The Successful Development of Shale Gas Resources in the United States*

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Abstract

In response to the price hikes and fuel shortages caused by the 1973-1974 oil embargo, the U.S. Energy Research and Development Administration initiated a number of efforts, including the Eastern Gas Shales Project (EGSP), to solve the "energy crisis" by developing new, domestic sources of oil and natural gas. The goals of the EGSP when studies began in 1975 were to assess the resource base and develop technology to overcome the challenges of recovering natural gas from organic-rich, Devonian-age shales in the eastern United States. This program became the responsibility of the U.S. Department of Energy (DOE) when it was created in August 1977.

The major components of the EGSP were resource characterization and inventory, the development of more effective extraction technology, and the transfer of that technology to industry. From 1976 to 1982, the EGSP used cooperative agreements with drillers to collect and characterize oriented core from 44 wells targeting a variety of Devonian shales in the Michigan, Illinois, and Appalachian Basins. Marcellus Shale core from an EGSP well in West Virginia was analyzed for DOE by the Institute of Gas Technology in 1986, with results suggesting that the Marcellus was capable of containing much more gas than had been previously estimated by the National Petroleum Council. Also in 1986, a horizontal well drilled by DOE in the Huron Shale tested many of the concepts that would later become part of the technology.

Shale gas development awaited improvements in production techniques. Mitchell Energy had been experimenting on the Barnett Shale in the Fort Worth Basin since the early 1980s, achieving success in 1997 from horizontal wells using offshore directional drilling technology and staged hydraulic fracturing. Field results convinced Mitchell that light sand fracs and slickwater fracs were the most effective completion methods on gas shale, and the Barnett Shale gas play began in the early

2000s. The Fayetteville and Haynesville Shales in Arkansas and Louisiana were recognized as sharing many of the same characteristics as the Barnett Shale, leading to the subsequent development of these formations a few years later.

Range Resources drilled the Renz #1 well in Pennsylvania in 2005 to test Silurian prospects. The target unit had poor gas shows, but evidence of gas in the overlying Marcellus Shale led Range to review the old DOE reports on shale gas. Renz #1 was recompleted with a hydraulic fracture in the Marcellus, and returned substantial initial production. Thus encouraged, Range adapted the Mitchell Energy completion procedures to the Marcellus. After a number of failed attempts, the Gulla #9 well was completed horizontally with an initial production of nearly 5 million cubic feet per day. Other Marcellus wells soon followed, developing the play remarkably within five years.

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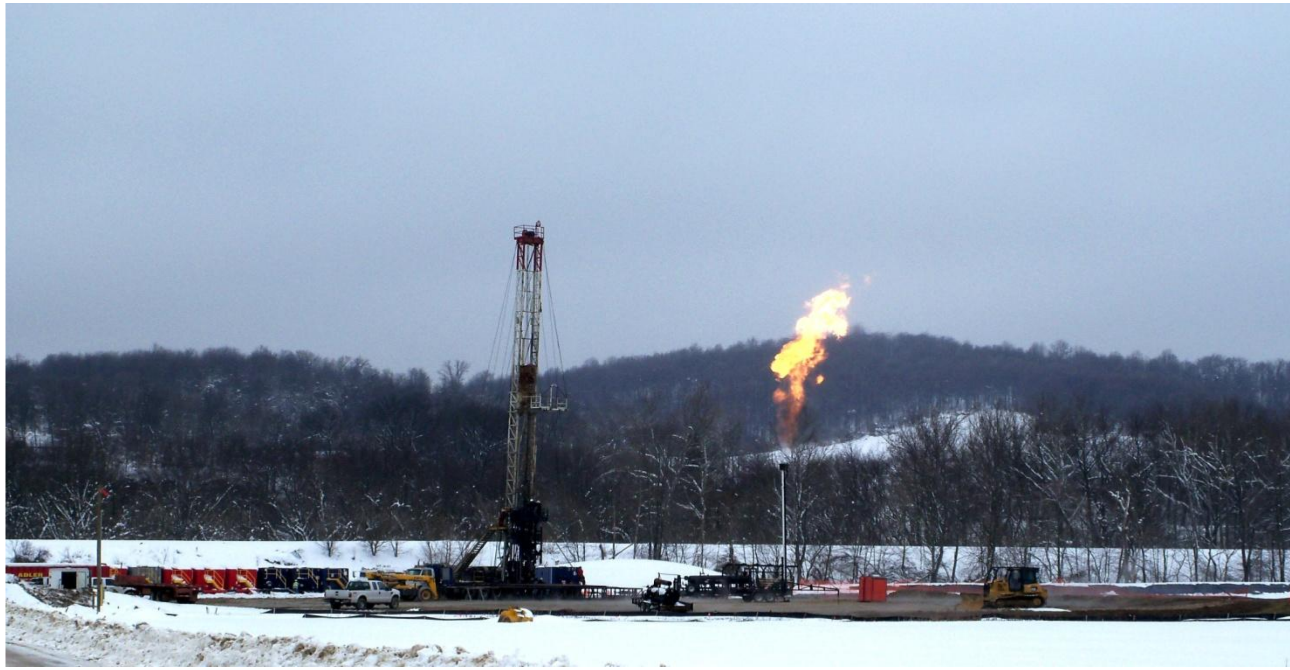
NATIONAL ENERGY TECHNOLOGY LABORATORY



The Successful Development of Shale Gas Resources in the United States

Daniel J. Soeder, NETL, Morgantown, WV

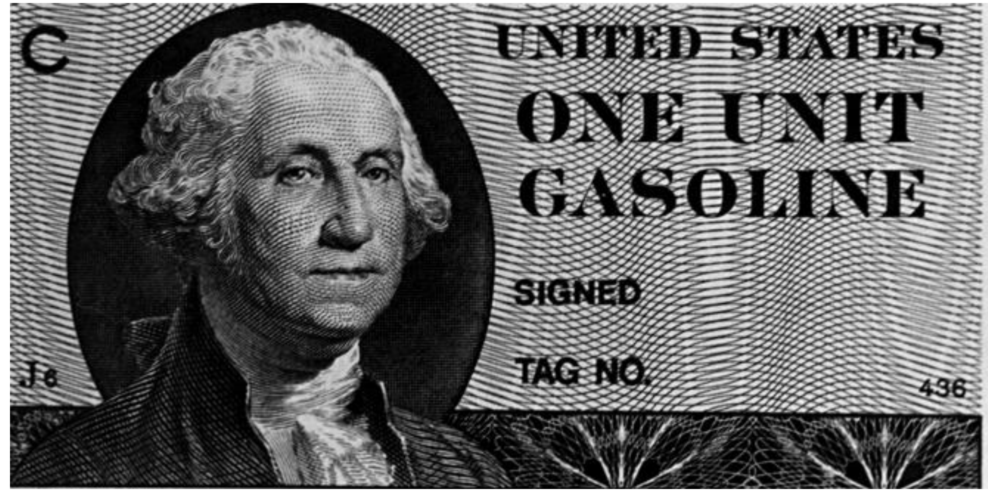
25 September 2012, Cleveland, Ohio

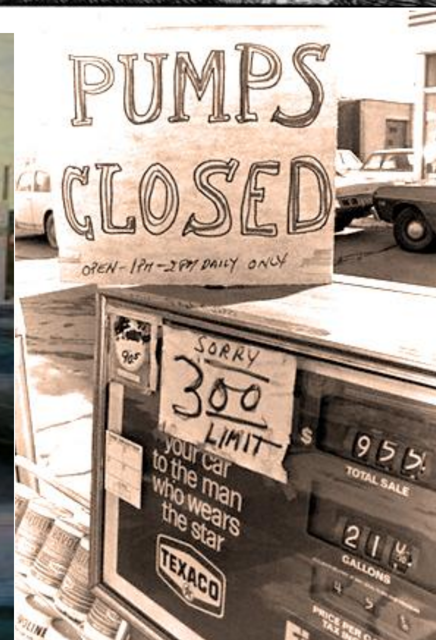
41st Annual Eastern Section AAPG Meeting

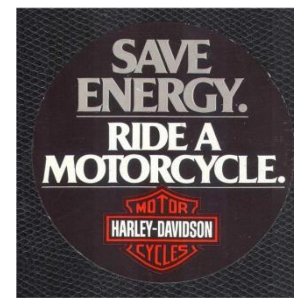
NETL-RUA Regional University Alliance

U.S. DEPARTMENT OF ENERGY

October 1973 to Spring 1974







Energy Crisis

- **October 6-25,1973: Yom Kippur War (Arabs vs. Israel)**
- **October 20, 1973 to Spring 1974: OPEC oil embargo**
  - Price of gasoline quadrupled in United States (0.40 - $1.60)
  - Today: $4.00/gallon to $16.00/gallon
  - Many service stations had no gas; those with gas had long lines
  - People felt stuck in the suburbs with a useless car
- **It is hard to overstate how traumatic this was to the American public, and to the post-1960s U.S. government**
- **U.S. Department of Energy formed by Carter Administration**
  - Created August 4, 1977 to deal with domestic energy issues
  - James R. Schlesinger was the first Secretary of Energy
- **Second Energy Crisis: Iran - 1979**
  - Turmoil over fall of the Shah disrupted oil exports
  - Not as severe - Saudi Arabia was able to make up shortfall
  - U.S. Government printed but never distributed ration coupons

New Sources of Natural Gas

- **Resources were known but not economical to produce.**
  - Dunkirk Shale in NY (1821)
  - Huron Shale in KY (early 1900s)
- **DOE funded natural gas R&D projects to increase domestic energy supplies:**
  - Eastern Gas Shales
  - Western Tight Gas Sands
  - Coal Bed Methane
- **Objective: Development of domestic sources of oil and gas**
  - Resource characterization/data transfer
  - Improved technology and engineering

SPE 7628

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.

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Devonian Shales

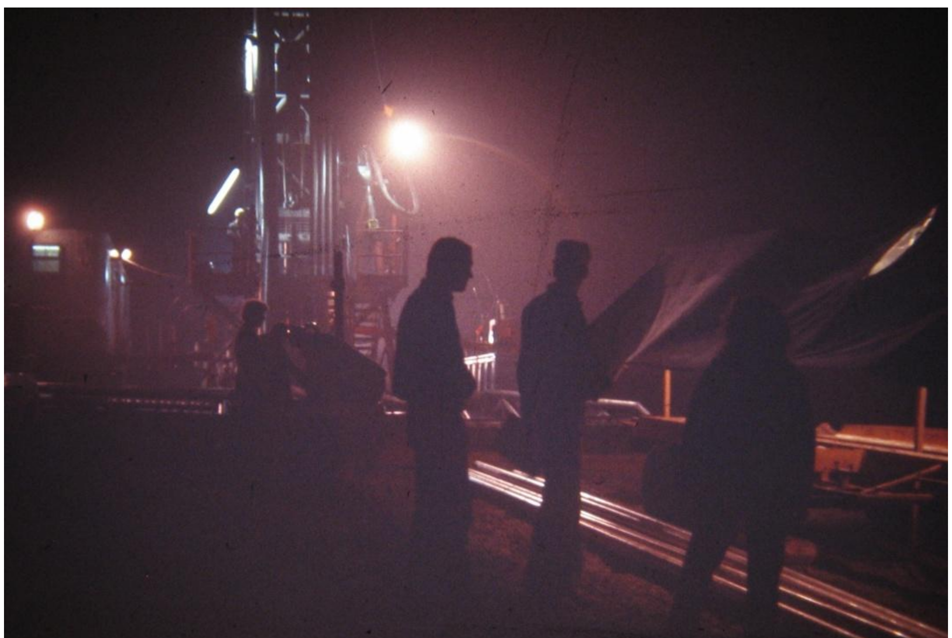
The Devonian shales of the Appalachian, Michigan, and Illinois basins have produced natural gas since the 1800's. These shales in the eastern U.S. (Fig. 1) contain a high volume of gas. Independent estimates of the recoverable gas range from 3 Tcf to several hundred times that amount. To date, the gas 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

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.

DOE Eastern Gas Shales Project 1976-1992



Gas Shale Geology

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

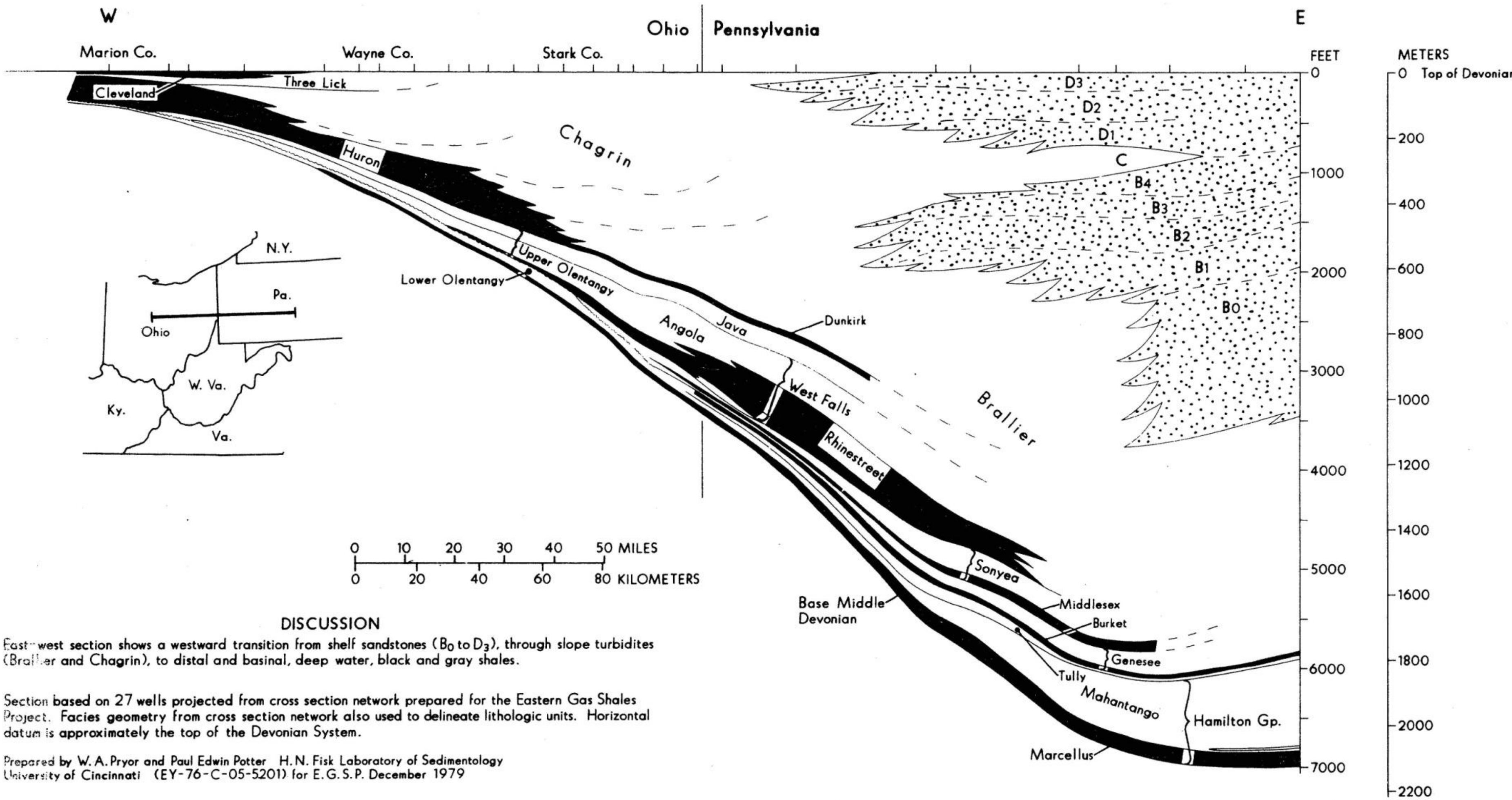
- Shale is organic-rich (black), or organic lean (gray or red), and commonly fissile.

- 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.

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.

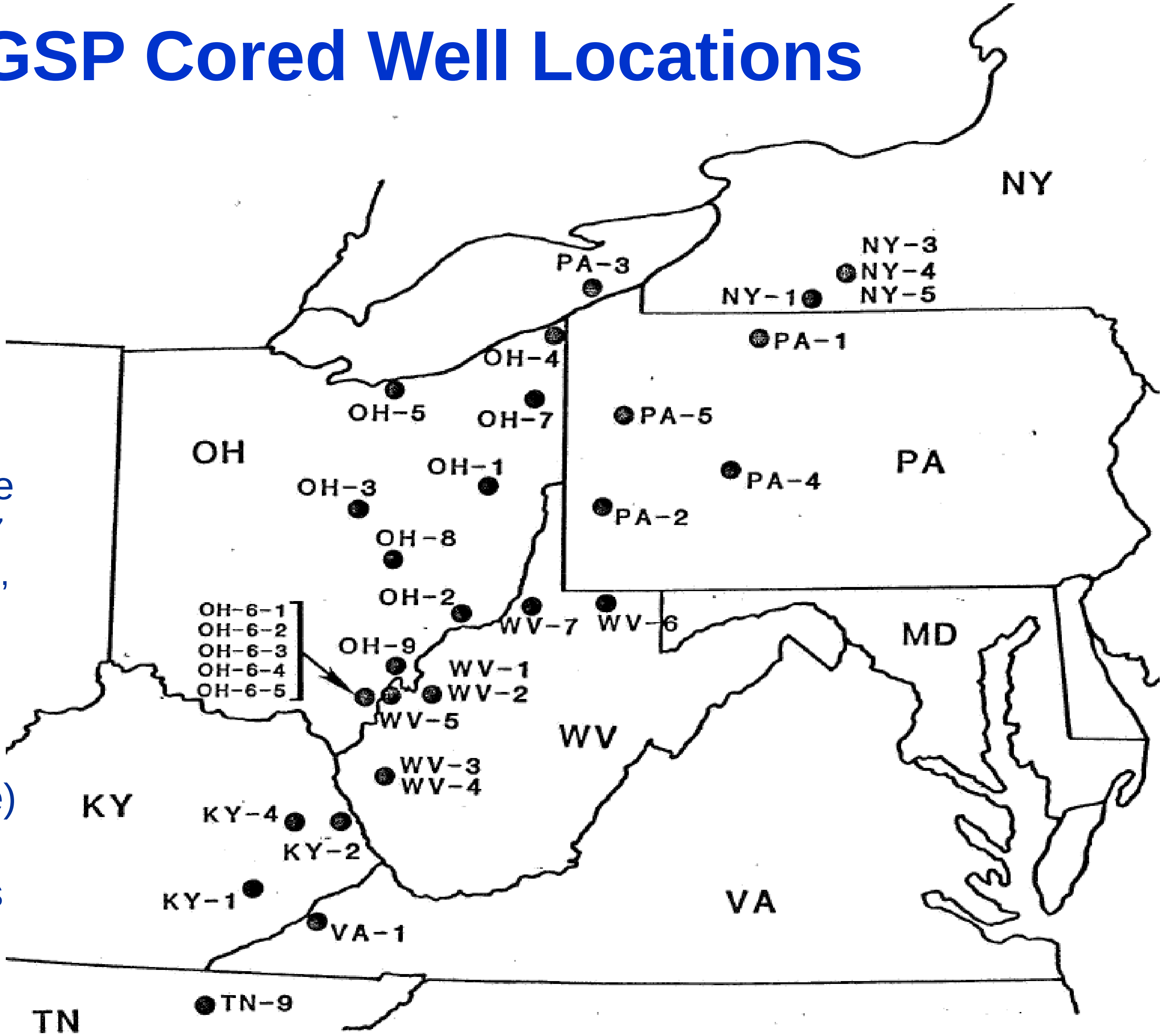
Section based on 27 wells projected from cross section network prepared for the Eastern Gas Shales Project. Facies geometry from cross section network also used to delineate lithologic units. Horizontal datum is approximately the top of the Devonian System.

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

EGSP Cored Well Locations

44 cores total

- 34 wells in the Appalachian Basin
  - Most Upper Devonian
  - Only 8 wells to Marcellus Shale
    - WV-6, WV-7
    - OH-7, OH-8,
    - PA-1, PA-2, PA-4, PA-5
- 3 wells in Michigan Basin (Antrim Shale)
- 7 wells in the Illinois Basin (New Albany Shale)

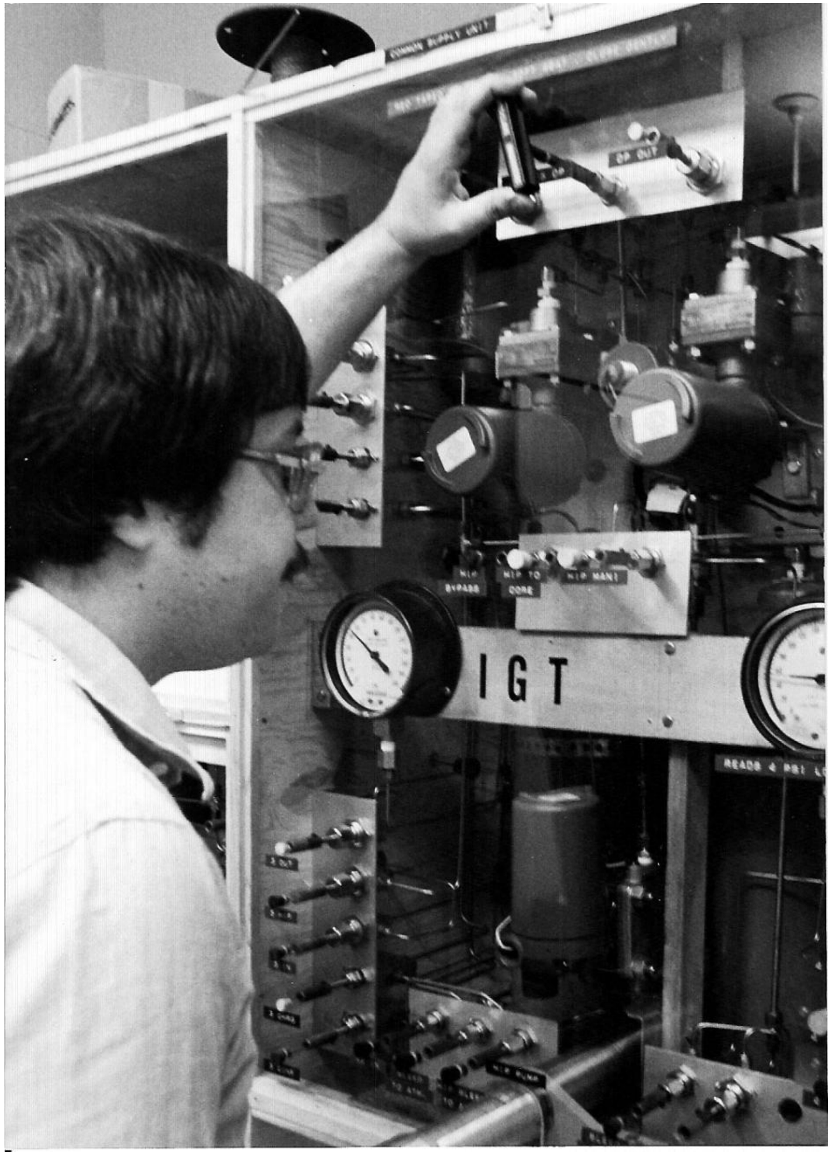


Institute of Gas Technology

- **Core analysis for the DOE Multiwell Experiment (MWX) tight sands**

- **Steady-state apparatus developed for φ and k on tight rocks**
  - Temperature control for pressure stability
  - Could simulate *in situ* net confining stress and drawdown
  - Flow limits 10-6 cc/sec

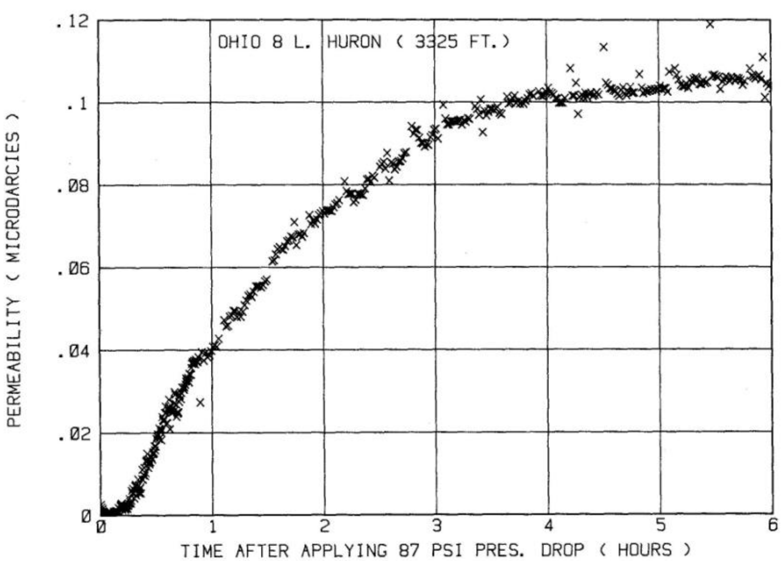
- **Devonian shale core analyses in 1984: 7 Lower Huron and 1 Marcellus sample from EGSP**

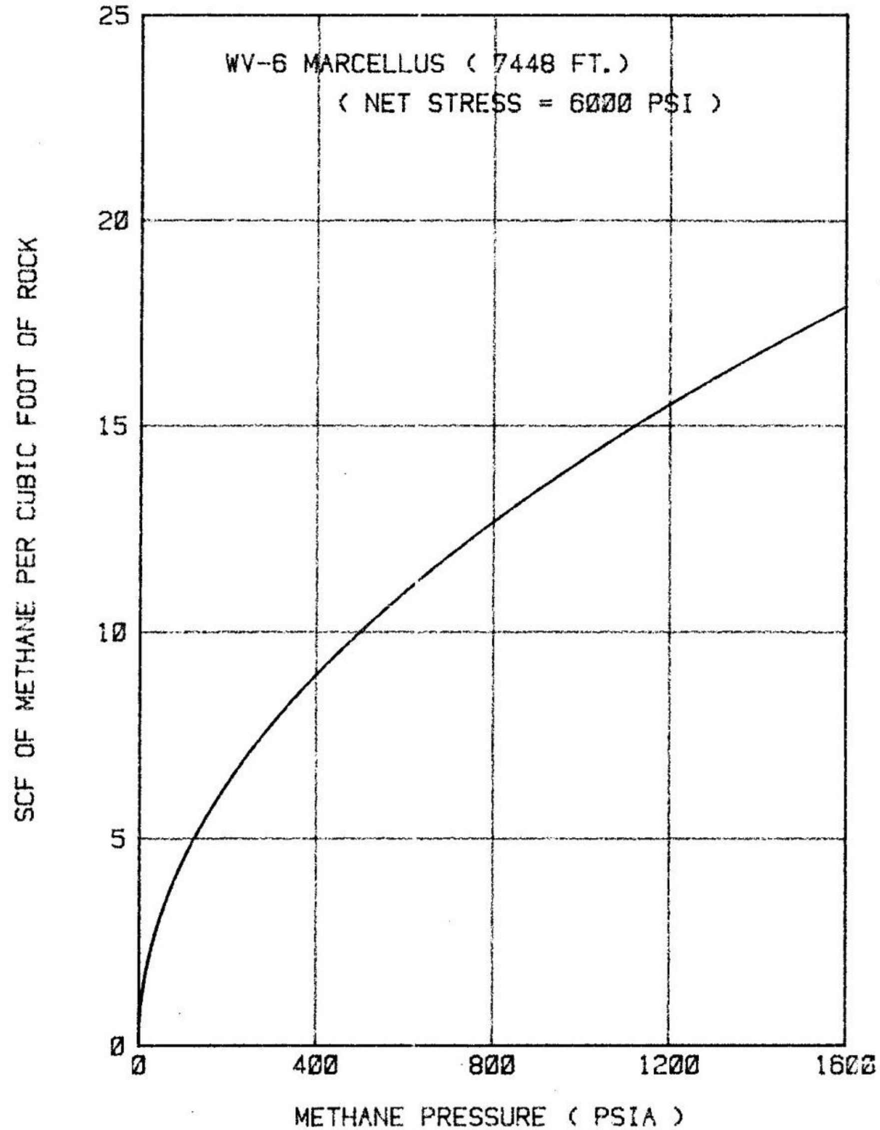


IGT Core Analysis Results

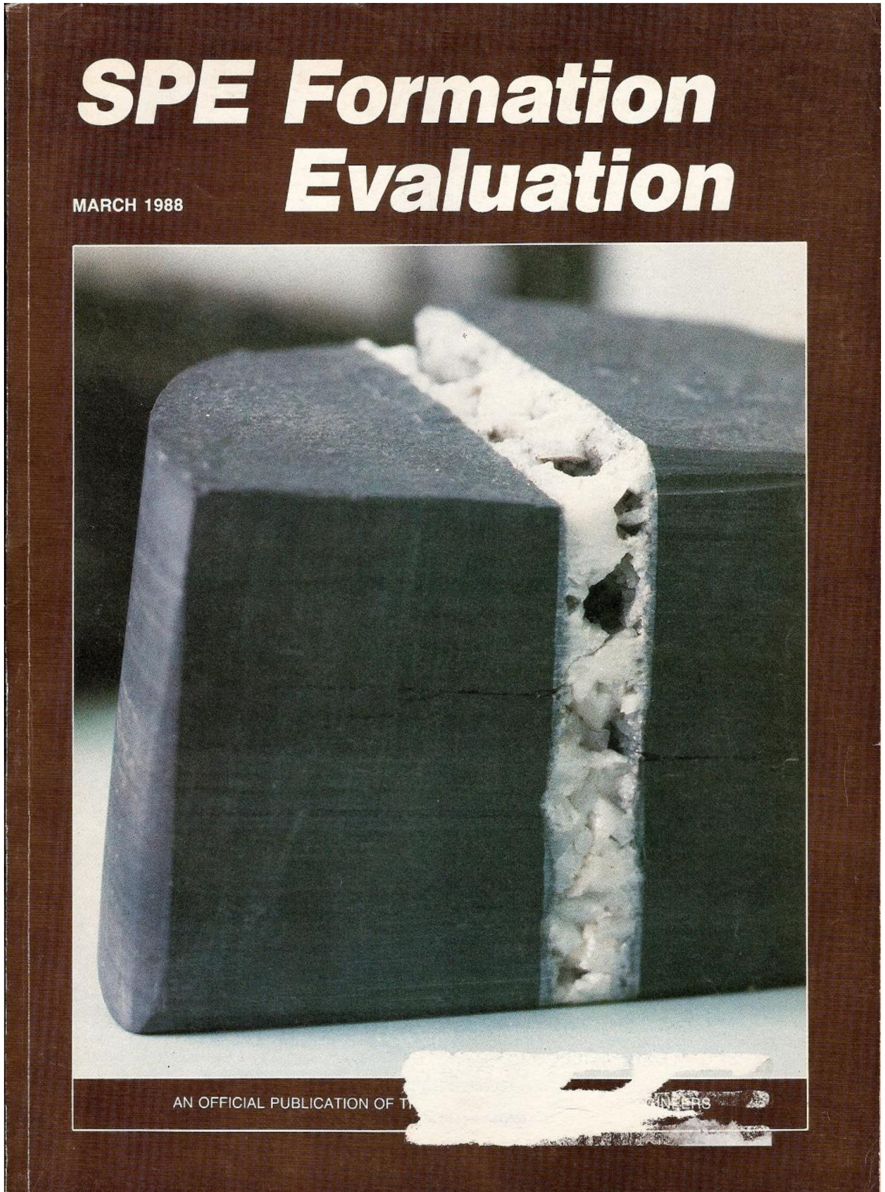
Two-phase flow in shale occurs only with great difficulty.

Marcellus: 26.5 scf/ft^3 GIP at 3500 psi reservoir pressure, compared to1980 NPC gas resource estimates for shale of 0.1 to 0.6 scf/ft^3 (44 to 265 X greater)





Published in 1988



Porosity and Permeability of Eastern Devonian Gas Shale

Daniel J. Soeder, SPE, Inst. of Gas Technology

Summary. High-precision core analysis has been performed on eight Devonian gas shale samples from the Appalachian basin. Seven of the core samples consist of the Upper Devonian Age Huron member of the Ohio shale, six of which came from wells in the Ohio River valley, and the seventh from a well in east-central Kentucky. The eighth core sample consists of Middle Devonian Age Marcellus shale obtained from a well in Morgantown, WV.

The core analysis was originally intended to supply accurate input data for Devonian shale numerical reservoir simulation. Unexpectedly, the work has identified a number of geological factors that influence gas production from organic-rich shales. The presence of petroleum as a mobile liquid phase in the pores of all seven Huron shale samples effectively limits the gas porosity of this formation to less than 0.2%, and gas permeability of the rock matrix is commonly less than 0.1 μd at reservoir stress. The Marcellus shale core, on the other hand, was free of a mobile liquid phase and had a measured gas porosity of approximately 10%, and a surprisingly high permeability of 20 μd. Gas permeability of the Marcellus was highly stress-dependent, however; doubling the net confining stress reduced the permeability by nearly 70%.

The conclusion reached from this study is that the gas productivity potential of Devonian shale in the Appalachian basin is influenced by a wide range of geologic factors. Organic content, thermal maturity, natural fracture spacing, and stratigraphic relationships between gray and black shales all affect gas content and mobility. Understanding these factors can improve the exploration and development of Devonian shale gas.

Introduction

Organic-rich, Devonian-Age shales in the Illinois, Michigan, and Appalachian basins are considered a major potential source of future domestic natural gas by the U.S. government and the gas industry.[1] As such, both the U.S. Department of Energy (DOE) and the Gas Research Inst. (GRI) have been funding research aimed at encouraging better gas recovery from this resource through improvements in recovery technology and increased understanding of where gas is trapped and how gas is transported within the shale formations.

Most of the difficulties with Devonian shale gas production are related to the fact that the matrix permeability of these rocks is very low, and an extensive natural and/or manmade fracture system is required in the reservoir to move economical quantities of gas to a wellbore. Shale wells generally exhibit a fairly rapid initial decline curve as gas is drained from the fracture system, followed by a slow, gradual decline as gas from the matrix moves into the fractures. This type of reservoir results in a well that produces slowly and steadily over long periods. The typical productive life of a shale gas well is about 40 years, although a few wells in the Appalachian basin have been producing for more than 100 years.[1]

The DOE was trying to model gas production from the Devonian shales using complex numerical simulations. The modelers were encountering difficulties in their simulation attempts because of a number of uncertain or unknown shale gas reservoir properties that resulted in inaccurate input parameters for the computer model. The parameters that caused the modelers the greater problems included measurements of shale gas content that varied with stratigraphy and geographic location (for poorly understood reasons), total gas content determinations that contained an unknown component of adsorbed gas, and matrix porosity and permeability values that were very close to the resolution limits of the equipment used to make the measurements. Other properties, such as the nature of shale pore structure and the effect of confining pressure on shale permeability, were unknown.

To address some of these data uncertainties and provide accurate input parameters for the reservoir modelers, the Inst. of Gas Technology (IGT) measured the porosity, permeability, and other properties of a limited number of Devonian shale samples with recently developed, high-precision core-analysis apparatus. It should be emphasized that porosity and permeability are *not* single numbers to be measured and reported for each sample analyzed in the laboratory. Rather, these are coefficients that appear in the differential equations used to calculate fluid content and movement in porous media. For most high-porosity, high-permeability formations, adequate descriptions of well and reservoir performance can be achieved by assuming that these coefficients are constants. This is not a valid assumption for such tight formations as Devonian shale, however, where the small pore sizes affect fluid flow through the rock matrix on a molecular scale.

Core-Analysis Procedure

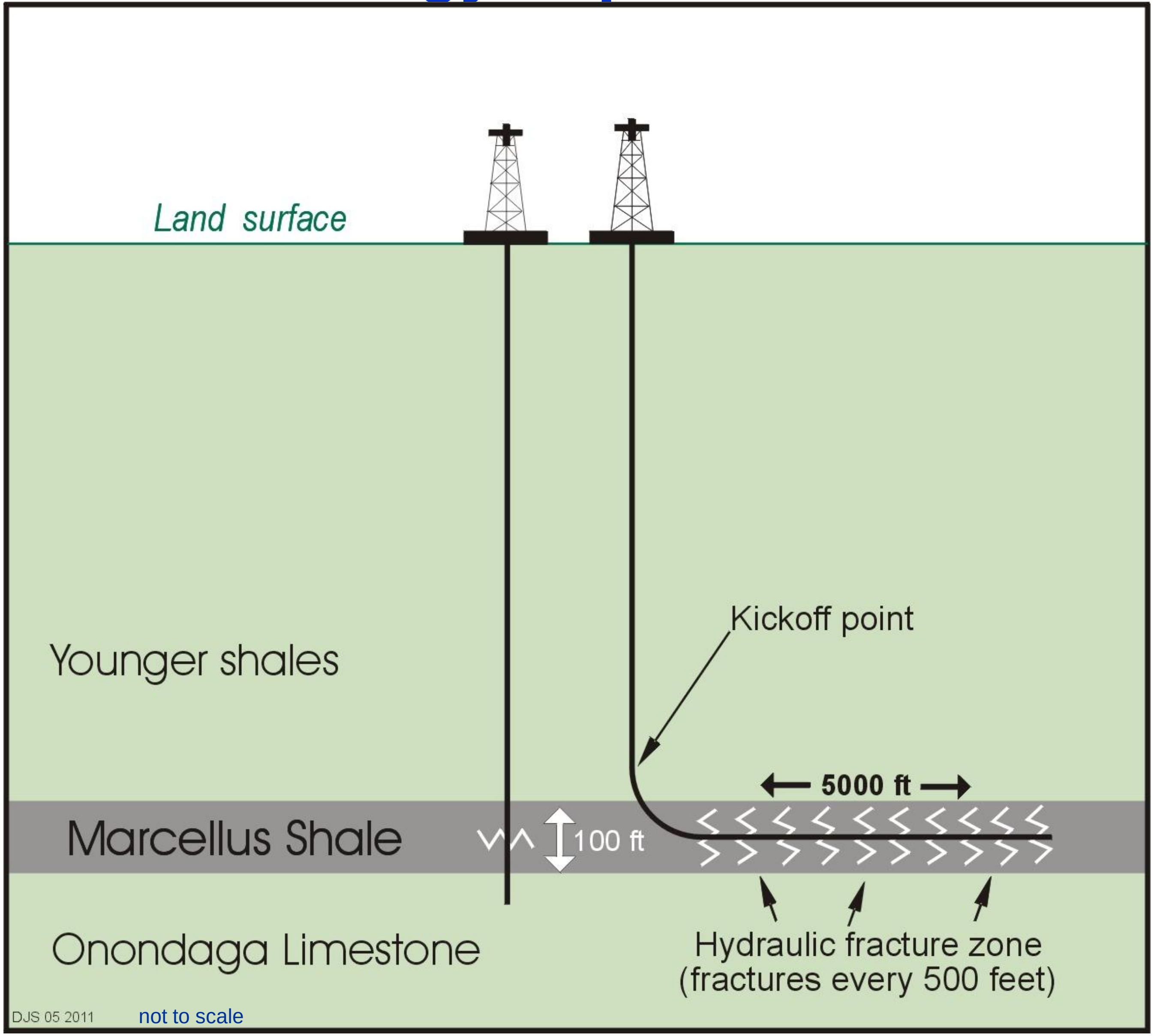
Between 1976 and 1981, the U.S. government cut and retrieved nearly 17,000 ft [5180 m] of Devonian shale drill core under the Eastern Gas Shale Project (EGSP).[2] This large supply of oriented core provided the raw material for the selection of a limited number of samples to be analyzed in our laboratory.

High-precision core analysis at IGT is performed in a device known as the computer-operated rock analysis laboratory (CORAL). CORAL is capable of measuring actual gas flow rates through rock as low as 10^{-6} std cm^3/s to an accuracy of a few percent, and can measure steady-state gas permeabilities with a resolution of $\pm$0.2 nd. Other rock properties measured by CORAL include gas porosity under stress with a resolution of about $\pm$2% of the measured value, and PV compressibility. A description of the engineering and operational design of CORAL has been presented by Randolph.[3]

Although CORAL was originally designed to perform high-precision core-analysis measurements on western tight gas sandstones, it soon became apparent that the accuracy and high resolution of this equipment would also have applications to other tight gas formations, such as Devonian shale. In the past, there have been several situations where Devonian shale permeabilities were reported from runs in equipment designed for tight sands.[4,5] In both cases reported, the porosity and permeability values measured were near the resolution limits of the equipment, resulting in a significant degree of uncertainty concerning the accuracy of the data. The approach taken toward the Devonian shale core measurements at IGT was to try to understand how the composition and internal pore structure of the rock control gas flow through the matrix into the fracture system, and thereby define the long-term gas production rates in a wellbore.

Twenty-eight zones of interest were sampled from 13 EGSP cores selected from a list supplied by DOE. Portions of the shale section

Technology Improvements for Shale Gas



Deepwater tension leg platforms drove the technology.

Directional drilling

- Downhole hydraulic motors
- Measurement while drilling
- Inertial navigation
- Improved telemetry: mud pulse and electronic
- 5,000+ ft laterals

Staged hydraulic fracturing

- Light sand frac
- Slickwater frac


CAT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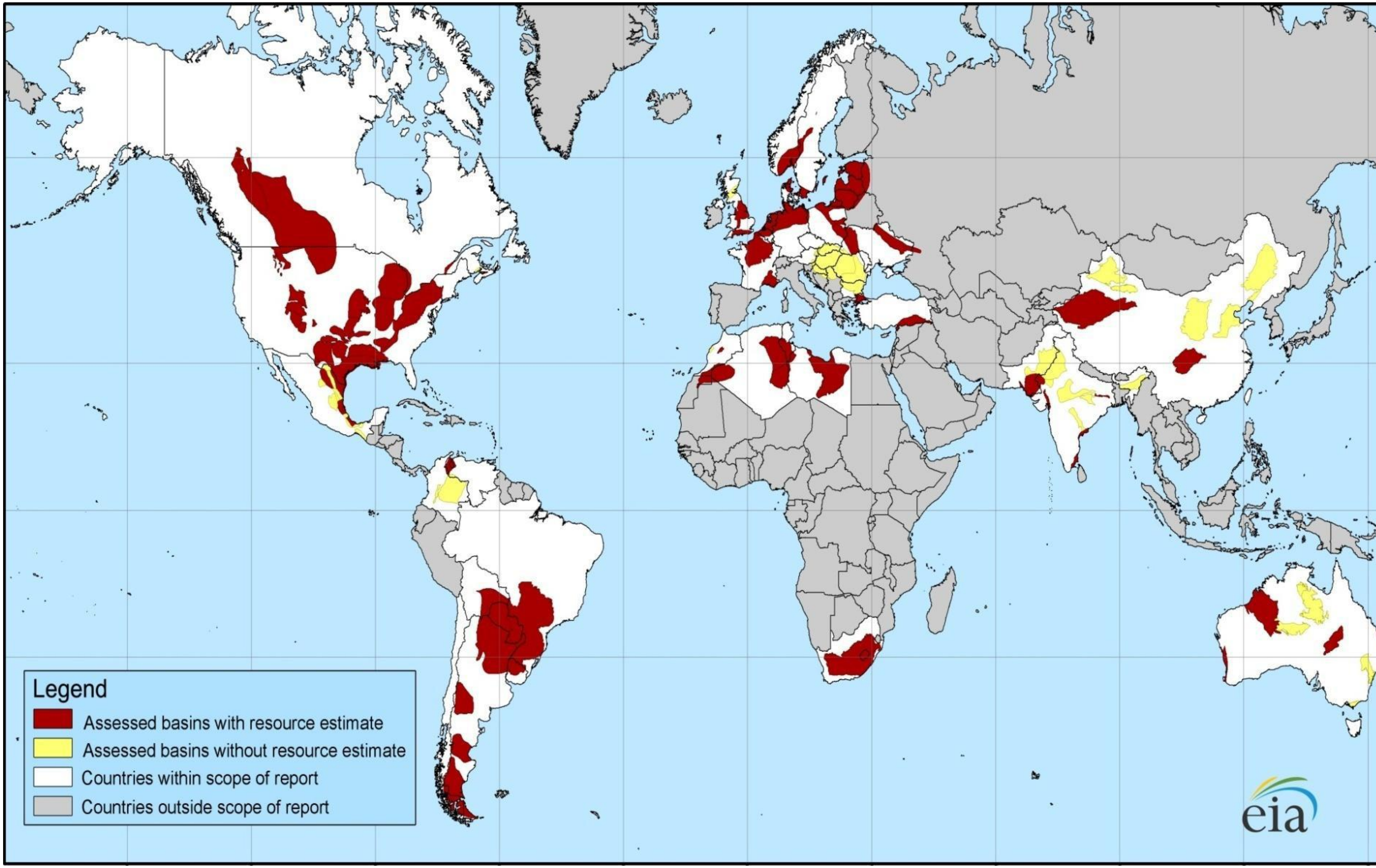
Shale Gas Production History

- **EGSP Data:** Many different completion and stimulation technologies were tested, directional drilling across fractures was prototyped in 1986.
- **Barnett Shale**, Ft. Worth Basin, Texas: Mitchell Energy adapted offshore technology and achieved economic production of shale gas in 1997.
- **Fayetteville Shale**: 2004, Southwestern Energy, Arkansas
- **Haynesville Shale**: Same period, Chesapeake Energy, ArkLaTex area
- **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 production
- **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.
- **Newest candidates:** Cummock Shale and others, Triassic Rift Basins, Atlantic Piedmont.
- Energy value of U.S. natural gas may be double the oil in Saudi Arabia.

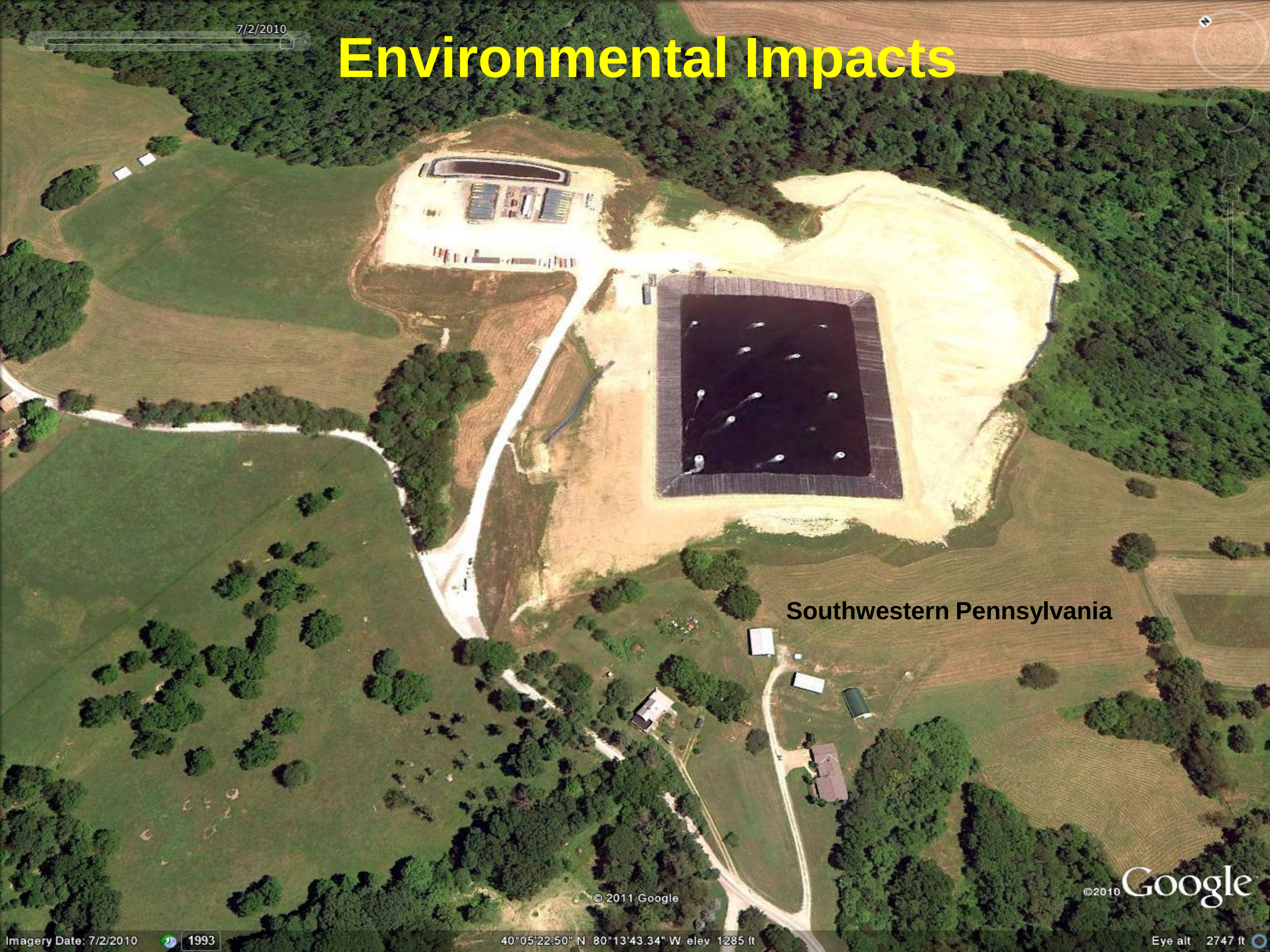
Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Shale Gas Worldwide

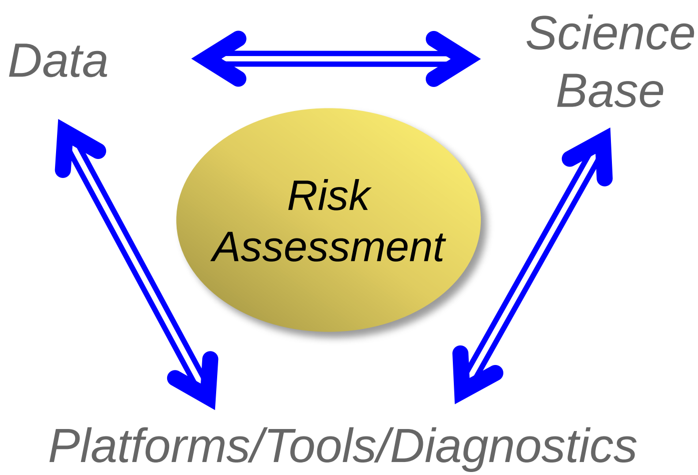


Source: U.S. Energy Information Administration

Environmental Impacts



Risk Assessment

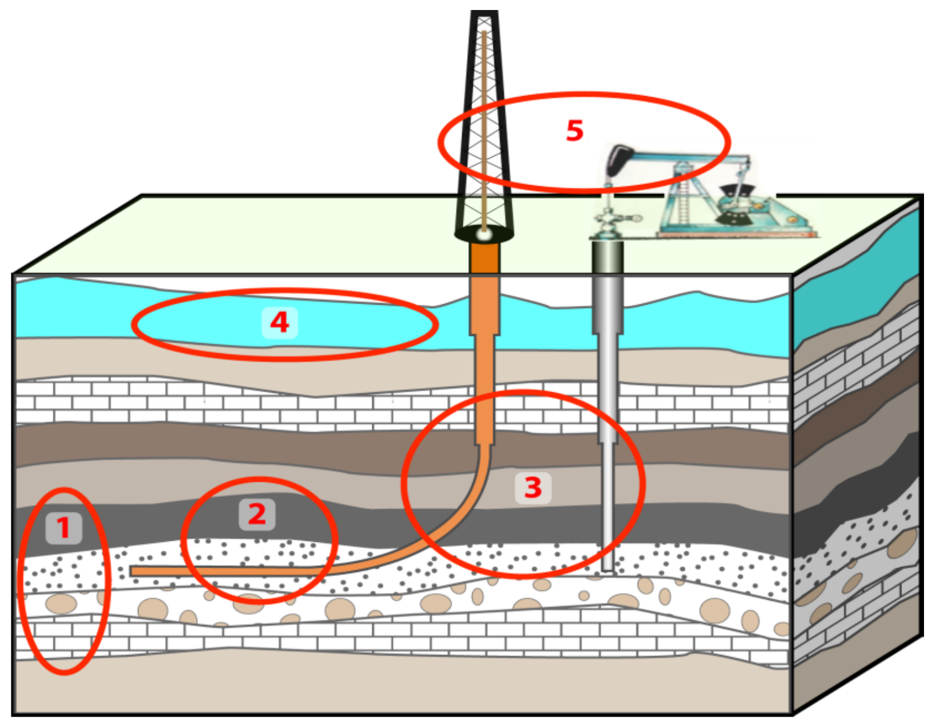


Risk = probability X consequence

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

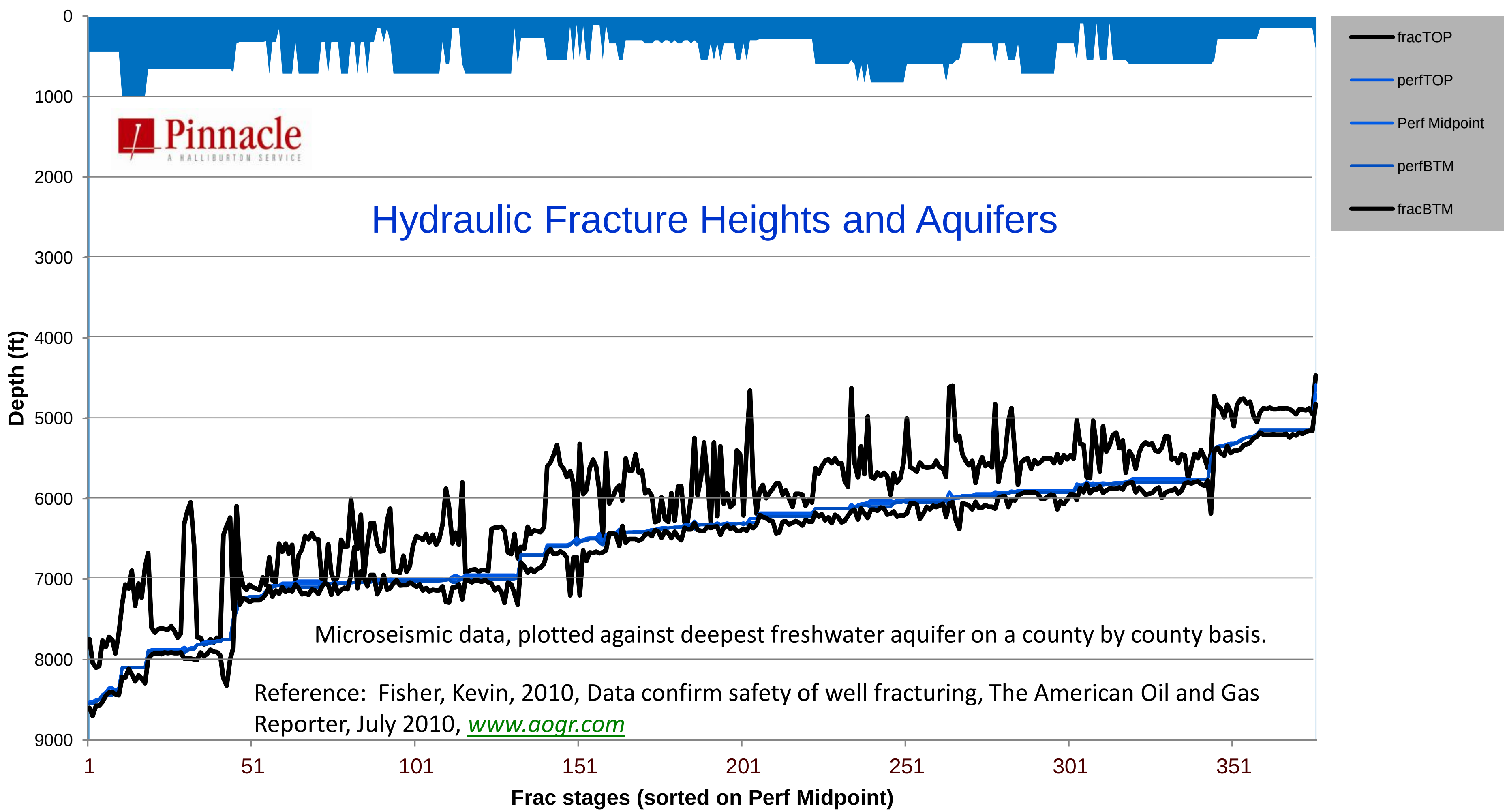
Direction from President Obama in April 2012:
DOE, USGS and EPA are to work together on this, primarily hydraulic fracturing.

- Risks/Receptors: resource base, air, water, landscapes, ecosystems, public health; induced seismicity
- Research focus: UOG national plan, case studies (Marcellus, Barnett, Bakken)



Popular Notions of Risk

Marcellus Mapped Frac Treatments

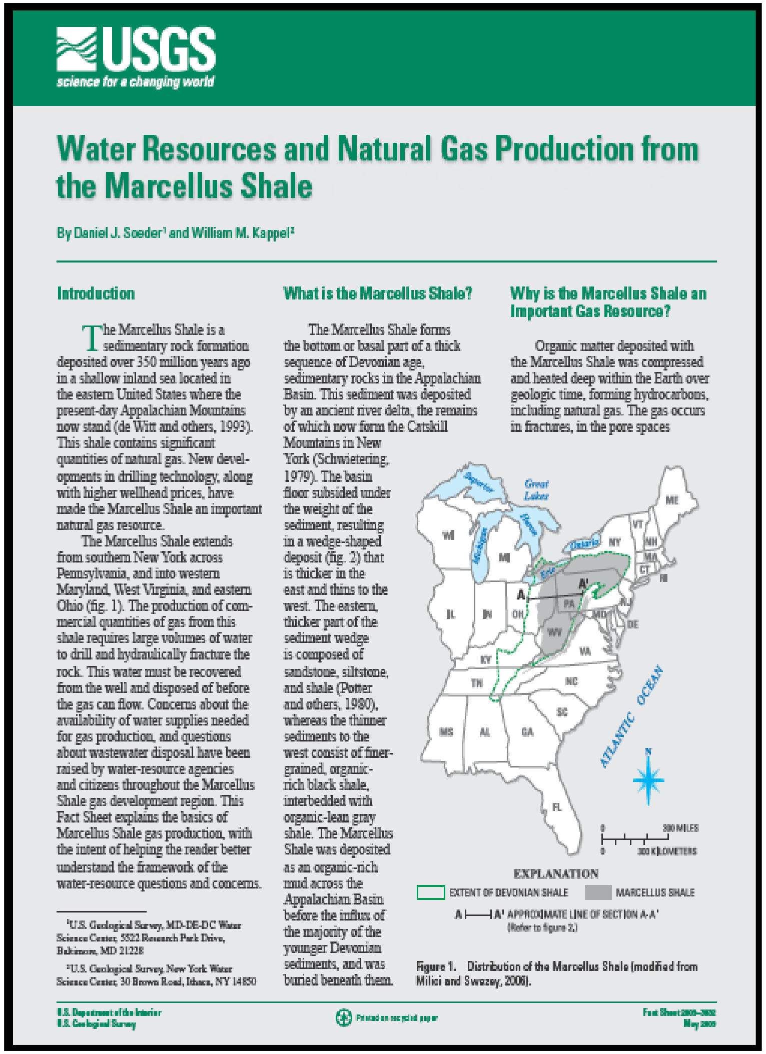


Actual Operational Risks

- **Surface leaks and spills are a much higher risk to groundwater and surface water than a frac (Groat, 2012)**
- **GW contamination occurs at less than 0.5% of well sites** (Kell, 2011, Ground Water Protection Council; Considine et al., 2012, SUNY University at Buffalo)
- **Baseline data on existing contaminants are required to assess drilling impacts.**
- **Potential leachate from drill cuttings**
- **Assessing cumulative impacts to small watersheds (Hopkinson - WVU)** White Day Creek monitoring stations; several stages of shale gas drill pads in watershed


Photo by Doug Mazer, used with permission.

Changing Risk Factors



USGS
science for a changing world

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.

[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

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).

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

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Fact Sheet 2009–3032
May 2009

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

- **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 disposal of high TDS flowback water into surface streams

- **Status of 2009 water risks in 2012**
  - 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 into next frac and UIC well disposal of residual waste have greatly reduced water quality concerns 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

Environmental Risk Assessment

Goals

- Assess short/long term environmental impacts of shale gas and deepwater/frontier oil and gas development.
- Investigate scientific concerns

Outcomes

- Rigorous study with conclusions supported by well-documented data

Benefits

- Public information to create a more informed environmental debate.
- Improved management practices to reduce risk.
- Environmental indicators for focused regulatory monitoring.

New Uses for Natural Gas

- **Electric power generation**
  - Cleaner than coal to extract, combust and exhaust; combined cycle unit is efficient.
  - No arsenic, selenium, mercury or sulfur in flue gas, no ash disposal
  - Gas produces half the CO_2 per BTU compared to coal
- **Vehicular fuel**
  - Current gasoline-powered vehicles can run on compressed natural gas (CNG) with a simple dual-fuel conversion to make up for the lower range of CNG
  - CNG burns cleaner than gasoline; help cities attain air quality standards, esp. ozone
  - CNG is cheaper per BTU than gasoline
  - Additional annual production of 13 TCF for vehicle fuel can replace ALL imported oil.

Is the "energy crisis" over? It can be.