NATIONAL ENERGY TECHNOLOGY LABORATORY

Modern Shale Gas Development in the United States: An Update

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Modern Shale Gas Development in the United States: An Update

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NATIONAL ENERGY TECHNOLOGY LABORATORY (NETL)

Strategic Center for Natural Gas and Oil

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Modern Shale Gas Development in the United States: An Update

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FORWARD

The original Primer on Modern Shale Gas Development in the United States was commissioned through the Ground Water Protection Council (GWPC) in an effort to provide sound technical information on natural gas resource development activity and environmental protection, especially water resource management.

Shale gas development both requires significant amounts of water and is conducted in proximity to valuable surface and ground water. Hence, it is important to reconcile the concurrent and related demands for local and regional water resources, whether for drinking water, wildlife habitat, recreation, agriculture, industrial or other uses. The original Primer was prepared in the spirit of furthering stakeholder communication on these issues and fostering the development of policy and regulation based on sound science.

In the four years since publication of the original Primer, shale gas (and shale oil) development has expanded and intensified in multiple plays across the Nation. Rapid changes have occurred in a number of related areas including: hydraulic fracturing technology, fracturing flowback water treatment and management, state regulations related to shale gas development and hydraulic fracturing, community reaction to development and local efforts to control or limit development. These changes, along with economic factors like the price of natural gas and the ability of technology advancements to reduce the cost of development, are shaping future expectations of how rapidly shale gas and shale oil resource development will grow. This revised version of the Primer has been published to provide an update on the status of development and an assessment of the challenges that remain.

As was the case with the original Primer, this document, "Modern Shale Gas Development in the United States: An Update," is intended to be an objective depiction of the current state of shale gas development and does not represent the view of any individual state or industry sector. Our understanding of shale gas and shale oil resources and their development will continue to evolve.

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THE IMPORTANCE OF SHALE GAS

The Role of Natural Gas in the United States' Energy Portfolio

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil (fossil fuels) together supply about 84% of the nation's energy, with natural gas supplying about 27% of the total (Figure 1).[1] The Department of Energy's Energy Information Administration (EIA) projects that the percent contribution of natural gas to the U.S. energy supply will remain fairly constant over the next 30 years.

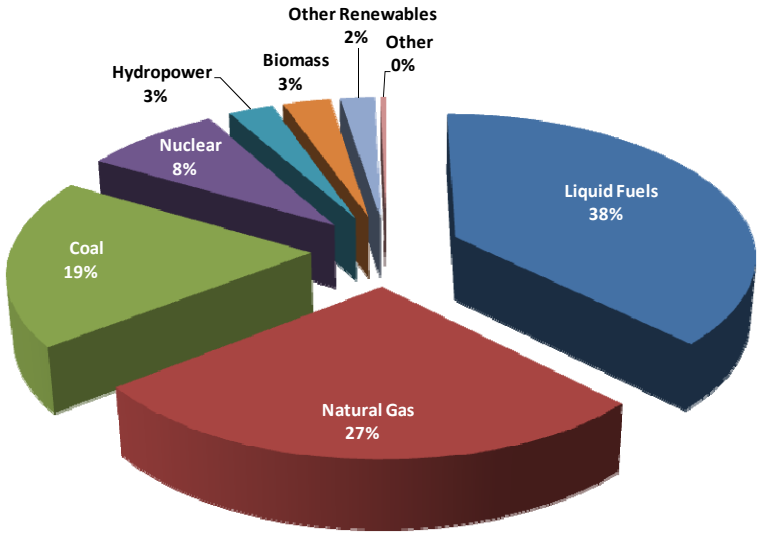

Figure 1. 2013 U.S. energy consumption by source, on an energy content basis (EIA 2013 Annual Energy Outlook data tables)

The United States has abundant natural gas resources. The EIA and U.S. Geological Survey (USGS) estimate that the U.S. has more than 1,864 trillion cubic feet (tcf) of technically recoverable natural gas (wet gas volume, including natural gas liquids), including 318 tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place).[2] Further, EIA estimates that U.S. technically recoverable shale gas resources total an additional 567 tcf, for a total future natural gas supply of 2,431 tcf. For comparison, in 2012 U.S. natural gas production totaled about 25.3 tcf.[3] (Note: See Appendix A for a discussion of "resources" and "reserves" terminology)

Other estimates of the U.S. natural gas resource are even more optimistic. The Potential Gas Committee, an independent organization that prepares biennial assessments of the technically recoverable natural gas resource base of the United States, estimates the total technically recoverable future gas supply to be 2,689 tcf as of the end of 2012.[4] The "most likely" contribution

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[1] EIA, Annual Energy Outlook 2013, http://www.eia.gov/forecasts/aeo/

[2] EIA, 2013, "Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States," Table 3, page 6, http://www.eia.gov/analysis/studies/worldshalegas/

[3] EIA online data table, accessed June 14, 2013, http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm

[4] Potential Gas Committee, 2013, Potential Supply of Natural Gas in the United States, http://potentialgas.org/press-release

of shale gas to this total is 1,073 tcf. In light of these estimates, shale gas can be expected to play an important future role in supplying about a third of U.S. energy demand, possibly even more, over the next several decades.

Natural gas plays an important role in the Nation's energy portfolio because its use is distributed across multiple sectors of the economy (Figure 2).[5] It is an important fuel for the electrical power generation sector, serves a vital role as an industrial feedstock and energy source, and is an important fuel for residential and commercial heating.

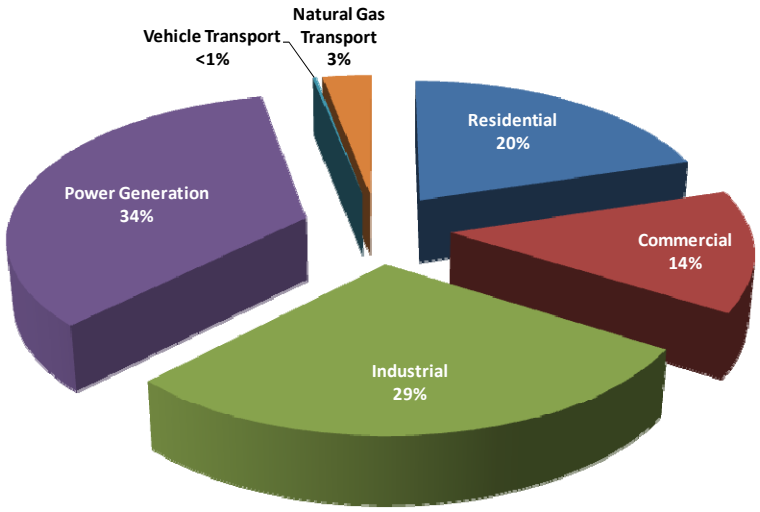

Figure 2. 2013 U.S. natural gas consumption by sector (EIA 2013 Annual Energy Outlook data tables)

Natural gas, due to its clean-burning nature relative to other fossil fuels and favorable economics, is an increasingly popular fuel choice for electricity generation. In the 1970s, 1980s, and early 1990s the choice for the majority of electric utility generators was primarily coal or nuclear power; but, due to economic, environmental, technological, and regulatory changes, natural gas has become the fuel of choice for most new power plants.

Natural gas is also a major fuel source for pulp and paper processing, metals refining, glass production, chemical production, petroleum refining, and food processing, and is an important feedstock for a variety of products, including plastics, chemicals, and fertilizers.

Figure 3 shows a comparison of historical and projected production, consumption, and import trends for natural gas in the U.S.[6] This EIA forecast shows U.S. natural gas production increasing 1.3 percent per year through 2040, outpacing domestic consumption by 2019 and supporting net exports of natural gas. Increasing volumes of shale gas production are a central element of this scenario and the primary factor behind a future U.S. shift from importer to exporter of natural gas. Most of the increase in net exports consists of increased pipeline exports to Mexico and declining imports from Canada. If additional liquefied natural gas (LNG) exports are approved, net exports could climb more quickly.

[5] EIA online data table, accessed June 14, 2013, http://www.eia.gov/oiaf/aeo/tablebrowser/
[6] EIA, Annual Energy Outlook 2013, http://www.eia.gov/forecasts/aeo/

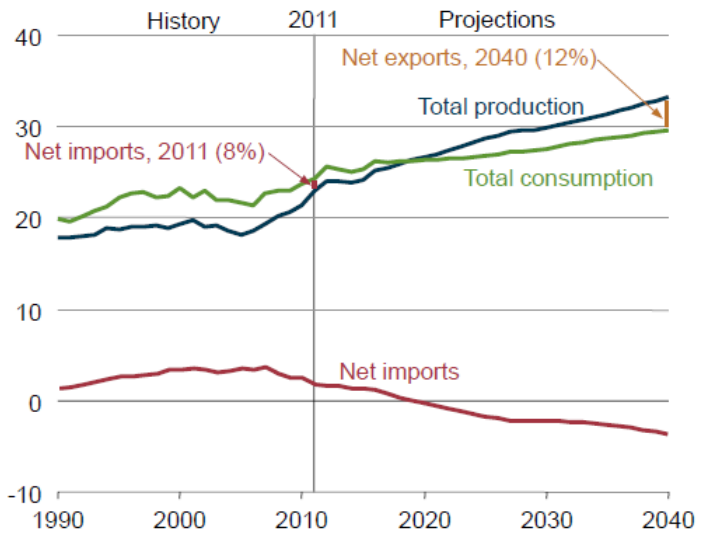

Figure 3. Total U.S. natural gas production, consumption, and net imports, 1990-2040, trillion cubic feet (EIA 2013 Annual Energy Outlook Reference Case)

The Environmental Advantages of Natural Gas

A key advantage of natural gas is that it is clean burning. It emits approximately half the carbon dioxide (CO_2) of coal along with lower levels of other air pollutants.[7] Coal and oil are composed of much more complex organic molecules with greater nitrogen and sulfur content. Their combustion byproducts include larger quantities of CO_2, nitrogen oxides (NOx), sulfur dioxide (SO_2) and particulate ash (Table 1). By comparison, the combustion of natural gas liberates very small amounts of SO_2 and NOx, virtually no ash, and lower levels of CO_2, carbon monoxide (CO), and other hydrocarbons.[8]

From 1990 to 2011, energy-related CO_2 emissions in the United States increased by about 0.4% per year. In 2010, the last year for which comparable data are available, the United States produced about 18% of the world's total energy-related CO_2.[9] However, the EIA estimates that U.S. CO_2 emissions from fossil fuels declined by 3.9 percent in 2012, dipping to a level last seen in the 1990s.[10] Switches from coal to natural gas in electric power generation accounted for about half of the drop.[11] Continued growth in natural gas's share of power generation could lead to continued reductions in carbon emissions.

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[7] EIA, Natural Gas 1998: Issues and Trends, 1999, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/natural_gas_1998_issues_trends/pdf/it98.pdf

[8] NaturalGas.org, 2008, Natural Gas and the Environment, accessed June 15, 2013, http://www.naturalgas.org/environment/naturalgas.asp

[9] EIA, U.S. Energy-related Carbon Dioxide Emissions, August 14, 2013, http://www.eia.gov/environment/emissions/carbon/

[10] EIA, Short Term Energy Outlook, June 11, 2013,, http://www.eia.gov/forecasts/steo/report/renew_co2.cfm

[11] Mufson, S., 2013, "Carbon dioxide emissions rose 1.4 percent in 2012, IEA report says," Washington Post, June 10, 2013, http://articles.washingtonpost.com/2013-06-10/business/39856466_1_carbon-dioxide-fatih-birol-greenhouse-gas-emissions

Air Pollutant	Combusted Fuel		
	Natural Gas	Oil	Coal
Carbon dioxide (CO_2)	117,000	164,000	208,000
Carbon monoxide (CO)	40	33	208
Nitrogen oxides (NO_x)	92	448	457
Sulfur dioxide (SO_2)	0.6	1,122	2,591
Particulates (PM)	7.0	84	2,744
Formaldehyde	0.750	0.220	0.221
Mercury (Hg)	0.000	0.007	0.016

Table 1. Combustion emissions, pounds per billion btu of energy input, (EIA, Natural Gas 1998: Issues and Trends)

Some researchers have raised concerns that expanded production of natural gas could result in expanded release of methane as fugitive emissions during the drilling, completion, production, transportation and use of natural gas. This is of concern because methane is a more potent "greenhouse gas" (GHG) than CO_2 and thus the potential exists for these fugitive emissions to offset the benefits of reduced coal use or possibly even lead to a net increase in GHG emissions. (Note: More on this topic in the section of this document focused on Environmental Impacts).

Additionally, the march towards sustainable renewable energy sources, such as wind and solar, requires that a supplemental energy source be available to accommodate changing weather conditions and limits to electrical storage capacity. Such a backstop energy source must be widely available on near instantaneous demand. The availability of extensive natural gas transmission and distribution pipeline systems makes natural gas uniquely suitable for this role.

Natural Gas Basics

Natural gas is a combination of hydrocarbon gases consisting primarily of methane (CH_4), and lesser percentages of butane, ethane, propane, and other gases. It is odorless, colorless, and, when ignited, releases a significant amount of energy. Table 2 shows the typical compositions (volume %) of natural gas as it reaches the wellhead and also after some constituents are removed and the gas is compressed for transport in a pipeline. Liquefied natural gas (LNG) is practically all methane.

Natural gas is found in rock formations (reservoirs) beneath the earth's surface. In some cases it may be associated with oil deposits (associated gas). Once extracted, the natural gas is processed to remove other gases, water, rock particles, and other impurities like hydrogen sulfide. Some hydrocarbon gases, such as butane and propane, are captured, liquefied and separately marketed as natural gas liquids (NGLs). Once processed, the cleaned natural gas (nearly all methane) is distributed through a system of pipelines to its endpoint for residential, commercial, and industrial use.

Component	Chemical Formula	Wellhead Gas (%)	Typical Pipeline Gas (%)	Liquefied Natural Gas (%)
Methane	CH_4	70-90	88.90	94.7
Ethane	C_2H_6	0-20	5.34	4.8
Propane	C_3H_8		0.46	0.4
Butane	C_4H_{10}		0.05	0.06
Pentane	C_5H_{12}	<1	0.03	0.01
Hexane	C_6H_{14}	<1	0.02	0.01
Nitrogen	N_2	0-5	5.50	0.02
Carbon Dioxide	CO_2	0-8	0.50	-
Hydrogen Sulfide	H_2S	0-5	-	-
Rare Gases	Ar, He, Ne, Xe	trace	-	-
Avg. btu/cu. ft.		1100-1300+	986	1047

Table 2. Composition of natural gas at various stages of production and distribution

Natural gas can be measured in either volumetric or energy units. As a compressible gas, it is measured by the volume it displaces at a standard temperature and pressure, expressed in cubic feet or cubic meters. Gas companies generally measure natural gas in thousands of cubic feet (Mcf), millions of cubic feet (MMcf), or billions of cubic feet (bcf), and estimate resources such as original gas-in-place or technically recoverable volumes in trillions of cubic feet (tcf). A typical U.S. household uses about 70 Mcf per year or less.[12]

Characterizing natural gas by volume is useful, but a quantity can also be defined by its value as a source of energy. This value is generally presented in British thermal units (Btu). One Btu is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at standard pressure. There are about 1,000 Btus in one cubic foot of natural gas delivered to the consumer. Natural gas streams with higher concentrations of non-hydrocarbon gases like nitrogen or CO_2 will have a lower Btu content, while streams with higher concentrations of heavier hydrocarbons like ethane, propane or butane will have higher Btu contents (see Table 2). Natural gas distribution companies typically measure the gas delivered to a residence in 'therms' for billing purposes. A therm is equal to 100,000 Btus—approximately 100 cubic feet—of natural gas.

"Unconventional" Natural Gas Resources

"Conventional gas" has been used to describe natural gas accumulations found in high permeability rock formations, typically sandstones or carbonates, where the hydrocarbons have migrated from finer grained source rocks like shales. These natural gas accumulations include some sort of

[12] EIA, Trends in U.S. Residential Natural Gas Consumption, http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngtrendsresidcon/ngtrendsresidcon.pdf

trapping mechanism that prevents the gas from migrating further and results in a high concentration of gas within the reservoir. Natural gas found in the shale source rocks themselves (shale gas), in very low permeability sandstones (tight gas), or in coal seams (coalbed methane), has been termed "unconventional gas."

In fact, while the gas is identical, the reservoirs are not. Since the late 1970s, interest has grown in finding ways to understand, quantify and develop this unconventional gas resource. A combination of rising natural gas prices, tax enhancements and technology advancements have enabled increased production of natural gas from these unconventional accumulations (Figure 4). The EIA projects that over the next several decades, while tight gas and coalbed methane more or less maintain their contribution to the U.S. natural gas supply, the shale gas contribution will grow significantly.[13]

Actually, the term "unconventional" has lost its original meaning. Currently, gas from shales, tight sands and coalbeds accounts for 65% of U.S. natural gas production.[14] By 2040 that share is expected to rise to 79%. The unconventional has become the conventional.

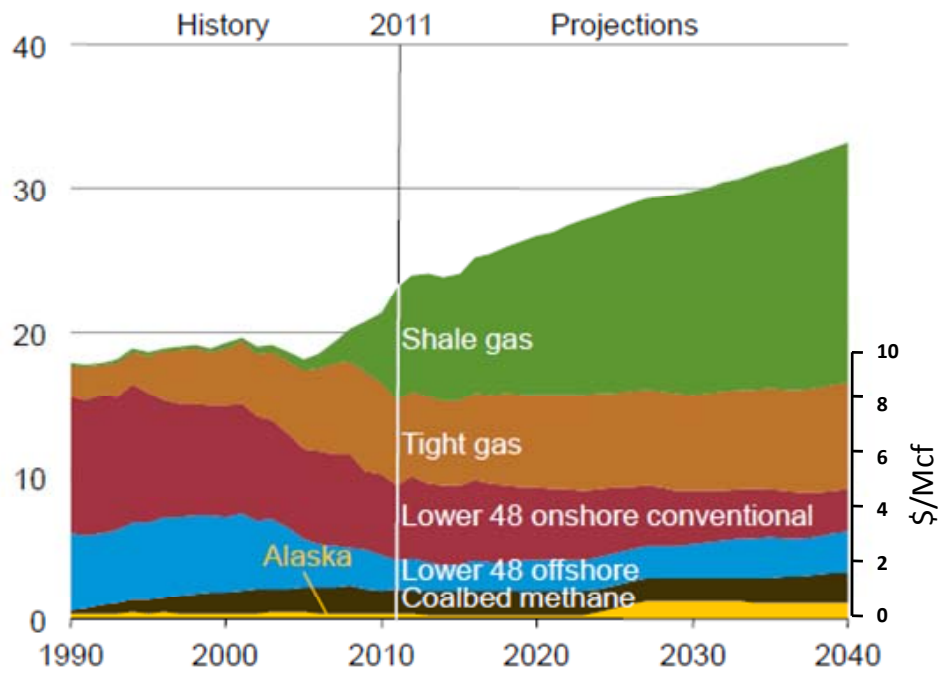


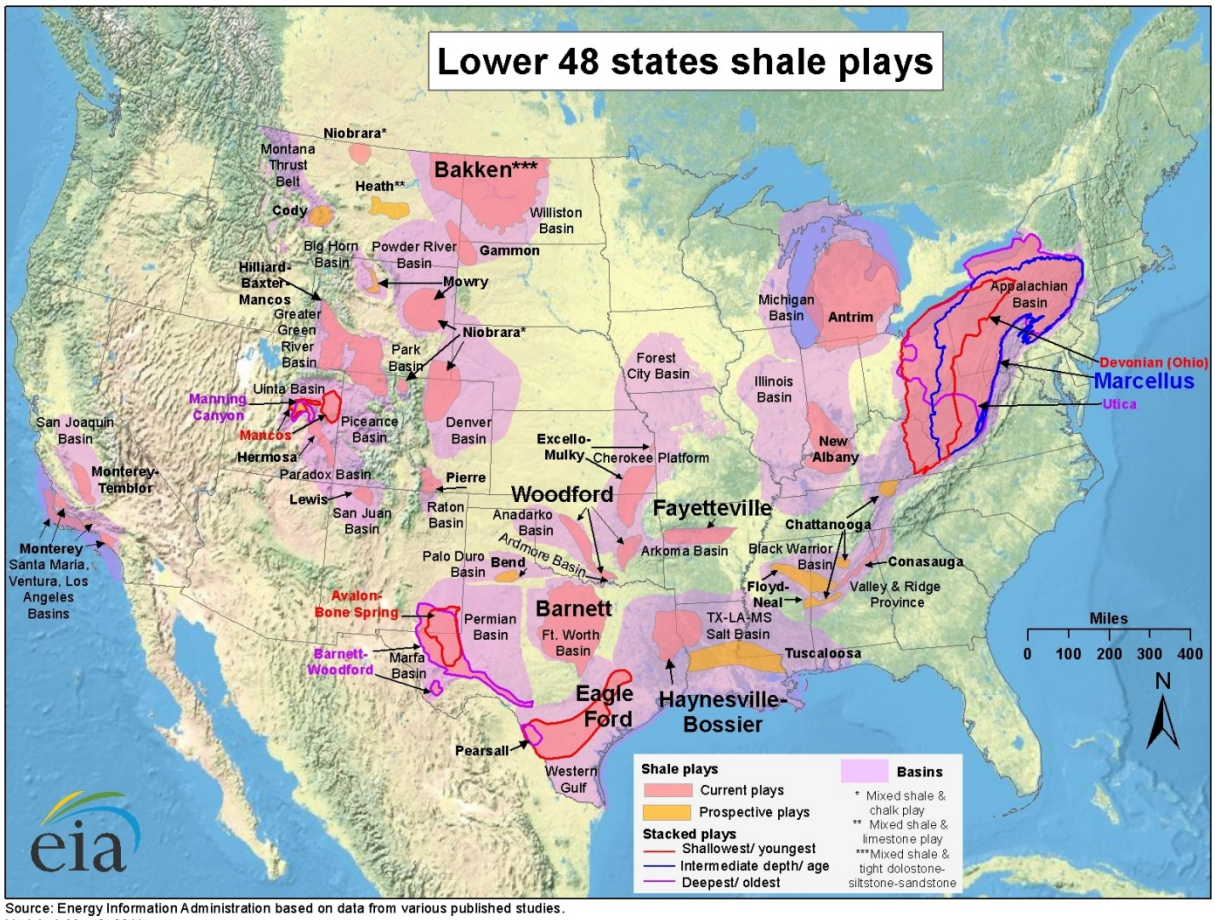
Figure 4. Natural gas production by source, 1990-2040 (trillion cubic feet) with historical U.S. natural gas wellhead price ($/Mcf) (EIA online data tables)

The Increasing Contribution of Shale Gas

The lower 48 states exhibit a wide distribution of highly organic shales containing vast amounts of natural gas and hydrocarbon liquids (Figure 5).[15] Three factors have combined in recent years to make shale gas production economically viable: 1) advances in horizontal drilling that make it more economical to drill longer horizontal laterals, 2) advances in hydraulic fracturing that have reduced the cost and increased the effectiveness of pumping multiple, large volume treatments in a single

[13] EIA, Annual Energy Outlook 2013, http://www.eia.gov/forecasts/aeo/
[14] EIA, Annual Energy Outlook 2013 online tables, http://www.eia.gov/oiaf/aeo/tablebrowser/
[15] EIA, Shale gas and oil plays, http://www.eia.gov/oil_gas/rpd/shale_gas.pdf

wellbore and, perhaps most importantly, 3) a relatively rapid increase in natural gas prices between 1998 and 2008 (from about $2/Mcf to more than $10/Mcf).



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 5. Lower 48 States shale plays (EIA)

Figure 6 shows the recent historical contributions of shale gas from twelve selected plays in the U.S.[16] The key plays contributing to the rise in shale gas production post-1998 are the Barnett shale in the Fort Worth Basin of central Texas, the Haynesville-Bossier shale in eastern Texas and northwestern Louisiana, the Fayetteville shale in the Arkoma basin in Arkansas, and to a lesser extent, the Woodford shale in Oklahoma's Anadarko and Arkoma basins. Post-2009, the contributions from the Marcellus shale of the Appalachian basin and the Eagle Ford shale of southern Texas have grown rapidly to have a significant impact on the total.

[16] EIA, "Today in Energy," March 2013, http://www.eia.gov/todayinenergy/detail.cfm?id=5370

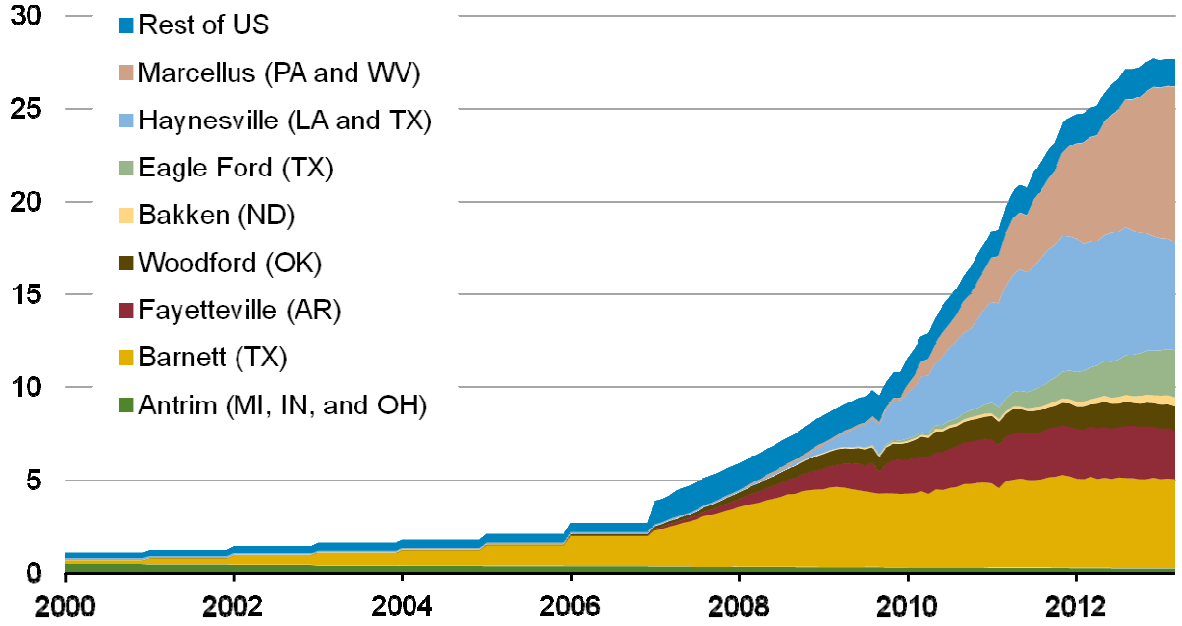


Figure 6. Gas production history for selected shale gas plays, dry gas in billion cubic feet per day (EIA, March 2013)

In its 2012 Annual Energy Outlook, EIA published estimates of technically recoverable resources for selected shale plays (Table 3).[17] While these estimates were made based on 2010 data and have likely already changed as new data have been revealed, they do give some indication of the relative size of the technically recoverable resource to be found within different plays. For example, the Marcellus is by far the largest play, more than twice the size of the Haynesville-Bossier, which in turn is a bit larger than the Eagle Ford. Plays such as the Utica, Caney and Pearsall are still in the early stages of development.

Ultimately, the portion of the technically recoverable resource which is translated into reserves in each of these plays will depend on economic decisions made by individual companies (see Appendix A for a discussion of resources versus reserves). According to a recent report from the Bureau of Economic Geology at the University of Texas, which takes into account expected economic conditions, the Barnett shale, which has been producing longest among the modern (post-1998) shale plays, is expected to ultimately produce 44 Tcf from a total of 28,000 wells.[18]

[17] EIA, Annual Energy Outlook 2012, http://www.eia.gov/forecasts/archive/aeo12/

[18] U. Texas, press release, "New, Rigorous Assessment of Shale Gas Reserves Forecasts Reliable Supply from Barnett Shale Through 2030," http://www.utexas.edu/news/2013/02/28/new-rigorous-assessment-of-shale-gas-reserves-forecasts-reliable-supply-from-barnett-shale-through-2030/

Basin/Play	Area (sq. mi.)	Avg. well spacing (wells per sq. mi.)	Percent of area untested	Percent of area with potential	Avg. EUR (Bcf/well)	Number of potential wells	TRR (Bcf)
Appalachian							
Marcellus	104,067	5	99	18	1.56	90,216	140,565
Utica	16,590	4	100	21	1.13	13,936	15,712
Arkoma							
Woodford	3,000	8	98	23	1.97	5,428	10,678
Fayetteville	5,853	8	93	23	1.30	10,181	13,240
Chattanooga	696	8	100	29	0.99	1,633	1,617
Caney	2,890	4	100	29	0.34	3,369	1,135
TX-LA-MS Salt							
Haynesville	9,320	8	98	34	2.67	24,627	65,860
Western Gulf							
Eagle Ford	7,600	6	99	47	2.36	21,285	50,219
Pearsall	1,420	6	100	85	1.22	7,242	8,817
Anadarko							
Woodford	3,350	4	99	29	2.89	3,796	10,981
Total						**181,714**	**318,825**

Table 3. Attributes of unproven technically recoverable resources for selected shale gas plays as of January 1, 2010 (EIA Annual Energy Outlook 2012)

Economics of Shale Gas Development

Some industry experts believe that the contribution of shale gas to the nation's energy supply could grow even more rapidly than forecast by EIA in Figure 4. In a 2012 study, IHS Global Insight projects that U.S. lower 48 shale gas productive *capacity* (the ability to produce gas from completed wells as opposed to actual production based on demand) will grow to more than 60 Bcfd by 2035,[19] compared to EIA's Annual Energy Outlook 2013 production projection of 42 Bcfd.[20]

[19] IHS Global Insight, 2012, "America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy," http://www.ihs.com/info/ecc/a/americas-new-energy-future.aspx
[20] EIA, Annual Energy Outlook 2013 online tables, http://www.eia.gov/oiaf/aeo/tablebrowser/

Others believe that the EIA projections are overly optimistic, and that many shale gas plays will not be economic unless natural gas prices rise significantly or drilling and completion costs drop significantly.[21] These more pessimistic opinions are based on a view that: 1) companies publicly understate the production decline rates of their wells as well as their true costs, 2) economically attractive "core area" wells that are highlighted by companies are not representative of the average performance for wells across a play's total productive area, and 3) the development and application of technology enhancements that could significantly lower costs in the future are not likely to happen. For example, a March 2013 report by The Post-Carbon Institute[22] states that 80 percent of shale gas production comes from five plays, several of which are already in decline, and that the very high decline rates of shale gas wells require continuous inputs of capital that exceed the value of production at current gas prices.

One factor that leads to uncertainty regarding shale gas economics is the scarcity of public information on individual well production volumes as a function of time. The frequency and level of detail of required production reporting vary from state to state. In some states, companies are not required to report production per well or per month, and only required to report comingled production every six months. This lack of public information makes objective third-party economic evaluation difficult. In addition, some shale plays have not been producing long enough for representative production decline characteristics to become well defined.

The Barnett Shale, the modern shale play with the longest period of available performance data, is one exception. The rigorous two-year assessment of Barnett production data undertaken by the University of Texas' Bureau of Economic Geology (BEG) determined that total recovery would be more than three times cumulative production to date. This forecast falls in between the "optimistic" and "pessimistic" predictions of Barnett production and suggests the formation will continue to be a major contributor to U.S. natural gas production through 2030.[23] As data become available on other plays, similar studies will permit a more accurate understanding of true play-by-play potential.

At the same time, individual producers continue to claim that EURs support continued development. Chesapeake Energy, for example, has published a distribution of 139 well EURs from its core Marcellus play area in NW Pennsylvania that shows an average of more than 10 Bcfe, supporting the payout of well costs of $6.7MM in less than one year (Figure 7).[24]

Other operators have published similar EUR estimates for current (or planned) well designs in various areas of the Marcellus play (Table 4), all of which promise very favorable economics at expected gas prices.[25,26,27] Some of these producers also claim that continued refinements in well

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[21] Powers, W., 2013, "Cold, Hungry and in the Dark: Exploding the Natural Gas Supply Myth," New Society Publishers.

[22] Hughes, J. David, 2013, "Drill, Baby, Drill: Can Unconventional Fuels Usher in a New Era of Energy Abundance?," Post Carbon Institute, http://www.postcarbon.org/drill-baby-drill/

[23] U. Texas, press release, "New, Rigorous Assessment of Shale Gas Reserves Forecasts Reliable Supply from Barnett Shale Through 2030," http://www.utexas.edu/news/2013/02/28/new-rigorous-assessment-of-shale-gas-reserves-forecasts-reliable-supply-from-barnett-shale-through-2030/

[24] Chesapeake Energy, Investor Presentation, June 2013, http://www.chk.com/investors/documents/latest_ir_presentation.pdf

[25] Range Resources, Investor Presentation, UBS Global Oil & Gas Conference, May 21, 2013, http://www.rangeresources.com/

[26] Cabot Investor Presentation, Citi Global Energy and Utilities Conference, Boston, MA, May 15, 2013, http://www.cabotog.com/presentations.html

[27] EQT Analyst Presentation, June 2013, http://ir.eqt.com/events.cfm?AcceptDisclaimer=yes

design (e.g., horizontal lateral length, number and placement of hydraulic fracturing stages) have led to increased initial rates and EURs, and when coupled with the reduction in drilling and completion costs that comes with experience (Figures 8 and 9) are improving economics.[28]

At the same time, an independent review of production data for 343 Marcellus wells produced a distribution of 30 year EURs that indicates average recovery could be much less than that projected by producers for selected wells (Figure 10).[29] This analysis shows a mean EUR of 1.57 Bcf. A more complete understanding of the actual range of recoveries across plays will become clearer as additional production data is collected.

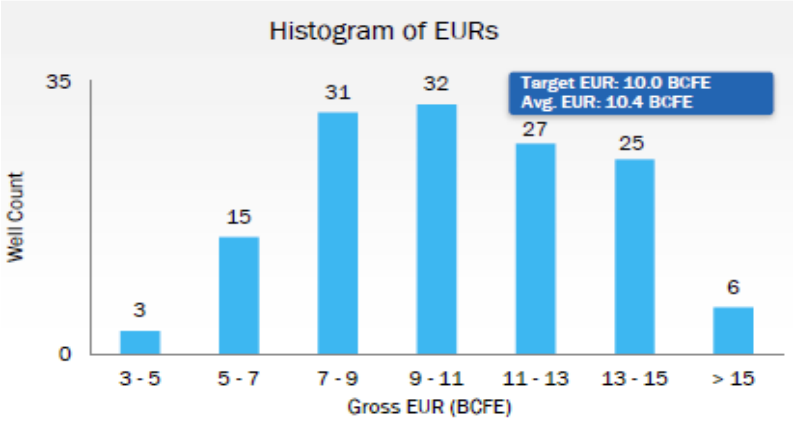

Figure 7. Histogram of gross EURs for Chesapeake Energy Marcellus Shale wells in core area (Investor presentation from June 2013)

Company	Area	EUR	Avg. Lateral Length (ft)	Frac Stages	Cost ($MM)
Range Resources	SW PA (wet)	8.7 Bcfe (4.4 Bcf +712 Mbbls liquids)	3,200	13	4.9
	SW PA (dry)	7.5 Bcf	2,900	10	4.5
Cabot Corp.	NE PA	14.1 Bcfe	4,100	18	6.5
EQT	SW PA and Northern WV	9.8 Bcfe	4,800	32	6.6
	Central PA	6.6 Bcfe	4,800	32	6.6

Table 4. Operator-published EUR values for current (or planned) well designs in various areas of the Marcellus play (Range Resources, Cabot Corp., and EQT investor presentations)

[28] Cabot Investor Presentation, Citi Global Energy and Utilities Conference, Boston, MA, May 15, 2013, http://www.cabotog.com/presentations.html

[29] Aucott, M. and J. Melillo, 2013, "A Preliminary Energy Return on Investment Analysis of Natural Gas from the Marcellus Shale," Journal of Industrial Ecology, http://onlinelibrary.wiley.com/doi/10.1111/jiec.12040/abstract

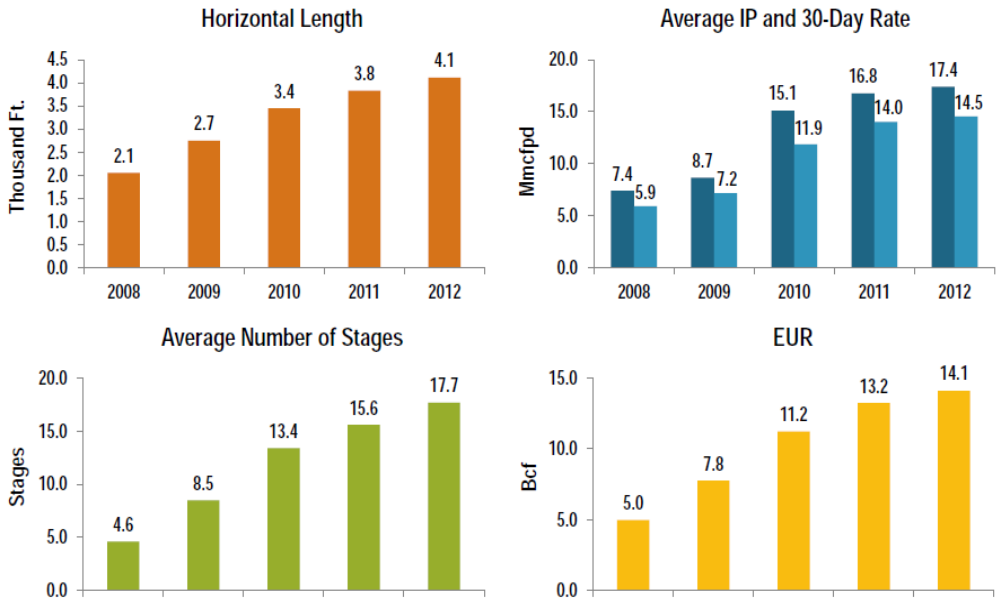

Figure 8. Cabot Corp. data showing that refinements in well design (horizontal lateral length and average number of hydraulic fracturing stages) have led to increased initial rates and EURs (Cabot investor presentation, May 2013)

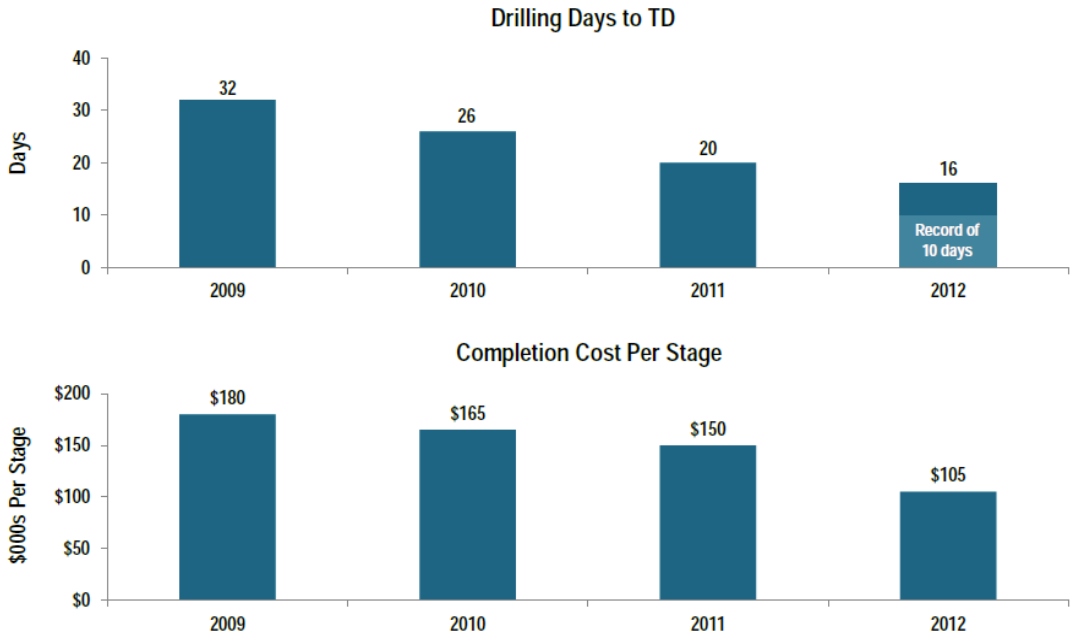

Figure 9. Cabot Corp. data showing that drilling time and completion cost reductions over time (Cabot investor presentation, May 2013)

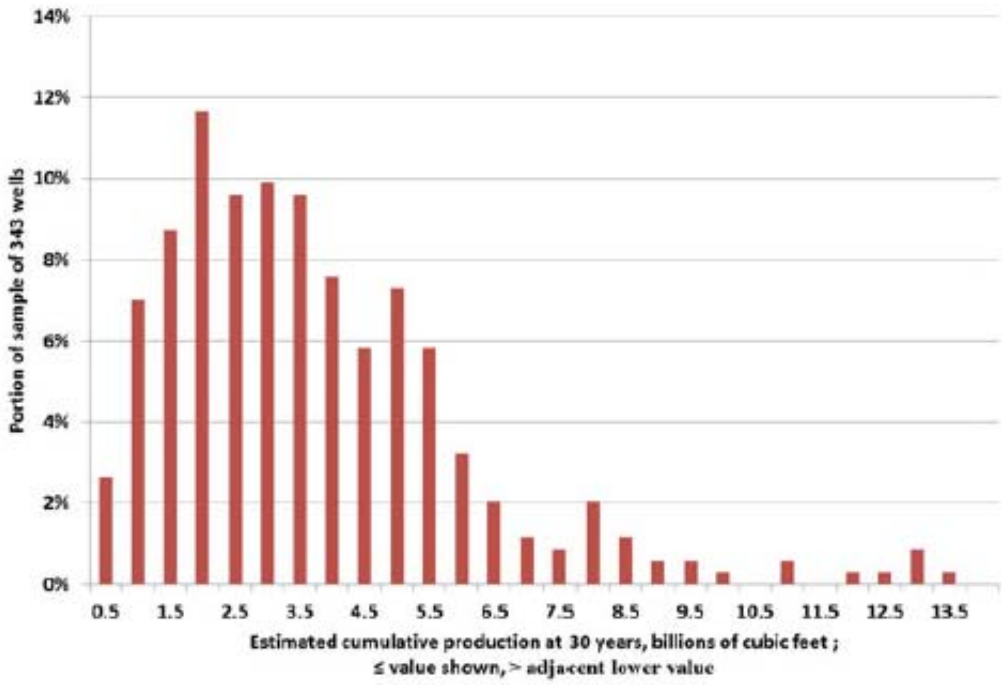

Figure 10. Histogram of 30-yr estimated recovery for 343 Marcellus wells showing a mean EUR of 1.57 Bcf (Aucott, and Melillo, 2013)

The long term economic viability of shale gas wells will depend on a gas price that supports future development costs, which will in turn depend on demand for natural gas continuing to rise across all sectors of the economy. In addition, continued technological improvements will need to be made, to lower the cost of development and increase the efficiency of production.

SHALE GAS GEOGRAPHICAL DISTRIBUTION

Shale formations across the U.S. have been developed to produce natural gas in small but continuous volumes since the earliest years of commercial natural gas production. The first producing gas well in the U.S. was completed in 1821 in Devonian-aged shale near the town of Fredonia, New York.[30] The first field-scale development of shale gas was the Ohio Shale's Big Sandy Field in Kentucky during the 1920s.[31] By the 1930s, gas from the Antrim Shale in Michigan had experienced moderate development; however, it was not until the 1980s that Antrim development began to expand rapidly (it has now reached a total of nearly 9,000 wells).[32] However, the majority of these early efforts to produce gas from shale formations did not differ markedly from the drilling and completion methods applied to conventional reservoir rocks: vertical wells coupled with relatively small stimulations.

During the 1980s Mitchell Energy began attempts to develop the Barnett Shale in the area around Fort Worth, Texas.[33] Through the mid 1990s Mitchell experimented in the Barnett with hydraulic fracturing techniques and to a more limited degree, horizontal drilling. In 1997 Mitchell engineers learned that less expensive, low viscosity "slickwater" fracturing treatments could be applied in the Barnett with good results. Through continued improvements in the techniques, development of the Barnett accelerated during the 2000s.

This combination of sequenced hydraulic fracture treatments and horizontal wellbores was crucial in facilitating the expansion of shale gas development. After the successful application of these two technologies in the Barnett Shale by Mitchell, other companies quickly took notice and development of shale gas resources in other basins grew rapidly during 2006-2011; the Fayetteville Shale in Arkansas, the Woodford shale in Oklahoma, the Haynesville-Bossier shale in eastern Texas and northwestern Louisiana, the Marcellus shale of the Appalachian basin, and the Eagle Ford shale of southern Texas followed in succession. Other shale plays have also begun to emerge, including those with higher liquids content such as the Bakken shale, Niobrara shale, and portions of the Eagle Ford shale. A number of companies, for the most part independent producers, saw opportunities and acquired acreage positions that would support large scale development.

Shale Gas – Geology

Shale is a sedimentary rock that is predominantly comprised of consolidated clay-sized particles. Shales are deposited as mud in low-energy environments (e.g., tidal flats, deep water) where the fine-grained clay particles fall out of suspension. During the deposition of these very fine-grained sediments, there can be simultaneous deposition of algae-, plant-, and animal-derived organic debris.[34] The naturally tabular clay particles (platelets) lay flat as the sediments accumulate, become compacted and eventually lithify (solidify) into thinly layered shale rock. The sheet-like

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[30] Schlumberger. 2005. Shale Gas White Paper. 05-OF299. Modified from: J. K., Frantz and V. Jochen. Schlumberger Marketing Communications. October 2005.

[31] Engelder, T., and G. G. Lash. 2008. Marcellus Shale Play"s Vast Resource Potential Creating Stir in Appalachia. The American Oil & Gas Reporter. May 2008.

[32] Harrison, W., 2006, "Production History and Reservoir Characteristics of the Antrim Shale Gas Play, Michigan Basin," Western Michigan University. 2006.

[33] Wang and Krupnick, 2013, "A Retrospective Review of Shale Gas Development in the United States," Resources for the Future, April, http://www.rff.org/Publications/Pages/PublicationDetails.aspx?PublicationID=22177

[34] Davis ,R., Jr. 1992, "Depositional Systems: An Introduction to Sedimentology and Stratigraphy," Prentice Hall, 2nd Edition, 1992.

clays result in a rock that has limited horizontal permeability and extremely limited vertical permeability unless fractured.

If the volume of organic material contained within the shale is significant, it can serve as a source rock for oil and gas as the buried material is subjected to high heat and pressure over millions of years. A portion of the hydrocarbons generated in shales escape to stratigraphically-associated sandstone and carbonate formations. These higher-permeability rocks may be overlain by other very low vertical permeability shales that act as seals to trap the oil and gas by preventing vertical movement.

The most productive gas shales are organic-rich "black" shales in the gas "window"[35] where their thermal maturity level has enabled the production of gas over geologic time. These shales contain oil-generative organic matter (kerogen) in quantities (measured as Total Organic Carbon) high enough to generate commercial quantities of methane. In addition to *free* gas stored in pores and fractures, gas shales can also contain *adsorbed* gas (methane molecules attached to organic material) and *absorbed* gas (methane molecules held in solution in hydrocarbon liquids)[36]

Some of the shale formations currently being tapped in the U.S. are the source rocks for hydrocarbons produced from conventional fields. For example, the Utica shale currently being developed in eastern Ohio is considered the source of oil and gas produced from the Lima-Indiana Trend oil fields of northwest Ohio.[37] Similarly, the Eagle Ford shale in south central Texas is considered the source rock for the Austin Chalk trend and the giant East Texas Field.[38] Generally speaking however, much of the hydrocarbons generated within these source beds remains in place.

Over geologic time, structural movements and stresses within the earth can cause fractures to appear within shale formations located deep in the subsurface. Often these "natural" fractures are oriented in particular directions as a function of the stress regimes in place, and may also be clustered in particular areas depending on the mechanical properties of the shale and surrounding formations. These natural fractures can hold gas and can also be conduits for its production from the shale. Locating such fracture "sweet spots" can be part of a company's development strategy.

The natural layering and fracturing of shales can be seen in outcrops. Figure 11 shows a typical shale outcrop that reveals the natural bedding planes, or layers, of the shale and near-vertical natural fractures that can cut across the naturally horizontal bedding planes.

In conventional oil and gas reservoirs —sandstones, and carbonates such as limestones and dolomites—the hydrocarbons are located within interconnected pore spaces that allow flow to the wellbore. In shale reservoirs this "interconnectedness" (permeability) is severely limited. Because

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[35] When organic rich shales are buried and subjected to increased temperatures and pressures oil begins to form in the source rock due to the thermogenic breakdown of kerogen. The oil "window" is a temperature dependant interval where oil is generated and expelled from the source rocks, often found in the 60-120 degree Celsius interval (aprox. 2-4 km depth). The corresponding gas window is found in the 100-200+ degree Celsius interval (3-6 km depth).

[36] American Association of Petroleum Geologists, Energy Minerals Division website http://emd.aapg.org/technical_areas/gas_shales/index.cfm accessed June 2013

[37] Wickstrom, L., et al., The Utica-Point Pleasant Shale Play of Ohio, http://www.dnr.state.oh.us/portals/10/energy/Utica-PointPleasant_presentation.pdf

[38] TRR web page for Eagle Ford Shale, http://www.rrc.state.tx.us/eagleford/, accessed June 2013

of the low permeability of these formations, it is necessary to stimulate the reservoir to create additional permeability. Hydraulic fracturing is the preferred stimulation method.

The potential of a shale formation to contain economic quantities of gas can be evaluated by identifying specific source rock characteristics such as total organic carbon (TOC), thermal maturity, and kerogen analysis. Together, these factors can be used to predict the likelihood that a prospective shale will produce economically viable volumes of natural gas. A number of wells may need to be analyzed in order to sufficiently characterize the potential of a shale formation, particularly if the geologic basin is large and there are variations in the target shale zone.

Figure 11. Marcellus Shale outcrop exposing near-vertical natural fractures that cut across the naturally horizontal bedding planes.

Shale Gas in the United States

Shales are present in sedimentary basins across North America, including the lower 48 states and Alaska. Originally, these basins were bodies of water where sediments and organic material were deposited over long periods of time, millions of years ago. For example, the Devonian aged shales of the Appalachian, Illinois, and Michigan basins were deposited 385 million years ago when the position of land masses and seas were much different than they are today (Figure 12).[39] Other shale formations within the lower 48 states were deposited during other geologic time periods. For

[39] Devonian map (http://jan.ucc.nau.edu/~rcb7/ Prof. Ron Blakey, Northern Arizona University)

example, the Barnett and Fayetteville shales were deposited during the late Mississippian Period (~325 million years ago) and the Haynesville-Bossier shale during the Jurassic period (~150 million years ago).

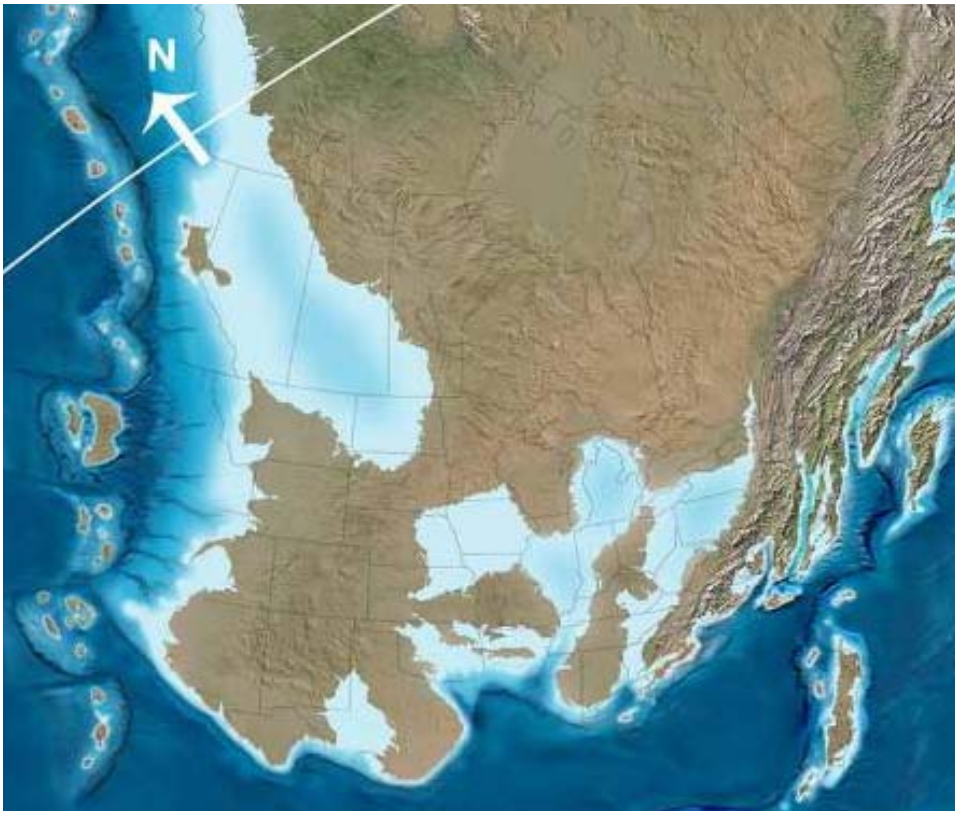

Figure 12. Map showing estimated positions of land masses and depositional basins 385 million years ago during the Devonian period. State borders highlight Appalachian, Illinois, and Michigan basins (Prof. Ron Blakey, Northern Arizona University)

The large number of sedimentary basins and the large volume of sediments within them mean that the United States is particularly rich in shale deposits. There are dozens of shale formations distributed across dozens of ancient depositional basins found across the U.S. (Table 5).[40] Each of these shale formations is different and each presents a unique set of challenges to development as sources of natural gas or liquids. For example, the Antrim (Michigan) and New Albany (Illinois and Indiana) shales are shallower formations that, unlike most of the other gas shales, produce significant volumes of formation water. The Fayetteville Shale play area is located in rural north central Arkansas, while portions of the Barnett Shale play area are found in urban and suburban environments near Fort Worth, Texas. Much of the Marcellus Shale play is being developed in areas of Pennsylvania where citizens are unfamiliar with modern oil and gas drilling and production activity.

As new technologies are developed and refined, shale gas plays once believed to have limited economic viability are now being re-evaluated. Appendix B summarizes some key characteristics of

[40] Cardott, B., 2008, "Shales Closing Conventional Gap," http://www.aapg.org/explorer/divisions/2008/11emd.cfm, accessed June 2013

the currently most active shale gas plays across the U.S. This appendix provides a means to compare the characteristics that are used to evaluate the different gas shale plays. Note that estimates of the shale gas resource, especially the portion that is considered technically recoverable, are likely to change over time as new data become available.

The following sections provide a summary of basic information regarding major producing shale gas plays and selected emerging plays. A number of these plays produce *both oil and natural gas*, and are included in this "shale gas primer" for completeness.

Table 5: Selected Shale Formations of the U.S. with Active Plays Highlighted (Cardott, 2008 and other sources)

Region	Basin	Status*	Shale	Age
Appalachian Mountains and Southeast	Appalachian (KY, OH, WV)	Developed	**Ohio**	Devonian
	Appalachian (NY, PA, WV)	Developing	**Marcellus**	Devonian
	Appalachian (OH, KY,VA, WV)	Developing	**Huron**	Devonian
	Appalachian (OH, PA, NY)	Developing	**Utica-Point Pleasant**	Ordovician
	Appalachian (AL,AR, KY,TN)		Chattanooga	Late Devonian
	Appalachian (KY)		Cleveland	Devonian
	Appalachian (NY)		Queenston	Ordovician
	Appalachian (PA, NY)		Rhinestreet	Devonian
	Appalachian (OH)		Sunbury	Mississippian
	Appalachian (KY)		Clinton	Early Silurian
	Black Warrior (AL)		Conasauga	Middle Cambrian
	Black Warrior (AL, MS)		Floyd/Neal	Late Mississippian
	Deep River (NC)		Cumnock	Triassic
Michigan	Michigan (MI)	Developed	**Antrim**	Late Devonian
	Michigan (MI)		Ellsworth	Late Devonian
	Michigan (MI)		Collingwood-Utica	Middle Ordovician
Mid-Continent	Arkoma (AR)	Developed	**Fayetteville**	Mississippian
	Arkoma, Anadarko, Ardmore, Permian (OK, TX)	Developing	**Woodford**	Late Devonian-Early Mississippian
	Illinois (IL)	Developing	**New Albany**	Devonian-Mississippian
	Arkoma (OK)		Caney	Mississippian
	Cherokee Platform (KS, OK)		Excello-Mulky	Pennsylvanian
	Arkoma (AR)		Moorefield	Mississippian
Texas and Gulf Coast	Forth Worth (TX)	Developed	**Barnett**	Mississippian
	East Texas-NW Louisiana (TX, LA)	Developed	**Haynesville/Bossier**	Late Jurassic
	Western Gulf, Maverick (TX)	Developing	**Eagle Ford**	Late Cretaceous
	Maverick (TX)	Emerging	**Pearsall**	Cretaceous

	Permian, Delaware (TX)	Emerging	**Cline, Wolfcamp, Bone Spring, Avalon (assoc. gas)**	Permian-Pennsylvanian
	Permian (TX)		Percha	Devonian-Mississippian
	Palo Duro (TX)		Bend	Pennsylvanian
	Central Louisiana (LA)	Frontier	Tuscaloosa Marine	Cretaceous
Rocky Mountains and Northern Great Plains	Denver, Park, Powder River (CO, WY)	Developing	**Niobrara**	Late Cretaceous
	Williston (ND, MT)	Developing	**Bakken (assoc. gas)**	Devonian-Mississippian
	San Juan (CO,NM)	Frontier	**Lewis**	Late Cretaceous
	Uinta (UT)	Frontier	**Mancos**	Cretaceous
	Paradox (CO, UT)		Gothic	Pennsylvanian
	Paradox (UT)		Cane Creek	Pennsylvanian
	Paradox (CO,UT)		Chimney Rock	Pennsylvanian
	Paradox (CO,UT)		Hovenweep	Pennsylvanian
	Paradox (UT)		Hermosa	Pennsylvanian
	Central Montana (MT)		Heath	Late Mississippian
	Big Horn and Wind River (ID, MT, WY)		Cody	Cretaceous
	San Juan (NM)	Frontier	**Mancos**	Cretaceous
	Uinta (UT)		Manning Canyon	Mississippian
	Greater Green River (WY)		Hilliard	Cretaceous
	Vermillion (CO, WY)		Baxter	Late Cretaceous
	Williston (MT)		Gammon	Late Cretaceous
	Greater Green River (CO, UT)		Green River	Eocene
	Big Horn and Powder River (WY)	Frontier	Mowry	Cretaceous
	Raton (CO)		Pierre	Cretaceous
California	Santa Maria (CA)	Frontier	**Monterey**	Miocene
	San Joaquin (CA)		McClure	Miocene

******Developed*** plays have seen extensive drilling and production, with acreage owners and development strategy well defined, although infill drilling continues; ***Developing*** plays have largely been leased and have also seen extensive drilling and production but significant acreage remains to be drilled; ***Emerging*** plays are in the early stages of drilling and production after significant leasing activity and some degree of drilling and testing; ***Frontier*** plays are in the early stages of leasing and/or drilling and testing, where a clear understanding of the best development strategy remains to be defined. Several of the uncategorized shales are quickly approaching frontier status.

Appalachia and Southeast

The Marcellus Shale

The Middle Devonian-age Marcellus Shale is the geographically largest shale gas play in the U.S. (Figure 13).[41] Depth of production is between 4,000 ft and 8,500 ft.

Range Resources Corporation drilled the first economically productive wells into the Marcellus formation in Pennsylvania in 2005. Since then, thousands of Marcellus wells have been drilled across Pennsylvania, northern West Virginia, and eastern Ohio. Although potentially productive areas of the Marcellus shale extend into southwestern New York and far western Maryland, legislators in those states have delayed development.

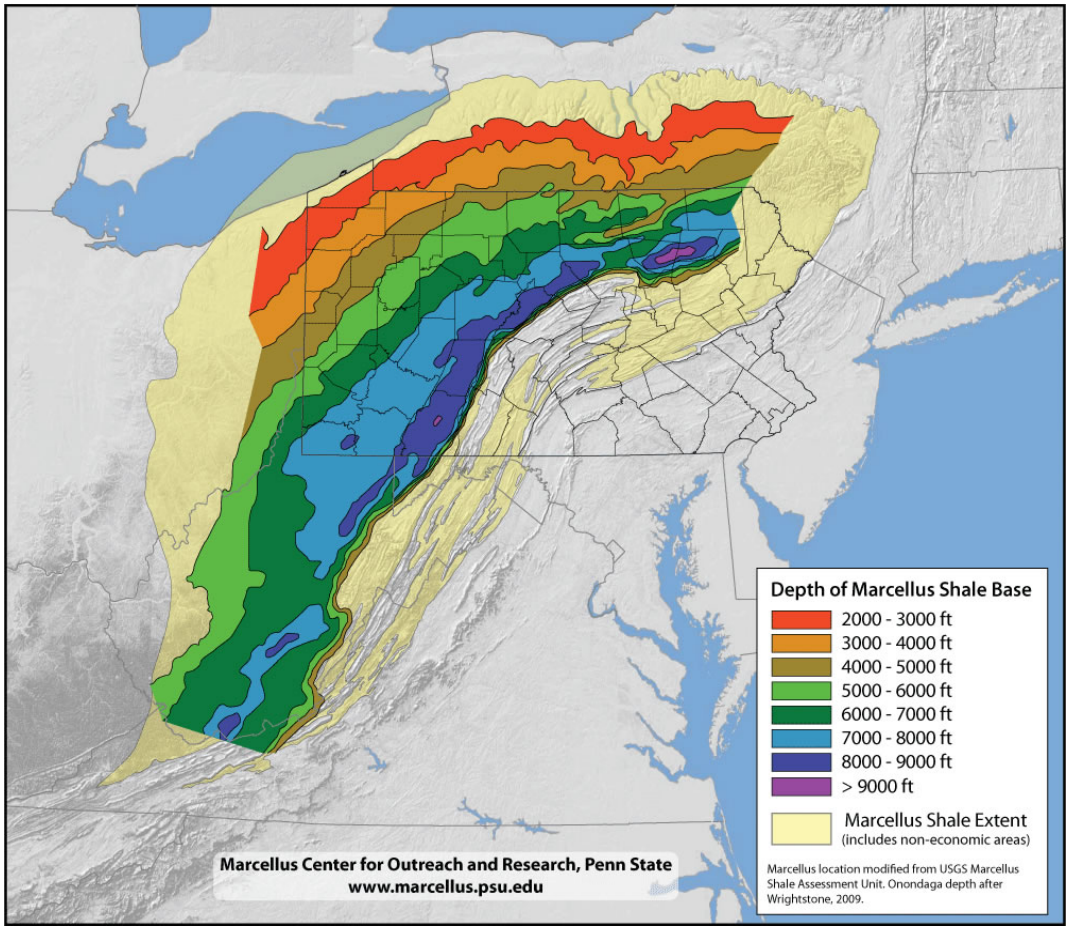

Figure 13. Marcellus Shale play geographical extent and depth of shale base across the basin (Marcellus Center for Outreach and Research, Penn State University)

The Marcellus Shale covers an area of more than 100,000 square miles at an average thickness of 50 ft to 200 ft. Currently, more than 3,600 wells are producing more than 8 Bcfd of gas from the Marcellus. Precise figures for the number of producing wells and production are hard to maintain because development has been rapid and the various states have different reporting requirements.

[41] Grant, S., "Pennsylvania's Buried Treasure," 2010, http://pabook.libraries.psu.edu/palitmap/Marcellus.html

For example, Pennsylvania only requires "unconventional" well operators to report individual well data for public posting twice a year, for preceding six month time periods. The latest available data (six months ending December 31, 2012) showed 6,178 Marcellus wells at various points along the path from permitting to producing. A total of 3,565 Marcellus wells show some amount of gas, condensate, or oil production during the previous six months. The remaining wells are completed and awaiting tie in to a gas sales line, or are in some other phase of the drilling, completion, hydraulic fracturing and testing process. Marcellus wells in Pennsylvania (Figure 14) are clustered in the northeast (fairly dry gas) and in the southwest (gas and condensate production) where geologic characteristics favor commercial production rates.[42]

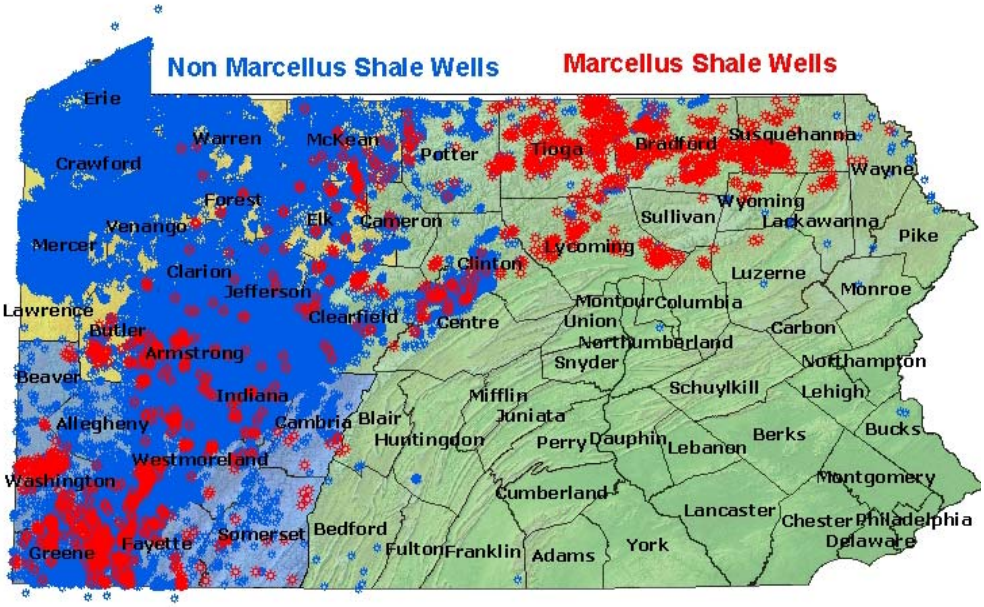

Figure 14. Map showing distribution of Marcellus Shale wells relative to non-Marcellus wells across Pennsylvania (PA Dept. of Environmental Protection website)

A smaller number of Marcellus wells are producing in northern West Virginia and eastern Ohio. More than 1000 wells have a reported pay interval in the Marcellus in West Virginia. However, most of these wells are older vertical wells located in the southwestern portion of the state rather than horizontal, multiple stage hydraulic fracture completions (Figure 15). By August 2013, about 340 horizontal Marcellus wells had been drilled in WV, primarily in the northern portion of the state.[43]

The Marcellus thins as it extends west from Pennsylvania into Ohio. As of May 2013, only a few dozen wells had been completed in the Marcellus in southeastern Ohio and only six were producing, mostly in Monroe and Belmont counties.[44]

Based on estimates of flow through the pipelines that take gas out of the Marcellus play area, Pennsylvania Marcellus production was about 2 trillion cubic feet in 2012 — roughly double the

[42] http://www.dep.state.pa.us/dep/deputate/minres/oilgas/2011PermitDrilledmaps.htm
[43] http://www.wvgs.wvnet.edu/www/datastat/devshales.htm
[44] http://www.dnr.state.oh.us/Portals/10/Energy/Marcellus/MarcellusWellsActivity_05042013.pdf

prior year — while production from West Virginia Marcellus wells was about 700 billion cubic feet in 2012, bringing the total 2012 Marcellus output to about 2.8 trillion cubic feet. Ultimately, as many as 90,000 wells could be drilled to fully develop the Marcellus.[45]

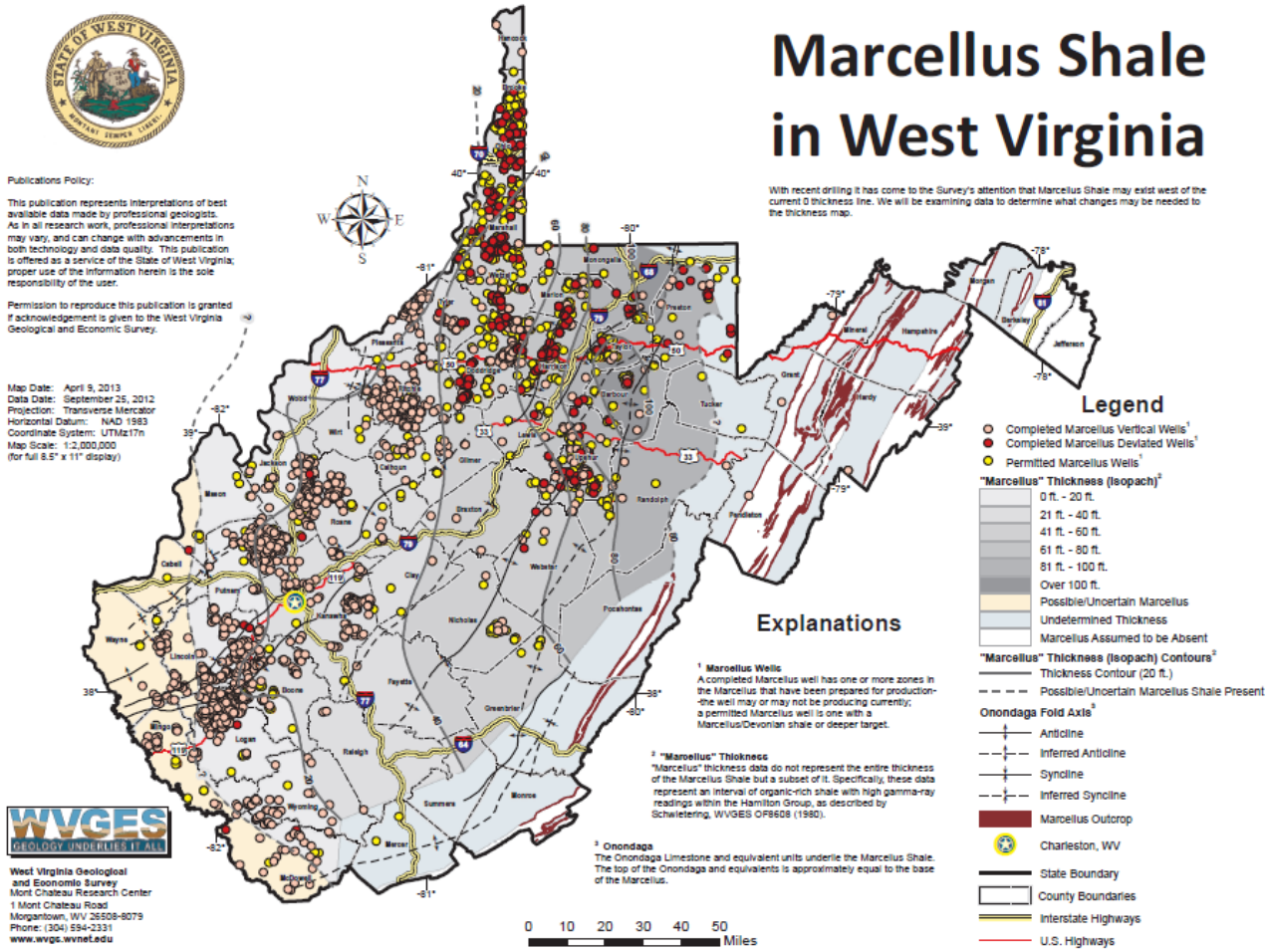

Figure 15. Map of Marcellus Shale well locations in West Virginia. Modern horizontal wells (shown in red) are found primarily in the northern portion of the state (WVGES website)

Utica-Point Pleasant

The Ordovician aged Utica-Point Pleasant play underlies the Marcellus Shale at depths that in some areas exceed 14,000 feet (Figure 16).[46] However, the depth of the productive areas appears to be at 3,500 to 10,000 feet. Currently the productive area extends from western Pennsylvania across eastern Ohio, including portions of northern West Virginia.

The productive intervals included in the play include the Utica Shale and associated organic-rich calcareous shale and interbedded limestones (termed the Point Pleasant formation in Ohio) found above the Trenton Limestone. The thermal maturity of the organic material is such that between

[45] EIA, Annual Energy Outlook 2012, http://www.eia.gov/forecasts/archive/aeo12/
[46] Penn State Marcellus Center for Outreach and Research, http://www.marcellus.psu.edu/images/UticaDepth.gif

the immature and overmature areas, a zone of wet gas and oil trends across eastern Ohio while the dryer gas areas are found in western Pennsylvania and northern West Virginia (Figure 17).[47] This trend, coupled with lower natural gas prices and relatively high oil prices, has led to a concentration of drilling in the wet gas and oil window in eastern Ohio.

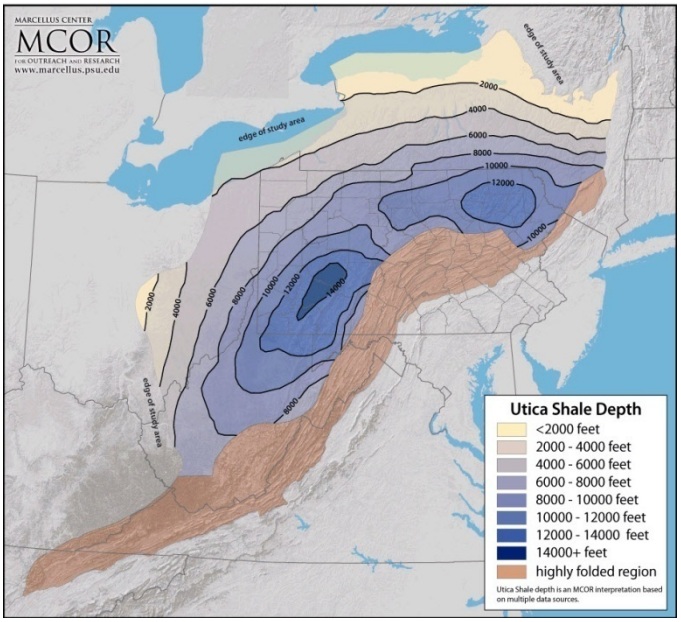

Figure 16. Utica Shale depth across basin (Penn State Marcellus Center for Outreach and Research website)

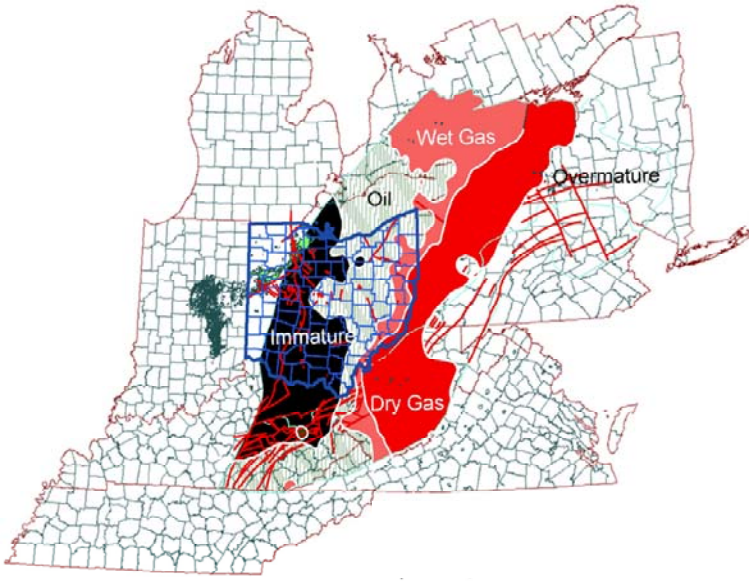

Figure 17. Areas of wet and dry gas within the Utica productive region (Wickstrom, 2011)

[47] Wickstrom, L., et al., 2011, "Utica Shale Drilling Activity and Resource Assessment in Ohio," presentation at Coalition of Ohio Land Trusts Summer Meeting, http://www.capitolintegrity.com/documents/UticapresentationJune2011Wickstrom.pdf

The Ohio Department of Natural Resources reports that as of September 21, 2013, a total of 899 Utica-Pt. Pleasant wells had been permitted, with 561 drilled and 152 producing.[48] During calendar year 2012 a total of 63 wells had commercial production from the Utica/Point Pleasant formation that totaled 12.8 Bcf and 636 thousand barrels of oil and condensate.

Michigan

Antrim

The Antrim Shale is located in the upper portion of the lower peninsula of Michigan within the Michigan Basin. This Late Devonian-age shale is bounded by shale above (Bedford Shale) and by limestone below (Squaw Bay Limestone) and occurs at depths of 600 ft to 2,200 ft. Such a shallow depth is more typical of coal seam gas production than gas shale. Similar to coalbed methane wells, the water within the Antrim's natural fracture network must be removed to enable the drop in reservoir pressure that drives desorption of the gas molecules adsorbed onto the organic material distributed in the shale matrix. Only then can wells produce gas at commercial rates.

The Antrim Shale has been one of the earliest actively developed shale gas plays with its major expansion taking place in the late 1980s. Although the greater Antrim play encompasses approximately 12,000 square miles, the core area along the northern edge of the basin comprises ~2,400 sq. miles in Antrim, Crawford, Montmorency, Oscoda and Otsego counties (Figure 18).[49]

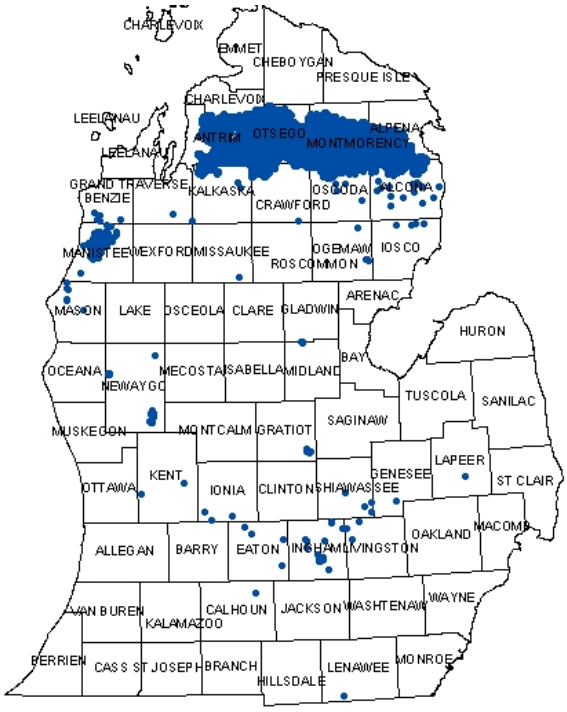

Figure 18. Location of Antrim Shale core area in Michigan Basin (Michigan DNR website)

The play is distinctly different than other gas shales with shallow depth, small stratigraphic thickness (average net pay of about 70 ft to 120 ft), and greater volumes of produced water (in the range of 5 to 500 bbls/day/well). Due to the shallow depth, nearly all wells are vertical rather than

[48] Ohio Department of Natural Resources website, http://oilandgas.ohiodnr.gov/shale#SHALE
[49] Michigan DNR web site, http://www.michigan.gov/images/FrmtnAntrim_163179_7.jpg

horizontal. Also, unlike most other shale gas plays, the natural gas from the Antrim appears to be biogenic (gas generated by the action of bacteria on the organic material found in the shale) rather than thermogenic (gas generated over geologic time through heat and pressure at depth).

Antrim shale gas production has been dropping as companies focus on more prolific plays with higher levels of liquids production. Total gas production was 85 bcf in 2011 compared with 131 bcf in 2008. The number of permits issued for Antrim shale development dropped to 43 in 2011 compared with 1,446 in 2006.[50] Nevertheless, the Antrim shale, along with coalbed methane plays and tight sand plays in the Rocky Mountain region, has an important place in the story of the development of the Nation's unconventional natural gas resource.

MidContinent

New Albany

The New Albany Shale, located in the Illinois Basin in portions of southeastern Illinois, southwestern Indiana, and northwestern Kentucky, is a Devonian- to Mississippian-age shale bounded by limestone both above (Rockford Limestone) and below (North Vernon Limestone). Similar to the Antrim Shale, the New Albany is relatively shallow, occurring at depths between 500 ft and 2,000 ft.

Also, similar to the Antrim Shale, the New Albany play has a thinner average net pay thickness (50 ft to 100 ft.). The New Albany is thickest in southeastern Illinois and western Kentucky, where it is over 450 ft thick (Figure 19).[51] While the New Albany shale can be found across an area spanning approximately 43,500 square miles, development has been largely focused within the southern depocenter in Indiana and Kentucky where the gross formation thickness is greatest (Figure 20).[52]

Several factors have inhibited larger scale development of the New Albany shale. These include: 1) the nitrogen content of the gas in some areas, 2) water encroachment from strata below and above the producing zone, and 3) fragmented mineral rights in historically heavily drilled areas that make it difficult to put together lease packages of sufficient size. The low level of thermal maturity, relatively low reservoir pressures and a poor understanding of the character of the natural fracture systems also combine to make the New Albany somewhat less attractive than other shale gas plays.[53] Nevertheless, a number of operators are continuing to develop prospects in the play. The Department of Energy has carried out research designed to characterize the New Albany and highlight promising completion technologies.[54]

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[50] OGJ, 2012, "GlobalData: Michigan's Antrim shale gas production drops," August 20, 2012, http://www.ogj.com/articles/2012/08/globaldata-michigans-antrim-shale-gas-production-drops.html
[51] OGJ, 2010, "The New Albany shale in Illinois: emerging play or prolific source," http://www.ogj.com/articles/print/volume-108/issue-33/exploration-__development/the-new-albany-shale.html
[52] Ibid
[53] Ibid
[54] NETL, New Albany Shale Gas (Project 07122-16), http://www.rpsea.org/0712216/

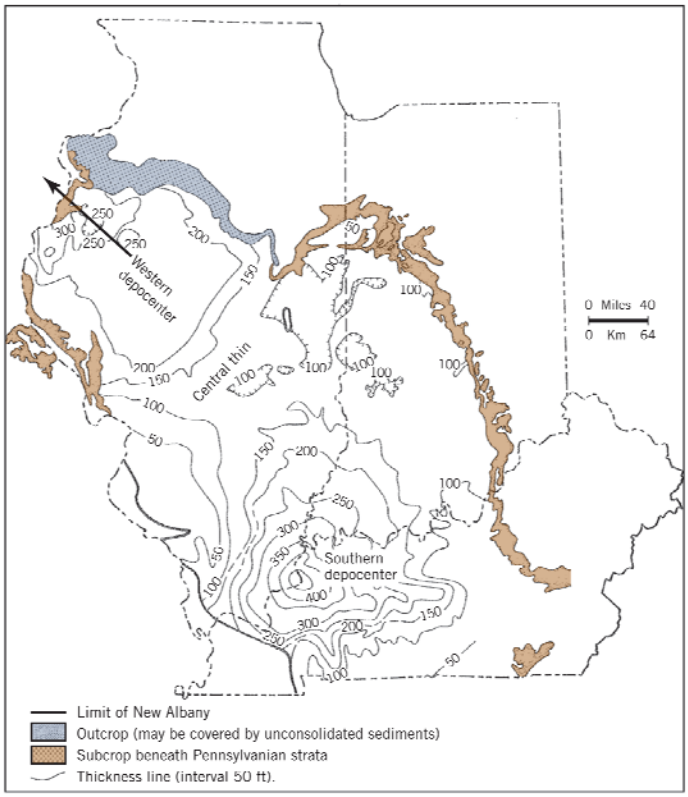


Figure 19. Isopach map of the New Albany Shale in the Illinois Basin (OGJ, 2012 after Illinois State Geological Survey, 1983)

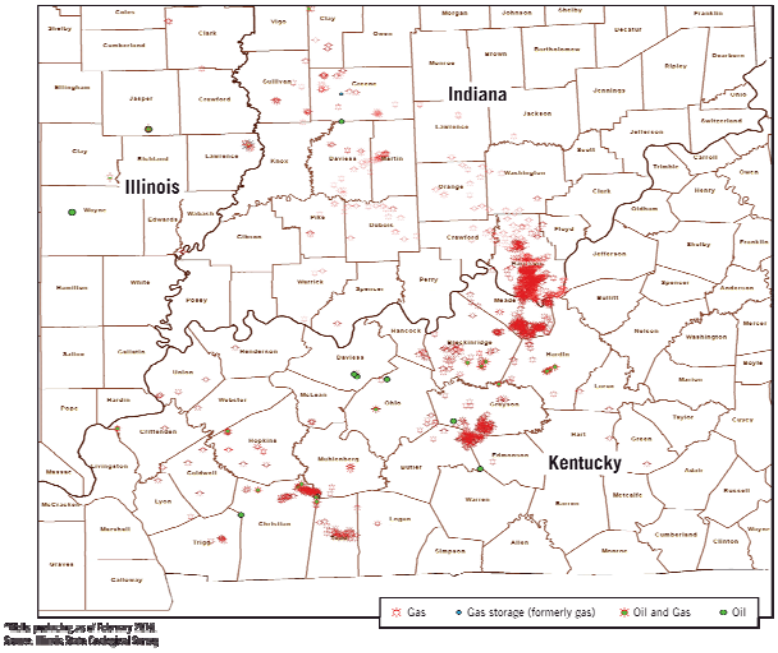


Figure 20. New Albany Producing well locations in Illinois Basin (OGJ, 2012 after Illinois State Geological Survey 2010)

Woodford

The Woodford Shale play, located in south-central Oklahoma, ranges in depth from 6,000 ft to 11,000 ft. This formation is a Devonian-age shale bounded by limestone (Osage Lime) above and undifferentiated strata below.

The Woodford play includes the largely dry gas-prone Arkoma Woodford in southeastern Oklahoma, the liquids-rich Anadarko Woodford (also known as the Cana or Caney shale) to the west and the South Oklahoma Woodford in the Ardmore Basin to the south (Figure 21).[55]

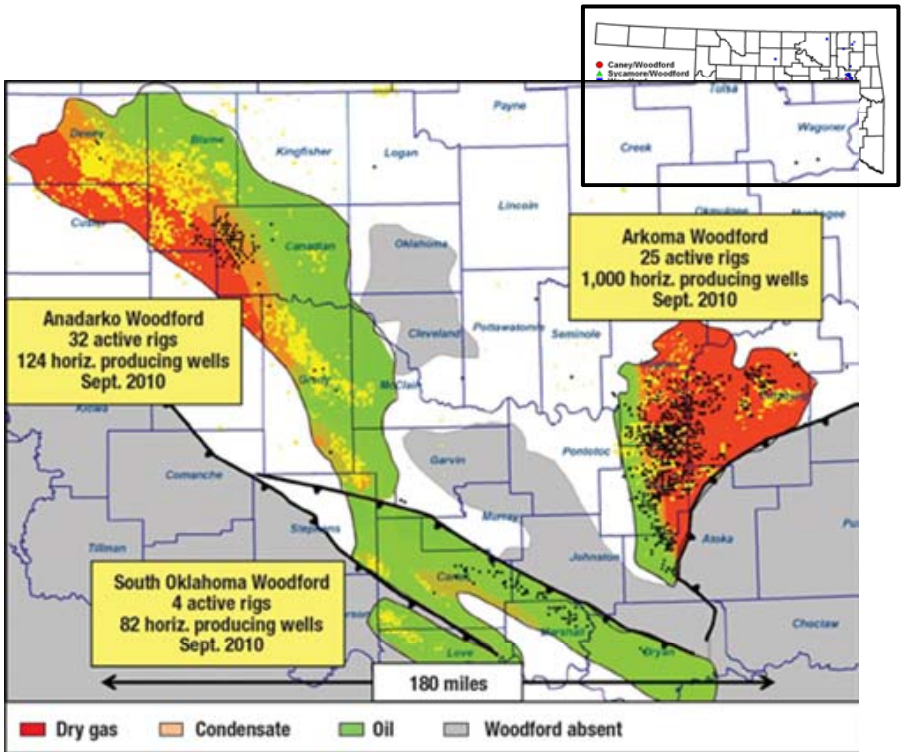


Figure 21. Map of the Woodford play including the Arkoma Woodford, Anadarko Woodford (Caney shale) and the South Oklahoma Woodford portions of the play (World Oil, 2011)

The Woodford has produced oil from conventionally drilled and completed wells since 1939, with total oil production from the region exceeding 4 million barrels. More recent natural gas production in the Woodford Shale began in 2003 with vertical well completions, and since then horizontal drilling has been adopted as it has in other shale gas plays.

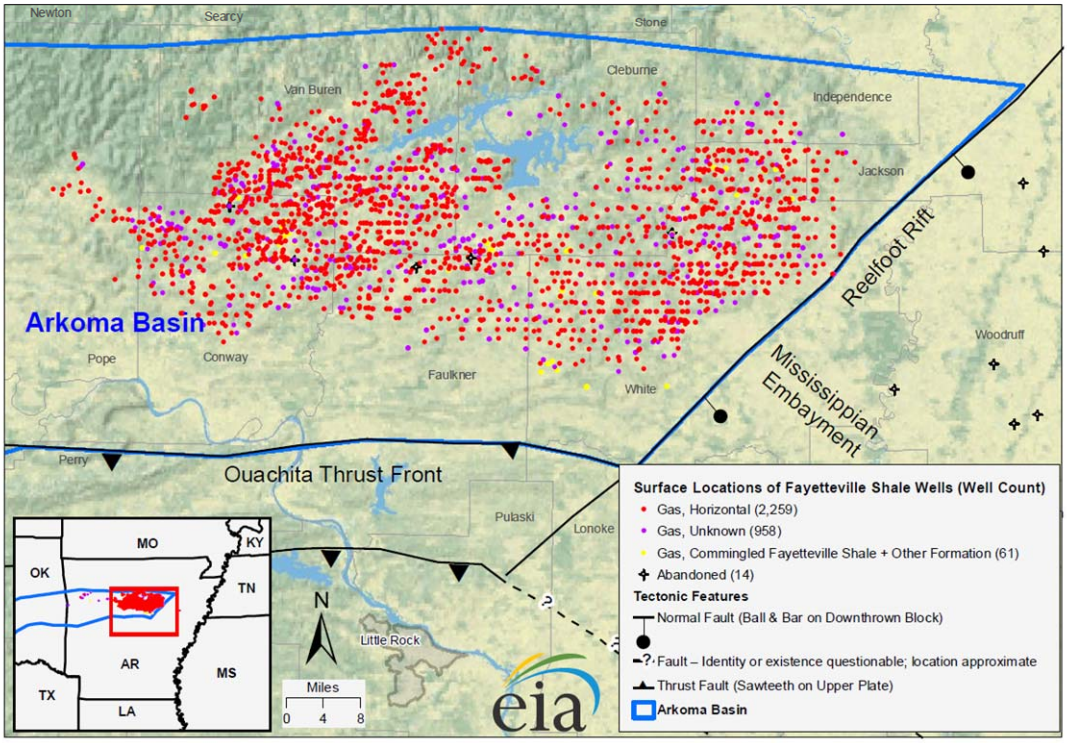
The Woodford Shale play encompasses an area of nearly 11,000 square miles, with a core development area of roughly 6,400 square miles. The average thickness of the Woodford Shale varies from 120 ft. to 220 ft. across the play.

[55] World Oil, Feb. 2011, http://www.worldoil.com/SHALE-ENERGY-Developing-the-Woodford-An-unconventional-play-with-conventional-EandP-constraints-February-2011.html

Fayetteville

The Fayetteville Shale play is located in the Arkoma Basin of northern Arkansas and eastern Oklahoma at a depth range of 1,000 to 7,000 ft. A Mississippian-age shale bounded by limestone (Pitkin Limestone) above and sandstone (Batesville Sandstone) below, the Fayetteville began to be developed in the early 2000s as companies that had experienced success in the Barnett Shale of the Fort Worth Basin identified parallels between the two formations. The shale is the geologic equivalent of the Caney Shale found on the Oklahoma side of the Arkoma Basin and the Barnett in north Texas.[56]

The primary focus of the play has been across a five-county area in north-central Arkansas (Figure 22). [57] The Arkansas O&G Commission reports a total of 4,825 active wells as of mid-July 2013, with cumulative production to date of just under 4 Tcf.[58] By the end of 2007, approximately two million acres were under lease to companies developing the Fayetteville Shale play. Production is relatively dry, and drilling dropped off in 2011-2013 as companies looked to develop wetter shale plays. However, the Fayetteville has the potential for perhaps 15,000 more wells to be drilled in coming years should natural gas prices rebound.[59]



Source: U.S. Energy Information Administration based on data from HPDI, Arkansas Geological Survey, Ratchford et al (2006)
Updated: May 31, 2011

Figure 22. Map of the Fayetteville Shale play of the Arkoma Basin (EIA, May 2011)

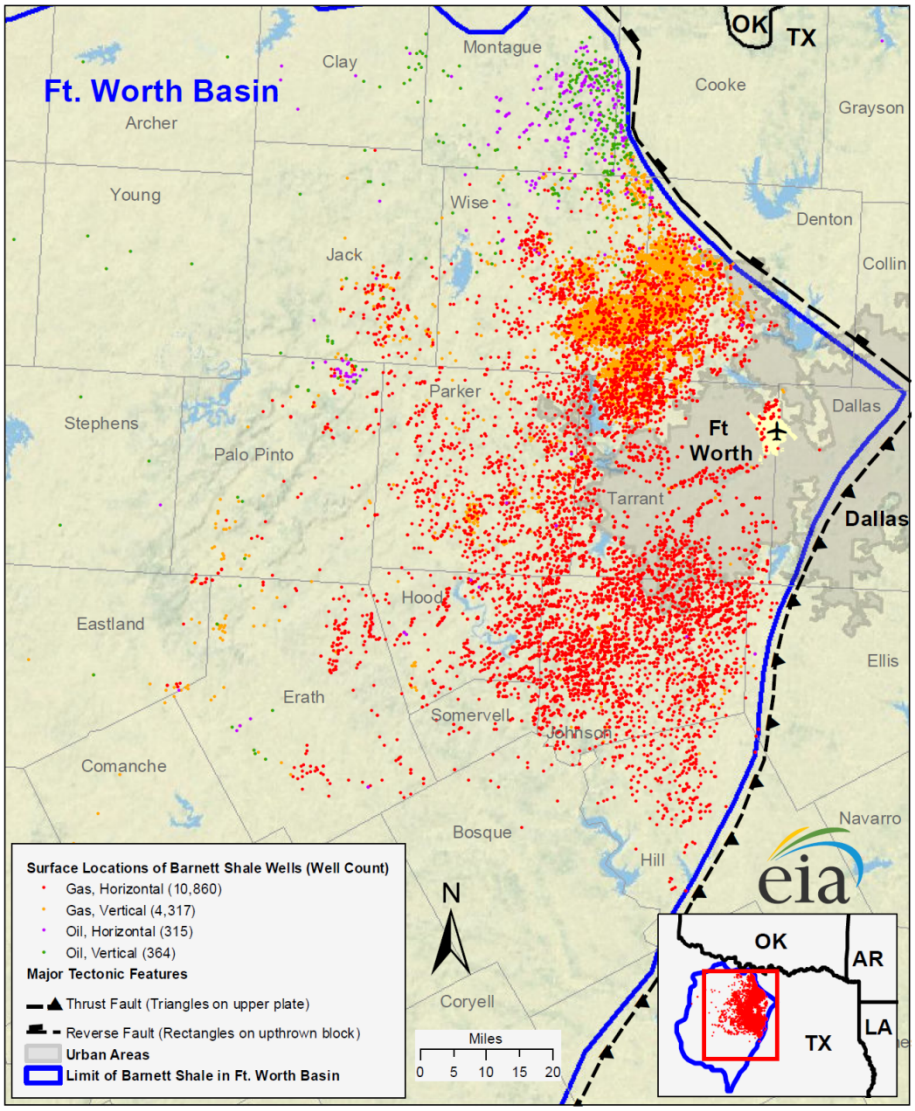
[56] U. of Arkansas Fayetteville Shale web site, http://lingo.cast.uark.edu/LINGOPUBLIC/about/index.htm
[57] EIA website, http://www.eia.gov/oil_gas/rpd/shaleusa3_letter.pdf
[58] AOGC web site, http://www.aogc.state.ar.us/Fay_Shale_Data.htm
[59] EON, 2013, "The Fayetteville Shale is Dry, But It's Hardly Dried Up," http://eon.businesswire.com/news/eon/20130620006151/en/natural-gas-Fayetteville-Shale-drilling-production

Texas and Gulf Coast

Barnett

The Barnett Shale is located in the Fort Worth Basin of north-central Texas. It is a Mississippian age shale occurring at a depth of 6,500 to 8,500 ft. and is bounded by limestone formations above (Marble Falls Limestone) and below (Chappel Limestone). With over 16,500 wells drilled to date, the Barnett Shale has been the showcase for modern drilling and well completion practices (horizontal drilling and large-volume hydraulic fracture treatments) now typical of nearly all shale gas plays.

The Barnett Shale covers an area of about 5,000 square miles with a thickness ranging from 100 to more than 600 ft. Drilling has been focused primarily in a twelve-county area west of Dallas-Ft. Worth (Figure 23).[60]



Source: US Energy Information Administration based on data from HPDI, USGS, Pollastro et al (2007)
Updated: May 31, 2011

Figure 23. Barnett Shale play of the Fort Worth Basin (EIA, May 2011)

[60] EIA, http://www.eia.gov/oil_gas/rpd/shaleusa1_letter.pdf

An assessment carried out by the Bureau of Economic Geology at the University of Texas on the production potential of the Barnett Shale, projects slowly declining production through the year 2030 and beyond and total recovery at greater than three times the cumulative production to date (Figure 24).[61] In the base case, the study forecasts a cumulative 44 Tcf of recoverable natural gas from the Barnett, with annual production declining from the current peak of about 2 Tcf per year to about 900 Bcf per year by 2030. The study's map of 30-year production estimates for individual wells highlights the variation in productivity that can be expected across shale plays (Figure 25).[62]

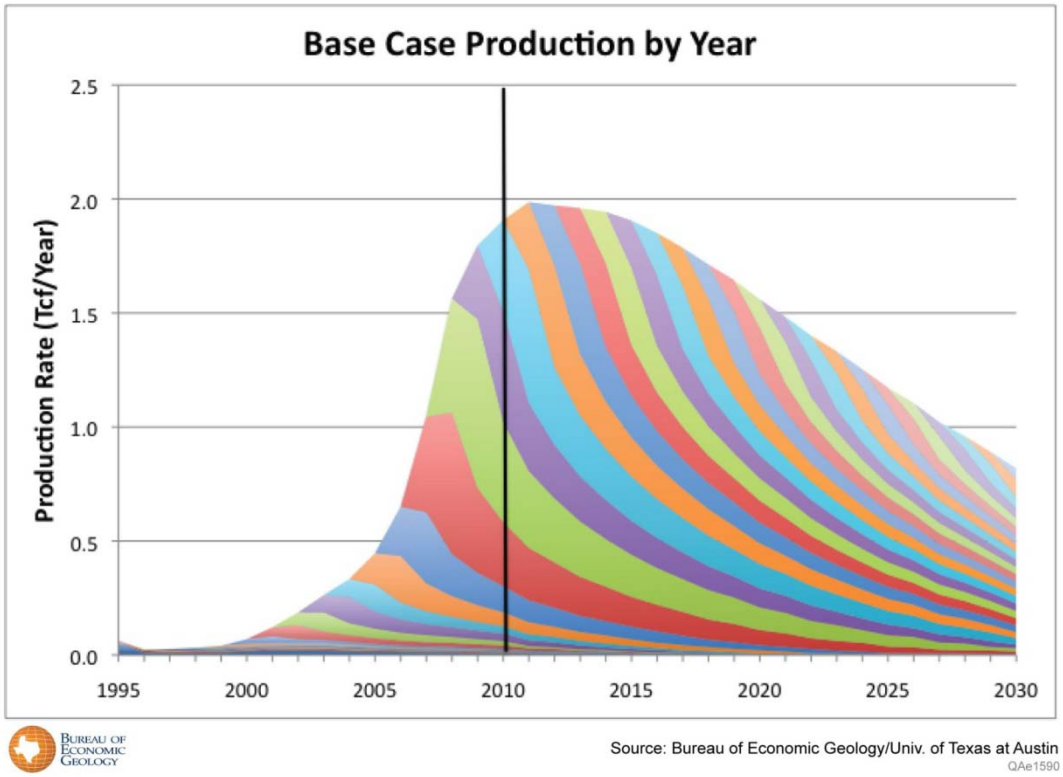


Figure 24. Production Outlook for the Barnett Shale through 2030 (BEG, Univ. of Texas, Austin, 2013)

[61] U. Texas, press release, "New, Rigorous Assessment of Shale Gas Reserves Forecasts Reliable Supply from Barnett Shale Through 2030," http://www.utexas.edu/news/2013/02/28/new-rigorous-assessment-of-shale-gas-reserves-forecasts-reliable-supply-from-barnett-shale-through-2030/

[62] Ibid

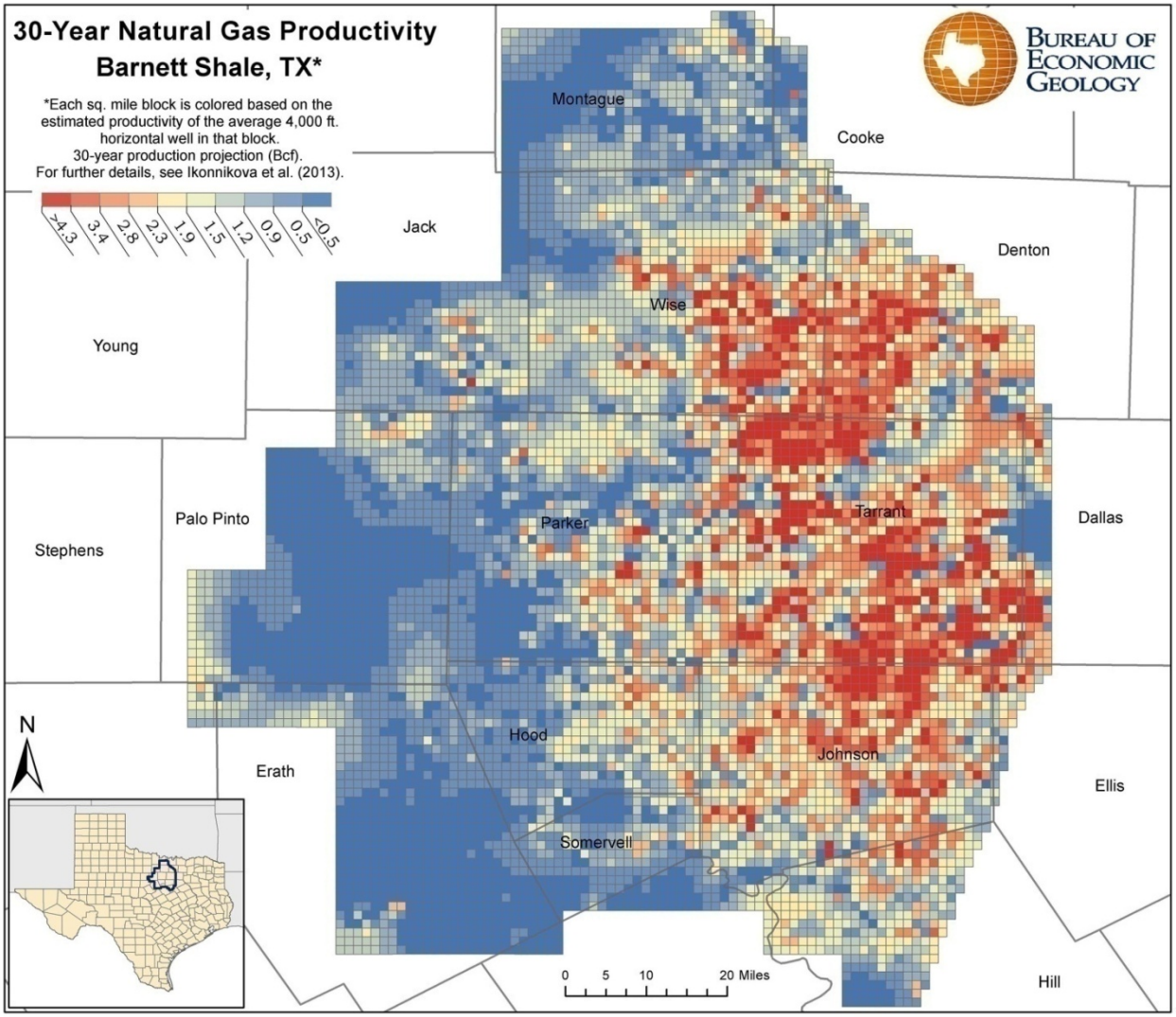


Figure 25. Variation in 30-year productivity across the Barnett Shale play (BEG, Univ. of Texas, Austin, 2013)

Haynesville-Bossier

The Haynesville Shale (also known as the Haynesville-Bossier) is situated in the North Louisiana Salt Basin in northern Louisiana and eastern Texas at depths ranging from 10,500 ft. to 13,500 ft. One of the deeper U.S. shale plays, the Haynesville is an Upper Jurassic-age shale bounded by sandstone (Cotton Valley Group) above and limestone (Smackover Formation) below.

The Haynesville Shale covers an area of approximately 9,000 square miles with an average thickness of 200 ft. to 300 ft. (Figure 26).[63] In June 2013 there were 2,437 producing Haynesville wells in Louisiana and 906 wells in Texas.[64,65]

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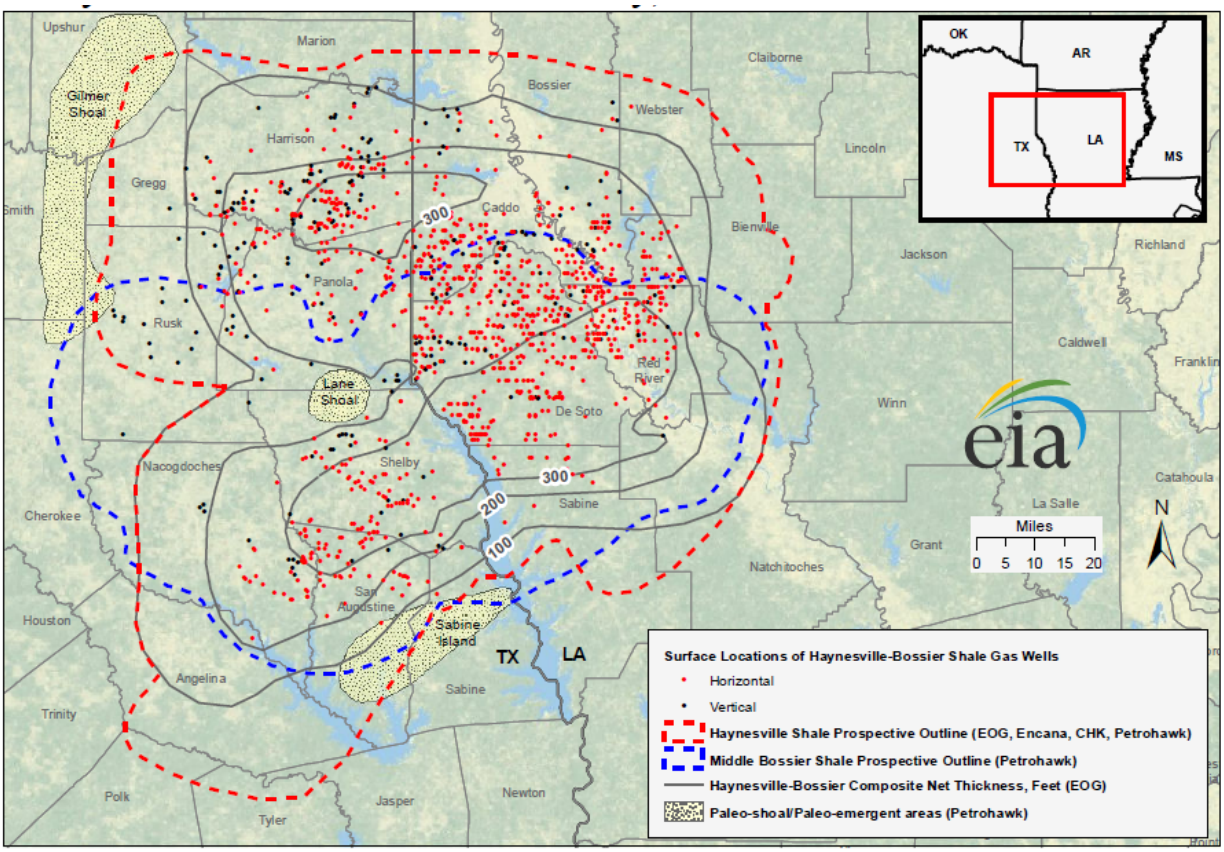
[63] EIA web site, http://www.eia.gov/oil_gas/rpd/shaleusa4.pdf
[64] Louisiana Dept. of Natural Resources, http://dnr.louisiana.gov/assets/OC/haynesville_shale/haynesville_monthly.pdf
[65] Texas RRC, http://www.rrc.state.tx.us/bossierplay/



Source: Energy Information Administration based on data from HPDI, TX Railroad Commission, LA Dept. of Natural Resources, Operators.
Updated May 26, 2011

Figure 26. Haynesville Shale play (EIA website)

The Haynesville Shale is a good example of how the drop in the price of natural gas after 2008 shifted drilling activity from relatively dry gas plays to wet gas plays and shale oil plays. Drilling in the Haynesville dropped dramatically from late 2010 thru late 2012 (Figure 27).[66] With the drop in drilling has come a drop in production (see Figure 6). This shift illustrates how economics drives shale gas development decision-making. Just as the Haynesville overtook the Barnett as the most productive shale gas play in the U.S., the Marcellus has now overtaken the Haynesville.

Eagle Ford

The Eagle Ford Shale play is one of the fastest growing plays in the U.S., in part because it includes areas with dry gas, wet gas and light oil production. This Cretaceous aged play in the Western Gulf Basin of south-central Texas extends across an area of about 7,600 square miles at depths from 4,000 to 12,000 ft. Drilling activity has been spread across a 15-county area (Figure 28).[67]

The Eagle Ford is considered to be the source rock for the Austin Chalk oil and gas formation, which it underlies.[68] The Eagle Ford "shale" formation's carbonate content can be as high as 70%, making

[66] Haynesvilleplay.com, http://haynesvilleplay.com/HV-runningrigcountchart(large).jpg
[67] EIA shale play maps, http://www.eia.gov/oil_gas/rpd/shaleusa9.pdf
[68] Eaglefordshale.com, http://eaglefordshale.com/geology/

the Eagle Ford more brittle and easier to fracture than most shale that is predominantly clay. The carbonate content increases as the shale deepens toward the southeast.

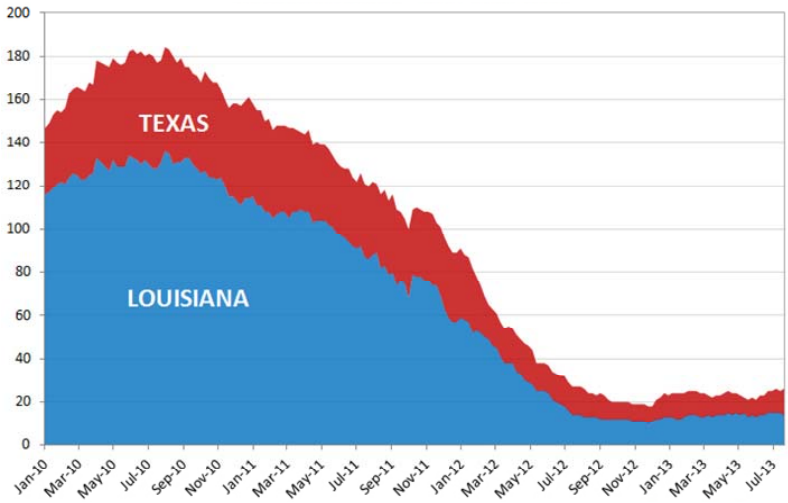


Figure 27. Haynesville Shale play rig count, January 2010 to July 2013 (haynesvilleplay.com)

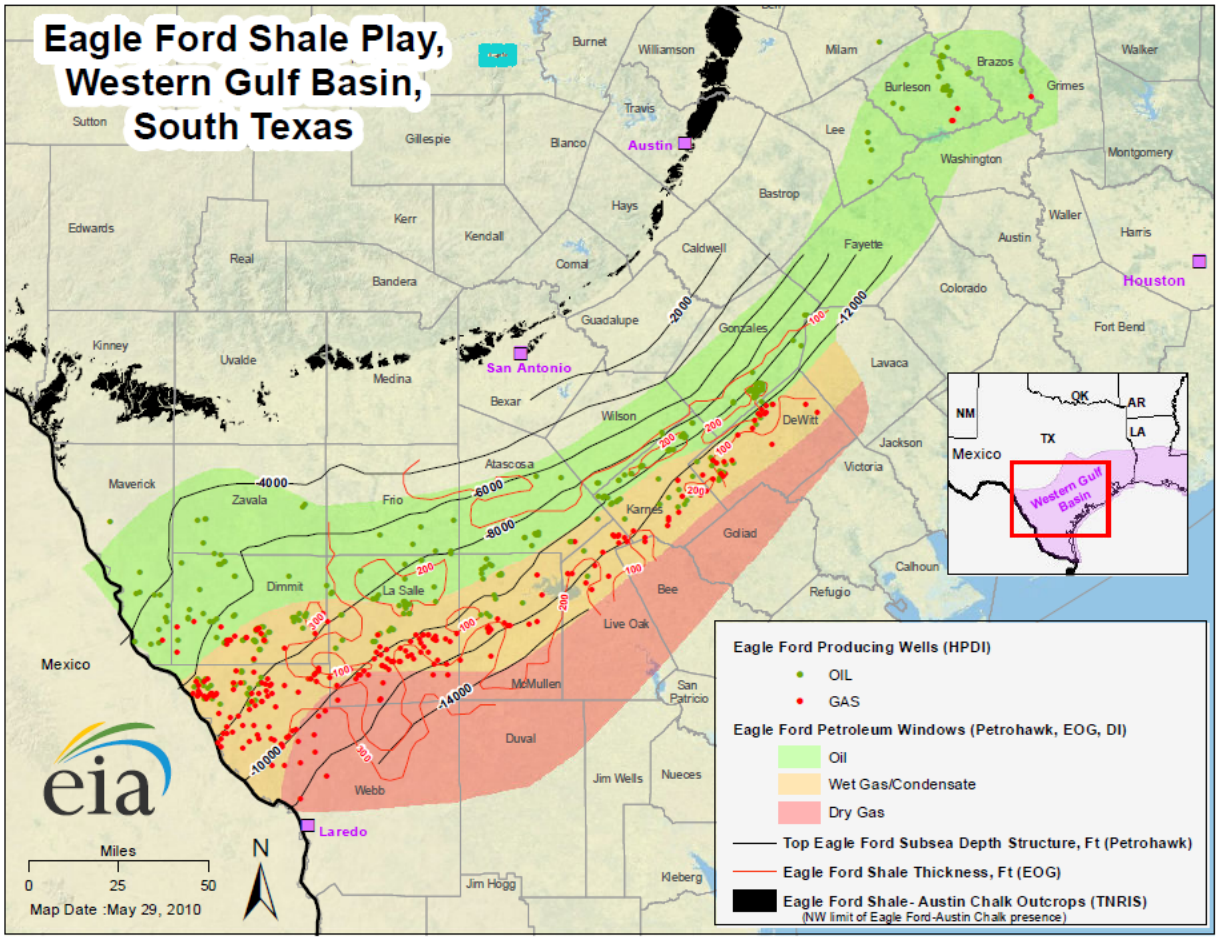


Figure 28. Eagle Ford Play (EIA website)

Production from the Eagle Ford averaged nearly 650 thousand barrels of oil and condensate per day and 2.14 billion cubic feet of gas per day from about 5,800 producing wells during the first half of 2013, and the volume of gas production is growing.[69]

Pearsall

The Pearsall Shale is a Cretaceous-aged shale formation found below the Eagle Ford at depths of 8,000 to 11,000 ft., with a thickness of 500 to 700 ft. The play area is located near the Texas-Mexico border in the Maverick Basin (Figure 29).[70] As of 2012, only a few wells had been drilled in the play outside of the Maverick Basin.[71]

By mid 2013 the Pearsall Shale had about 22 producing wells; mostly natural gas producers in Dimmit and Maverick counties that were drilled in 2010 and 2011. Like the Eagle Ford, the Pearsall has "windows" where more oil or more gas can be produced. Leasing by companies interested in developing the Pearsall is accelerating, although in many cases ongoing drilling in the overlying Eagle Ford effectively "holds" the deeper Pearsall indefinitely for the company operating there.[72]

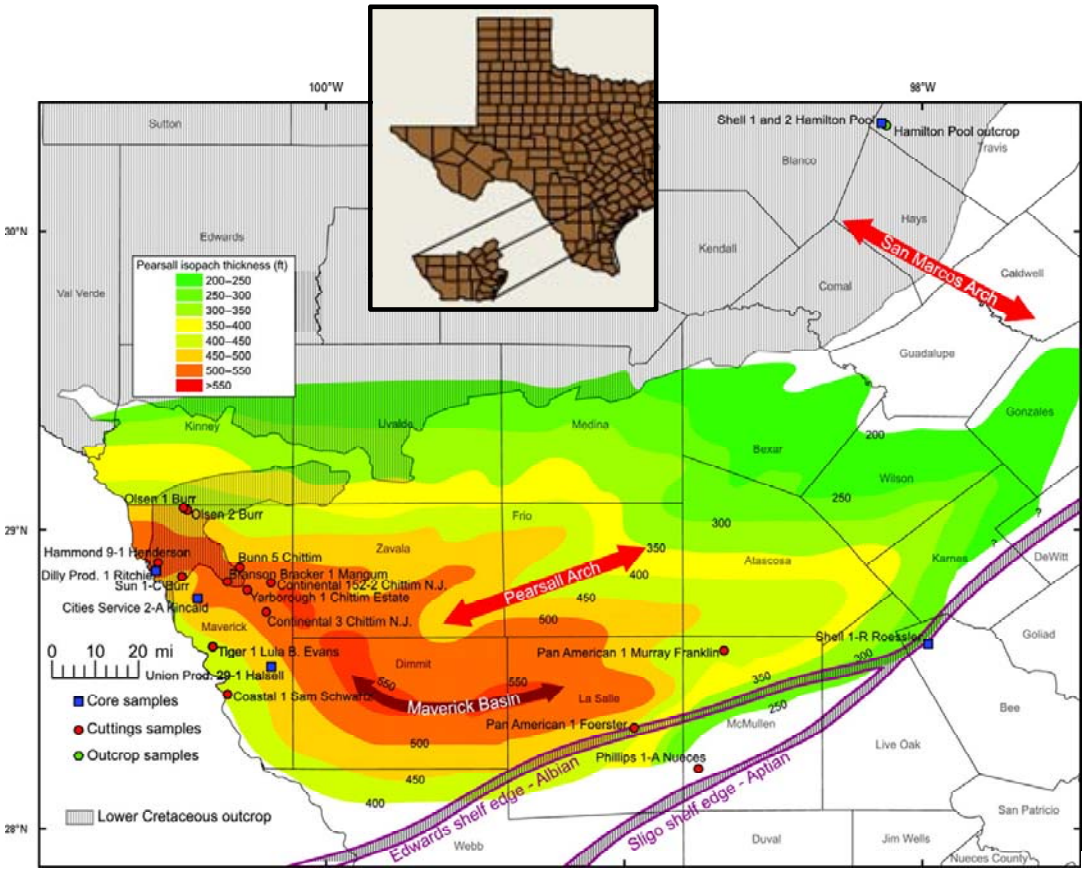


Figure 29. Map of Pearsall Play (ShaleExperts.com)

[69] Texas RRC, http://www.rrc.state.tx.us/eagleford/
[70] ShaleExperts.com, http://www.shaleexperts.com/plays/pearsallshale
[71] Eaglefordshale.com, http://eaglefordshale.com/geology/
[72] FuelFix, 2013, "Excitement grows for another South Texas shale," http://fuelfix.com/blog/2013/05/25/excitement-grows-for-another-south-texas-shale/

Permian (Cline, Wolfcamp, Wolfberry, Wolfbone, Bone Spring, Avalon)
There are a number of shale plays in the Permian Basin of western Texas that have seen active horizontal well development over the past several years. The various plays are sometimes collectively referred to as "Permian Shales" due to their overlapping nature. Most are primarily oil producers with some associated gas. The play locations are highlighted in Figure 30.[73]

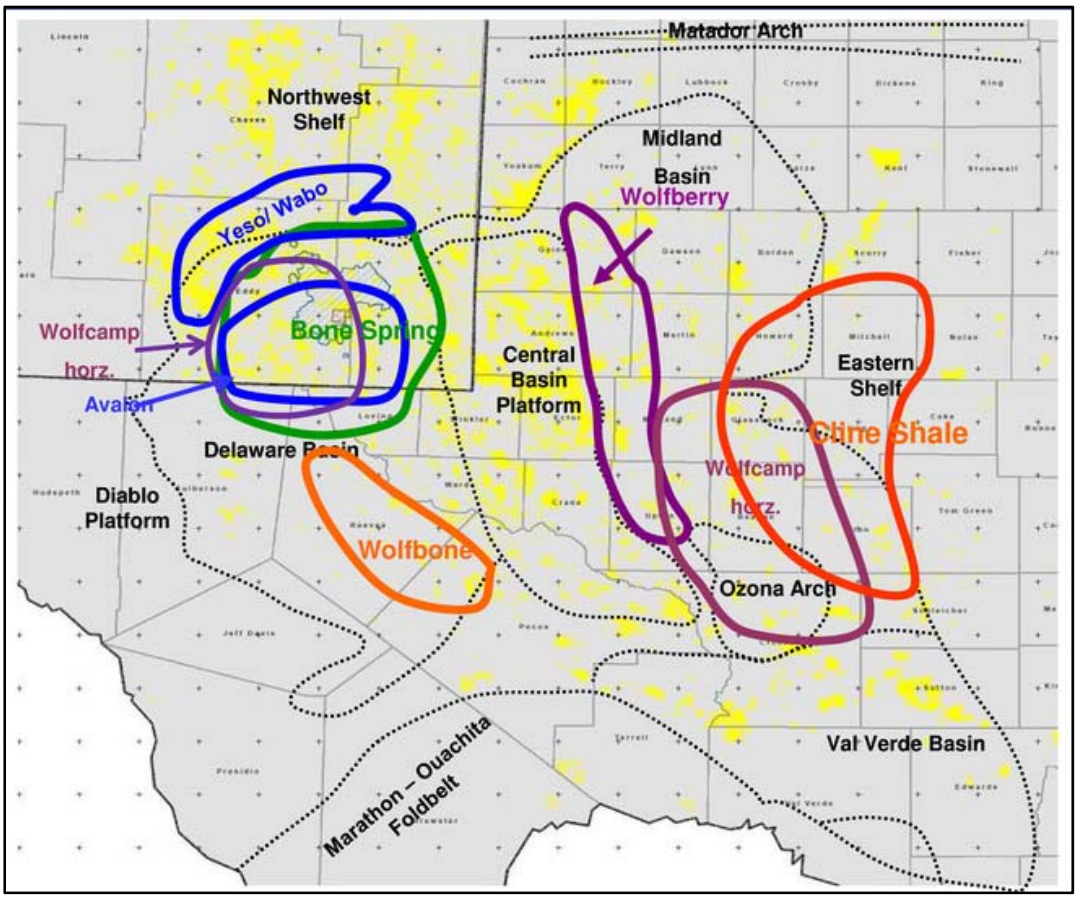


Figure 30. Relative location of various shale plays within the Permian Basin area (Oxy, 2013)

Collectively, there is potential for tens of thousands of vertical and horizontal shale well locations to be drilled in the Permian Basin in coming years. Permian Basin well permits have more than doubled between 2005 and 2012, while oil production has jumped 23%, largely due to the activity generated by these plays.[74]

- **<u>Cline</u>** The Pennsylvanian Cline Shale is found at a depth of about 9,000 feet across an area of approximately 1.6 million acres in the Midland Basin portion of the greater Permian Basin. The formation thickness varies from 200 to 550 feet and produces light sweet crude.

[73] Oxy presentation at Howard Weil conference, March 2013, http://www.sec.gov/Archives/edgar/data/797468/000079746813000013/hwconference2013presentatio.htm
[74] TRRC web site, http://www.rrc.state.tx.us/permianbasin/index.php

About 100 horizontal wells have been drilled through mid 2013. EURs for the Cline have been estimated at roughly 420,000 barrels of oil equivalent (boe) per well.[75]

- **Wolfcamp** The Permian Wolfcamp Shale, is being developed via horizontal, hydraulically fractured completions in at least two areas of the Permian Basin. The Wolfcamp lies above the Cline in the portion of the basin where they coexist, at depths between 7,000 and 8,500 feet. There are up to five productive intervals within the Wolfcamp, each between 300 and 600 feet thick. In some places the deepest Wolfcamp interval (Wolfcamp "D") is correlative with the Cline Shale. Companies are developing the play by drilling "stacked laterals," where individual wells from a single pad target individual productive intervals of the Wolfcamp with long horizontal laterals (up to 10,000 feet in length). To the east of the Central Basin Platform (CBP) where the Wolfcamp lies below the Sprayberry limestone, in some areas vertical wells are completed in both zones, this being referred to as the "Wolfberry" Play. To the west of the CBP where the Wolfcamp Shale underlies the Bone Spring Shale in the Delaware Basin, similar comingled completions are termed the "Wolfbone" Play.

- **Bone Spring Formation** In the Delaware Basin, the Bone Spring formation consists of three separate pay zones, each having a thickness of 150 to 350 feet. The play covers about 2.8 million acres at depths of 6,000 to 9,800 feet. Each of the intervals is being developed with horizontal wells after operators experienced fairly sub-par production via vertical wells. The initial targets in the Bone Spring were conventional sandstones but wells now target carbonate lenses and tight sandstones.

- **Avalon** The Avalon Shale overlies the Bone Spring formation in the Delaware Basin. When developed concurrently with the Bone Spring it is sometimes called the Avalon-Bone Spring. While operators have always recognized the potential of the Avalon as a producing zone, it has often been passed by for deeper targets. In some places, the Avalon Shale interval is separated into two shale intervals by a limestone layer.

Rocky Mt. and Northern Great Plains

Niobrara

The Niobrara shale formation is an Upper Cretaceous hybrid shale/carbonate reservoir found in northeastern Colorado and parts of Wyoming, Nebraska, and Kansas.[76] Oil from the Niobrara formation is produced at depths of 6,000 to 9,000-plus feet in several basins in Colorado and Wyoming (Figure 31), where the inter-bedded, naturally fractured carbonate facies appears to be a key reservoir rock. Overall thickness of the Niobrara system is about 300 feet, with at least three carbonate-rich targets for horizontal laterals that average from 10–25 ft thick with 5–10% porosity. The Niobrara is primarily an oil play with associated gas, and historical oil production has come from mostly vertical wells in the deeper, more mature portions of the Denver-Julesberg, Powder River, and North Park basins from fields like Silo, Wattenberg, Teapot, Sage Creek and Buck Peak. The gas prone area is found farther towards the eastern edge of the Denver Basin.

[75] Rigzone, "Future Looks Bright for Cline Shale Potential," http://www.rigzone.com/news/oil_gas/a/127338/Future_Looks_Bright_for_Cline_Shale_Potential/?pgNum=0

[76] OGI, http://www.oilandgasinvestor.com/OGI-Magazine/Niobrara-Oil-Regional-Spotlight_64050?ch=more-title

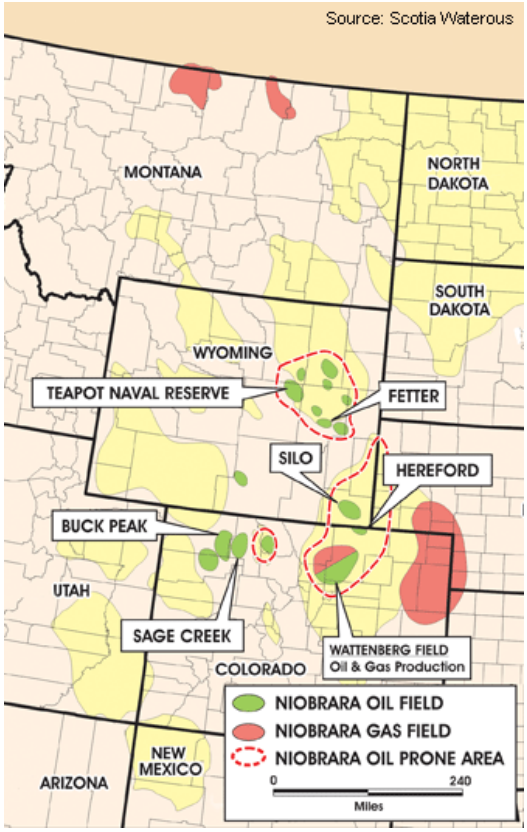


Figure 31. Map of Niobrara Shale play fields (Oil and Gas Investor after Scotia Waterous, August 2010)

Bakken -Three Forks

Through 2012, about 680 million barrels of oil have been produced from the Bakken shale play. Modern development via horizontal, hydraulically fractured wells began in earnest in 2000 in Montana's Elm Coulee Field and spread eastward into North Dakota where development has been focused (Figure 32).[77] Elm Coulee has produced about 131 million barrels of the Bakken total. Currently, there are about 900 wells producing in Montana and about 5,000 producing in North Dakota. Production in 2012 amounted to more than 15 million barrels in Montana and 219 million barrels in North Dakota.[78, 79] Development of the Bakken Shale has dramatically changed the economy of North Dakota, helping to make its unemployment rate the lowest in the nation.[80]

Throughout most of the Williston Basin, the Upper Devonian/Lower Mississippian Bakken Formation has three members: the Upper Member, a 23-foot thick black marine shale; the Middle Member, an 85-foot thick interbedded layer of limestone, siltstone, dolomite, and sandstone; and the Lower Member, a 50-foot thick black marine shale.[81] The formation depth ranges from 11,000

[77] EIA, Bakken shale play production animation, 1985 to 2010, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm
[78] MT, http://bogc.dnrc.mt.gov/annualreviews.asp
[79] ND, https://www.dmr.nd.gov/oilgas/
[80] Bureau of Labor Statistics, http://www.bls.gov/web/laus/laumstrk.htm
[81] EIA, Technology-Based Oil and Natural Gas Plays: Shale Shock! Could There Be Billions in the Bakken?, http://www.eia.gov/ftproot/features/ngshock.pdf

feet at the center of the basin to just over 3,000 feet along its northern limit. The shale members are notable for their high organic carbon content, but early Bakken production efforts focused on the shales had very limited success. Current efforts are now focused on the Middle Member, which has more porosity and permeability than the adjacent shales. The thermally mature areas of the Bakken are overpressured, often oil-wet, with 41°API gravity crude oil in natural fractures capable of producing at high production rates. [82]

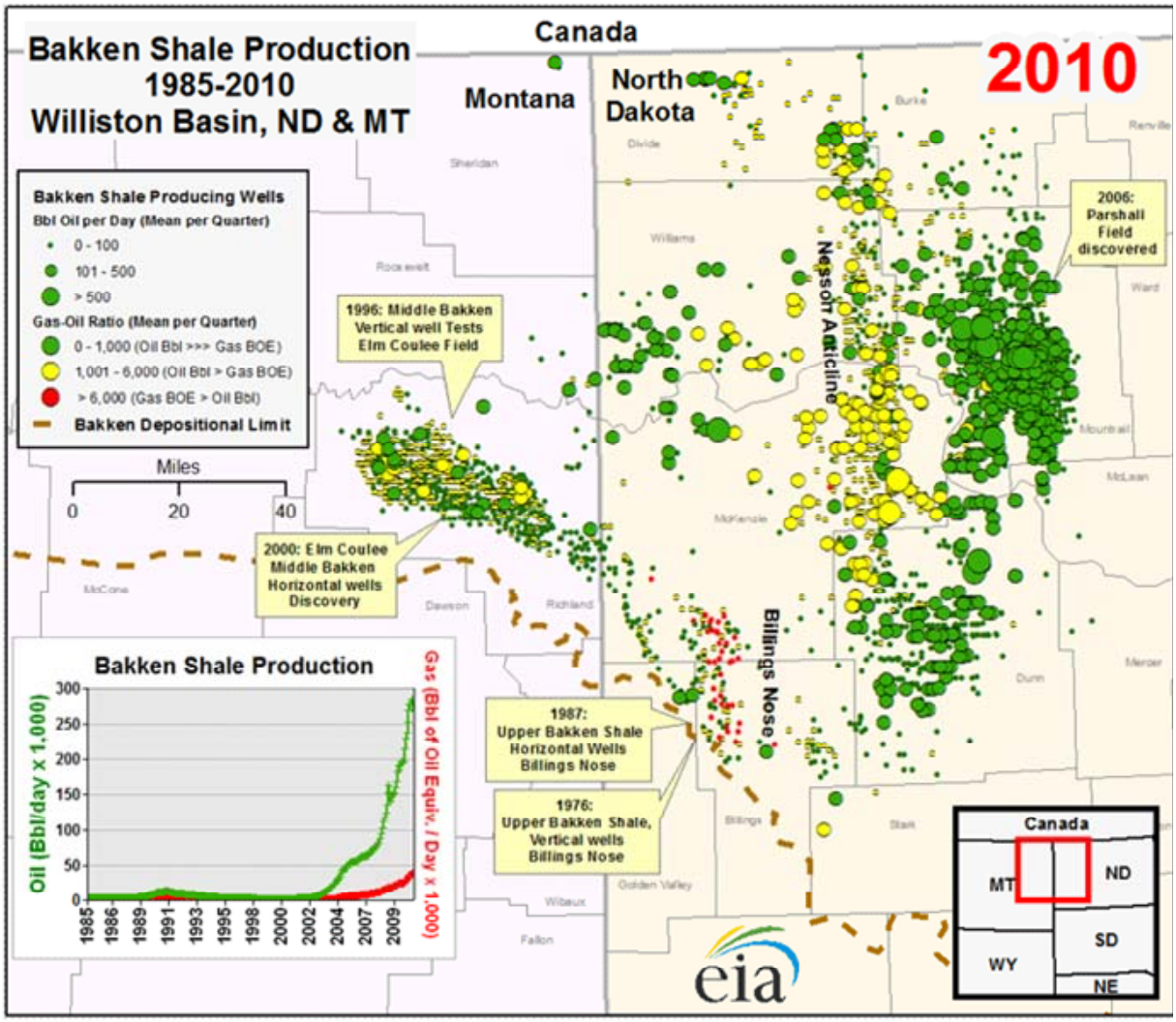


Figure 32. Map of Bakken Shale play (EIA website)

The petroleum system that includes the Bakken also includes underlying strata from the Devonian Three Forks Formation, and overlying strata from the lower part of the Mississippian Lodgepole Formation that may contain Bakken-sourced oil.[83] The Three Forks consists of interbedded

[82] EIA, Technology-Based Oil and Natural Gas Plays: Shale Shock! Could There Be Billions in the Bakken?, http://www.eia.gov/ftproot/features/ngshock.pdf
[83] USGS, http://pubs.usgs.gov/fs/2013/3013/fs2013-3013.pdf

dolomitic mudstones, silty dolostones, and anhydrite and reaches a maximum thickness of 270 feet in the central portion of the basin.

In April 2013, the United States Geological Survey (USGS) released updated oil and gas resource assessments for the Bakken Formation and a new assessment for the Three Forks Formation in North Dakota, South Dakota and Montana. The assessments found that the formations contain an estimated mean of 7.4 billion barrels of undiscovered, technically recoverable oil, a twofold increase over what has previously been thought.[84] Previously, very little data existed on the Three Forks Formation and it was generally thought to be unproductive. However, new drilling resulted in a new understanding of the reservoir and its resource potential.

In addition to oil, these two formations are estimated to contain a mean of 6.7 trillion cubic feet of undiscovered, technically recoverable natural gas and 0.53 billion barrels of undiscovered, technically recoverable natural gas liquids. This estimate represents a nearly threefold increase in mean natural gas and a nearly threefold increase in mean natural gas liquids resources from the 2008 assessment, due primarily to the inclusion of the Three Forks Formation.[85]

Associated gas production from the Bakken play totals more than 850 MMcfd, but roughly a third of that gas is flared due to insufficient natural gas pipeline capacity and processing facilities.[86,87]

Mancos

The Mancos Shale is an Upper Cretaceous aged shale present in a number of Rocky Mountain Basins. Found at depths from 2,000 to 6,000 feet, the gross thickness of the shale is about 3,700 feet.[88] In the San Juan Basin of New Mexico, the Mancos Play is split between oil and gas prone areas; the northern part of the basin is gas prone while the southern part of the basin is oil prone. A second area where operators are investigating the potential of the Mancos Shale is in Utah's Uinta Basin. Here, there are at least four members of the Mancos with productive potential: the Prairie Canyon (Mancos B), the Lower Blue Gate Shale, the Juana Lopez, and the Tropic-Tununk Shale.[89]

Lewis

The Lewis Shale is another Late Cretaceous aged shale present in the Rocky Mountain region. It is a potential target in the San Juan Basin of New Mexico, where it is found at depths from 4,500 to 6,000 feet and with a thickness of 500 to 1,900 feet.[90,91] The Lewis is comprised of sandy mudstone and shale, averages 1,400 ft. in thickness and lies stratigraphically above the Cliff House

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[84] USGS, http://pubs.usgs.gov/fs/2013/3013/fs2013-3013.pdf
[85] Ibid
[86] OGFJ, http://www.ogfj.com/articles/2013/05/the-fight-to-limit-bakken-shale-flaring-.html
[87] EIA, http://www.eia.gov/todayinenergy/detail.cfm?id=4030
[88] Schamel, S., 2005, "Shale Gas Reservoirs of Utah: Survey of an Unexploited Potential Energy Resource," prepared for Utah Geological Survey, http://ugspub.nr.utah.gov/publications/open_file_reports/OFR-461.pdf, accessed June 2013
[89] Utah Geological Survey, http://geology.utah.gov/emp/shalegas/cret_shalegas/index.htm
[90] Curtis, J., et al, "Shale Gas: From Onerous Stepchild to Premier Resource," http://www.rpsea.org/attachments/contentmanagers/429/Shale_Gas_Resources_-_Dr._John_Curtis_Potentail_Gas_Agency.pdf, accessed June 2013
[91] Schamel, S., 2005, "Shale Gas Reservoirs of Utah: Survey of an Unexploited Potential Energy Resource," prepared for Utah Geological Survey, http://ugspub.nr.utah.gov/publications/open_file_reports/OFR-461.pdf, accessed June 2013

sandstone.[92] One development strategy proposed for this play is to identify the higher productivity, naturally fractured parts of the trend and then take advantage of the roughly 3,000 Lewis shale penetrations to recomplete wells uphole in naturally fractured "sweet spots."[93]

Pacific

Monterey

The Miocene-age Monterey shale in southern California has produced oil for more than 100 years, either directly or as source rock.[94] It is the source rock for about 37 to 38 billion barrels in conventional traps such as sandstones and is estimated to contain more than 500 billion barrels of oil in place. However, the estimated ultimate recovery from fields identified as Monterey producers is only 2.5 billion barrels.

Production of gas in excess of solution gas in the oil, along with recent core and gas desorption data, indicate that the Monterey may hold substantial volumes of adsorbed gas.[95] Initial estimates indicate gas concentrations on the order of 100-120 bcf/sq. mile in some areas. Methane adsorbed on organic matter in the shale accounts for about 70% of the in-place gas resource. The most intensive development of the Monterey has been in the Buena Vista field in the southeast portion of the San Joaquin basin, at depths of 4,000 to 5,000 ft., where 105 wells have produced 168 bcf.[96]

The Monterey shale is a challenging formation to develop because it is comprised of a variety of diatomaceous rock types with properties that vary depending on depth and location. An added challenge is the large degree of folding and rock compression that the rocks have been subjected to across this tectonically active region (Figure 33).[97]

Figure 33. Outcrop of the Monterey Shale revealing intense folding (AAPG, 2013)

[92] Kuuskraa, et al. OGJ, http://www.ogj.com/articles/print/volume-96/issue-23/in-this-issue/exploration/diverse-gas-plays-lurk-in-gas-resource-pyramid.html
[93] Ibid
[94] AAPG Explorer, http://www.aapg.org/explorer/2010/11nov/monterey1110.cfm
[95] Kuuskraa, et al. OGJ, http://www.ogj.com/articles/print/volume-96/issue-23/in-this-issue/exploration/diverse-gas-plays-lurk-in-gas-resource-pyramid.html
[96] Ibid
[97] Durham, L., "Monterey Shale Continues to Tempt and Tease," AAPG Explorer, February 2013, https://www.aapg.org/explorer/2013/02feb/monterey_shale0213.cfm

CURRENT SHALE GAS DEVELOPMENT TECHNOLOGY

The practices followed by natural gas producers in developing shale gas plays are constantly evolving. Within each play and across multiple plays, operators gain experience, new technologies are invented, old technologies are refined, service company innovations are introduced, and the economic drivers of well costs and product value rise and fall. As a point of reference, the following section briefly describes how a Marcellus shale well pad is developed and produced.

Drilling Practices

Once the appropriate permits are in place, well pad construction begins. The typical Marcellus well pad comprises an area about five acres in size (2.5 football fields) and includes enough wells to drain the gas from 500 to 1,000 acres. Pad drilling greatly reduces the environmental "footprint" (area disturbed) per well. After construction of the well pad, a drilling rig will move in; a process that can involve 50-65 tractor trailers. In 2009, one drilling rig would typically drill 8 to12 wells per year, but today drilling efficiency has nearly doubled in some areas (see Figure 9).

Marcellus shale wells are drilled directionally from the pad. Depending on the location within the play, the vertical portions of these wells are roughly 5,000 to 9,000 feet deep, most with horizontal laterals that extend for distances of from3,000 to as much as 10,000 feet (Figure 34). The shape of the typical well trajectory can include a "sail angle" where the wellbore is extended in the direction opposite of the horizontal lateral before it curves around to enter the reservoir. Marcellus Shale wells generally take between 15 and 30 days to drill. Typically, the rig is skidded a few yards to the adjacent location on the pad after each well has been drilled. When all the drilling is completed for the pad, the rig is moved off of the location prior to the hydraulic fracturing process beginning. When viewed from above, the well trajectories for multiple wells from a single pad show how the horizontal laterals parallel each other (Figure 35).[98]

As the well is deepened, multiple strings of casing are run and cemented into place. Casing programs vary; some operators use three strings and some four strings beyond the conductor pipe. Generally, 24 inch conductor pipe is installed up to 30 to 60 feet deep and cemented to the surface. Next, the surface hole is drilled on air to 200 to 500 feet of depth and casing (typically 16 to 20 inches in diameter) is cemented to the surface to isolate and protect near-surface groundwater. Next, the well is deepened using air hammers or air motors to a depth of about 700 to 1200 feet and casing (typically with a diameter of 11¾ to 13⅜ inches) is run and cemented to the surface to isolate groundwater aquifer zones from the well and from potential gas migration from coal seams or other shallow zones containing natural gas. At this point the drill string is separated from groundwater aquifers by roughly nine inches of cement and two inches of solid steel

The well is deepened and 8⅝ to 9⅝ inch casing may be run (if necessary to seal off shallow oil, gas or brine bearing formations) between 1,000 feet and about 5,000 feet of depth. The well is turned to become horizontal and the lateral portion of the well is drilled horizontally along the Marcellus formation. Finally, production casing, typically 5½ inch diameter, is run to the bottom of the well and cemented into place.

[98] Barth, J., et al, 2012, "Frac Diagnostics Key In Marcellus Wells," AOGR, May 2012 issue http://www.aogr.com/index.php/magazine/frac-facts

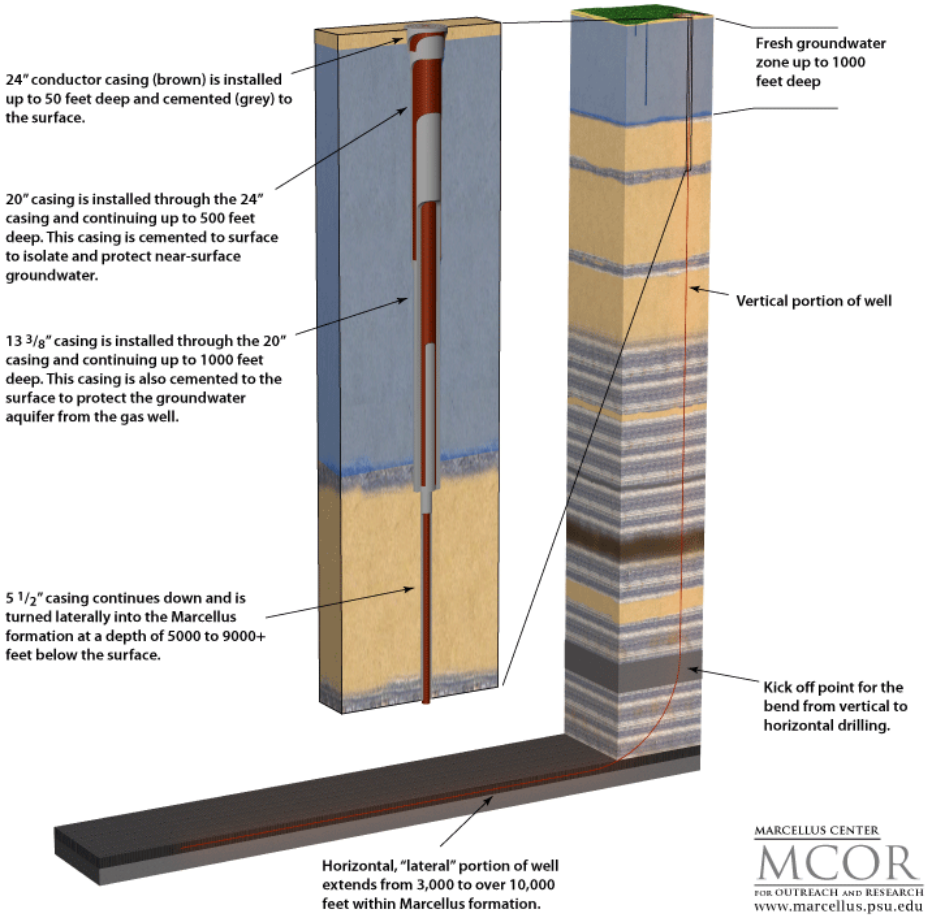


Figure 34. Schematic of a typical horizontal Marcellus shale well (Penn State Marcellus Center for Outreach and Research website)

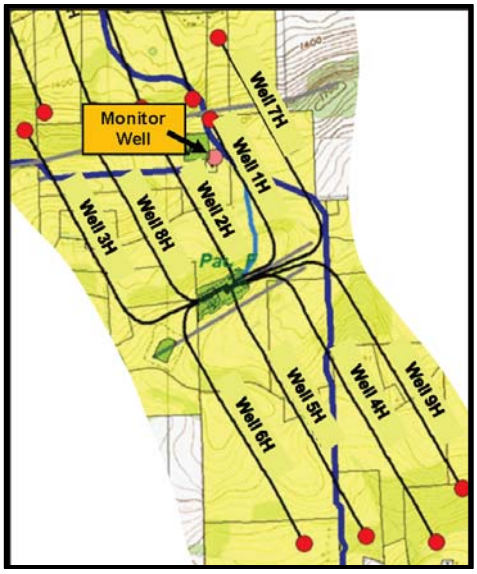


Figure 35. Example of Marcellus well trajectories from well pad (AOGR, May 2012)

Hydraulic Fracturing and Well Completion Practices

The large volume hydraulic fracturing treatments that are employed in Marcellus wells involve a lot of equipment operated in a closely coordinated manner. The equipment includes pump trucks, blending systems, storage tanks for water, sand and chemicals, tanks to capture produced liquids, piping systems to connect elements of the system, and specialized monitoring and control systems (Figure 36).[99] The first step in the well completion process involves perforating the well casing in the horizontal portion of the well. A string of electrically activated shaped explosive charges are detonated in the casing across from the zone to be hydraulically fractured, perforating the casing and cement. The fracturing fluid is then injected under controlled high pressure to part the rock while the proppant (typically quartz sand grains) carried in the fluid "props" open the fracture when the fluid pressure is released and the fracture begins to close up. This propped fracture provides the permeability necessary for the gas to flow from the formation into the well.

Figure 36. Marcellus well site during hydraulic fracturing operations (PIOGA)

Hydraulic fracturing shale gas formations like the Marcellus Shale typically involves the use of 3 to 6 million gallons of water per well. Convoys of tank trucks deliver this water, or in some cases it is pumped to the location through above ground plastic piping from large volume impoundments of fresh water constructed by the drilling company to service multiple well pads.

Fracturing generally takes a few days per well as multiple zones along the horizontal lateral are sequentially perforated and fractured, beginning at the bottom ("toe") of the wellbore and working back toward the "heel" where the horizontal portion of the well begins. As many as 25 or more such

[99] PIOGA website, http://www.pioga.org/environment-safety/hydraulic-fracturing/

treatments may be pumped within a single wellbore. Temporary plugs are set after each treatment to isolate the zone being pumped from the previously fractured intervals, and these plugs are removed before the well is flowed back (Figure 37).[100] The sequence in which wells on the same pad are fractured varies. Companies operating in the Marcellus continue to vary the number of treatments, the volume of water pumped, and the spacing of perforations as they try to optimize the completion process. Using microseismic monitoring, companies can map micro-seismic events related to the fracturing process, revealing how the fractures extend from the lateral wellbore and how they may or may not interact with fractures created along adjacent parallel laterals (Figure 38).[101]

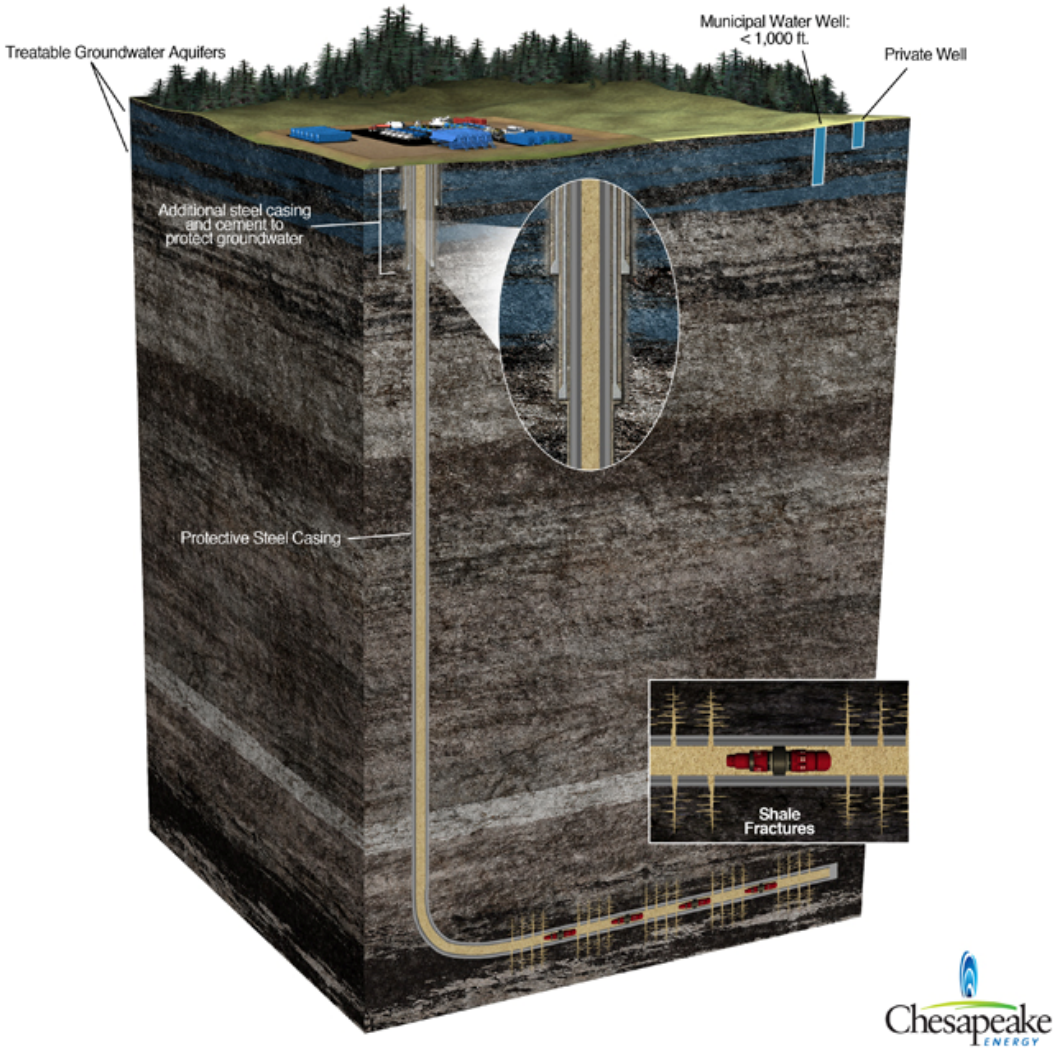


Figure 37. Schematic showing multiple fracturing treatment stages in horizontal well lateral (Chesapeake Energy)

[100] Hydraulicfracturing.com website, http://www.hydraulicfracturing.com/Process/Pages/information.aspx
[101] Barth, J., et al, 2012, "Frac Diagnostics Key In Marcellus Wells," AOGR, May 2012 issue, http://www.aogr.com/index.php/magazine/frac-facts

Following the hydraulic fracturing process the well is flowed back and tested using a controlled flaring process. In some areas a pipeline ready to take the gas to market will be in place and flaring will not be necessary. In the Marcellus, roughly 20 to 25 percent of the water injected will come out of the well as "flow-back water." Over the life of the well additional volumes of the water will ultimately be produced, but as of yet it is unclear exactly how much will return to the surface. Both the flowback water and the produced water must be separated from the gas and hydrocarbon liquids, and either cleaned up and reused or disposed of in deep disposal wells. In some plays more than 90% of flowback water is reused in fracturing other wells.

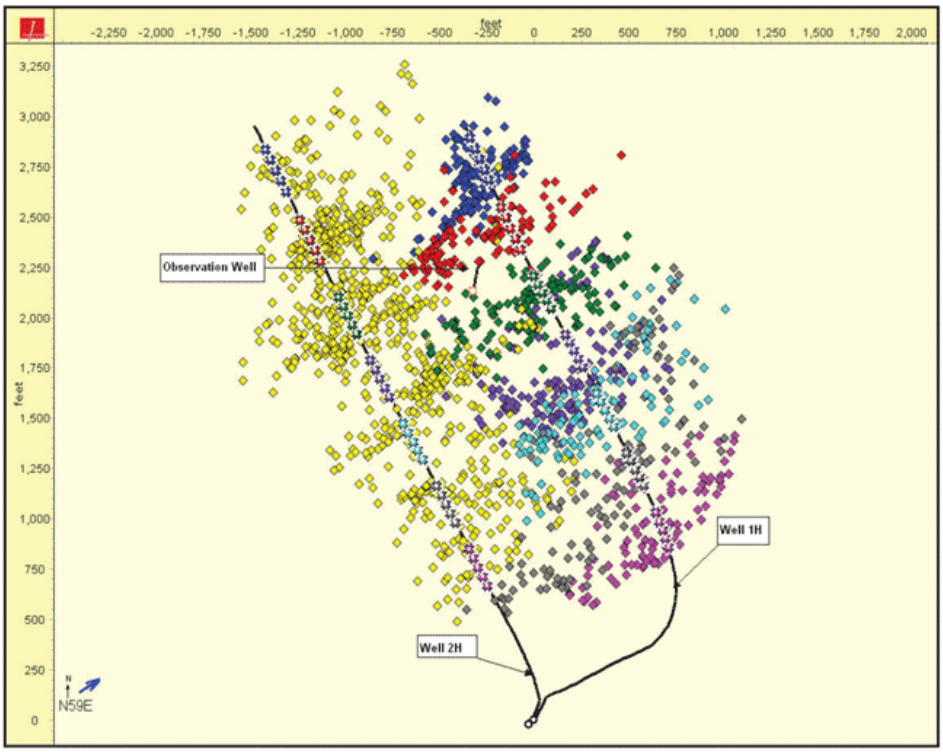


Figure 38. Data from microseismic monitoring reveal how hydraulic fractures extend from a lateral wellbore and interact with fractures created along adjacent parallel laterals (AOGR, 2012)

Production Practices

After all of the wells on a pad have been drilled, completed (hydraulically fractured), and prepared for production (well heads, piping and surface equipment installed, flowback period completed) the wells are ready for production. The water and hydrocarbons (oil or condensate) produced along with the natural gas from multiple wells on a pad is separated and stored in tanks on the pad (Figure 39).[102] If there are multiple wells on the pad, each may have its own separate meter. In most situations within the Marcellus play the gas is sent through a gathering line to a central facility where it is processed before being compressed and piped to a sales line. The condensate and water that is collected is trucked to a central tank battery where it is separated. The actual set up on any given well pad may vary depending on the number of wells, the ratio of gas to liquids in the

[102] GoMarcellusShale.com website, http://gomarcellusshale.com/forum/topics/after-the-well-drilling-has-finished

production stream, and the location of the well pad relative to other pads and facilities. Eventually, the water is sent for disposal in deep injection wells or cleaned and reused, the gas is delivered into a sales line, and the condensate is delivered to a pipeline or other transport alternative (tank truck, rail car, or barge) that can carry it to a refinery.

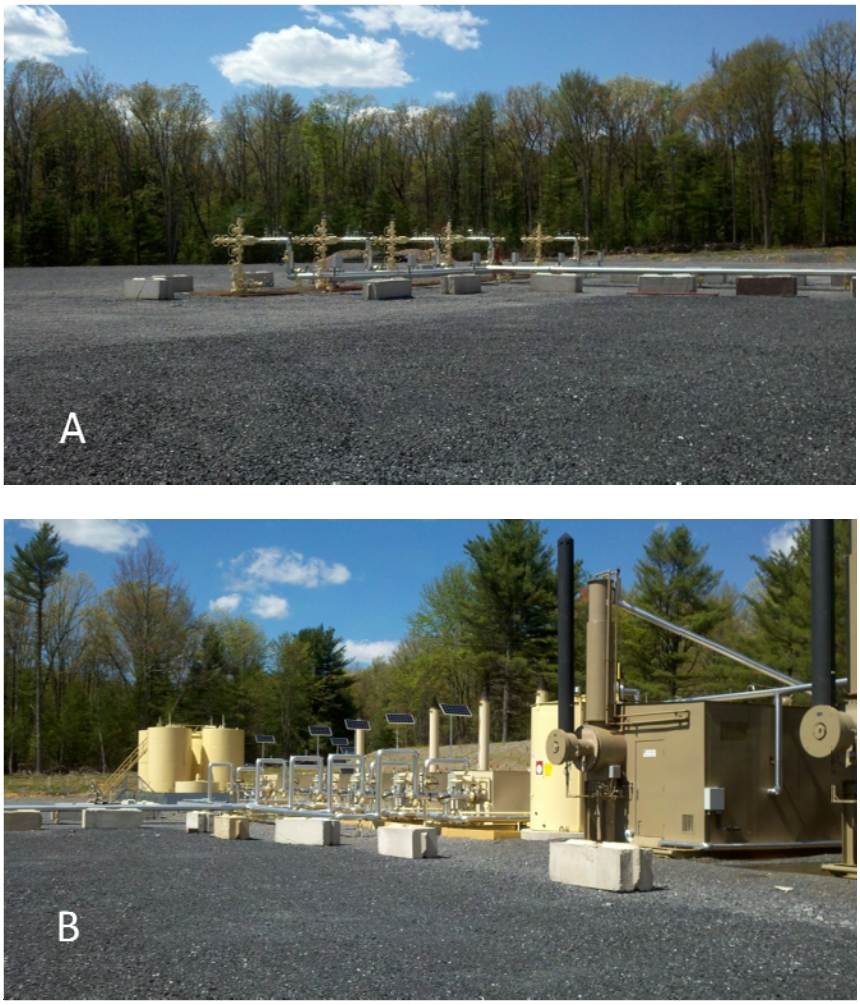


Figure 39. Typical Marcellus well pad with multiple adjacent trees (A), and pad production processing equipment including condensate tanks (B) (GoMarcellus Shale.com)

Midstream Processing and Transportation

Handling of the natural gas stream after production is done by what is termed the *midstream* sector of the natural gas exploration and production industry. In the Marcellus play the nature of the production stream —dry gas or wet gas— varies across the play. The southwestern Pennsylvania area produces a larger amount of natural gas liquids (NGLs) with the gas. Heavier liquids (condensate) can be removed at the well site or at centralized lease production facilities. But the gas must be pipelined to gas processing facilities (Figure 40)where the liquids content can be lowered much further, removing nearly all of the NGLs (ethane, propane, butane and iso-butane).[103]

[103] MarkWest investor presentation, http://investor.markwest.com/phoenix.zhtml?c=135034&p=irol-presentations

NGLs are separated from a gas stream by employing any of three different types of processing plants: "lean oil" plants, refrigeration plants and cryogenic plants.[104] The first uses a petroleum solvent to absorb the NGLs from the gas stream. Refrigeration plants use propane to cool gas until most of the NGLs condense and can be separated, while cryogenic plants super cool the gas to remove nearly all NGLs (see Appendix C for a discussion of the differences among condensate, NGLs and crude oil).

Figure 40. Gas processing facility in Marcellus shale region of Pennsylvania (Markwest)

The NGLs are then separated into their component parts at a *fractionation* plant and sold. The second lightest hydrocarbon, ethane, requires more effort to separate from the natural gas. A lean oil plant removes only about 15% of the ethane, although it can capture up to 99% of butane, iso-butane and heavier hydrocarbons. Refrigeration plants remove at least 85% of the ethane, while cryogenic plants can extract up to 90% of the ethane. Cryogenic plants are the most efficient, but also the most costly. If the natural gas stream contains a significant amount of ethane, as it does in portions of the Marcellus play, special de-ethanization equipment must be used to further lower the ethane content before the gas can be sold. The captured ethane is pipelined away to become a feedstock for chemical production.

After being processed to remove heavier hydrocarbons, the natural gas stream (now nearly all methane) is ready for transportation to the consumer. While the U.S. enjoys an extensive system of natural gas pipelines and associated infrastructure (e.g., compressors to maintain the pressure needed to move the gas down the line), large portions of this infrastructure have been set up to move natural gas from the historical *producing* regions (Gulf Coast, Texas) to historical *consuming* regions (Northeastern states). The rapid development of shale gas plays like the Marcellus and Utica in the Northeast and smaller plays in the Rocky Mountain states, has disrupted this system. Changes to the infrastructure needed to rebalance the flow of gas around the Nation are underway,

[104] Troner, 2013, "Natural Gas Liquids in the Shale Revolution," http://www.bakerinstitute.org/publications/Troner_NGL%20vApr-29-2013-1.pdf/view

but the large investments involved and the uncertainty of regional supply and demand mean that these changes take some time to be implemented.

REGULATORY FRAMEWORK

The development and production of oil and gas in the U.S., including shale gas, are regulated under federal, state, and local laws that address every aspect of the exploration, production and transportation processes. All of the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities apply equally to shale gas and shale oil activities. The U.S. Environmental Protection Agency (EPA) administers most of the federal laws, although development on federally owned land is managed primarily by the Bureau of Land Management (BLM), which is part of the Department of the Interior, and the U.S. Forest Service, which is part of the Department of Agriculture.

In addition, each state in which oil and gas is produced has one or more regulatory agencies that permit wells (including their design, location, spacing, operation, and abandonment) and regulate activities with potential environmental impacts (including water withdrawals and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety) (Figure 41).[105]

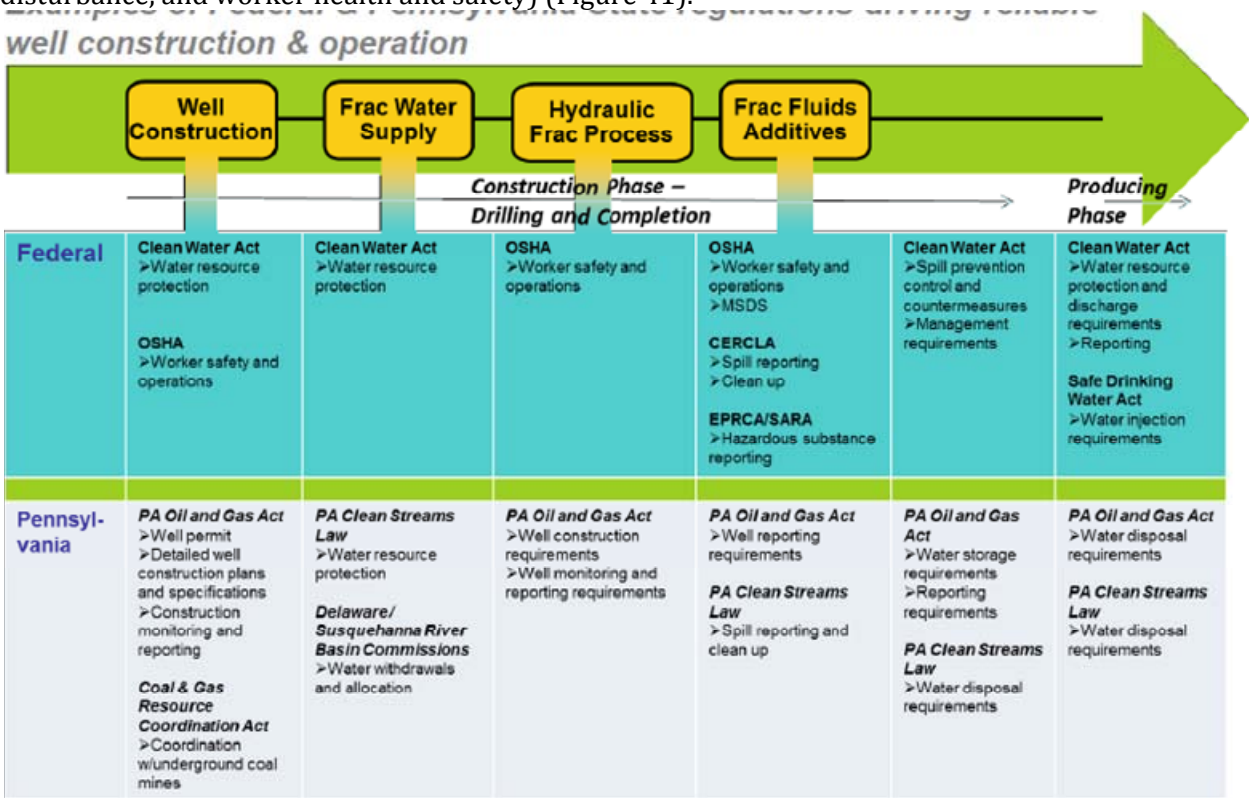


Figure 41. Examples of Federal and Pennsylvania State regulations driving reliable well construction and operation in the Marcellus play (Nygaard, 2013)

[105] Nygaard, 2013, "Shale Development: Understanding and Mitigating Risks Associated with Well Construction and Hydraulic Fracturing," NRC Workshop, Washington, D.C., http://sites.nationalacademies.org/DBASSE/BECS/DBASSE_083187

Many of the federal laws are implemented by the states under agreements and plans approved by the appropriate federal agencies. The basic framework of those laws and their delegation are discussed in detail in the original version of this document, "Modern Shale Gas Development in the United States: A Primer," published in 2009. The material that follows does not duplicate that document but provides a short summary of events and initiatives related to these issues that have occurred during the past four years.

Current Issues Regarding Regulation of Shale Wells

Regulation of shale gas development is complicated and evolving. The complexity largely stems from the multiple layers of government responsibility and variation in regulatory approaches across the states. In addition, the speed of shale gas development has left some state legislatures and regulators, particularly in states where this level of oil and gas activity is unprecedented in modern times (Pennsylvania, New York), playing a game of "catch up." In addition, at the federal level there have been efforts to modify or create regulations to address potential impacts.

State Issues

A recent review of state regulation of shale gas by Resources for the Future listed a number of key findings.[106] First, states with active shale gas production vary significantly in the number of elements of the shale gas development process they regulate. Geology, geography, history, demographics, economic conditions, and other factors may lead states to justifiably make different regulatory decisions. However, the study failed to find any statistical correlation between regulatory heterogeneity and underlying differences among states.

The study also found that almost all states are changing their regulations, some quickly, and that new regulations are generally more stringent than existing rules. The primary areas were state regulations are evolving are listed in Table 6.[107]

The study also determined that states vary greatly in terms of how difficult it is to determine relevant regulatory requirements from their regulations and/or state code (transparency). The researchers found that relevant provisions are often scattered throughout the code or appear only in uncodified regulations, which may be difficult to find or even contradictory. This lack of transparency is identified as a significant barrier for stakeholders, whether they are firms seeking to comply with the law or interested members of the public trying to understand it in light of environmental risks.

[106] Richardson, et al., 2013, "The State of State Shale Gas Regulation," http://www.rff.org/RFF/Documents/RFF-Rpt-StateofStateRegs_Report.pdf

[107] Horner, et al., 2012, "The Evolving Regulatory Landscape of Shale Gas Development," Western Energy Policy Research Conference, August 30-31, Boise, ID

Table 6: State and Local Regulatory Strategies

Impact Area	Possible Risks	Major Regulatory Strategies
Water Quality	• Leakage of hydraulic fracturing fluid or flowback water through or around the well bore casing to shallow groundwater • Leakage of hydraulic fracturing fluid from shale formation to shallow groundwater • Accidental spilling of hydraulic fracturing fluid or flowback water into surface water • Intentional dumping of hydraulic fracturing fluid or flowback water into surface water	• Well construction standards, including wellbore integrity testing and certification • Hydraulic fracturing fluid chemical constituent disclosure • Pre-development (baseline) and post-drilling groundwater testing • Response plan for reported events • Total Dissolved Solid (TDS) concentration limits for surface-disposed effluents
Gas Migration	• Leakage of methane through or around the well bore casing to shallow groundwater • Leakage of methane from shale formation to shallow groundwater	• Well construction standards, including wellbore integrity testing and certification • Response plan for reported events
Air Quality	• Volatile Organic Compounds (VOCs) escaping from the wellhead during well completion and from condensate storage tanks	• Reduced-emission ("Green") well completions • Requirements for vapor recovery units on tanks • Requirements for low emission production facilities and associated piping, vales, etc.
Induced Seismicity	• Disposal of used hydraulic fracturing fluids in deep injection wells either at too high a pressure or to near an existing geologic fault	• Limit injection pressures • Restrict permits to areas of sufficient geologic knowledge
Noise, Traffic	• Placement of shale gas development infrastructure and movement of equipment in areas where noise and/or traffic negatively affects local residents	• Agreements between local jurisdictions and operating companies on timing and level of activities • Requirements for noise mitigation technologies • Conditional use zoning
All Areas	All risks	Ban or moratorium on shale development

A related issue that has come to the forefront with rapid development is how effectively regulations are enforced. Post-2008 economic stresses have left states facing fiscal shortfalls, while at the same time the growth in the private oil and gas sector has meant many state oil and gas regulators struggle to retain qualified staff.

Federal Issues

The Bureau of Land Management (BLM) has been working to develop updated regulations for shale gas development on federal lands, and EPA has been conducting research and writing regulations for the risks within its jurisdiction.

EPA released new source performance standards and national emissions standards for hazardous air pollutants in the oil and natural gas sector on April 17, 2012. The standards for hydraulically fractured gas wells require reduced emission ("green") completions or flaring or released natural gas for wells developed prior to January 1, 2015 and green completions only on wells developed in 2015 and thereafter. This regulation is expected to reduce VOC emissions from shale gas wells by 95%.

The Energy Policy Act (EPAct) of 2005 excludes underground injection of any fluid during hydraulic fracturing operations (except for diesel) from EPA's regulatory authority under the Safe Drinking Water Act. However, EPA retains authority to regulate surface water pollution, and has imposed penalties on companies for stream disturbance. EPA is attempting to exercise authority under the Toxic Substances Control Act to issue a rulemaking requiring disclosure of chemical constituents of fracking fluid. EPA is also in the midst of a multi-year assessment of the risks of hydraulic fracturing to groundwater.

The Bureau of Land Management (BLM) and other land management agencies have some authority over shale gas development on lands for which they are responsible. BLM has issued draft rules for shale gas development on public lands, which require disclosure of chemical constituents of fracking fluids and the submission of an operation plan for BLM evaluation prior to hydraulic fracturing operations. This plan must address: groundwater protection, anticipated surface disturbance, management and disposal of recovered fluids, self-certification that fracking fluids comply with all applicable laws, information to confirm wellbore integrity before, during, and after hydraulic fracturing, and a post-fracking report that includes the specific chemical makeup of fracturing fluids.

ENVIRONMENTAL IMPACTS: ISSUES AND MITIGATION

As shale gas development activity has increased over the past decade, the level of attention being paid to the potential for environmental impacts resulting from that activity has also increased. There are several reasons for this. One is the fact that both industry groups and non-governmental organizations focused on environmental issues are able to employ new information outlets to highlight their viewpoints and raise awareness of potential problems. Another is the fact that much of the new development is taking place in areas where residents are unfamiliar with oil and gas drilling and production activity at the level being witnessed (e.g., Marcellus Shale).

In states where oil and gas production is already an important part of the local economy (e.g., Texas, Oklahoma, Louisiana, Arkansas) shale gas development is largely seen as an expansion of ongoing activity. In other states (e.g., New York, Pennsylvania) shale gas development is being scrutinized more intently. The following sections describe the key issues that are currently the focus of discussion.

Surface Impacts

Development of well sites, processing facility sites, pipeline right-of-ways, and the access roads required to create, service, and maintain these locations, directly impact the environment. The impacts include: fragmentation of forest ecosystems through the creation of open spaces where there were once trees (Figure 42), increased potential for sediment runoff from cleared sites to streams, potential alteration of surface drainage patterns, creation of corridors for invasive species, and alteration of the viewscape.[108]

Of these, the areas of greatest immediate concern appear to be forest fragmentation and stream sedimentation. Both of these impacts can affect the ability of some native species of birds, mammals and aquatic creatures to flourish. The creation of larger "edge" areas between forest and open space can benefit some species (e.g. deer, certain types of birds) but forest fragmentation can also reduce the habitat needed for deep forest species (e.g. certain songbirds). The potential for pipeline and gathering line right-of-way clearing to have greater longer term environmental impact than the drilling pads themselves is also a possibility.

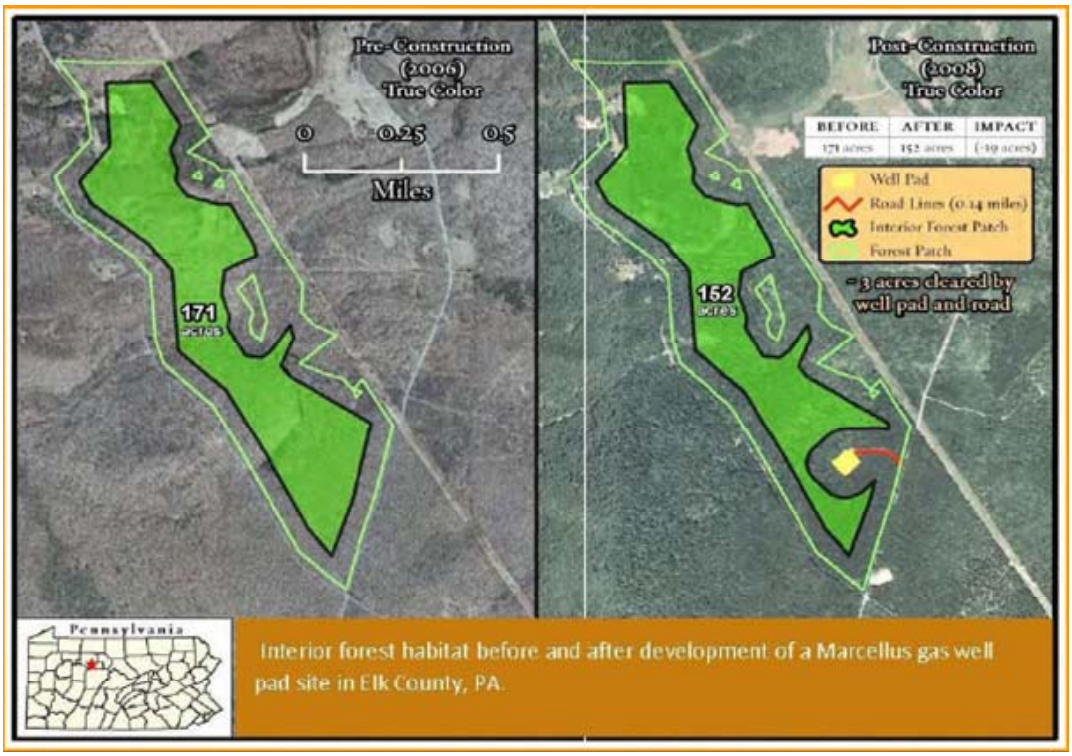


Figure 42. Example of forest fragmentation resulting from placement of a well pad (USGS, 2013)

The use of multiwall drilling pads to limit the area of surface disturbance per well is an important feature of shale well development. However, at this point in some plays (e.g., Marcellus) the average number of wells drilled per pad is still relatively low (about 2.3 wells per pad). In addition, the large

[108] Bowen, Z., 2013, "Ecological Considerations in Shale Gas Development," NAS Workshop on Risks of Unconventional Shale Gas Development, Washington, DC. May 31, 2013, http://sites.nationalacademies.org/DBASSE/BECS/DBASSE_083187

number of pads that could eventually be constructed could still mean that the impact will be significant. For example, between 2005 and 2011 there were 2350 drilling pads constructed in Pennsylvania, of which roughly half were in farm land and half in forest land. The average pad footprint is about 2.47 acres and with associated local disturbances (roads, facilities, etc.) included, about 6.7acres.[109] In places like Pennsylvania, West Virginia and Ohio, the differences between historical, relatively low impact oil and natural gas stripper well production and modern shale gas development is significant.

Wildlife Impacts

In addition to indirect impacts wildlife may encounter due to surface impacts, there is also the potential for direct impacts to wildlife due to alteration of migration routes, mating locations, or feeding locations as a result of drilling and production activity (rig noise, compressor noise, lights, and increased human presence). There is also the increased potential for animal mortality from vehicles and other industrial activities associated primarily with the pad construction, well drilling and completion, and pipeline construction phases.

Community Impacts

While the immediate benefits of increased natural gas production in communities located within shale gas plays can be measured fairly easily (e.g., jobs, income levels, tax revenues) the potential for other types of impacts is also there but harder to measure. Some of these less beneficial socio-economic impacts can be: rapid, unplanned industrialization, the effects of an uneven distribution of costs and benefits among community members, loss of community cohesiveness, and increased stress levels.

Rapid growth can result in strained municipal services (e.g., utilities, police, schools) and an overall reduction in quality of life for the average resident, unless careful planning is implemented. In some communities, the planning and management tools may be insufficient to handle sudden changes in activity, resulting in a "boomtown" situation. The impacts of rapid growth in shale play communities have varied depending on initial population density, growth rate, and the availability of funds for mitigating impacts.

The affects of an uneven distribution of costs and benefits are harder to measure but are being observed in developing shale plays. These result from non-uniform leasing terms and royalty rates, severing of mineral and surface rights, the number of landowners versus non-landowners in a community, and how the money that is obtained from development is spent (or not spent) within communities. If conflict levels rise within communities, it can lead to hampered decision-making, broken lines of communication, and increased levels of misinformation, disinvestment and out-migration.

[109] Brittingham, M., "Ecological Risks of Shale Gas Development," NAS Workshop on Risks of Unconventional Shale Gas Development, Washington, DC. May 31, 2013, http://sites.nationalacademies.org/DBASSE/BECS/DBASSE_083187

Groundwater Impacts

While the potential impacts to wildlife and social structures are important, the greatest degree of concern and public scrutiny related to shale gas development has been largely focused on the potential impacts to water resources (surface and subsurface) and air quality. Much of the discussion about changes to regulation of shale gas development has been driven by fears that water supplies will be contaminated by the drilling and hydraulic fracturing process or that air quality will be reduced.

Surface Spills

Surface spills of hydraulic fracturing fluids, fracture flowback water, diesel fuel, or produced hydrocarbons have the potential to introduce contaminants into surface or subsurface water supplies. Such spills can occur through leakage of containment ponds, impoundments, or tanks, as the result of tank truck accidents during transportation, through faulty equipment, or as the result of operator error. Companies must have spill containment systems and spill mitigation procedures in place and if accidents occur can be liable for cleanup costs and fines. While the probability of such events can increase with increased development activity, appropriate regulatory monitoring and enforcement and company adherence to best practices can minimize the impacts.

While not a spill *per se*, the potential for unauthorized, illegal dumping of waste water (particularly fracture flowback water) into streams or rivers is another concern. Regulatory monitoring and enforcement coupled with tight subcontracting standards by drilling companies is considered to be the best way of dealing with such incidents.

Finally, the legal treatment and disposal of fracture flowback and produced water via public water treatment plants, which may eject treated water into surface waterways, has received scrutiny. In some cases, the fees obtained by the public water utilities for this service can be a significant revenue stream. Treatment standards and practices are being reviewed and in some cases modified to make certain that all potential contaminants are removed.

Subsurface Migration

Probably the greatest amount of attention has been directed toward the possibility of subsurface migration of fracturing fluids or hydrocarbons into subsurface potable water aquifers. Several different pathways for such migration have been proposed but the risks vary. One potential pathway is through the casing/wellbore annulus when there is poorly cemented casing across and beneath potable water aquifers (Figure 43).[110] In this situation, the drilling of new shale wells could connect deeper natural gas-bearing formations with shallower aquifers and in the presence of sufficient pressure differential, cause natural gas to reach the water zone. Another potential pathway is a case where the drilling of the shallow section of a new shale gas well temporarily permits communication between shallow gas-bearing zones and water supply aquifers. Pressure fluctuations under these circumstances could potentially cause gas communication. Both of these situations can be prevented through the application of best practices during drilling.

Another pathway could be through poorly cemented (or uncemented) wellbores from long abandoned "orphan" wells that are found throughout some parts of certain plays (e.g. parts of Pennsylvania, West Virginia and Ohio in the Marcellus play). In this case, higher pressure gas from deeper formations could potentially find a path behind poorly cemented casing to a shallower, lower pressure zone of past production, which in turn communicates with an even shallower

[110] Vengosh, A., et al., "Risks of Shale Gas Exploration and Hydraulic Fracturing to Water Resources in the United States," Washington, DC. May 31, 2013, http://sites.nationalacademies.org/DBASSE/BECS/DBASSE_083187

aquifer via the abandoned wellbore. This potential problem can be averted through cementing best practices and by finding and plugging abandoned wellbores in areas where drilling is taking place.

A third potential pathway that is receiving a lot of attention is a potential connection between multiple hydraulic fractures created in the deep shale gas zones and shallower natural fractures or faults that may extend upwards into water supply aquifers (See Figure 43). Based on geologic and engineering factors, the risk of this happening is thought to be very small given the great distance between shale gas producing zones and shallow aquifers. Several recent studies have attempted to find incontrovertible positive evidence of a connection between hydraulic fracturing and shallow water zone contamination, without success. A number of ongoing studies are continuing to assess this risk. To date, such studies have been complicated by a lack of pre-drilling baseline data in regions where natural gas is a common constituent of rural water supplies due to a long history of poor well construction and natural gas seeps from coal seams.

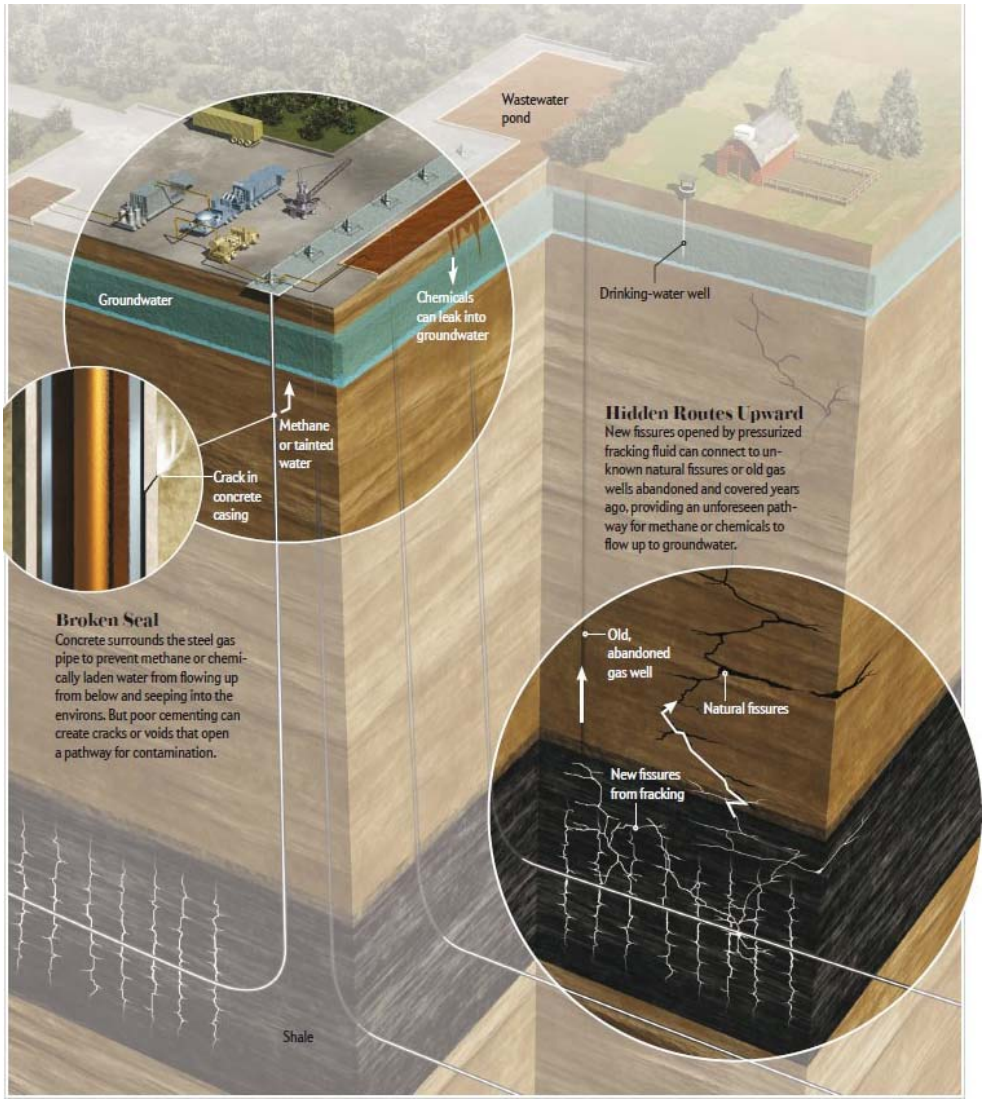


Figure 43. Schematic illustrating the possible pathways for subsurface migration of fracturing fluids or hydrocarbons into subsurface potable water aquifers (Vengosh, 2013 after Scientific American, November 2011)

Fresh Water Supply

Another concern is that the volume of water demanded to supply extensive hydraulic fracturing for shale gas development, particularly in dry areas where there is growing competition for scarce water supplies (e.g. West Texas, some Rocky Mountain states), will lead to a scarcity of water (and increased cost) for irrigation, livestock watering, residential use, competing business uses). In some cases, withdrawal of water from aquifers or surface sources can also have environmental impacts as well as economic impacts.

Induced Seismicity

Studies have shown that there is an apparent correlation between deep injection of waste water in disposal wells with injection zones near faults and fault movements that result in earthquakes. These earth quakes are generally low level and undetectable, but some have resulted in relatively minor damage to structures. At this point there has been no correlation between the injection of fluids for hydraulic fracturing purposes and seismic activity, although this is not beyond the realm of possibility.

The primary concern is that the increasing volumes of flowback water from hydraulic fracturing of shale wells will need to be disposed of and that an increase in the number of disposal wells and the volumes being injected into them will lead to an increase in related earthquakes and, if they increase intensity, damage to life and property.

Cuttings and Naturally Occurring Radioactive Material

Shale formations can contain naturally occurring radioactive materials (NORM) like uranium, thorium, potassium and radium. While these materials emit low-level radiation, their concentration does not present a health hazard to anyone (e.g., at a surface outcrop of shale). NORM that becomes concentrated in the production process may also be referred to as Technologically-Enhanced, or TENORM. This concentrated material can sometimes be found in oil and gas piping or processing equipment through which large volumes of produced fluids pass and NORM can become filtered out and concentrated in sludges or scale deposits (e.g., oil-water separators, pipes, tubing, filters).

Oilfield NORM is only a potential exposure risk for oilfield workers when such equipment is opened up for cleaning or when wastes from such cleaning operations are disposed of. The practices followed at cleaning facilities are designed to protect workers and the public from possible exposures.

The oil and gas industry is subject to general radiation standards issued by federal and/or state agencies. Regulations of those agencies follow Environmental Protection Agency guidance on radiation protection of the public. Other provisions to limit exposures to the public include licensing requirements for facilities handling equipment and materials with NORM concentrations over a certain level, and waste management requirements. If NORM-containing wastes or drill cuttings are sent to landfills for disposal, they must meet appropriate limits for radiation emissions before they can be accepted. Materials exceeding such limits must be disposed of in alternative manner according to applicable regulations.

Air Quality

Stakeholder concerns related to air quality impacts that can occur during shale gas development can be divided into several categories. The first relates to emissions from equipment used to create

drilling pads and access roads, operate drilling equipment, and transport equipment and materials. These emissions are largely from diesel fuel combustion and include primarily ozone precursors like NOx and non-methane volatile organic compounds, and particulates. The second category relates to methane emissions during the well completion process when wells are flowed back or tested. This can include emissions from flares. The third category includes non-combustion particulates, both from gravel roads constructed for drill pad access and also from silica dust from proppant handling during hydraulic fracturing. The fourth category includes emissions from equipment during the gas and liquids production process, including methane releases from valves, compressor blowdown, and VOCs or BTEX (Benzene, Toluene, Ethylbenzene and Xylenes) that escape from condensate or oil tanks.

While states and Federal regulations control the impacts of many of these emissions categories, concerns have been raised about the cumulative impacts of all of them over a long period of time and with a large number of wells across a play region. A number of studies are under way to attempt to quantify the individual as well as cumulative impacts in different regions.

Climate Change

Efforts to estimate the relative contribution to climate change of natural gas as an energy source compared to other options (e.g. coal) have included life cycle systems analyses that incorporate all emissions from exploration through end use combustion. Because methane is a more potent greenhouse gas than carbon dioxide, methane emissions during natural gas production and transport can offset the carbon dioxide saving of gas over coal at the combustion point. A number of studies have concluded that a key element of calculating the emissions from shale gas development is better estimates of the volumes of methane lost to the atmosphere during well completions and production activities. Efforts are underway to more accurately characterize exactly how much methane is lost across the entire natural gas value chain.

For example, a major suite of studies measuring methane emissions throughout the natural gas production and transportation system is underway. The University of Texas at Austin is leading this effort with support from the Environmental Defense Fund and a group of nine producing companies.[111] The first of a series of reports, published in September 2013, focused on extensive measurements of methane emissions — including the first measurements for methane emissions taken directly at the well pad — during completion operations for hydraulically fractured wells. Measurements at 190 natural gas production sites across the United States found that the majority of hydraulically fractured well completions had equipment in place that reduces methane emissions by 99 percent. Because of this equipment, methane emissions from well completions are 97 percent lower than calendar year 2011 national emission estimates, released by the Environmental Protection Agency (EPA) in April 2013.

The study also found that emissions from certain types of pneumatic devices are 30 percent to several times higher than current EPA estimates for this equipment. Combined, emissions from pneumatics and equipment leaks account for about 40 percent of estimated national emissions of methane from natural gas production. Results for the studies addressing other parts of the supply chain will be reported over a one to two year time period.

[111] Unprecedented Measurements Provide Better Understanding of Methane Emissions During Natural Gas Production, University of Texas, http://www.engr.utexas.edu/news/releases/methanestudy

Advancing Shale Gas Development Technology

Shale gas development has been made possible due to the application of advanced technologies, primarily lower cost and more accurate horizontal drilling systems and lower cost methods for hydraulic fracturing along horizontal laterals. Progress in auxiliary technologies has also played a role, for example microseismic fracture mapping and improved water treatment technologies. But challenges remain. Three of the areas where new technologies could enhance recovery of the shale gas resource are outlined here.

Improving Ultimate Recovery of the Resource

While the percentage recovery of natural gas in place in conventional reservoirs can approach 90%, recovery in shale gas reservoirs appears to be averaging closer to 20%. Part of this is due to the low permeability nature of the shale matrix, but technologies that can increase this level of recovery can have a great impact due to the large in place volumes. One potential area where advances are likely is improved well completion strategies that optimize the placement of perforations in a fracture treatment stage, the number and location of stages along the horizontal lateral, and the spacing of laterals on a pad. Another area could be improved techniques for assessing the contribution of various sections of a horizontal lateral to overall production, and improved methods for re-fracturing zones that have potential to improve. This may require an improved understanding of how well current completion practices are achieving the design configurations of fracture dimensions and proppant placement.

Reducing Water Use and Other Environmental Impacts

Currently, reuse of fracturing flowback water is on the rise, but in plays like the Marcellus only 20% of the water comes back during the flowback period. Finding economic alternatives to water (e.g., carbon dioxide, LNG, or LPG) could potentially solve the problem of water demand conflicts and potentially lead to unforeseen improvements in productivity. Operators are already experimenting with alternative fluids (such as LPG) in selected plays.

There are also opportunities to develop and apply new approaches to pad construction, drilling and well completion, site remediation, and production operations that can further reduce environmental impacts. “Green” completions with entirely closed cycle drilling and flowback fluid control are commercially available, but refinements can help to lower the costs of these options and broaden their application.

Quantifying Risks and Benefits of Shale Gas Development

In the case of shale gas development, as with any human activity, there are risks and benefits. Accurately characterizing these risks and benefits and quantifying them are critical steps in providing stakeholders (citizens, non-governmental organizations, legislative policymakers, regulators, industry, and local businesses) with information that can be used to make decisions that maximize benefits and minimize negative impacts. The first step in this process is often the gathering of scientifically accurate, unbiased data that can be used to establish a baseline of current conditions (i.e., environmental and socio-economic). The second step is acquiring unbiased, objective data that accurately characterize the impacts of shale gas drilling and production operations. The third step is to apply objective analytical techniques to assess and quantify the risks of environmental impacts.

These same steps, gathering objective data and applying analytical techniques, can also be applied to the benefits side of the issue. When both benefits and risks are quantified, stakeholders can make informed decisions about how to proceed with development.

Currently, while a number of academic, industry and government entities are actively involved in these efforts, data holes and analytical weakness remain. Research to address these problems is needed. One problem is the fact that data acquisition often requires partnering among stakeholders, and some stakeholders discount the validity of data gathered in that manner. In these situations, a federal laboratory can play a role in providing an objective clearinghouse of information and analysis.

Summary

Natural gas plays a key role in meeting U.S. energy demands and will continue to do so for the next 30 years. The United States has abundant natural gas resources, between 2,000 and 3,000 tcf of technically recoverable gas. The contribution of shale gas to the Nation's natural gas production stream will continue to grow, driven by advances in technology and economic factors.

A combination of sequenced hydraulic fracture treatments and horizontal wellbores has facilitated the expansion of shale gas development, first in the Barnett Shale of Texas, and then in the Fayetteville Shale in Arkansas, the Woodford shale in Oklahoma, the Haynesville-Bossier shale in eastern Texas and northwestern Louisiana, the Marcellus shale of the Appalachian basin, and the Eagle Ford shale of southern Texas. Other plays have also begun to emerge, including those with higher liquids content such as the Bakken, Niobrara, and portions of the Eagle Ford. While each of these plays is geologically unique, collectively they support a major shift in the Nation's oil and gas supply system.

The practices followed by natural gas producers in developing shale gas plays are constantly evolving. Within each play and across multiple plays, operators gain experience, new technologies are invented, old technologies are refined, service company innovations are introduced, and the economic drivers of costs and product value rise and fall.

As shale gas development activity has increased over the past decade, the level of attention being paid to the potential for environmental impacts resulting from that activity has also increased. Shale gas development has been made possible due to the application of advanced technologies, primarily lower cost and more accurate horizontal drilling systems and lower cost methods for hydraulic fracturing along horizontal laterals. But challenges remain. Minimizing environmental impacts while maximizing the benefits of shale gas development require continued advancements in technology and collaborative efforts to accurately quantify both the potential risks and the potential benefits.

Appendix A: Resources and Reserves

All the gas that exists:

- GAS-IN-PLACE (GIP)
- *f(geology)*

All the gas that could be expected to be produced:

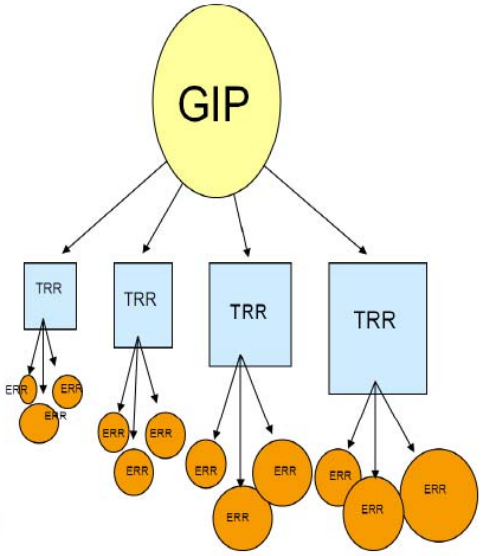
- TECHNICALLY RECOVERABLE RESOURCE (TRR)
- *f(GIP, technology, policy, regulations)*
- *f(demonstrated capability, well spacing)*

All the gas that should be produced:

- ECONOMICALLY RECOVERABLE RESOURCE (ERR)
- *f(TRR, market conditions)*

All the gas defined by drilling, ready for production:

- RESERVES
- Various categories (Proven, Probable, Possible) … *f(data certainty, legal definitions, corporate standards)*



Original ***gas-in-place*** (OGIP or GIP) is the total volume of gas present in a subsurface accumulation. It is a function of the geologic processes that have acted over geologic time to concentrate methane molecules in a certain portion of a sedimentary basin. The ***technically recoverable resource*** (TRR) is the volume of gas (represented as a percentage of the OGIP or as an absolute volume for a given play) that can reasonably be expected to be recovered through the application of current technologies under current regulations. Estimates of TRR are often made based on per well recovery estimates applied across a play at a reasonable well spacing. As technology advances, the TRR portion of OGIP will increase. The ***economically recoverable resource*** (ERR) is that portion of the TRR that can be expected to be produced given an expected natural gas price. Wells will not be drilled unless there is an expectation of a certain minimum rate of return, regardless of the technical capacity to produce natural gas. If the cost of E&P technology is reduced, the ERR will increase. **Reserves** are volumes of economically recoverable gas defined by drilling. They are categorized as *proven*, *probable* or *possible* in order to allow investors to better appreciate the risks associated with a company's discoveries of oil or natural gas.

Appendix B: Selected Shale Gas Play Descriptive Data

	Barnett	Fayetteville	Haynesville-Bossier	Marcellus	Woodford	Antrim	New Albany	Utica-Pt. Pleasant	Eagle Ford	Pearsall	Mancos	Lewis
Basin (States)	Fort Worth (TX)	Arkoma (AR)	Gulf Coast Salt Basin (TX, LA)	Appalachian (PA, WV, OH, NY, MD	Anadarko-Arkoma (OK)	Michigan (MI)	Illinois (IN, KY)	Appalachian (OH, PA, WV)	Western Gulf, Maverick (TX)	Maverick (TX)	Uinta (UT)	San Juan (NM)
Estimated Area, sq. mi.	~5,000[1]	5,853[2]	9,320[3]	104,067[4]	6,350[5]	~2,400[6]	15,200[7]	16,590[8]	7,600[9]	1,420[10]	9,750	7,500[11]
Depth, ft.	6, 500 - 8,500[12]	1,000 - 7,000[13]	10,500 - 13,500[14]	4,000 - 8,500[15]	6,000 - 11,000[16]	600 - 2,200[17]	500 - 2,000[18]	3,500-10,000[19]	4,000 – 12,000[20]	~8,000-11,000[21]	2,000-6,000[22]	4,500-6,000[23]
Net Thickness, ft.	100 – 600[24]	20 – 200[25]	200[26]-300[27]	50 – 200[28]	120 – 220[29]	70 – 120[30]	50 – 100[31]	150-300[32]	250[33]	500-700[34]	~3,700 (gross)[35]	500-1,900[36]
Depth to Base of Treatable Water, ft.	~1,200	~500[37]	~400	~850	~400	~300	~400	~1000[38]	~1,200	na	na	na
Distance from Top of Pay to Bottom of Usable Water, ft.	5,300 - 7,300	500 - 6,500	10,100 - 13,100	2,125 - 7650	5,600 - 10,600	300 - 1,900	100 - 1,600	2,500-9,000	2,800-10,800	na	na	na
Total Organic Carbon, %	4.5[39]	4.0 - 9.8[40]	0.5 - 4.0[41]	3 – 12[42]	1 – 14[43]	1 – 20[44]	1 – 25[45]	1.34[46]	4.5[47]	na	0.44 – 4.32[48]	0.5-1.75[49]
Total Porosity, %	4 – 5[50]	2 – 8[51]	8 – 9[52]	10[53]	3 – 9[54]	9[55]	10 – 14[56]	8[57]	11[58]	na	na	2-5[59]
Gas Content, scf/ton	300 - 350[60]	60 – 220[61]	100 – 330[62]	60 – 100[63]	200 - 300[64]	40 – 100[65]	40 – 80[66]	na	na	na	na	15-45[67]
Well spacing, acres	60 – 160[68]	80 - 160	40 – 560[69]	40 – 160[70]	640[71]	40 – 160[72]	80[73]	Not yet determined	65-120[74]	na	na	80-320[75]
Original Gas-In-Place, tcf[76]	327	52	717	1,500	23	76	160	na	270[77]	na	na	96.8[78]
Estimated Technically Recoverable Resources, tcf	44[79]	13.2[80]	65.9[81]	141[82]	21.7[83]	20[84]	19.2[85]	3.75 to 15.7 Tcf and 1.3 to 5.5 Bbbls[86]	50.2[87]	8.8[88]	~ 5 (Mancos-Mowry)[89]	10.2[90]
Producing Wells (date)	16,743 (4-22-13)[91]	4,678 (1-31-12)[92]	3,300 (6-23-13)[93]	PA only 8,982[94] "active" wells (6-1-13)	~2890 (1-1-13)[95]	~9,600[96]	na	Ohio only 85 (1-13)[97]	10,020 permits (5-13)[98]	~22 (2013)[99]	na	101 completions (1997)[100]
Estimated Cumulative Production, tcf (date)	14 (6-13)[101]	4 (6-13)[102]	8.2 (6-13)	7 (6-13)	1.7 (6-13)	~3 (1-13)[103]	na	Ohio only 0.0128 (plus 636,000 Bbls) (1-13)	2.16 (plus 548 MMB liquids) (4-13)[104]	na	na	na

na = not available

Appendix B Footnotes

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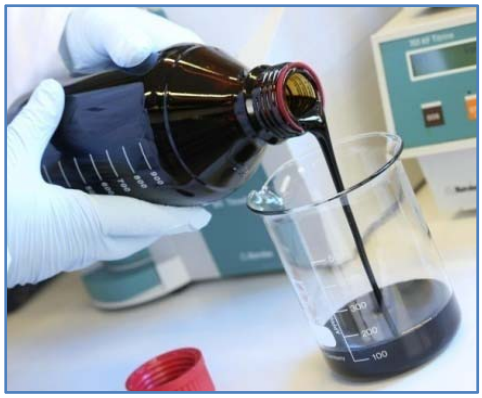
Appendix C: NGLs, Condensate, and Crude Oil

Natural Gas Liquids (NGLs): Hydrocarbons with more than one carbon in their molecular structure that exist as a vapor within a natural gas stream under subsurface conditions of pressure and temperature. These include ethane, propane, butane and iso-butane. A mixture of propane, butane and iso-butane is also referred to as liquefied petroleum gas or LPG, which can also be a product of the crude oil refining process. In the US petrochemical market NGLs are often sold in a mixed stream. A common example is an 80% ethane/20% propane mixture (called E/P Mix).

Condensate: Condensate is made up of hydrocarbons with five or more carbons (pentane, iso-pentane and heavier) that are produced along with natural gas. While some of these hydrocarbons may exist as a vapor at reservoir conditions, they can remain in a liquid state at surface conditions without a special pressurized container. Condensates are light (generally having a density of 50 degrees API or higher) and sweet (generally containing less than 0.3% sulfur). Condensate is sometimes referred to as natural gasoline or field condensate or lease condensate.



Crude oil: Crude oil exists as a liquid in the reservoir and on the surface and is made up of hydrocarbon molecules that have many more carbons and more complicated structures than condensate. Generally, crude oil is darker and denser than condensate and contains relatively larger amounts of metals and sometimes, sulfur. However, the crudes oils and condensates produced from shales are generally lighter and sweeter than conventional crudes. US Gulf Coast refineries are designed to process heavier, sour grades of crude oil, so the sudden increase in production of domestic sweet light crude has led to some challenges in the refining sector.

Acronyms and Abbreviations

bcf	billion cubic feet
Btu	British thermal units
CO2	Carbon Dioxide
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ft	foot/feet
GHG	Greenhouse Gases
Mcf	thousand cubic feet
MMcf	million cubic feet
NETL	National Energy Technology Laboratory
NORM	Naturally Occurring Radioactive Material
NOx	Nitrogen Oxides
SC	standard cubic feet
SO2	Sulfur Dioxide
tcf	trillion cubic feet
TDS	Total Dissolved Solids
U.S.	United States
USDW	Underground Source of Drinking Water
USGS	United States Geological Survey
VOC	Volatile Organic Compound

Definitions

AIR QUALITY. A measure of the amount of pollutants emitted into the atmosphere and the dispersion potential of an area to dilute those pollutants.

AQUIFER. A body of rock that is sufficiently permeable to conduct groundwater and to yield economically significant quantities of water to wells and springs.

BASIN. A closed geologic structure in which the beds dip toward a central location; the youngest rocks are at the center of a basin and are partly or completely ringed by progressively older rocks.

CASING. Steel piping positioned in a wellbore and cemented in place to prevent the soil or rock from caving in. It also serves to isolate fluids, such as water, gas, and oil, from the surrounding geologic formations.

COAL BED METHANE/NATURAL GAS (CBM/CBNG). Natural gas found deep inside and around coal seams. The gas has an affinity to coal and is held in place by pressure from groundwater. CBNG is produced by drilling a wellbore into the coal seam(s), pumping out large volumes of groundwater to reduce the hydrostatic pressure, allowing the gas to dissociate from the coal and flow to the surface.

COMPLETION. The activities and methods to prepare a well for production and following drilling. Includes installation of equipment for production from a gas well.

DISPOSAL WELL. A well which injects produced water into an underground formation for disposal.

DIRECTIONAL DRILLING. The technique of drilling at an angle from a surface location to reach a target formation not located directly underneath the well pad.

DRILL RIG. The mast, draw works, and attendant surface equipment of a drilling or workover unit.

EMISSION. Air pollution discharge into the atmosphere, usually specified by mass per unit time.

EXPLORATION. The process of identifying a potential subsurface geologic target formation and the active drilling of a borehole designed to assess the natural gas or oil.

FLOW LINE. A small diameter pipeline that generally connects a well to the initial processing facility.

FORMATION (GEOLOGIC). A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.

FRACTURING FLUIDS. A mixture of water and additives used to hydraulically induce cracks in the target formation.

GROUND WATER. Subsurface water that is in the zone of saturation; source of water for wells, seepage, and springs. The top surface of the groundwater is the “water table.”

HABITAT. The area in which a particular species lives. In wildlife management, the major elements of a habitat are considered to be food, water, cover, breeding space, and living space.

HORIZONTAL DRILLING. A drilling procedure in which the wellbore is drilled vertically to a kickoff depth above the target formation and then angled through a wide 90 degree arc such that the producing portion of the well extends horizontally through the target formation.

HYDRAULIC FRACTURING. Injecting fracturing fluids into the target formation at a force exceeding the parting pressure of the rock thus inducing a network of fractures through which oil or natural gas can flow to the wellbore.

INJECTION WELL. A well used to inject fluids into an underground formation either for enhanced recovery or disposal.

NORM (Naturally Occurring Radioactive Material). Low-level, radioactive material that naturally exists in native materials.

ORIGINAL GAS- IN- PLACE. The entire volume of gas contained in the reservoir, regardless of the ability to produce it.

PARTICULATE. A small particle of solid or liquid matter (e.g., soot, dust, and mist). PM10 refers to particulate matter having a size diameter of less than 10 millionths of a meter (micrometer) and PM2.5 being less than 2.5 micro-meters in diameter.

PERMEABILITY. A rock's capacity to transmit a fluid; dependent upon the size and shape of pores and interconnecting pore throats. A rock may have significant porosity (many microscopic pores) but have low permeability if the pores are not interconnected. Permeability may also exist or be enhanced through fractures that connect the pores.

PRODUCED WATER. Water produced from oil and gas wells.

PROPPING AGENTS/PROPPANT. Silica sand or other particles pumped into a formation during a hydraulic fracturing operation to keep fractures open and maintain permeability.

PROVED RESERVES. That portion of recoverable resources that is demonstrated by actual production or conclusive formation tests to be technically, economically, and legally producible under existing economic and operating conditions.

SHALE GAS. Natural gas produced from low permeability shale formations.

TECHNICALLY RECOVERABLE RESOURCES. The total amount of resource, discovered and undiscovered, that is thought to be recoverable with available technology, regardless of economics.

TIGHT GAS. Natural gas trapped in a hardrock, sandstone or limestone formation that is relatively impermeable.

WATERSHED. All lands which are enclosed by a continuous hydrologic drainage divide and lay upslope from a specified point on a stream.

WELL COMPLETION. See Completion.