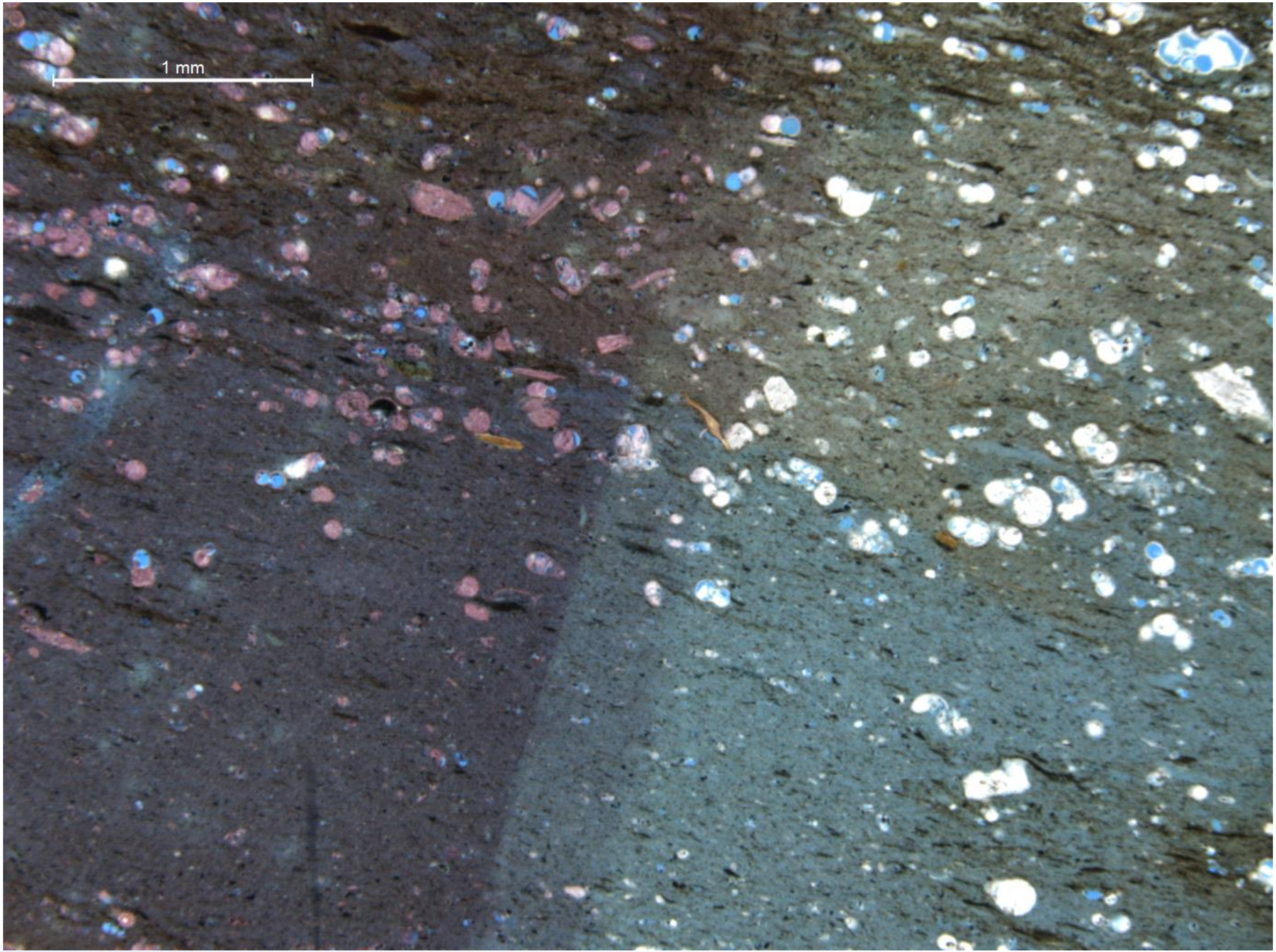
Photomicrograph by Yael Tucker

Niobrara Shale



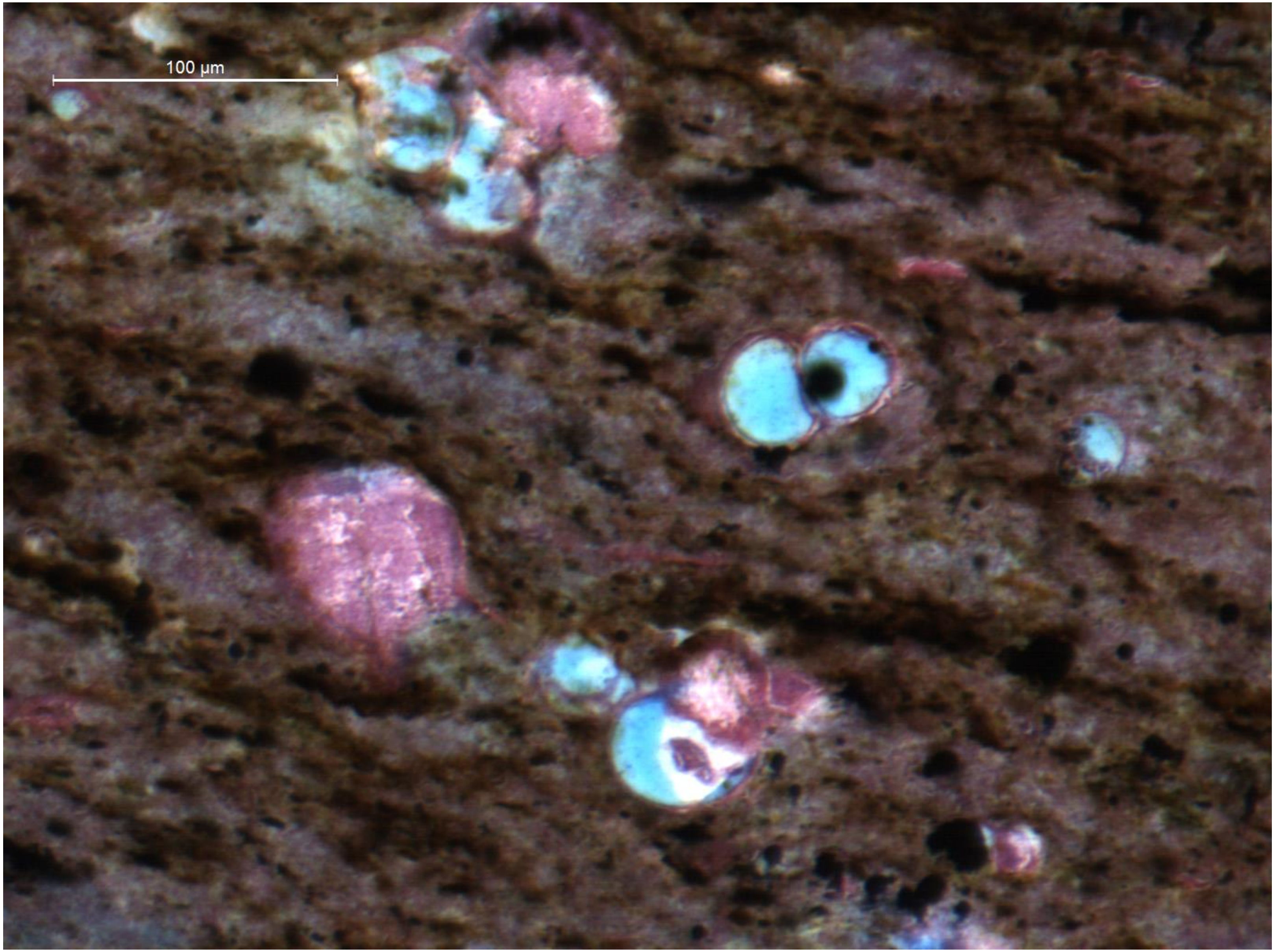
Photomicrograph by Yael Tucker

Niobrara Chalk



Photomicrograph by Yael Tucker

Niobrara Chalk 320X



Photomicrograph by Yael Tucker

Niobrara Resource Assessment

- Depth and thickness of target rocks
- Organic carbon content (should be >2%)
- Type of organic matter: kerogen types 1, 2 or 3
- Thermal maturity: biogenic gas – wet gas – oil generation (some gas) – dry gas – overmature
- Porosity and pore structure: gas containment ability
- Liquids content and mobility of gas/liquid phases
- Geologic structure/fracture systems: need enough to help gas flow to production well; too many will result in gas migration from the source rock
- Trends of all these across the Reservation
- Utilization of the produced gas

Potential Environmental Risks

Southwestern Pennsylvania

Drilling operations, Greene Co., PA, 2011 (Photos by D. Soeder)

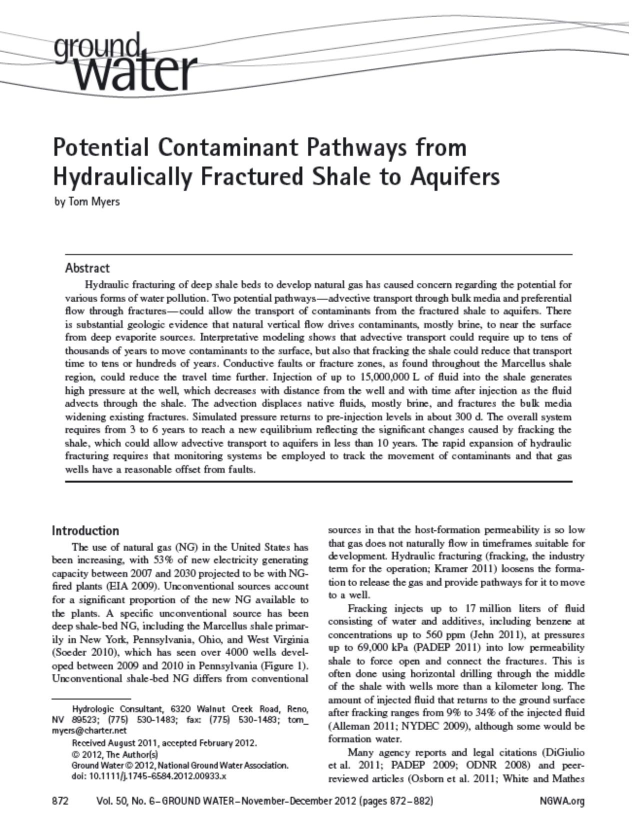
Hydraulic fracturing operations near Waynesburg, PA, 2011 (Photo by D. Soeder)

Alarming Assertions

1. Hydraulic fracturing can directly contaminate groundwater (Myers, 2012)

2. Hydraulic fracturing introduces natural gas into groundwater (Osborn et al., 2011)

3. Hydraulic fracturing of shale releases more greenhouse gas than burning coal (Howarth et al., 2011)



ground water

Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers

by Tom Myers

Abstract

Hydraulic fracturing of deep shale beds to develop natural gas has caused concern regarding the potential for various forms of water pollution. Two potential pathways—advective transport through bulk media and preferential flow through fractures—could allow the transport of contaminants from the fractured shale to aquifers. There is substantial geologic evidence that natural vertical flow drives contaminants, mostly brine, to near the surface from deep evaporite sources. Interpretative modeling shows that advective transport could require up to tens of thousands of years to move contaminants to the surface, but also that fracking the shale could reduce that transport time to tens or hundreds of years. Conductive faults or fracture zones, as found throughout the Marcellus shale region, could reduce the travel time further. Injection of up to 15,000,000 L of fluid into the shale generates high pressure at the well, which decreases with distance from the well and with time after injection as the fluid advects through the shale. The advection displaces native fluids, mostly brine, and fractures the bulk media widening existing fractures. Simulated pressure returns to pre-injection levels in about 300 d. The overall system requires from 3 to 6 years to reach a new equilibrium reflecting the significant changes caused by fracking the shale, which could allow advective transport to aquifers in less than 10 years. The rapid expansion of hydraulic fracturing requires that monitoring systems be employed to track the movement of contaminants and that gas wells have a reasonable offset from faults.

Introduction

The use of natural gas (NG) in the United States has been increasing, with 53% of new electricity generating capacity between 2007 and 2030 projected to be with NG-fired plants (EIA 2009). Unconventional sources account for a significant proportion of the new NG available to the plants. A specific unconventional source has been deep shale-bed NG, including the Marcellus shale primarily in New York, Pennsylvania, Ohio, and West Virginia (Soeder 2010), which has seen over 4000 wells developed between 2009 and 2010 in Pennsylvania (Figure 1). Unconventional shale-bed NG differs from conventional sources in that the host-formation permeability is so low that gas does not naturally flow in timeframes suitable for development. Hydraulic fracturing (fracking, the industry term for the operation; Kramer 2011) loosens the formation to release the gas and provide pathways for it to move to a well.

Fracking injects up to 17 million liters of fluid consisting of water and additives, including benzene at concentrations up to 560 ppm (Jehn 2011), at pressures up to 69,000 kPa (PADEP 2011) into low permeability shale to force open and connect the fractures. This is often done using horizontal drilling through the middle of the shale with wells more than a kilometer long. The amount of injected fluid that returns to the ground surface after fracking ranges from 9% to 34% of the injected fluid (Alleman 2011; NYDEC 2009), although some would be formation water.

Many agency reports and legal citations (DiGiulio et al. 2011; PADEP 2009; ODNR 2008) and peer-reviewed articles (Osborn et al. 2011; White and Mathes

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Hydrologic Consultant, 6320 Walnut Creek Road, Reno, NV 89523; (775) 530-1483; fax: (775) 530-1483; tom_myers@charter.net

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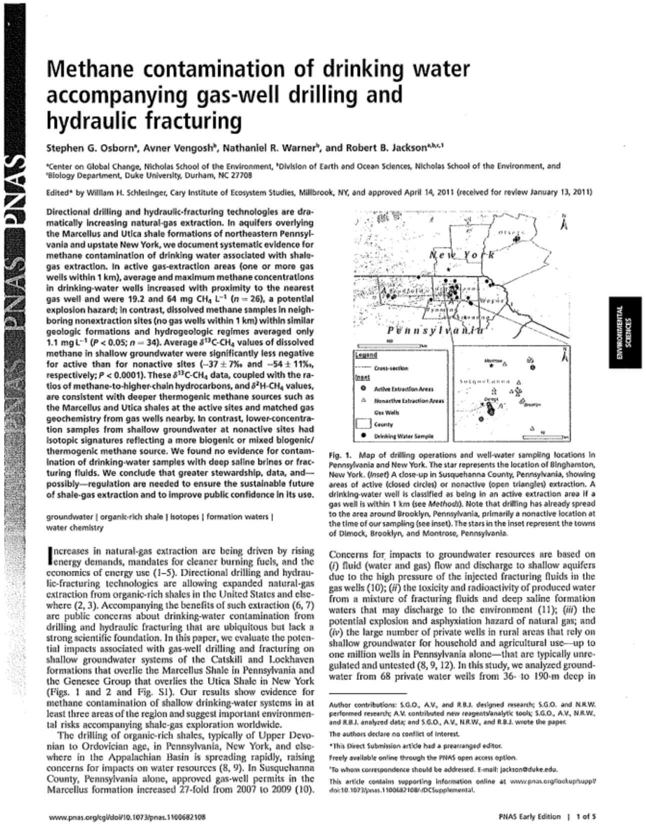


Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing

Stephen G. Osborn[a], Avner Vengosh[b], Nathaniel R. Warner[b], and Robert B. Jackson[a,b,c,1]

[a]Center on Global Change, Nicholas School of the Environment, [b]Division of Earth and Ocean Sciences, Nicholas School of the Environment, and [c]Biology Department, Duke University, Durham, NC 27708

Edited* by William H. Schlesinger, Cary Institute of Ecosystem Studies, Millbrook, NY, and approved April 14, 2011 (received for review January 13, 2011)

Directional drilling and hydraulic-fracturing technologies are dramatically increasing natural-gas extraction. In aquifers overlying the Marcellus and Utica shale formations of northeastern Pennsylvania and upstate New York, we document systematic evidence for methane contamination of drinking water associated with shale-gas extraction. In active gas-extraction areas (one or more gas wells within 1 km), average and maximum methane concentrations in drinking-water wells increased with proximity to the nearest gas well and were 19.2 and 64 mg CH_4 L^{-1} ($n = 26$), a potential explosion hazard; in contrast, dissolved methane samples in neighboring nonextraction sites (no gas wells within 1 km) within similar geologic formations and hydrogeologic regimes averaged only 1.1 mg L^{-1} ($P < 0.05$; $n = 34$). Average $\delta^{13}C$-CH_4 values of dissolved methane in shallow groundwater were significantly less negative for active than for nonactive sites (−37 ± 7‰ and −54 ± 11‰, respectively; $P < 0.0001$). These $\delta^{13}C$-CH_4 data, coupled with the ratios of methane-to-higher-chain hydrocarbons, and $\delta^{2}H$-CH_4 values, are consistent with deeper thermogenic methane sources such as the Marcellus and Utica shales at the active sites and matched gas geochemistry from gas wells nearby. In contrast, lower-concentration samples from shallow groundwater at nonactive sites had isotopic signatures reflecting a more biogenic or mixed biogenic/thermogenic methane source. We found no evidence for contamination of drinking-water samples with deep saline brines or fracturing fluids. We conclude that greater stewardship, data, and—possibly—regulation are needed to ensure the sustainable future of shale-gas extraction and to improve public confidence in its use.

groundwater | organic-rich shale | isotopes | formation waters | water chemistry

Increases in natural-gas extraction are being driven by rising energy demands, mandates for cleaner burning fuels, and the economics of energy use (1–5). Directional drilling and hydraulic-fracturing technologies are allowing expanded natural-gas extraction from organic-rich shales in the United States and elsewhere (2, 3). Accompanying the benefits of such extraction (6, 7) are public concerns about drinking-water contamination from drilling and hydraulic fracturing that are ubiquitous but lack a strong scientific foundation. In this paper, we evaluate the potential impacts associated with gas-well drilling and fracturing on shallow groundwater systems of the Catskill and Lockhaven formations that overlie the Marcellus Shale in Pennsylvania and the Genesee Group that overlies the Utica Shale in New York (Figs. 1 and 2 and Fig. S1). Our results show evidence for methane contamination of shallow drinking-water systems in at least three areas of the region and suggest important environmental risks accompanying shale-gas exploration worldwide.

The drilling of organic-rich shales, typically of Upper Devonian to Ordovician age, in Pennsylvania, New York, and elsewhere in the Appalachian Basin is spreading rapidly, raising concerns for impacts on water resources (8, 9). In Susquehanna County, Pennsylvania alone, approved gas-well permits in the Marcellus formation increased 27-fold from 2007 to 2009 (10). Concerns for impacts to groundwater resources are based on (*i*) fluid (water and gas) flow and discharge to shallow aquifers due to the high pressure of the injected fracturing fluids in the gas wells (10); (*ii*) the toxicity and radioactivity of produced water from a mixture of fracturing fluids and deep saline formation waters that may discharge to the environment (11); (*iii*) the potential explosion and asphyxiation hazard of natural gas; and (*iv*) the large number of private wells in rural areas that rely on shallow groundwater for household and agricultural use—up to one million wells in Pennsylvania alone—that are typically unregulated and untested (8, 9, 12). In this study, we analyzed groundwater from 68 private water wells from 36- to 190-m deep in

Fig. 1. Map of drilling operations and well-water sampling locations in Pennsylvania and New York. The star represents the location of Binghamton, New York. (*Inset*) A close-up in Susquehanna County, Pennsylvania, showing areas of active (closed circles) or nonactive (open triangles) extraction. A drinking-water well is classified as being in an active extraction area if a gas well is within 1 km (see *Methods*). Note that drilling has already spread to the area around Brooklyn, Pennsylvania, primarily a nonactive location at the time of our sampling (see inset). The stars in the inset represent the towns of Dimock, Brooklyn, and Montrose, Pennsylvania.

Author contributions: S.G.O., A.V., and R.B.J. designed research; S.G.O. and N.R.W. performed research; A.V. contributed new reagents/analytic tools; S.G.O., A.V., N.R.W., and R.B.J. analyzed data; and S.G.O., A.V., N.R.W., and R.B.J. wrote the paper.

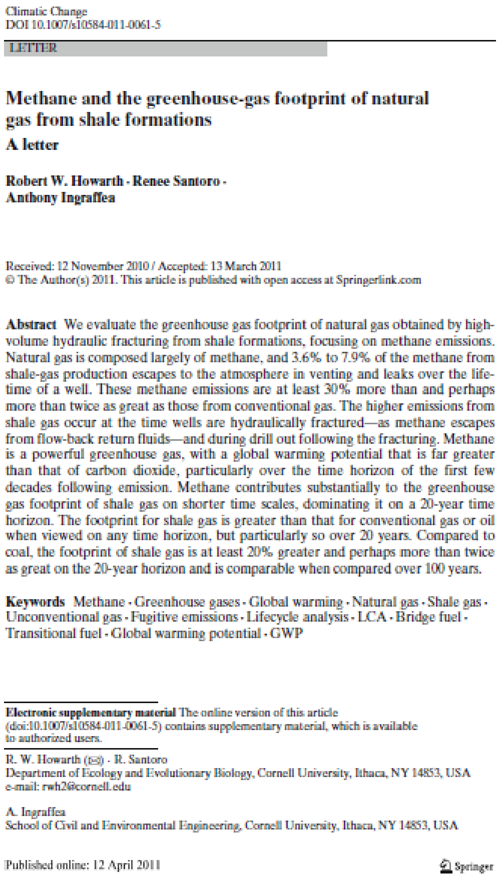
The authors declare no conflict of interest.

*This Direct Submission article had a prearranged editor.

[1]To whom correspondence should be addressed. E-mail: jackson@duke.edu.

This article contains supporting information online at www.pnas.org/lookup/suppl/doi:10.1073/pnas.1100682108/-/DCSupplemental.

www.pnas.org/cgi/doi/10.1073/pnas.1100682108 PNAS Early Edition | 1 of 5



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

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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

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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

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"Seem logical" - but are they?

Looking a bit more closely…

- **Myers' paper is a modeling exercise with no data; simulates five scenarios**
- **Gas shales are gas-saturated, and gas is the mobile phase. The partial water saturation present in gas shales is not mobile (Soeder et al., 1986)**

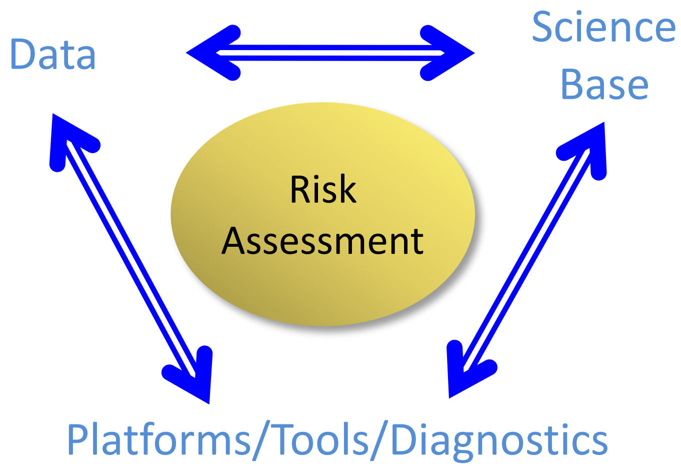
- **The Duke study offers no baseline data of pre-drilling methane.**
- **Baseline data show that methane is ubiquitous in northeastern PA groundwater, and appears to have migrated upward along natural fracture systems from shallow geologic sources (Molofsky et al., 2012)**

- **The Cornell paper admits up front that their leakage data are very uncertain, but draws broad conclusions anyway.**
- **Greenhouse gas life cycle calculations for natural gas suffer huge levels of uncertainty in the data on leakage downstream, midstream and upstream, ranging from 1% to 11% of throughput (Stephenson et al., 2011)**

What Are the Real Risks?

- **Probabilistic risk assessment following valid scientific principles**
- **Separating real risks from perceived risks**
- **Engineering risk:**
  - **Potential for a contaminant release**
    - Risk varies with phase of operations
    - Short-term versus long-term risks
  - **Potential for an induced seismic event**
- **Cumulative risk:**
  - **Multiple wells impacting landscapes & watersheds**
  - **What are the thresholds?**
- **Receptors: Air, water, landscapes, ecosystems (including human health)**
- **Reduction of uncertainty, improving recovery efficiency**
- **Regulations and enforcement**
  - **Engineering of gas wells is understood, they can be installed without incident**
  - **Most risk is introduced by human error, not following prescribed engineering procedures, not understanding impacts.**
  - **This can be addressed through enforcement of regulations**
  - **Many problems seem to occur because industry did not know they were problems.**
  - **Industry is adaptable and always learning, but changes must make sense technically and economically.**

Multi-Agency Environmental Assessment



Data

Science Base

Risk Assessment

Platforms/Tools/Diagnostics

Direction from DOE Secretary Chu in 2011: Assess environmental risk of oil and gas: 1) unconventionals; 2) deepwater/frontier

Executive Order from President Obama in April 2012: DOE, USGS and EPA are to jointly investigate risks from hydraulic fracturing.

- Assess the risks and receptors
- Research focus: UOG national plan, case studies (Marcellus, Barnett, Bakken)
- Plan completed November 2012, sent to White House for review.

EPA

- Air monitoring
- Environment and human health risk
- Water quality

ENERGY

- Wellbore integrity, flow and control
- Green technologies
- System engineering, imaging, and materials

USGS

- Resource assessment
- Hydrology and geology
- Land use, wildlife, and ecological impact

Collaboration

Collaboration

Collaboration

Collaboration

DOE Risk Assessment for Shale Gas Development

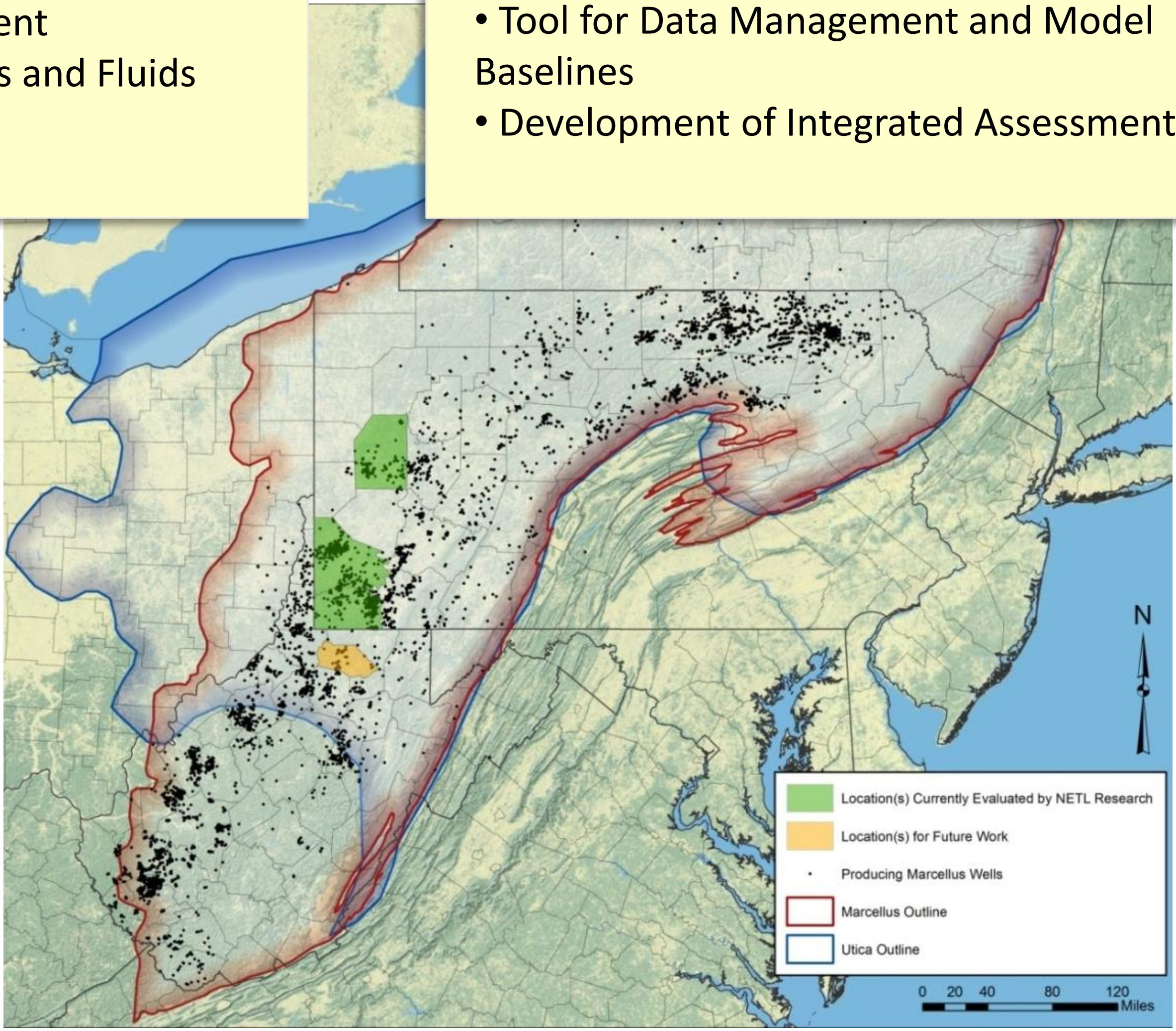
Goal: Deliver Integrated Assessments for

- Fugitive Air Emissions and GHG
- Produced Water Management
- Subsurface Migration of Gas and Fluids
- Induced Seismicity

Research Plan Organization

- Science Base to Support Assessments
- Tool for Data Management and Model Baselines
- Development of Integrated Assessments

- Field Data to establish baselines and impacts of processes
- Laboratory Data for simulations and confirmation of field data
- Computational Tools to characterize and predict system baselines and behavior



Field-Based Monitoring for Site Evaluation

Air Quality

NETL Air Quality Monitoring Trailer

Currently assessing shale gas drillsites in PA

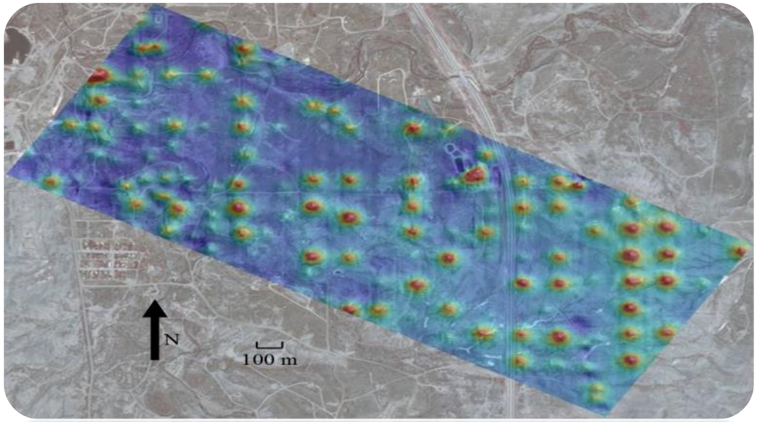
Reducing uncertainty of GHG emissions for life cycle calculations

Orphaned/Abandoned Wells

Airborne magnetic surveys.

Reviewing state records in PA

IR hydrocarbon detections.



Hydrology

Groundwater flow and chemistry

Surface water impacts; cumulative impacts

Using opportunistic data when available

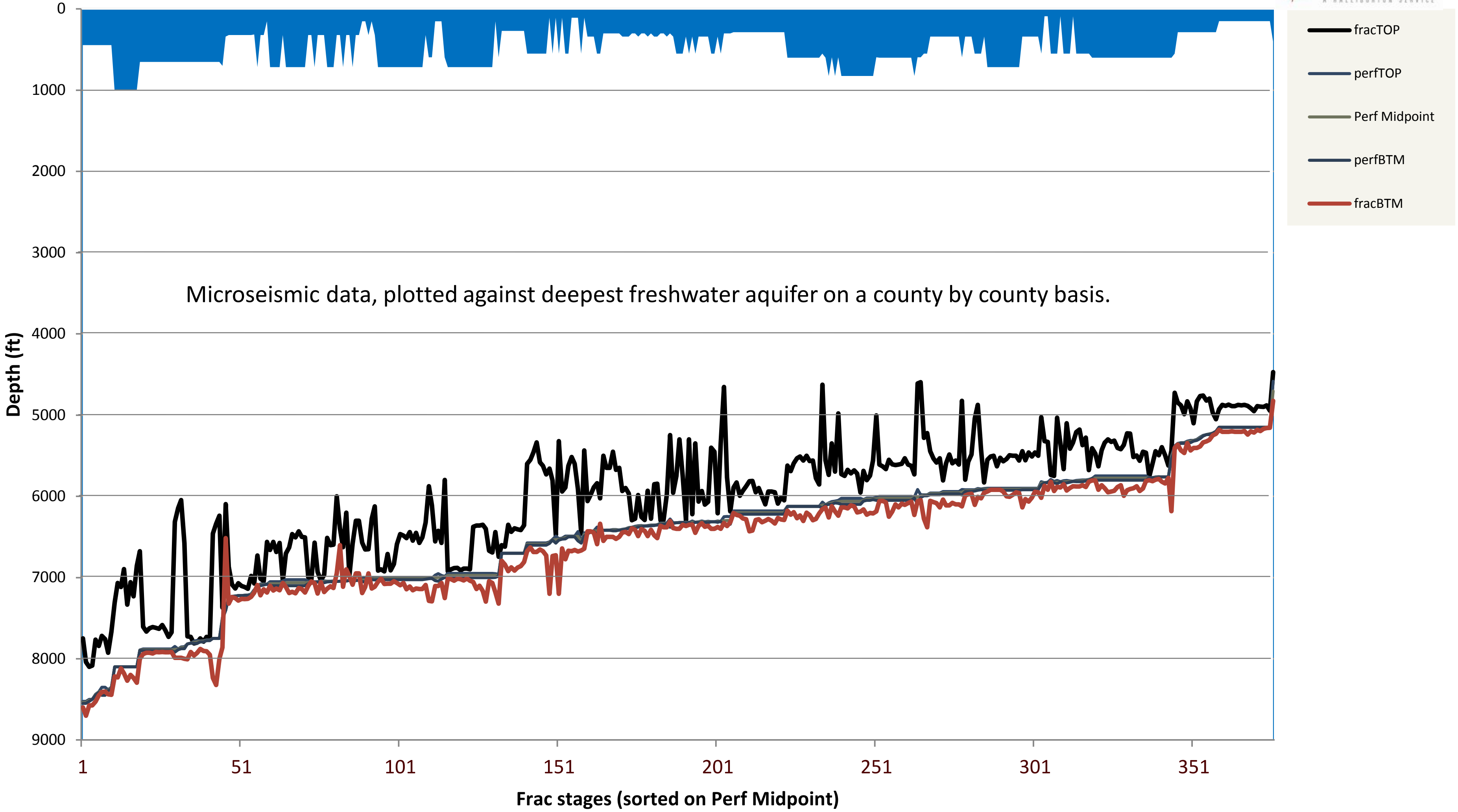
Induced Seismicity

Rock strength analyses

Modeling of recent events

Out of Zone Fractures

Marcellus Mapped Frac Treatments



Microseismic data, plotted against deepest freshwater aquifer on a county by county basis.

Kell (2011): Both Ohio and Texas reported zero contamination incidents directly associated with hydraulic fracturing (221,092 wells total) over the time periods studied.

Fisher, Kevin, 2010, Data confirm safety of well fracturing, The American Oil and Gas Reporter, July 2010, www.aogr.com

Surface Leaks and Spills

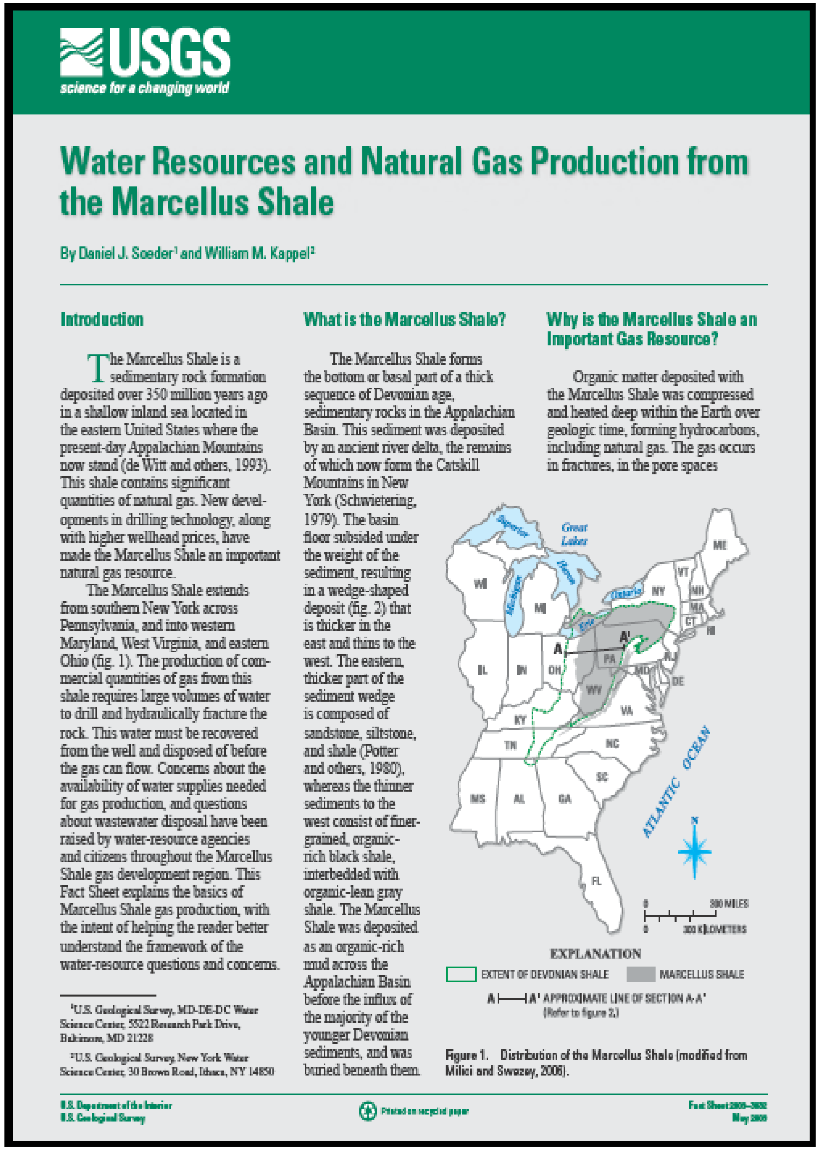
- Much greater risk to groundwater that direct contamination from frac.
- Indicators like Sr isotopes needed to detect drilling, frac, and produced fluids (Chapman and others, 2012)
- Cumulative effects are a concern in small watersheds (Streets, 2012)
- Leachate from drill cuttings may be a potential risk to groundwater (Soeder, 2011)
- Groundwater contamination sources from produced hydrocarbons and spilled frac chemicals need definition.
- Natural attenuation may break down both hydrocarbons and organic frac chemicals, but data are needed on the processes and rates.


Photo by Doug Mazer, used with permission.

Groundwater Risk per Production Phase

Production Activity	Potential GW Risks
initial spud-in	air/fluid infiltration into aquifer
set surface casing; drill vertical well	well integrity; annular migration of fluids from open hole
set intermediate casing; drill lateral	low risk to groundwater
set production casing; complete well	frac chemicals on site; surface spills, potential leakage
hydraulic fracturing	potential to intercept abandoned well; frac chemicals on site
flowback and produced waters	frac chemicals and high TDS waters on site; surface spills
long term gas production	chemicals offsite, reduced produced waters; potential weathering of cuttings

Changing Risk Factors over Time



Water Resources and Natural Gas Production from the Marcellus Shale

By Daniel J. Soeder[1] and William M. Kappel[2]

Introduction

The Marcellus Shale is a sedimentary rock formation deposited over 350 million years ago in a shallow inland sea located in the eastern United States where the present-day Appalachian Mountains now stand (de Witt and others, 1993). This shale contains significant quantities of natural gas. New developments in drilling technology, along with higher wellhead prices, have made the Marcellus Shale an important natural gas resource.

The Marcellus Shale extends from southern New York across Pennsylvania, and into western Maryland, West Virginia, and eastern Ohio (fig. 1). The production of commercial quantities of gas from this shale requires large volumes of water to drill and hydraulically fracture the rock. This water must be recovered from the well and disposed of before the gas can flow. Concerns about the availability of water supplies needed for gas production, and questions about wastewater disposal have been raised by water-resource agencies and citizens throughout the Marcellus Shale gas development region. This Fact Sheet explains the basics of Marcellus Shale gas production, with the intent of helping the reader better understand the framework of the water-resource questions and concerns.

What is the Marcellus Shale?

The Marcellus Shale forms the bottom or basal part of a thick sequence of Devonian age, sedimentary rocks in the Appalachian Basin. This sediment was deposited by an ancient river delta, the remains of which now form the Catskill Mountains in New York (Schwietering, 1979). The basin floor subsided under the weight of the sediment, resulting in a wedge-shaped deposit (fig. 2) that is thicker in the east and thins to the west. The eastern, thicker part of the sediment wedge is composed of sandstone, siltstone, and shale (Potter and others, 1980), whereas the thinner sediments to the west consist of finer-grained, organic-rich black shale, interbedded with organic-lean gray shale. The Marcellus Shale was deposited as an organic-rich mud across the Appalachian Basin before the influx of the majority of the younger Devonian sediments, and was buried beneath them.

Why is the Marcellus Shale an Important Gas Resource?

Organic matter deposited with the Marcellus Shale was compressed and heated deep within the Earth over geologic time, forming hydrocarbons, including natural gas. The gas occurs in fractures, in the pore spaces

Figure 1. Distribution of the Marcellus Shale (modified from Milici and Swezey, 2006).

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[1] U.S. Geological Survey, MD-DE-DC Water Science Center, 5522 Research Park Drive, Baltimore, MD 21228

[2] U.S. Geological Survey, New York Water Science Center, 30 Brown Road, Ithaca, NY 14850

U.S. Department of the Interior
U.S. Geological Survey

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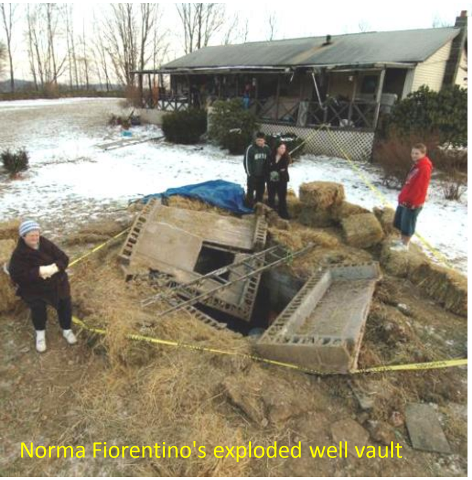
Fact Sheet 2009–3032
May 2009

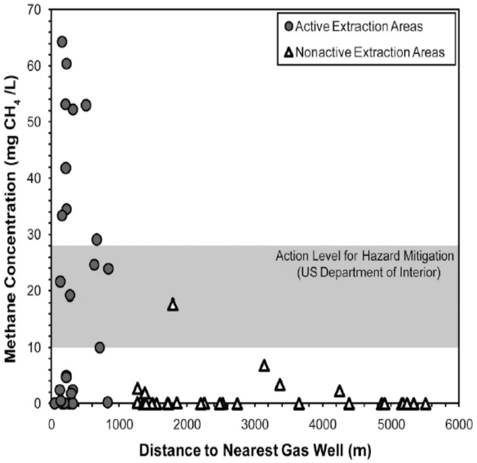
- **Water risks identified in the 2009 Fact Sheet:**
  - Municipal water supplies used for frac fluid
  - Damage to small watersheds and headwater streams from land-use activities
  - Water quality degradation from high TDS flowback water in surface streams via municipal WWT
- **Status of 2009 water risks in 2013**
  - Tap water not used for frac fluid - raw water directly from streams is now impounded during high flow periods.
  - Well spacing of 640 acres has lessened small watershed impacts, but they still exist.
  - Recycling of flowback fluid and UIC well disposal of residual waste have greatly reduced water quality impacts from high TDS
- **Risks NOT identified in the 2009 Fact Sheet**
  - Induced seismicity from UIC injection
  - Potential for toxic leachate from cuttings
  - Mobilization of stray gas in nearby water wells
  - Microbiology of recycled frac fluid

http://pubs.usgs.gov/fs/2009/3032/

Complications of Stray Gas

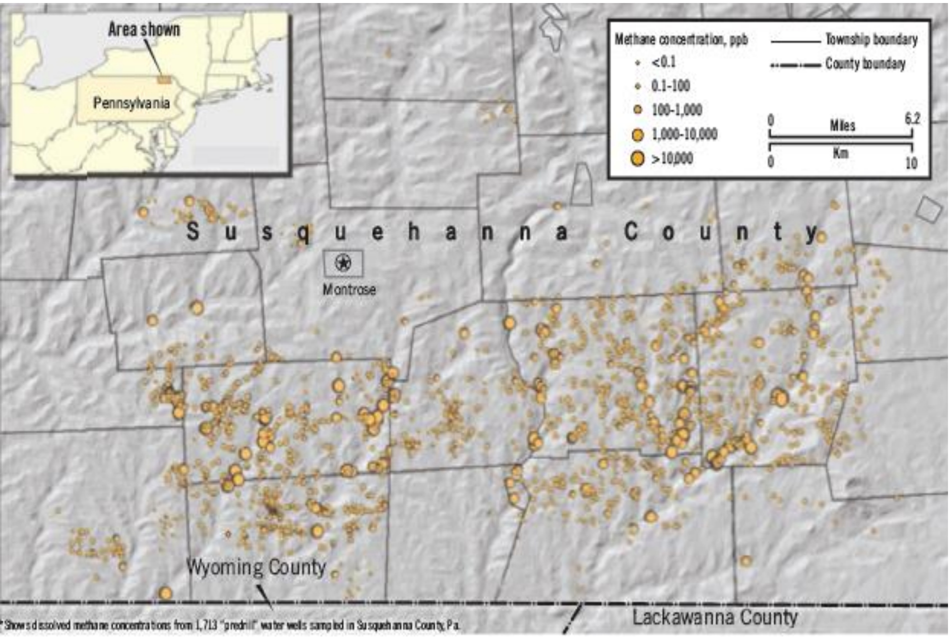


Norma Fiorentino's exploded well vault



Duke University study on 68 wells shows methane in groundwater in NE PA occurs in much higher concentrations near gas wells, and concluded it is related to wells.

(Osborn, Stephen G., Avner Vengosh, Nathaniel R. Warner, and Robert B. Jackson, 2011, Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing: PNAS Early Edition Direct Submission article, available on-line only; Proceedings of the National Academy of Sciences, 5 p)

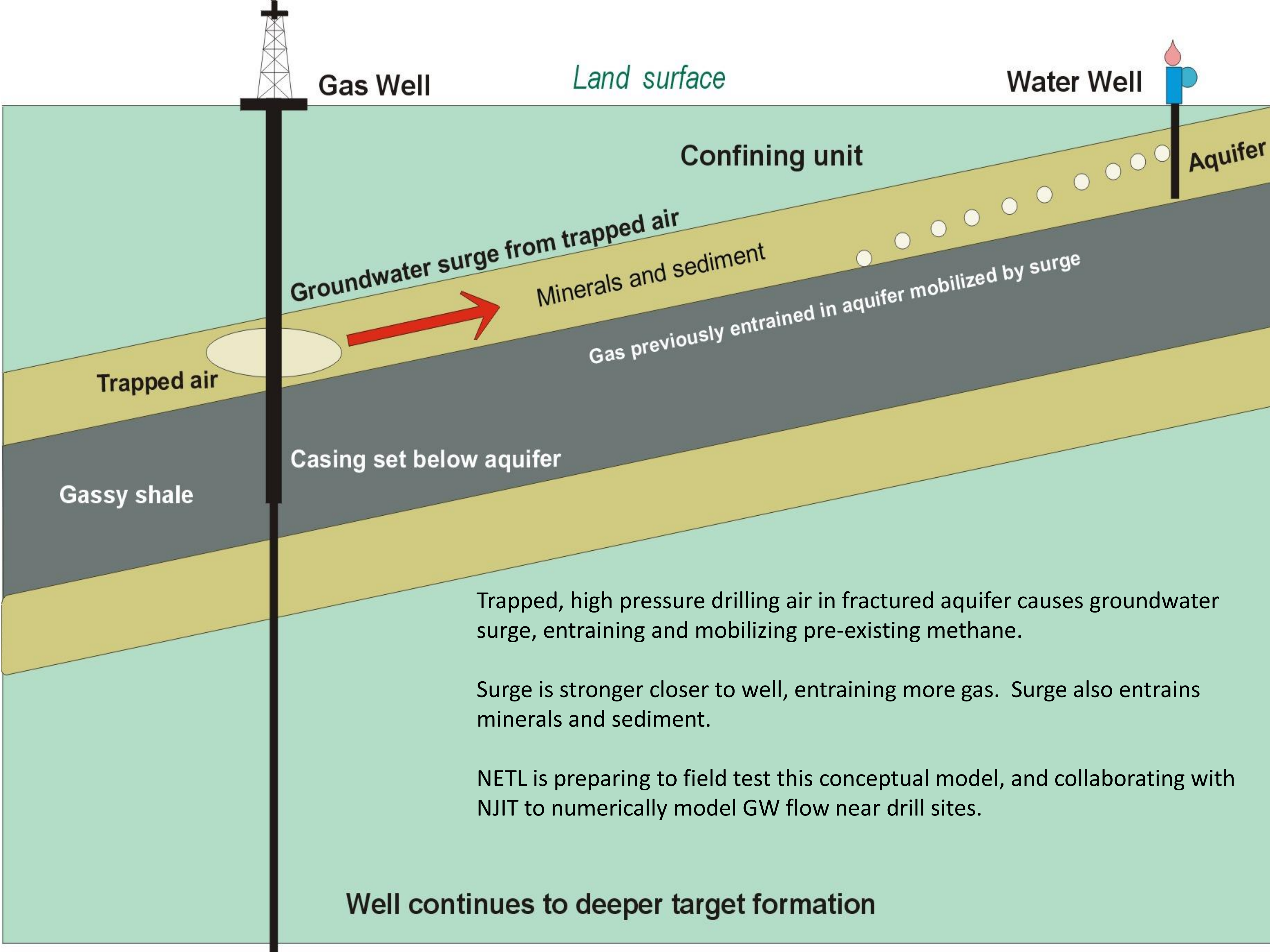


*Shows dissolved methane concentrations from 1,713 "predrill" water wells sampled in Susquehanna County, Pa.

Baseline data on 1700 water wells prior to gas drilling shows methane is common in NE PA groundwater, and related to topography (highest in stream valleys).

(Molofsky, L. J., J.A. Connor, S.K. Farhat, A.S. Wylie, Jr., and Tom Wagner, 2011, Methane in Pennsylvania water wells unrelated to Marcellus shale fracturing: Oil & Gas Journal, Vol. 109, no. 49, December 5, 2011, p. 54-67)

The proper question might be: how might drilling affect domestic water wells when methane is present in the aquifer?



Trapped, high pressure drilling air in fractured aquifer causes groundwater surge, entraining and mobilizing pre-existing methane.

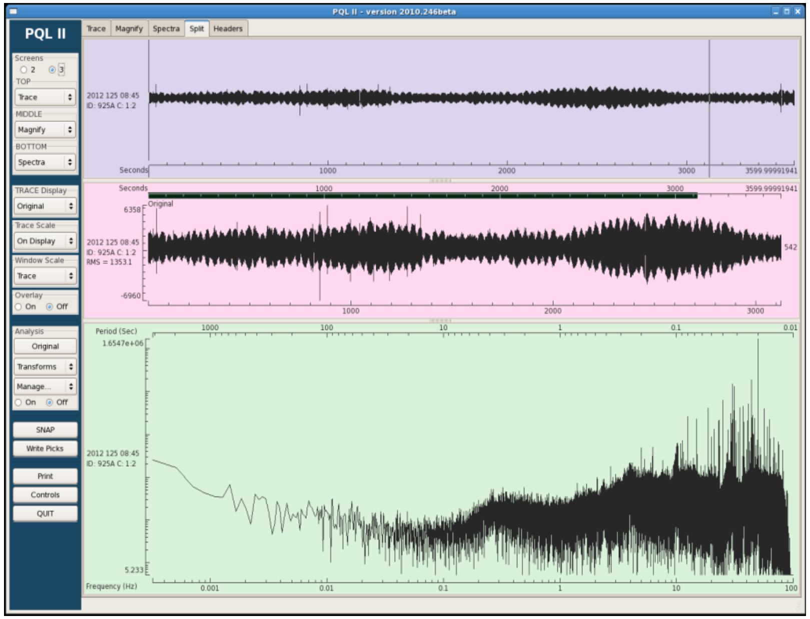
Surge is stronger closer to well, entraining more gas. Surge also entrains minerals and sediment.

NETL is preparing to field test this conceptual model, and collaborating with NJIT to numerically model GW flow near drill sites.

Induced Seismicity

- Induced seismicity: "felt" = M>2; "damaging" = M>4+
- Induced seismicity from **hydraulic fracturing** believed to be low, but some examples exist (notably an incident in England in 2011)
- Induced seismicity from **flowback disposal** down UIC wells of much greater concern (AK, OH, OK, TX)
- Currently generating database (literature and measurement) of Marcellus and surrounding rock properties

Energy technology	Number of Projects	Number of Felt Induced Events	Maximum Magnitude of Felt Events	Number of Events $M \geq 4.0^d$	Location of $M \geq 2.0$ Events
Secondary oil and gas recovery (waterflooding)	~108,000 (wells)	One or more events at 18 sites across the country	4.9	3	AL, CA, CO, MS, OK, TX
Tertiary oil and gas recovery (EOR)	~13,000	None known	None known	0	None known
Hydraulic fracturing for shale gas production	35,000 wells total	1	2.8	0	OK
Hydrocarbon withdrawal	~6,000 fields	20 sites	6.5	5	CA, IL, NB, OK, TX
Waste water disposal wells	~30,000	8	4.8^c	7	AR, CO, OH



Integrated Risk Assessment

- **DOE National Risk Assessment Partnership (NRAP)**
  - Cooperative effort among NETL, LBNL, LLNL, LANL, and PNNL
  - Scenario-based, site modeling for carbon dioxide storage in engineered geologic systems
- **Integrated Assessment Models (IAM)**
  - Probabilistic assessment of system risk (multi-site)
  - Use feature-event-process (FEP) scenarios and probabilities
  - Develop high fidelity, validated models of system components (Design Basis Document)
  - Reduce uncertainty and develop reduced order models (ROMs)
  - Integrate ROMs through IAM to predict total system performance, interactions, individual and cumulative risk
  - Calibrate using field data, validate by monitoring
- **Sometimes called a site performance assessment**
- **Adapt and modify for unconventional oil and gas**

Shale Gas Environmental Risk Assessment


Utica Shale, New York

Goals

Assess short/long term and cumulative environmental impacts.

Define engineering risks.

Data-based, scientific investigations of impacts and processes.

Outcomes

Rigorous study with conclusions supported by well-documented data

Benefits

Information-based regulations and indicators for regulatory monitoring

Improved management practices for shale gas production to mitigate problems

Create a more informed environmental debate