

NATURAL GAS:

*An Energy
Game Changer*



Muhlenkamp & Company, Inc.
Intelligent Investment Management



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Mr. Muhlenkamp received a Bachelor of Science degree in Engineering from M.I.T. in 1966, and a Masters in Business Administration from the Harvard Business School in 1968. He holds a Chartered Financial Analyst (CFA) designation. He and his wife, Connie, make their home on a farm near Pittsburgh, but travel extensively to meet and talk with companies and clients around the country.

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This booklet, *Natural Gas: An Energy Game Changer*, is an adaptation of the presentation that Ron Muhlenkamp, Portfolio Manager, delivered at the Muhlenkamp & Company investment seminar in November 2013.

Archives of past seminars are available at www.muhlenkamp.com. We hope you find this booklet useful. Let us know what you think.

Investments are focused in the natural gas distribution and transmission industry, which may be adversely affected by rising interest rates, weather, and the wholesale pricing of alternative fuels.

Natural Gas: An Energy Game Changer

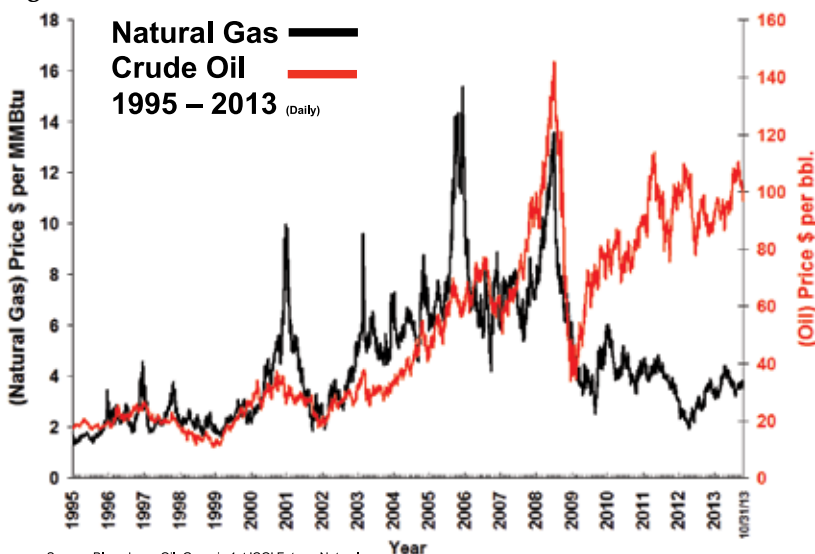
My wife, Connie, and I own a farm in Butler County, (southwestern) Pennsylvania, where Marcellus Shale is located. Being curious about what's taking place in my back yard, I did a lot of research on the implications of shale gas drilling, not only as a landowner—but as a consumer, environmentalist, engineer, and investment manager. My research generated various “white papers” that have been published by area newspapers and are available on our website. Today's presentation, *Natural Gas: An Energy Game Changer*, builds on that work.

Reality versus Reality

We are investors—and, as investors, we make our living on the difference between reality and perception. Today, we're finding a significant gap between reality and reality, which is why we think what's taking place with natural gas is an energy game changer.

Let me explain...

Figure 1 Natural Gas and Crude Oil Prices, 1995-2013



Source: Bloomberg; Oil: Generic 1st 'CO' Future, Natural Gas: Generic 1st 'NG' Future delivery to Henry Hub

As an investor, Figure 1 is the most interesting chart that I can find. This plot shows the daily natural gas price at the Henry Hub and the daily price of crude oil in Cushing, Oklahoma, since 1995.

The relationship between prices for crude oil (red) and natural gas (black) was set by the relative energy density between the two: a ratio of about 9:1. So to get similar prices per Btu (British Thermal Unit)—energy content—if the price of crude oil is at \$90 per barrel, the price of natural gas should be at about \$10 per MMBtu (Million Btu). The prices of crude oil and natural gas have pretty much moved in lockstep; as one went up, so did the other.

Historically, nearly half of natural gas usage in the U.S. has been for home heating. With a particularly cold winter like the one we experienced in 2005-06, there was a natural gas shortage, resulting in a spike in natural gas prices relative to crude oil. Prices ran up together again in 2008, and came back down in 2009. Since 2009, the price of crude oil has gone back up, but the price of natural gas has not, tracking at about a \$4 per MMBtu level. Early in 2012, prices got down to \$2 per MMBtu, making natural gas cheaper than coal. This lower price since 2009 is the result of the horizontal drilling and hydraulic fracturing of natural gas in the United States.

Hydraulic fracturing (“fracking”) involves pumping fluid into a shale formation under sufficient pressure to create small fractures in the rock, allowing oil or gas to flow more freely. The first commercial use of fracking likely took place in 1946, but it wasn’t until recent years that it was successfully combined with horizontal drilling to give widespread and dramatic results.

As long as the price spread between crude oil and natural gas remains wide, we’re going to see a shift in consumption to natural gas.

Shale Gas: A Consumer Perspective

In this country, a quarter of our natural gas production is used by industry, a quarter is used to generate electricity, and half is used for home heating. As investors, we learned a long time ago that if a product or service makes sense to the consumer it probably will last a long time.

Connie and I live in a 100-year old farm house, heated by natural gas. I wondered if the low price of natural gas was reflected in my gas bill. Looking back at my gas bills over the past 6½ years, the charges break down into three categories:

- Customer charge;
- Delivery charge; and
- Commodity charge.

Figure 2 How Shale Gas Benefits the Homeowner

How Shale Gas Benefits the Homeowner

	Cost per mcf at 11/2006 rates	Cost per mcf at 11/2008 rates	Cost per mcf at 11/2011 rates	Cost per mcf at 7/2013 rates	Difference per mcf between 2013 and 2008
Delivery Charge	\$4.76890	\$4.88940	\$4.77030	\$4.72170	-\$0.16770
Gas Cost Adjustment	-\$0.59220	\$0.48500	-\$0.49780	\$1.08520	\$0.60020
Commodity Charge	\$8.29520	\$11.19840	\$5.51330	\$4.17880	-\$7.01960
Total	\$12.47190	\$16.57280	\$9.78580	\$9.98570	-\$6.58710

Source: Muhlenkamp & Company, Inc.

The customer charge is a flat monthly fee, which does not vary with the volume or price of gas delivered, so it's not included in Figure 2. A comparison of my gas bills from November 2006, November 2008, November 2011, and July 2013 is presented.

The row across the top is the delivery charge (the price for the lines bringing the gas to my house), which runs about \$4.75 per Mcf (thousand cubic feet); it hasn't changed over this period. The bottom row lists the commodity charge (the cost of the gas itself), and above that is a cost adjustment because much of the gas is bought on a contract. As you can see in Figure 2, the difference between 2013 and 2008 is a savings of approximately \$7 per Mcf on the gas used to heat my house (relative to what I would be paying had the price of natural gas gone back up with the price of crude oil).

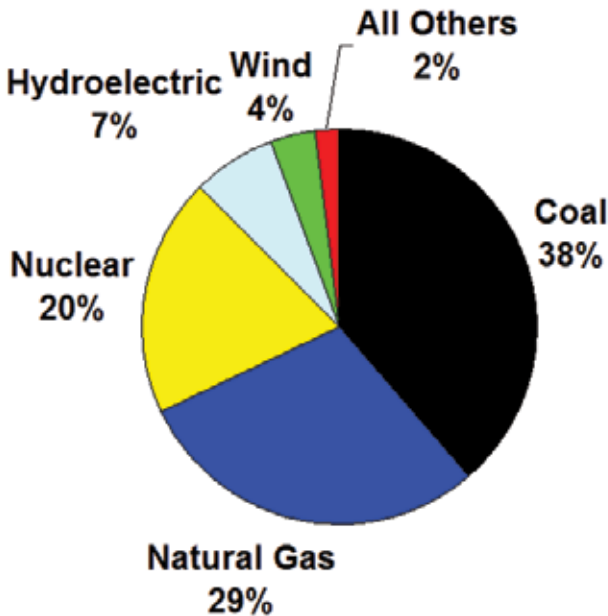
I believe that in the current decade we have a good shot at cutting the price of energy in this country in half—and it's already happened for everybody who heats their house with natural gas! I encourage any of you who heat with natural gas to check your latest bill; you are likely saving \$7 per Mcf, compared to your costs five years ago. If you consume 100 Mcf per year, that's \$700 you are not spending for the natural gas to heat your house. (A review of your own gas bill and a bit of arithmetic will allow you to determine the amount of your savings.)

I read a lot of stories in the paper about certain companies getting rich from shale gas. Once in a while, I'll read a story about a farmer (landowner) who is buying a new tractor with the money he got from signing a lease with a drilling company. Usually, the focus is on the companies doing the drilling and how much money they are making and taking home to places like Texas and Oklahoma where some of their corporate headquarters are located. Don't let the popular media fool you into thinking that only the gas companies are benefitting from shale gas. The consumer is, too, and his natural gas bill is the most obvious of the benefits.

Have you heard the radio advertisements offering cheaper electricity? Because the price of natural gas is less than what the utilities expected, I recently was able to lower my electric rate by 10 percent. Electricity is not a primary source of energy—it's a delivery mechanism of energy from a wide variety of sources. Figure 3 presents the percentages of total U.S. electricity net generation by energy source in 2012:

Figure 3 Percent of Total U.S. Electricity Net Generation by Energy Source, 2012

Percent of Total U.S. Electricity Net Generation by Energy Source 2012

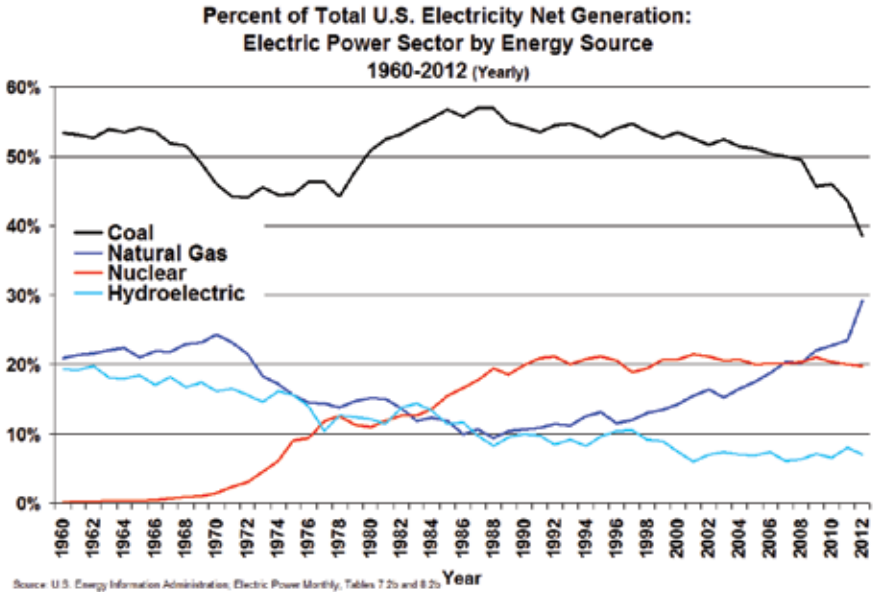


Source: U.S. Energy Information Administration; Electric Power Monthly, Tables 7.2b and 8.2b

The primary sources of energy to generate electricity are coal (38%); natural gas (29%); nuclear (20%); and hydroelectric power (7%). Wind and solar are available on an intermittent basis.

Figure 4 presents the various sources of our electric power in the form of a line chart:

Figure 4 Percent of Total U.S. Electricity Net Generation: Electric Power Sector by Energy Source, 1960–2012



Hydroelectric power (light blue line) is located near the bottom of the plot. Once a dam is built, there's almost no cost involved in supplying hydroelectric power—it's simply a matter of how much snowfall we have in the Rockies; how much rainfall we get in various places. The first big power station in this country tapped the Niagara Falls; circa 1880. The Hoover Dam was constructed between 1931 and 1936. By the 1930-40s, we had pretty much finished building dams. In 1950, 30% of our electricity came from hydroelectric power. As the total amount of electricity increased, the percentage of hydroelectric power declined to 20% in 1960; it's now down to 7 percent.

In the 1960-70s, we built nuclear plants (red line), and we get about 20% of our electricity from nuclear energy. Building a nuclear power plant is very expensive; the fuel, however, is cheap. But it takes a month or so to crank up a nuclear plant or to bring it down—so once you've got it running, you keep it running.

Referring to Figure 4...

Since 1960, roughly 50% of our electricity has come from coal (black line). In the last two years, coal usage declined; it's now at 38 percent.

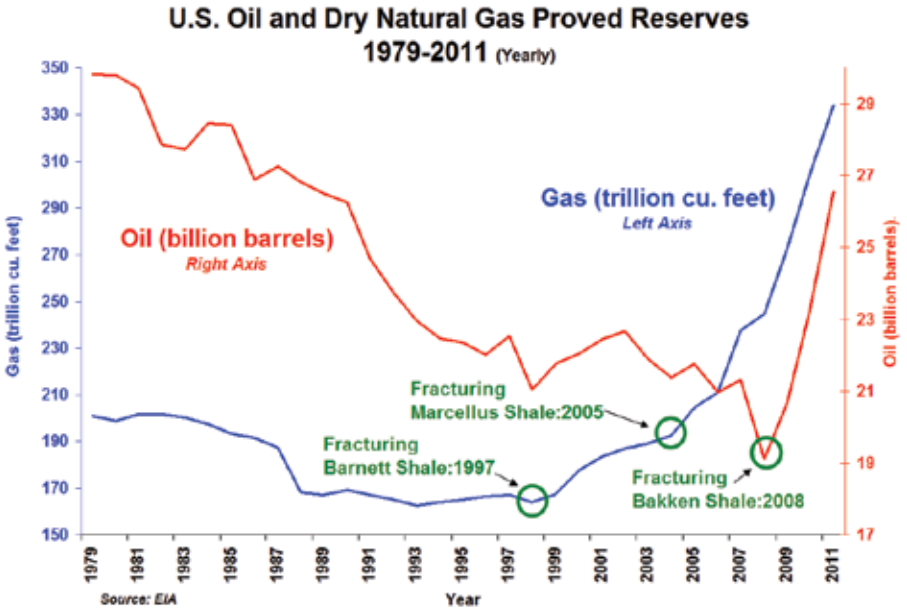
Natural gas usage (dark blue line) picked up a bit in the early 1970s. As a percentage, it came down and was running about 10 percent. In April 2012, the price for natural gas got down to \$2 per MMBtu. At this point, the price of natural gas was cheaper than coal. As a result, electric utilities went from producing 50% of our power from coal to 38%; they went from producing 20% of our power from natural gas to 29 percent. This shift took place in less than a year based on natural gas getting cheap. It looks like the price parity for gas and coal is around \$3 per MMBtu for gas.

As consumers, we do not use electricity at the same rate for every hour of the day and every day of the year. It swings every day, and it swings on a seasonal basis. Historically, natural gas plants were fairly cheap to build, but the fuel was expensive. Natural gas plants are basically a "747 engine with a generator;" i.e. if you need more power, you crank it up—in a few minutes, you have it. So, we use them for "peaking" power; e.g., in the morning when we're turning on the lights and taking showers, and in the evening when we're back at home. My point being, the natural gas plant was there...the pipelines to get the natural gas to the plant were there...the infrastructure was already in place... So, when the price of natural gas became cheap enough, more natural gas plants were put to use on a full-time basis and some coal plants were shut down.

As of November 7, 2013, the Henry Hub price for natural gas was \$3.52 per MMBtu, so there's no longer a price incentive for electric utilities to shift from coal to more natural gas. In fact, electric utilities have shifted back a little bit. I believe that \$3 per MMBtu will end up being a floor for the price of natural gas because, at that point, it becomes competitive with coal. On a spot basis, sometimes, the price of natural gas hits \$1.50 per MMBtu, but that's measured in hours, not days. There is also an awful lot of natural gas that is nicely profitable at \$5 per MMBtu, so we expect the price for natural gas to be at \$4 per Mcf (plus or minus \$1) for the next 20-30 years.

The reality of crude oil being priced at approximately \$100 per barrel, and the reality of natural gas priced at \$4 per Mcf—instead of \$11 per Mcf—is the "reality versus reality" that we think presents a huge investment opportunity.

Figure 5 U.S. Oil and Dry Natural Gas Proved Reserves, 1979-2011



When thinking about “proved reserves” of either crude oil or natural gas, people generally think of the physical commodity—but, that’s not an accurate definition. “Proved reserves” mean the physical amount in the ground that is *economical* to bring out at a given price.

In Figure 5, the blue line plots proved reserves of natural gas. Barnett Shale was the first shale gas formation that was horizontally drilled and fracked starting back in 1997. This was followed by Marcellus Shale in 2005, at which point proved reserves of natural gas at \$4-\$5 per Mcf increased significantly. By the way, we’ve known about Marcellus Shale for over 50 years, but it was never economical to get out of the ground. Horizontal drilling and fracturing changed that. Remember, five years ago, people were talking about importing Liquefied Natural Gas (LNG) into the country. Now, we’re talking about exporting it. It’s been that big a change.

The red line in Figure 5 plots proved reserves of crude oil. As most of you may know, the big play in crude oil has been in the Bakken Shale, underlying parts of Montana and North Dakota, where horizontal drilling and fracturing commenced in 2008. (North Dakota now ranks second in domestic oil production, behind Texas.) In contrast to natural gas, crude oil has always been an international commodity—it’s easy to ship across an ocean.

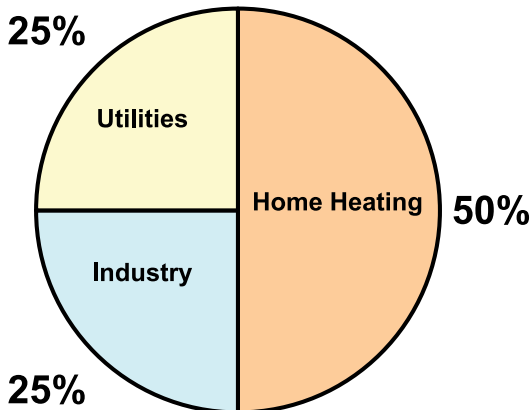
Incidentally, they are flaring the natural gas in the Bakken fields. Here's why:

The transportation of Compressed Natural Gas (CNG) by truck or rail is not cost effective. The standard for compressed natural gas is 3500 psi (pounds per square inch). But natural gas at 3500 psi takes 3½ times the volume to give you the same BTUs as gasoline for diesel fuel; instead of a 10-gallon tank, you need a 35-gallon tank. So from a user's point of view, one of the disadvantages of using CNG is that it requires 3½ times the volume. Because of that, it currently doesn't pay to ship natural gas unless you do it by pipeline—which is why they're flaring the natural gas in North Dakota.

By the way, if you go to Las Vegas and open the trunk of a taxi, you may see a cylindrical fuel tank that's used for storing CNG to power the vehicle. Roughly half of the taxis in Las Vegas are powered by CNG. And, in Los Angeles, "Nation's Largest Clean Air Fleet" appears on the sides of many buses. (LA Metro has the largest fleet of CNG buses in the nation—approximately 2,200. After purchasing its first natural gas bus in 1995, the system retired its last diesel bus in 2011.) Manufacturers are also making CNG tanks for pickup trucks. In fact, you can now purchase a natural gas fired pickup truck from Ford, Chevy, or Dodge that uses a cylindrical fuel tank.

Figure 6 Historical Natural Gas Consumption in the U.S.

Historical Natural Gas Consumption in the U.S.

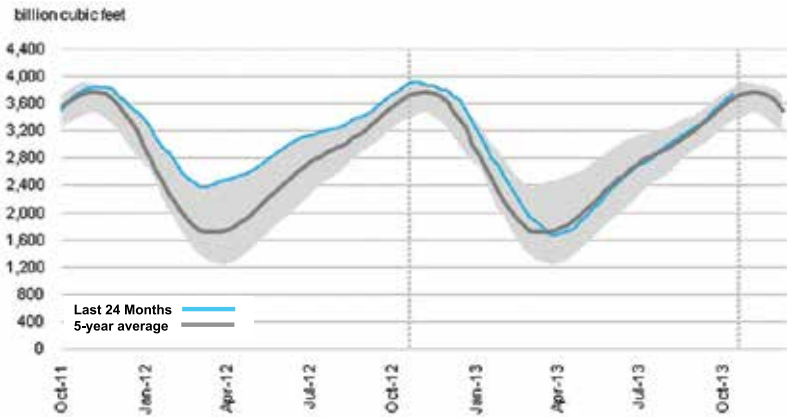


Source: Muhlenkamp & Company, Inc.

Earlier I stated that utilities use about 25% of the natural gas in the U.S., and so does industry. The remaining 50% of consumption applies to home heating; refer to Figure 6. Let's take a look at the implications:

Figure 7 Working Gas in Underground Storage Compared with 5-Year Range

Working Gas in Underground Storage Compared with 5-year Range Week ending October 24, 2013



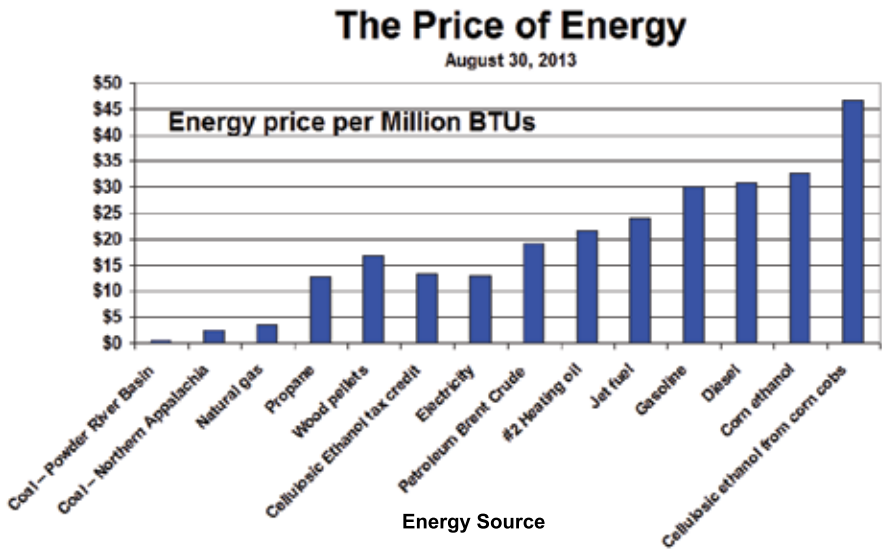
Note: The shaded area indicates the 5-year range between the minimum and maximum values for the weekly series. Source: U.S. Energy Information Administration; Form EIA-912, "Weekly Underground Natural Gas Storage Report."

Figure 7 demonstrates that because half of our natural gas is used for home heating (making it seasonal), the amount of gas in storage peaks every fall. We use natural gas during the winter months, and what's in storage declines until April; then, storage is rebuilt from April to October.

In 2011, not only were we producing more natural gas, but we had a mild winter. So the storage swing that normally occurs between ~3.6 trillion cubic feet and ~1.6 trillion cubic feet went down to only 2.4 trillion cubic feet by April 2012. Some analysts predicted that the normal buildup of natural gas would fill the storage sites by August and that the "spot" price of natural gas would go to \$0.00 per MMBtu. Instead—because power utilities used so much additional natural gas—we were back on track for normal storage by October 2012.

Lesson learned: Cheap natural gas prices provided the incentive for power utilities to increase their use—and they responded quickly—resulting in a greater impact than anyone had expected.

Figure 8 The Price of Energy per MMBtu



Spot prices used to calculate price/MMBTU

Sources for Data: U.S. Energy Information Administration (EIA) - Coal News and Markets Report 2, EIA, Natural Gas Futures Prices, Bloomberg, Propane Bloomberg generic Future 1 month, Volumetric Ethanol Excise Tax Credit (VEETC) - Ethanolira.org, Wood Pellets - Bloomberg, Electricity - Bloomberg, Petroleum - Bloomberg, EIA, #2 Heating Oil - infocemundi.com; Jet Fuel - Infocemundi.com; Gasoline - Bloomberg; Diesel - EIA Weekly Retail On-Highway Diesel Price US Total/USD gallon; Corn Ethanol - Chicago Board of Trade Ethanol Futures for September 2012 Contract, Cellulosic ethanol - ethanolproducer.com

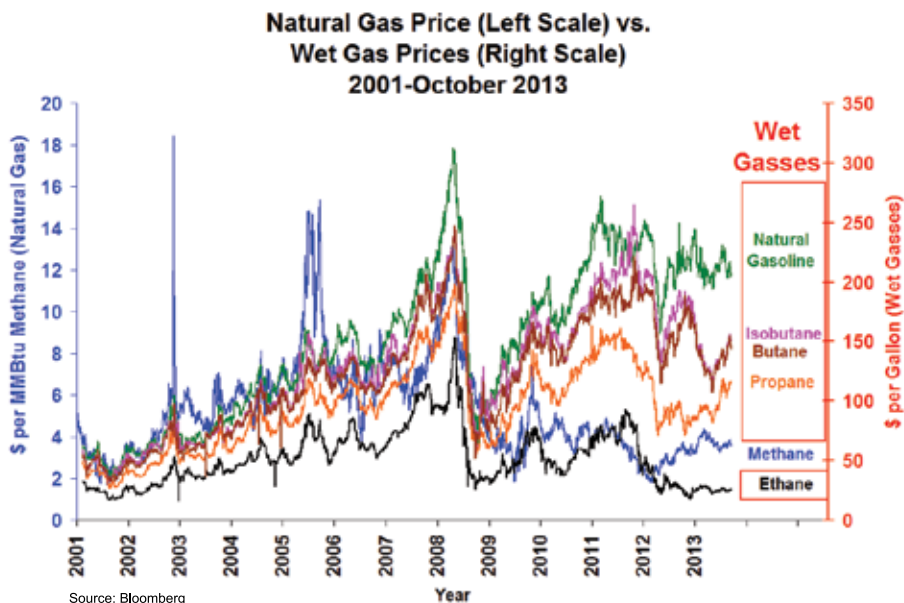
To the far left on Figure 8, you'll find the price for coal in the Powder River Basin (located in southeast Montana/northeast Wyoming), where surface mining takes place using big equipment. This coal runs about \$10 per ton, but must be transported by rail to the power plants in the east, adding to its overall cost of usage per MMBtu. Coal in Northern Appalachia runs about three times the cost of Powder River Basin coal on an MMBtu basis.

Natural gas is the third entry (its price is close to Northern Appalachian coal), followed by propane, wood pellets, cellulosic ethanol (which includes a tax credit), and electricity. (Electricity is not a source of power—it is simply a distribution mechanism.)

Moving to the right from electricity, Figure 8 lists petroleum, #2 heating oil, jet fuel, gasoline, diesel, and corn ethanol. The last item on the plot (far right) is the price per MMBtu for cellulosic ethanol from corn cobs—which is why we're not using corn cobs yet!

Looking at the prices per MMBtu for diesel, corn ethanol, and cellulosic ethanol from corn cobs, if you can displace all of them with natural gas, you'll save a whole lot of money.

Figure 9 Natural Gas Price versus Wet Gas Prices, 2001-October 2013



As you can see on Figure 9, historically, natural gas and wet gas prices generally tracked together. Since 2009, that's been changing. To appreciate what's happening, you must understand that there are two types of gas locked inside Marcellus Shale, "wet gas" and "dry gas." Here's the difference, and why it matters:

"Dry gas" is essentially methane—that's all that's in it. The bulk of the natural gas produced in north central and northeast Pennsylvania is dry.

Gas extracted from Marcellus Shale in southwestern Pennsylvania, on the other hand, is considered "wet." That means in addition to methane, the gas contains compounds like ethane, propane, and butane, and some crude oil. These natural gas liquids (NGLs) can be separated and sold on their own as industry feedstock (the raw material required for an industrial product). For example, the market for ethane has gotten a lot of attention in southwestern Pennsylvania recently, as Shell considers building a petrochemical plant in Beaver County that would convert ("crack") ethane into ethylene, a compound used in making plastic.

The difference between wet and dry gas matters because increased natural gas production has driven down the price at which drillers can sell their products. As a result, drillers are turning their attention to wet shale plays, where they can extract ethane and other NGLs in addition to gas. The revenue generated from NGL sales helps offset the low price of natural gas.

Aside from retail consumers of natural gas, you can see from this discussion that other consumers include utilities, industry feedstock (particularly ethane), and manufacturers; e.g. steel mill furnaces are fired by natural gas—and have been for 50 years. Bottom line... *The long-term result of this energy revolution is lower energy bills for U.S. consumers and businesses.*

But what about the environment?

Shale Gas: An Environmental Perspective

Our study on the environment is not complete—and is not meant to be—as various factors are always changing. We do believe, however, it can serve as a useful benchmark.

I mentioned earlier that over the last five years, while use of nuclear energy has been stable at approximately 20%, coal usage has dropped from over 50% to 38%, and natural gas has increased from 20% to 29 percent. As a result of these changes, total U.S. carbon dioxide emissions from energy consumption are down 14% from their peak.

Let's explore this further.

Figure 10 shows the chemical compositions of various fuel sources in terms of their carbon/hydrogen makeup.

Figure 10 Chemical Compositions of Selected Fuel Sources

Common Name	Chemical Composition	%Carbon	% Hydrogen
Coal	Several	>50	<50
Wood	Several	>35	<65
Diesel Fuel	$C_{16}H_{34}$	32	68
Gasoline	C_8H_{18}	31	69
Propane	C_3H_8	27	73
Ethanol	C_2H_6O	25	75
Methane	CH_4	20	80
Hydro	-----	0	0
Nuclear	-----	0	0
Wind	-----	0	0
Solar	-----	0	0

Source: Muhlenkamp & Company, Inc.

As you can see from Figure 10, coal is the most carbon-intensive fossil fuel—more than 50 percent. (Coal, oil, and gas are called “fossil fuels” because they have been formed from the organic remains of prehistoric plants and animals.)

Wood, diesel fuel, and gasoline are all composed of more than 30% carbon.

Natural gas (methane) is CH_4 : 20% carbon, 80% hydrogen. If you combine CH_4 with oxygen, you get one molecule of CO_2 , and two molecules of H_2O ...water. In moving towards a hydrogen economy, using natural gas gets us halfway there! And, if you move from using coal, oil, or gasoline to using natural gas for the same amount of energy, you produce about half as much carbon dioxide (CO_2).

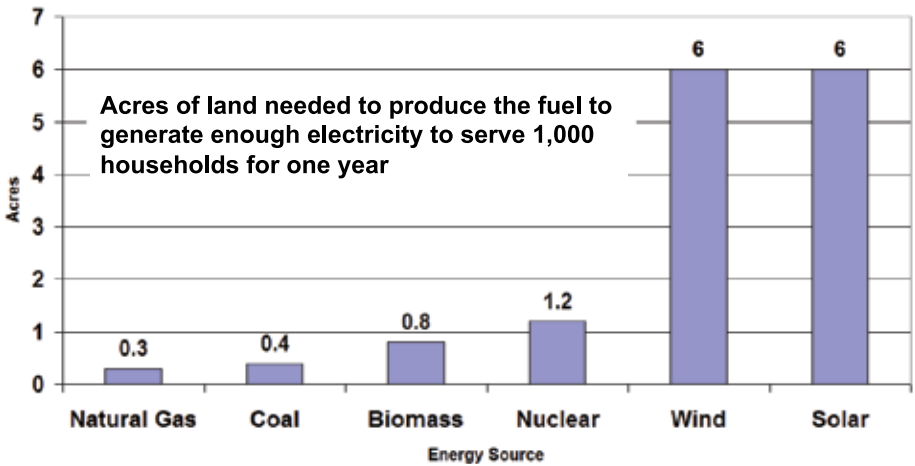
Take a look at Figure 10. Which of these fuels would you be willing to burn in an open flame in your kitchen? Until I was seven, my mother cooked on a wood stove—but we made sure the smoke went up the chimney. Wood is a dirty fuel. Would you burn gasoline in your kitchen? Diesel, coal... all are dirty or emit toxic fumes. That’s why the range in your kitchen is either electric or natural gas.

It's worth noting that all of the different fuel sources have negative side effects which we broadly label as pollution. As such, pollution includes the various "dirty" aspects of coal, wood, and diesel, along with carbon monoxide output from burning gasoline, the effects of hydroelectric dams on fish, and the impact on birds from wind turbines and large-scale solar installations.

One of the undesirable effects that clean energy has is land use. Let's look at the land areas required to produce the fuel to generate enough electricity to serve 1,000 households for one year:

Figure 11 Land Usage: Favors Natural Gas for Power Generation

Land Usage: Favors Natural Gas for Power Generation



Source: Consol Energy

Serving 1,000 households via natural gas for one year requires 0.3 acres of land. The typical well pad is 3 acres, so that's 10,000 homes. Where I live in Butler County, many of the well pads are not visible from the road. In contrast, serving 10,000 homes with windmills requires 60 acres and roughly 60 windmills—and I suspect you could locate the windmills without much problem.

To power 10,000 homes with solar energy also requires 60 acres. I'm not sure that 60 acres of solar cells makes sense in Pennsylvania—but, in southern California, where they are building solar plants in the desert (using 900 acres in one case), it makes perfect sense.

If the required land surface is of any importance to you, natural gas looks better in a lot of cases than wind or solar.

What about biomass?

Waste Management, Inc. (WM) is the largest refuse hauler in the country. WM's services include collection, landfill, transfer, recycling, and waste-to-energy facilities and independent power production plants, among others. On WM's website, I found its *2012 Sustainability Report: Embracing the Zero Waste Challenge*. The report states WM harvested the methane generated from its landfills to furnish electricity for 1.17 million homes in 2012. A bit curious, I sent WM an email, asking how many refuse customers it serves. WM reported it has 21 million refuse customers, some of which are commercial and industrial. (I assume that the commercial and industrial customers have as least as much waste as the homes.) Well, if you've got 21 million customers, and you can power 1.2 million homes, you might get 6% of the necessary power from the refuse. WM also reports the tons of refuse it hauls, which turns out to be about 24 pounds per week per customer, so the amounts are plausible.

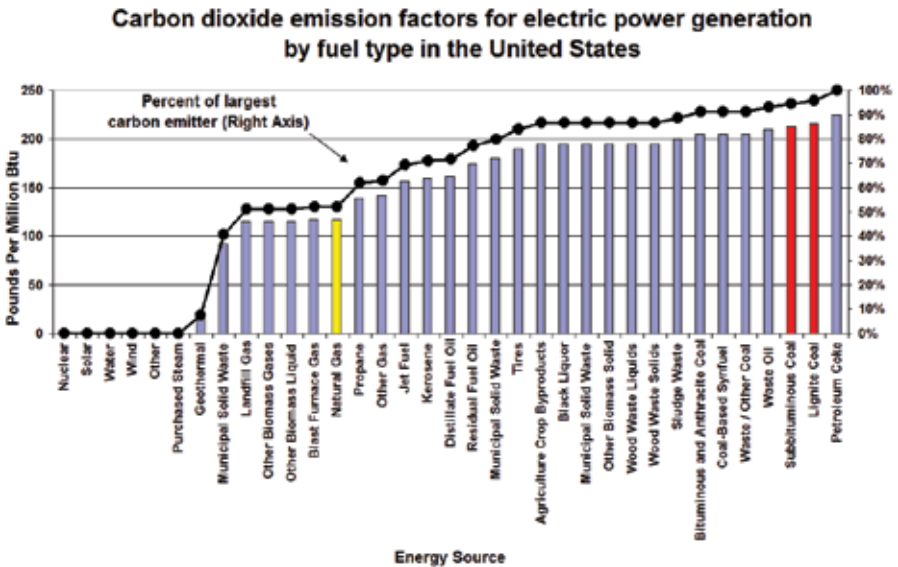
In any case, let's use all the biomass that's available, but I don't think it's going to generate more than 6% of the power we need.

Here's another example:

A friend of mine has a dairy farm in Wisconsin; 4,000 head. He runs the waste through an anaerobic digester which creates methane—and enough energy to run the dairy farm.

Again, by all means, let's use all the biomass we can, but it's never going to generate more than a few percent of the energy needed to live the way we do.

Figure 12 Carbon Dioxide Emission Factors by Fuel Type



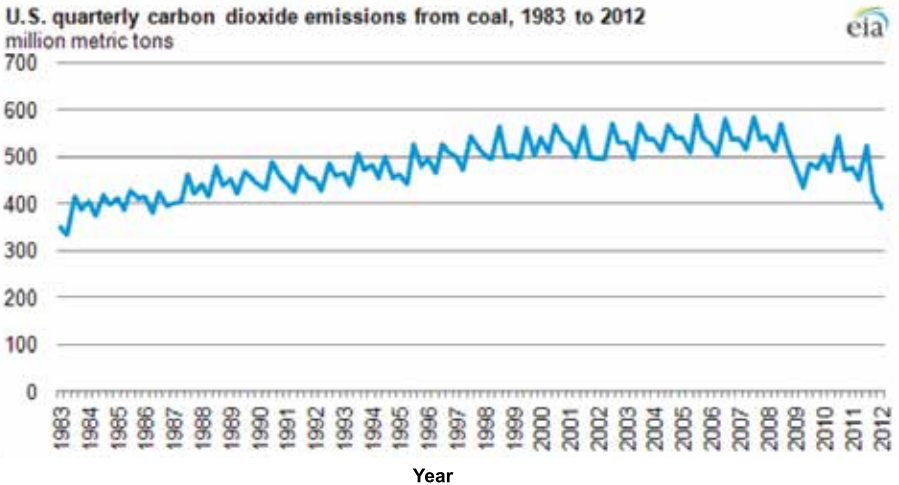
Source: U.S. Energy Information Administration, Carbon Dioxide Emissions Coefficients Report

Some people maintain that man-made carbon dioxide (CO₂) emissions are a major contributor to global warming. The Environmental Protection Agency (EPA) labels CO₂ emissions a pollutant.

As you can see from Figure 12, carbon dioxide (CO₂) emissions from nuclear, solar, water, wind, and “other” are zero.

The next batch of fuel types includes geothermal, municipal solids, landfill gas, other biomass, and blast furnace gas. Natural gas is highlighted in yellow. Following are propane, jet fuel, kerosene, distillate fuel... and, over on the right, are SB (sub-bituminous) coal and lignite coal. The point is, as you saw earlier in Figure 10 (Chemical Composition of Fuel Type), natural gas produces about half the CO₂ that we get from coal.

Figure 13 U.S. Quarterly Carbon Dioxide Emissions from Coal, 1983-2012



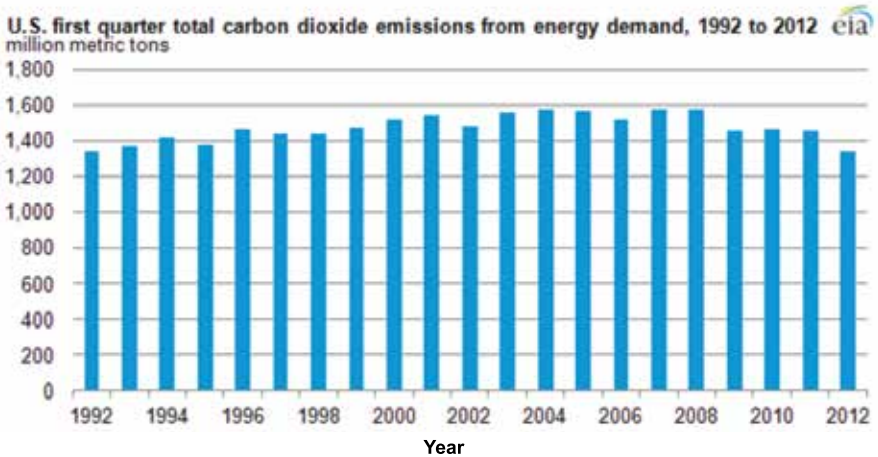
Source: U.S. Energy Information Administration, [Monthly Energy Review](#).

Note: Reflects total carbon dioxide emissions in [metric tons](#) by quarter.

CO₂ emissions from coal have decreased the last few years because some coal—used almost exclusively for electricity generation—has been replaced by natural gas, a less carbon-intensive fuel for power generation.

Figure 14 U.S. Energy-Related CO2 Emissions in Early 2012 Lowest since 1992

U.S. energy-related CO2 emissions in early 2012 lowest since 1992



Source: U.S. Energy Information Administration, [Monthly Energy Review](#).

Note: Reflects total carbon dioxide emissions in metric tons by quarter.

From Figure 14 you can see that in early 2012, CO2 emissions were back to 1992 levels. In fact, the U.S. became the first major industrialized nation in the world to meet the United Nation's original Kyoto Protocol target for CO2 reductions. ("Kyoto" was an international agreement proposed in December 1997, requiring nations to reduce CO2 emissions by 5.2% by 2012.) Note: The U.S. never signed the agreement.

One of the concerns often voiced by opponents of the production of natural gas from shale rock by hydraulic fracturing is that the process uses a lot of water.

Water comes into play in five different ways:

1. Into the well;
2. The flowback;
3. The water table;
4. Burning methane (CH₄);
5. Ethanol (C₂H₆O)

According to Chesapeake Energy, it takes between 65,000 and 650,000 gallons of water to drill a well, and 4.5 million gallons of water to hydraulically fracture the shale.¹ Call it 5 million gallons in all. A Marcellus Shale well typically drains the natural gas from underneath 80 acres.

¹ <http://www.hydraulicfracturing.com/Water-Usage/Pages/Information.aspx>

One way to think about the water is to calculate how much rain would have to fall on those 80 acres to supply 5 million gallons of water. Figure 15 shows the math:

Figure 15 Water into the Well

Water into the Well

**It takes 5 million gallons to frac 1 well
which drains 80 acres**

$$\begin{array}{r} \text{ft}^3 \\ \hline 7.5 \text{ Gals.} \end{array} \times \begin{array}{r} \text{Acre} \\ \hline 43,560 \text{ ft}^2 \end{array} \times \begin{array}{r} 1 \\ \hline 80 \text{ Acres} \end{array}$$

$$\frac{12 \text{ Inches}}{\text{ft}} = \frac{2.3 \text{ Inches of Rain}}{\text{ft}}$$

Source: Muhlenkamp & Company, Inc.

We conclude that 2.3 inches of rain over 80 acres are required to supply 5 million gallons of water. That's about three or four rainy days here in Pennsylvania, where the annual rainfall is 35-40 inches. (It takes 25-30 inches of rain for me to grow corn.) Put that way, 5 million gallons of water doesn't sound as impressive.

What about the flowback?

Studies and standards published by the Center for Sustainable Shale Development (www.sustainable shale.org) in the Appalachian Basin indicate that when you put 5 million gallons of water into the well, two-thirds of it comes back: one-third fairly quickly, and another third over a reasonable period of time. So, rather than bury or treat the flowback water, drillers are now putting it to use in fracking the next well. In fact, new treatment technologies have made it possible to recycle the water recovered from hydraulic fracturing. The reuse of treated flowback fluids from hydraulic fracturing is being conducted by operators in the Marcellus Shale and Barnett Shale regions.

Figure 16 Water Table (General Casing Design for a Marcellus Shale Well)

Water Table...

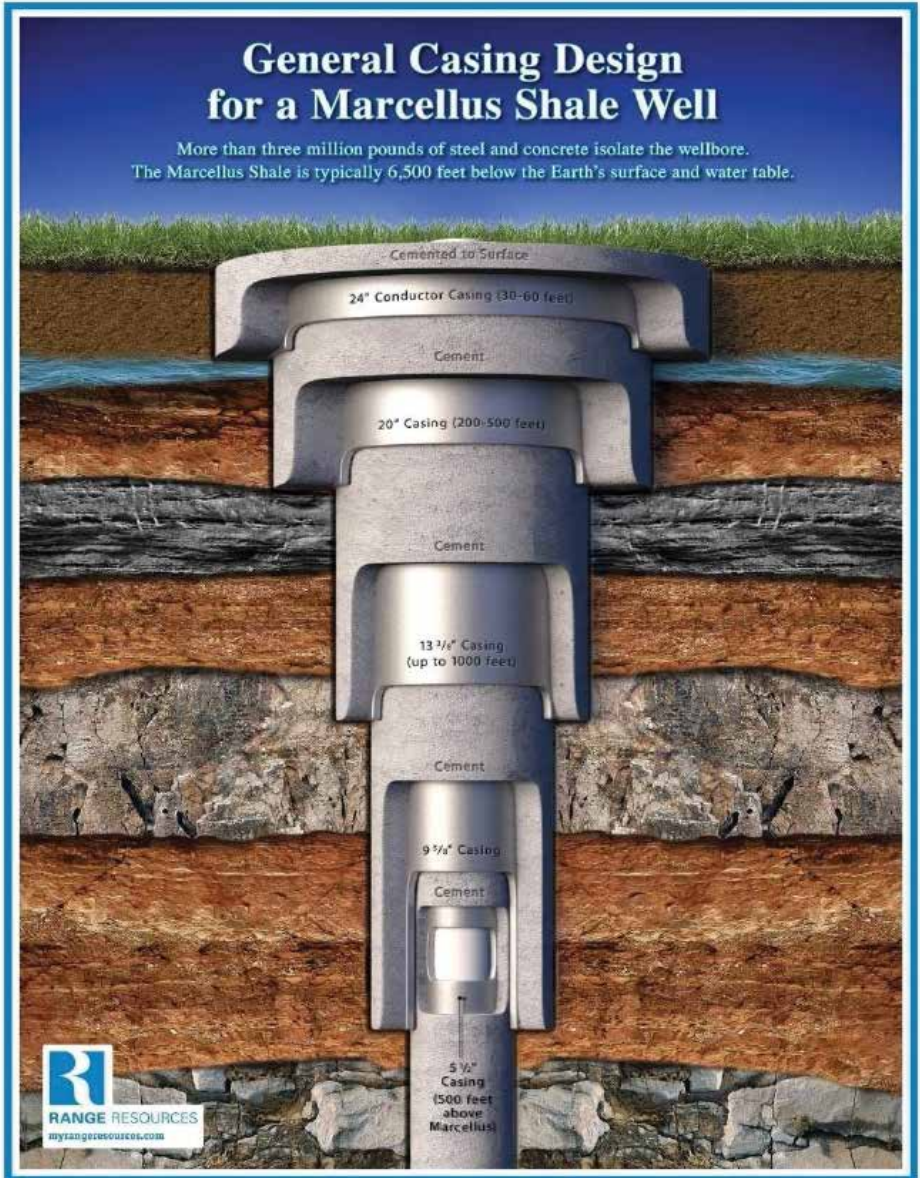


Figure 16 states “More than three million pounds of steel and concrete isolate the wellbore.”

How is this done?

Casing is hollow steel pipe used to line the inside of the wellbore (drilled hole). The casing of oil and gas wells (both vertical and horizontal) is accomplished in multiple phases from the largest diameter casing to the smallest. The first phase involves the setting of conductor casing, which is used to prevent the sides of the hole from caving in. After the conductor casing is set, drilling continues to far below the lowest water table. Additional (surface) casing is then set in place to just above the bottom of the hole.

To seal the gap between the well casing and the surrounding earth, drillers pour concrete into the gap. Early methods involved simply pouring concrete into the gap, allowing gravity to take it down—but this can allow voids in the concrete. Current usage pumps the concrete down the casing, forcing it up through the gap, resulting in a better seal.

Figure 16 also states, “Marcellus Shale is typically 6,500 feet below the earth’s surface and water table.”

In my area, the water table is about 150-200 feet down. Let’s assume the water table is 20 feet thick; on the south side of our farm, we have 20 neighbors, each with a water well. Let’s suppose that one neighbor drilled down one foot into the water table, hit water, and stopped. The next neighbor drilled two feet into the water table, and the next drilled three feet... So you’ve got 20 neighbors, one of whom goes one foot into the water table, and one who goes 20 feet into the water table. Who’s going to have the best well? I would say the one who drilled to 19 feet. When everybody turns on their showers, the neighbors whose well is one foot or two feet into the water table will soon run out of water, right?

Here’s another example...

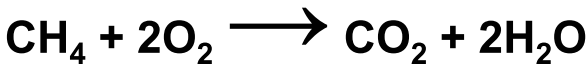
Anybody have a swimming pool? When you clean the water in your swimming pool, do you filter all of it—or do you throw in some chlorine, and filter the top inch and the bottom inch? When we had a swimming pool, we threw in some chlorine, vacuumed the bottom and skimmed the top—because all of the dirt goes to the bottom or floats on the top.

So, I don't want my water well at 20 feet; I want it at 19 feet. I don't want to dredge the dirt off the bottom, and I don't want to skim the dirt off the top. It's not quite that simple, but pretty close. The point being, well drilling is a science, but it's also a bit of an art. Of some 400 households who live in "The Woodlands" in Butler County, about 20 claim that fracking has caused their wells to go bad. From my experience, however, you can drill a well and think you've got decent water—but as soon as somebody builds a house next to you, you don't. Not all wells are well-drilled.

When thinking about the water used to drill for natural gas, it occurred to me that when you burn natural gas, for every molecule of methane, you get a molecule of CO₂ and two molecules of water. ...So how much water do you get?

Figure 17 Burn Methane, CH₄

Burn Methane, CH₄



1 Billion ft³ → 11 Million Gallons of H₂O

Source: Muhlenkamp & Company, Inc.

It turns out that if you burn one billion cubic feet (1 Bcf) of methane, you get 11 million gallons of water.

Range Resource and Rex Energy report that the average estimated ultimate recovery (EUR) of a Marcellus well is 6-8 Bcf of natural gas in its lifetime. If you get 11 million gallons of water for every Bcf of methane, a gas well can generate as much as 88 million gallons of water. Remember, it takes 5 million gallons of water to frack a well, which means you net 83 million gallons of water at about six cents per gallon. Gas wells generate fresh water!

Recently, a sizable shale gas deposit was found off the coast of Israel. In Israel, there's been a chronic shortage of fresh water for years; they could definitely benefit from desalinization plants. Folks, if you use 5 million gallons of salt water to frack a well and get back 83 million gallons of fresh water in return, that is a desalinization plant!

In terms of water usage, how does ethanol production compare to methane (natural gas)?

We make the comparison for two reasons:

- Last year, approximately 30% of the corn crop in this country was used for ethanol production; and
- Many folks who are concerned about the use of water to release natural gas think of ethanol as a great “green” way to produce energy.

Figure 18 Ethanol: What about the Water?

Ethanol: What about the Water?

- **≈ 30% of U.S. corn crop is used for ethanol production**
- **25-30” of rainfall are required to grow corn**
- **Average corn yield of 1 acre of farmland ≈ 147 bushels**
- **1 bushel of corn ≈ 2.77 gallons of ethanol**
- **677,724 gallons of water ≈ 450 gallons of ethanol**

Source: Muhlenkamp & Company, Inc.

Our farmer friends tell us 25-30 inches of rainfall during the growing season are required to grow corn. We'll use 25 inches in our calculations. Data from the U.S. Department of Agriculture indicate that the average corn yield of an acre of farmland in 2012 was 147 bushels of corn.² We also know that one bushel of corn yielded 2.77 gallons of ethanol in 2012;³ we'll call it 3 gallons per bushel. So, 677,000 gallons of water can yield about 450 gallons of ethanol.

² http://www.nass.usda.gov/Charts_and_Maps/A_to_Z/in-corn.asp

³ www.fapri.missouri.edu/outreach/.../2006/biofuelconversions.pdf

Here's the math:

$$2.08 \text{ ft water} \times 43,560 \text{ ft}^2 \times 7.48 \text{ gal/ft}^3 = 677,724 \text{ gal}$$

$$150 \text{ bushels/acre} \times 3 \text{ gallons ethanol/bushel} = 450 \text{ gal ethanol}$$

The heat content of a gallon of ethanol is 76,100 BTUs, so 450 gallons of ethanol is equivalent to 300 gallons of gasoline.

$$\frac{450 \text{ gal ethanol} \times 76,100 \text{ BTU/gal ethanol}}{114,000 \text{ BTU/gal gasoline}} = 300 \text{ gal gasoline}$$

Therefore, 677,724 gallons of water invested in corn production results in the equivalent of 300 gallons of gasoline via corn ethanol. Do a little more math and you conclude that corn ethanol requires 2,259 gallons of water to produce the energy equivalent of a gallon of gasoline.

$$\frac{677,724 \text{ gallons water}}{300 \text{ gal equiv gasoline}} = 2,259 \text{ gallons water/gallon gas equivalent}$$

In other words, shale gas is 14,000 times more water efficient in the production of energy than corn ethanol:

$$\frac{2,259 \text{ gal water/gal equiv gasoline}}{0.16 \text{ gal water/gal equiv gasoline}} = 14,118$$

We recognize that this comparison is by no means a complete accounting of water usage for either process. We haven't accounted for the evaporation from the fields, the runoff from the fields, or the amount of water used in the fermentation process as corn is converted into ethanol. We haven't accounted for the amount of water that comes back up a gas well (flowback), or tried to characterize the utility of the waste water from either production process.

Finally, we haven't accounted for the difference in the amount of water produced by the combustion of ethanol versus the amount of water produced by burning natural gas. So there are limitations to this discussion. Having said that, a **14,000:1 ratio in water efficiency is huge**. If there's a choice between irrigating a corn field and fracking a shale well, you get a whole lot more energy for your water investment with the shale well. We don't think this calculation has entered into the public debate over water use in the production of energy, but frankly, it should.

Something to consider... When my grandfather farmed, he farmed with horses. A man with horses could farm 80 acres (which is why so many farms were 80 acres), but it took 25 acres to feed the horses. When farming evolved from using horses to using tractors, food production went up by 50% because they didn't have to feed the horses. Today, we take our biggest food crop—corn—and use a third of it to make ethanol! So, we've gone backwards. We are now converting food into fuel, whereas in the 1940-50s, they found a way to produce more food by using the fuel in the ground.

Most hydraulic fracturing uses water-based fluids. In addition to water, fracking fluids can contain a wide array of additives, each designed to serve a particular function. I live above the Marcellus gas field, so I'm keenly interested in knowing what additives—chemicals—are used for shale fracking. So I researched a variety of sources, including Pennsylvania's Department of Environmental Protection (DEP), where the gas companies must file reports. Another wonderful resource is "marcellusgas.org." While a small fee is required for using this website, the information is user-friendly and includes the chemicals that are put down the well, the number of inspections the well has had (including demerits, if applicable), as well as the amount of gas that comes out of the well every six months.

Regarding the use of chemicals, Figure 19 comes directly from marcellusgas.org:

Figure 19 Stimulation Fluid Additives

STIMULATION FLUID ADDITIVES							
Note: Information designated as Trade Secret or Confidential proprietary information must be clearly identified as such and should be submitted on the "Confidential Stimulation Fluid Additive" form.							
Trade Name	Supplier	Purpose	Ingredients	CAS # of Chemical Component	Max. Component % Mass in Additive	Chemical Component % Mass used in Total Base Fluid (Pg 3)	Comments
Water			Water	7732-10-5	100.00%	80.50	
Sand		Proppant	Sand	14658-00-7	100.00%	10.51	80A over
						99.77	500,000 Gal/s = 7 1/2 i
MEX-14-5	MUSI Chem	Friction Reducer	Hydroreated Light Distillate	8742-47-8	30.00%	0.016	1.90 = 50,000 Gal/100 gal
			Other		70.00%	0.027	1.0170 = 500 Gal/s/100
							= 6 Gal/100
B-0050	MUSI Chem	Biocide	Guanidylsulfide	111-30-8	80.00%	0.031	
			Other			0.022	
B-8020	MUSI Chem	Biocide	4,4-Dimethylpiperazine	51200-57-4	95.00%	0.012	
			3,4,4-Triethylpiperazine	75673-43-7	4.50%	0.001	
			2-Amino-2-Methyl-1-Propanol	124-09-5	0.50%	0.000	
MX 588-2	MUSI Chem	Scale Inhibitor	Non Hazardous		100.00%	0.010	
HCL	Universal	Clean Ports	Hydrogen Chloride	7647-01-0	7.50%	0.021	
			Other		92.00%	0.368	
Uni-HB G	Universal	Corrosion Inhibitor	Short Chained Glycol Ether	112-34-5	80.00%	0.000	
			Ethoxylated Alcohol		20.00%	0.000	
			Heavy Metal Nonionic Inhibitor		20.00%	0.000	

Source: MarcellusGas.org

As you can see from Figure 19, the water is commonly mixed with a friction reducer to lessen the resistance of the fluid moving through the casing, biocides to prevent bacterial growth, scale inhibitors to prevent buildup of scale, and proppants, such as sand or ceramic beads to hold the fractures open.

Friction reducers, biocides, and scale inhibitors...pretty scary stuff, right?

Let's take a look at these chemicals.

Figure 20 Examples of Typical Shale Fracturing Mixture Makeup

Examples of Typical Shale Fracturing Mixture Makeup



Also found in:

- .12% Diluted Acid: Household Cleaner, Swimming Pool Cleaner
- .09% Friction Reducer: Water Treatment, Candy, Make-up Remover
- .09% Surfactant: Glass Cleaner, Antiperspirant, Hair Color
- .06% Potassium Chloride: Low Sodium Table Salt Substitute
- .06% Gelling Agent: Toothpaste, Baking Goods, Ice Cream, Sauces, Cosmetics
- .04% Scale Inhibitor: Household Cleaners, Deterging Agent
- .01% pH Adjusting Agent: Detergents, Washing Soda, Water Softener, Soap
- .01% Breaker: Hair Cosmetics, Household Plastics
- .007% Crosslinker: Soaps, Laundry Detergent
- .004% Iron Control: Food Additive, Lemon Juice, Flavoring in Food & Beverage
- .002% Corrosion Inhibitor: Pharmaceuticals, Plastics
- .0001% Antibacterial Agent: Disinfectant, Used to Sterilize Medical Equipment



Source: AXPC

Water and sand make up 99.51% of the mixture. What about the other 0.49%? Other ingredients include:

Hydrochloric acid

Anybody ever clean concrete or dirty tile? You probably used hydrochloric acid, also called muriatic acid. Is it toxic? Yes.

Glycol

Did you drive here today? Glycol is also known as antifreeze; it's a rust inhibitor. I brought four gallons of glycol with me today... And, yes, it's toxic.

Detergent

We wash our dishes and our clothes with detergents—toxic chemicals—and I hope we rinse them well.

Chlorine

Is chlorine toxic? Absolutely. That's why we use it in our water and in our swimming pools. We try to use it in a concentration that kills bugs, but doesn't kill us. Is it toxic? You bet.

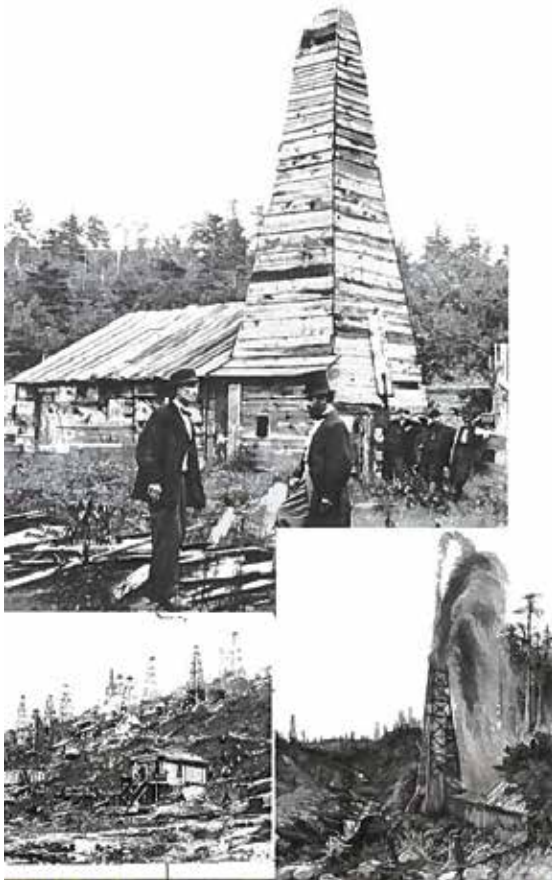
The point is, all of these are toxic chemicals; whether they're considered safe (or not) depends on the concentration. Note that none of them are as toxic as gasoline or brake fluid, which most of us use every day.

Shale Gas: A Landowner's Perspective

The first oil well in the U.S. was drilled by Colonel Edwin Drake in Titusville, Pennsylvania, back in 1859. From that point until the early 1930s, exploration and production generally proceeded without much formal regulation, either at the state or federal level. In 1890, Pennsylvania passed the first law requiring non-producing wells to be plugged.

Here's what southwestern Pennsylvania looked like some 150 years ago:

Figure 21 Natural Gas in Pennsylvania: Round 1

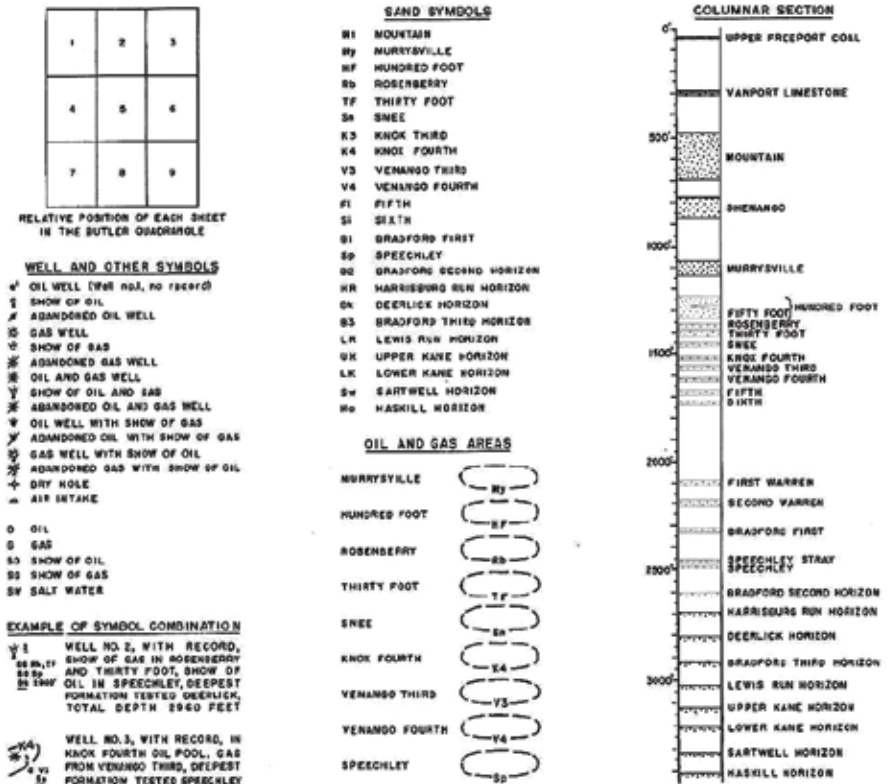


Source: sjvgeology.org

Look at the lower left, and notice the number of derricks in a small area.

A friend of mine has a book, published in 1955, showing where the oil and gas wells were located in a part of Butler County, Pennsylvania in 1955. Following is a page from that book:

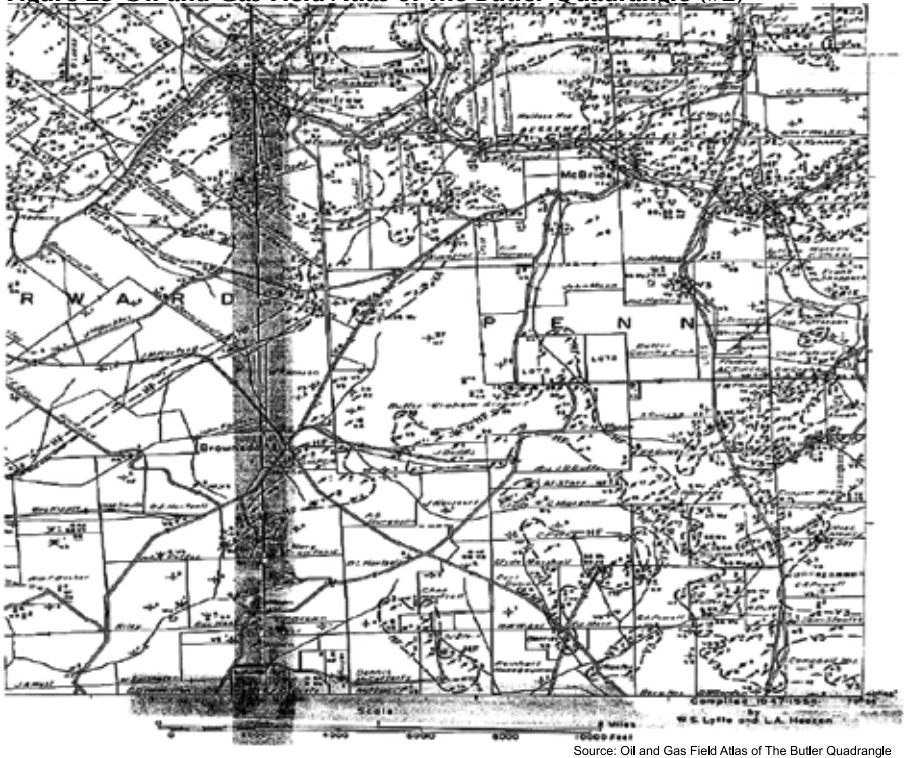
Figure 22 Oil and Gas Field Atlas of The Butler Quadrangle (#1)



Source: Oil and Gas Field Atlas of The Butler Quadrangle

The column on the right side ("Columnar Section") starts with zero and goes down to 3,500 feet. Each of the labeled depths was a level at which you could (and still can) expect to find oil or gas deposits.

Figure 23 Oil and Gas Field Atlas of The Butler Quadrangle (#2)



On Figure 23, the dots note the location of oil and gas wells in my neighborhood in 1955. At one time on my 95-acre farm in Penn Township, there were five oil wells. If we put a chisel into the dirt too deep, we still dredge up pipe. My point being, this isn't the first time we've had oil and gas drilling in western Pennsylvania.

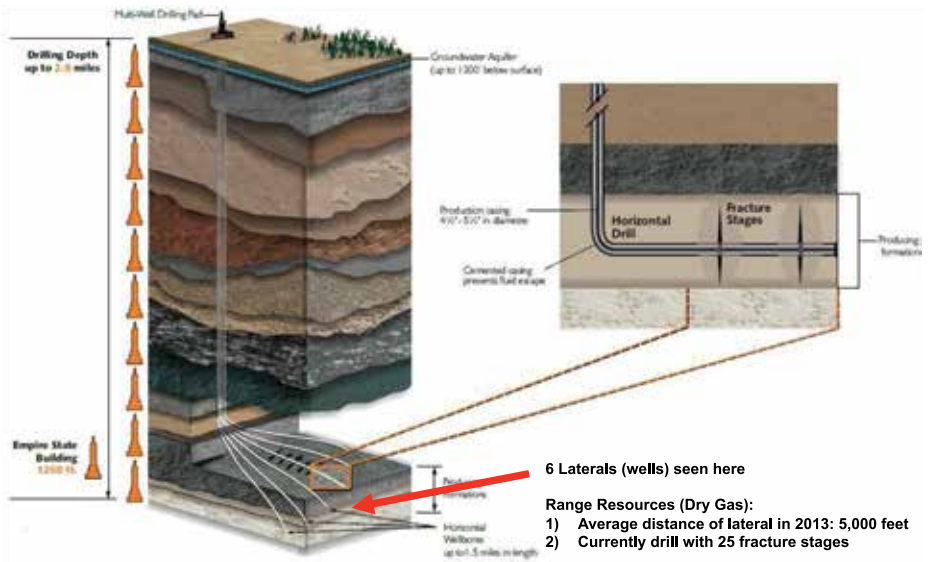
Here's a related anecdote...

In our house, there is a plaque naming Connie "Fire Person of the Year." (Connie and I were both volunteers at our local fire department.) Our neighbors had just come home from work, flipped an electric switch, and their house blew up. Connie got them out of the house safely before the fire got fully involved. Here's what happened...

At some point, the homeowners had built a room over their water well. That morning, the john got stuck, pumping water below the bottom of the well casing, permitting methane to vent up into the house. When they came home from work and turned the switch, the house exploded. I remember well that their picture window blew out... A neighbor saw it fly from the house, hit the ground about 14 feet away, and then, shatter. The fire marshal, looking for the source of the fire, put a probe down into the water well and the needle registered a very high level of methane—that was back in 1984, long before they were doing any fracking in this area. Bottom line: there is gas in the ground all through western Pennsylvania; if you have a water well in your house, make sure it's vented to the outside. The gas wants out!

What does "Round Two" of gas exploration look like in Pennsylvania?

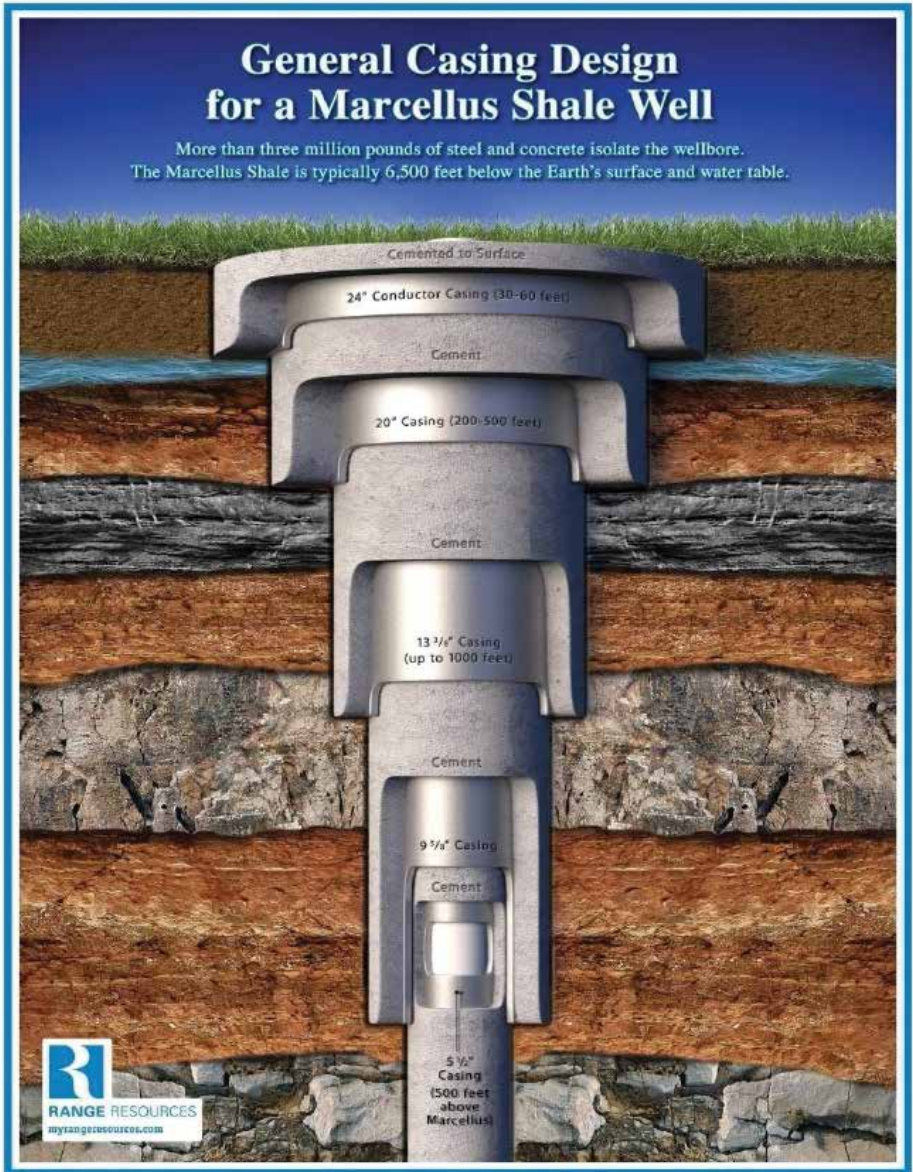
Figure 24 Drilling Depth and Laterals



Source: EnCana. BofA Merrill Lynch Global Research

Horizontal drilling allows wells to be drilled laterally instead of going straight down, so a larger area can be reached without boring as many holes into the surface. Unlike a vertical well, a horizontal well can stretch for up to two miles along a shale deposit. As you can see from Figure 24, horizontal drilling begins as a typical vertical well, but when the desired depth is reached, it makes a 90-degree turn so that the well can run along the length of the seam. The average distance of a lateral in 2013 was 5,000 feet.

Figure 25 General Casing Design for a Marcellus Shale Well

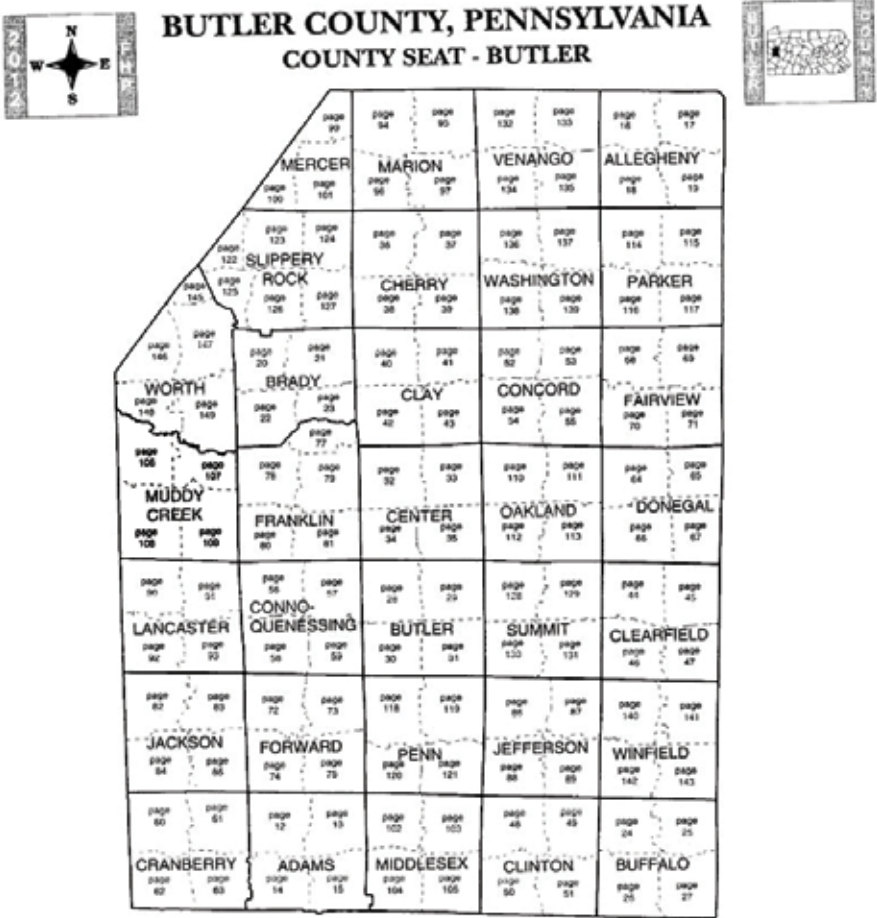


You'll recall seeing Figure 25 from our discussion about the water table.

Once again, when the target distance is reached, the drill and pipe are removed and casing is inserted into the full length of the wellbore. Concrete is pumped down the casing and out through the hole, forcing it up between the casing and the wall of the hole, filling the open space. Casing the well is a very important process because it permanently secures the wellbore, preventing hydrocarbons from seeping out as they are brought to the surface. At this point, the drilling rig is no longer needed, and a temporary well head is installed.

By the way, John Hanger is a former Secretary of the Pennsylvania Department of Environmental Protection, a position he held between September 2008 and January 2011; he is currently a candidate for Governor of Pennsylvania in 2014. Hanger is adamant that we've never had the water or the chemicals that we pump a mile down into the pipe propagate its way back up into the water table. Can it happen? Yes. Has it happened in Pennsylvania? According to Hanger, no.

Figure 26 Butler County, Pennsylvania

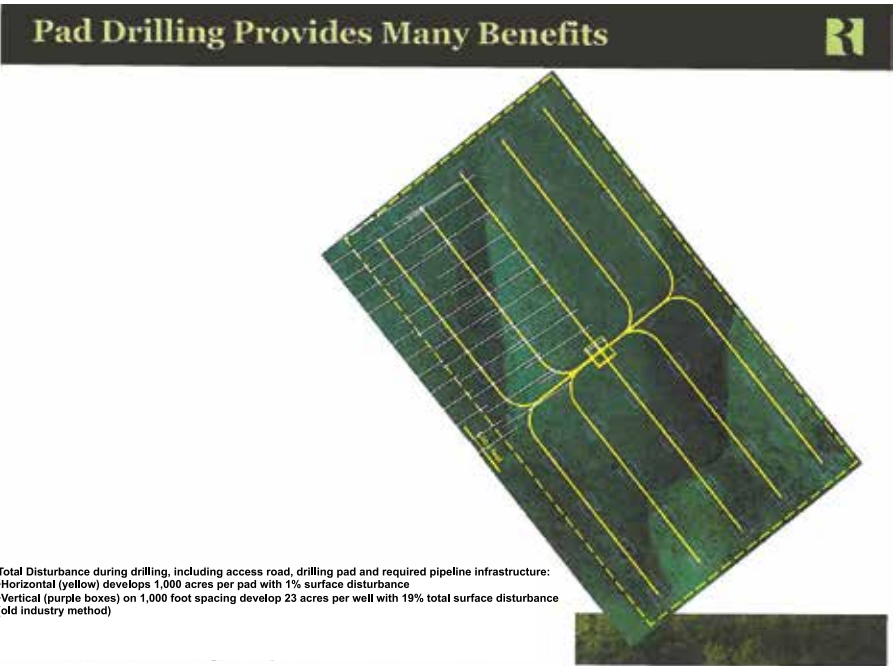


Source: Oil and Gas Field Atlas of The Butler Quadrangle

In Butler County, each township is 4.8 miles square; it's surveyed as regular as Illinois. The difference is that if you fly over western Ohio, Indiana, or Illinois, as you look down, you can see a square mile; (a square mile is 640 acres, where each township is 4.8 miles square). When flying over Butler County, it doesn't look as regular, as we farm on the contour to minimize erosion.

When drilling for natural gas in southwestern Pennsylvania, because of the way the Appalachian Mountains run, if you're going to run laterals and fracture horizontally, you want to go northwest or southeast. Drillers want the configuration to look like Figure 27:

Figure 27 Pad Drilling

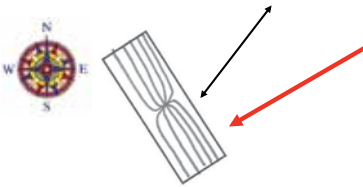


Source: Range Resources; Pennsylvania's Marcellus Gas Play Its History, Potential, and Challenges, 8/31/11

For drillers to be effective at fracturing, an ideal unit is 640 acres, but it's not a mile by a mile—it is two miles by one-half mile. This configuration allows drillers to put their pad in the middle, and place five wells going northwest at 500 feet apart—that's 2,500 feet, which is fairly close to 2,640 feet (a half-mile). If they place a 4,500 foot lateral going each way, they're going nearly a mile in each direction—their ideal pattern.

When units are placed in contiguous order, they look like this from the air:

Figure 28 Units (Aerial View)



10 Laterals (wells) seen here

Range Resources (Dry Gas):

- 1) Average distance of lateral in 2013: 5,000 feet
- 2) Currently drill with 25 frac stages

Source: Muhlenkamp & Company

Figure 29 Statutory Pooling

Statutory pooling

A section of approximately 27,000 acres of Washington County, showing the possible drilling pattern without and with statutory pooling.

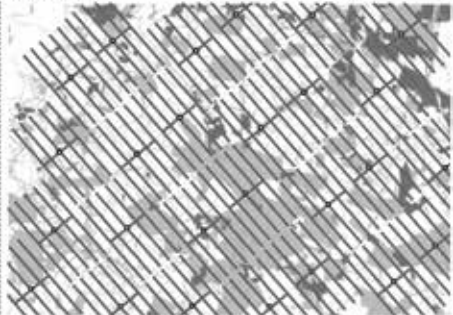
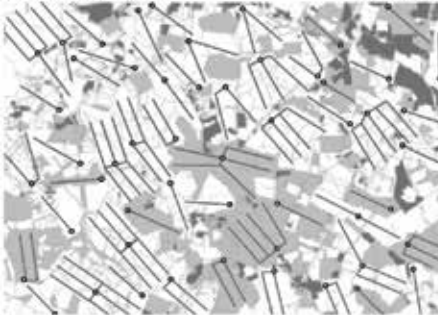
DEVELOPMENT WITHOUT STATUTORY POOLING

Number of drilling pads required	53
Number of wells	109
Acres developed	12,535 (46%)
Recoverable natural gas*	436 billions of cubic feet
Total revenue	\$2.18 billion
Landowner royalties (16%)	\$349 million

DEVELOPMENT WITH STATUTORY POOLING

Number of drilling pads required	24
Number of wells	240
Acres developed	27,600 (100%)
Recoverable natural gas*	960 billions of cubic feet
Total revenue	\$4.8 billion
Landowner royalties (16%)	\$768 million

KEY	□ Company A leasehold (71%)
	■ Company B leasehold (24%)
	■ Unleased (5%)
	● Drill site
	— Lateral wellbore



Source: Range Resources Corp.

*4 billions of cubic feet per well

James Hilston/Post-Gazette

In Figure 29, the assumption is that there are two drilling companies that have signed leases: one driller has signed 71% of the area; the other has signed 24% of the area; and 5% remains unleased; (i.e. 5% of the landowners have said they won't sign a lease). In some states, there is statutory or "forced" pooling, such that if 70% of your neighbors sign a lease, they can drill under your land as well; (they must pay royalties). Drillers do not need to have 100% of signed leases.

The left side of Figure 29 shows the drilling patterns when drilling companies do not cooperate and 5% of the leases remain unsigned, versus when drilling companies do cooperate and forced pooling is applied (right side). On the same geography, instead of requiring 53 pads yielding 109 wells, 24 are needed, yielding 240 wells. With forced pooling, recoverable reserves are more than double, and so are the landowners' royalties. Today, Pennsylvania does not have forced pooling, but this is the argument being made for it.

Figure 30 Drill Pad with Sound Fence



Source: National Geographic

Folks, while the drilling is taking place, it is a big deal. The crews run 12 hours on, 12 hours off; two weeks on, two weeks off; the drilling takes place 24/7 and it's noisy.

It takes 10 days to two weeks to drill a well, and another 10 days to two weeks for fracking. For a while, after they're done drilling, there will be some tanks collecting the water. The tanks are about 25-30 feet in diameter and 25-30 feet tall.

When the process is completed, the site looks like this:

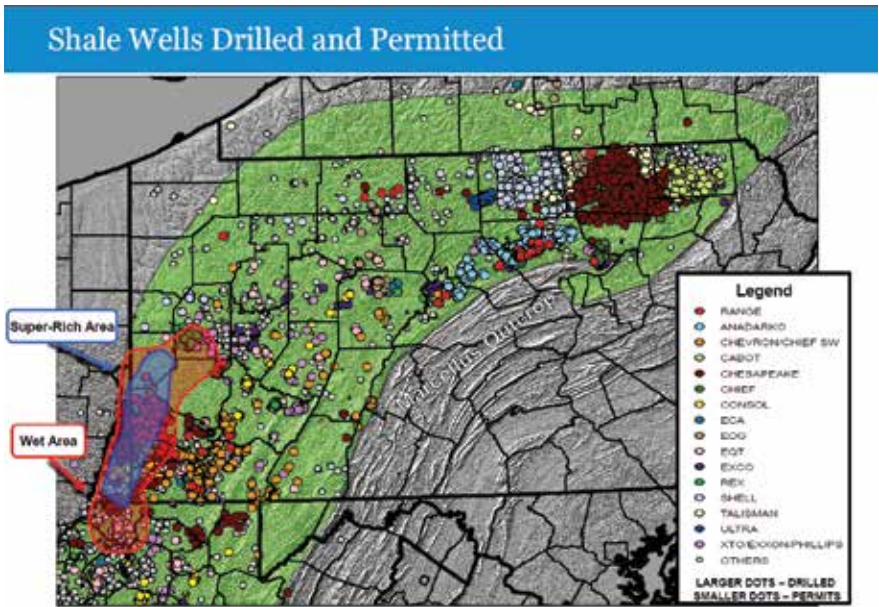
Figure 31 Finished Drill Pad



Source: Range Resources

What's the status of shale drilling in Pennsylvania?

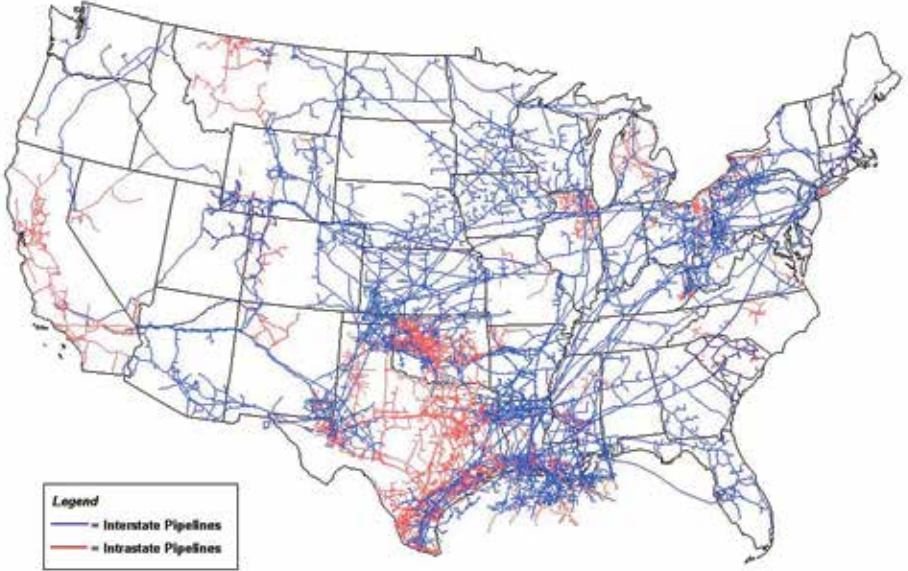
Figure 32 Shale Wells Drilled and Permitted



The circles on Figure 32 note the locations of drilled wells. As you can see, there are large concentrations in the northeast and southwest regions of Pennsylvania.

Figure 33 U.S. Natural Gas Pipeline Network

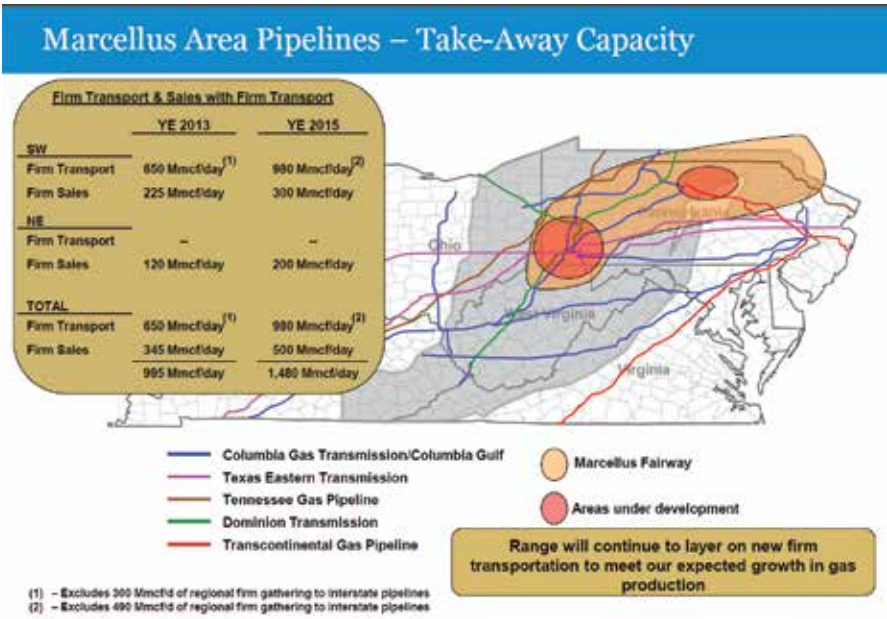
U.S. Natural Gas Pipeline Network



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

The blue lines on Figure 33 indicate interstate pipelines, with a concentration running from the Gulf of Mexico to the northeast. The red lines indicate intrastate pipelines. As mentioned earlier, natural gas is being flared in the Bakken Shale fields in North Dakota and Montana because there are insufficient interstate pipelines in that region.

Figure 34 Marcellus Area Pipelines—Take-Away Capacity



R RANGE RESOURCES October 29, 2013; Company Presentation

In contrast, in western Pennsylvania, because of the abundance of interstate pipelines, we are readily equipped for the building of nearby gathering lines and processing plants as you can see in Figure 34.

Figure 35 SW PA Wet Area Marcellus Type Curve

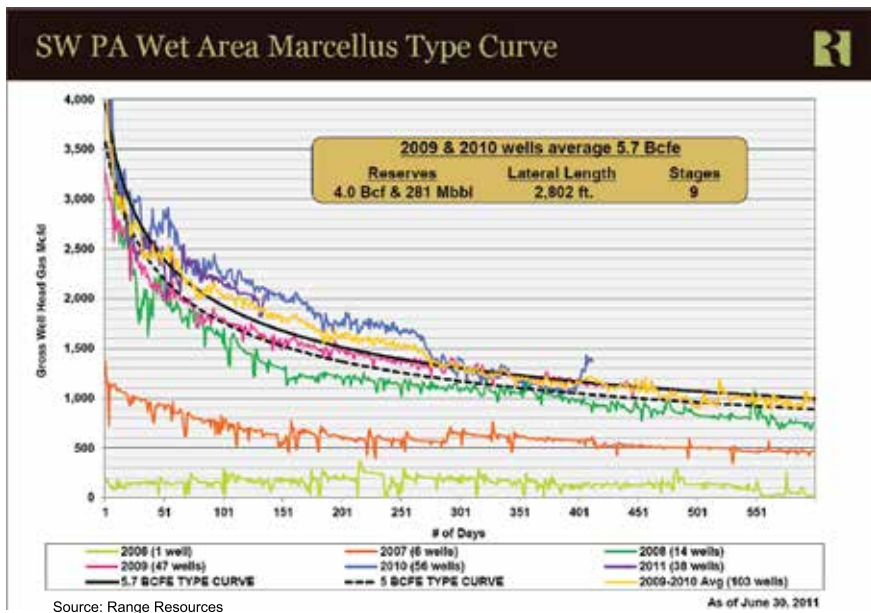


Figure 35 illustrates the yearly production curves, starting in 2006 and running through 2009-10.

As a landowner, if you're wondering why signing bonuses increased over the years, it's because the wells became more efficient and they were able to harvest more gas. Recently, however, signing bonus amounts have curtailed because the price of natural gas is decreasing given its abundance.

Figure 36 Southwest PA – Wet Marcellus Well Projection

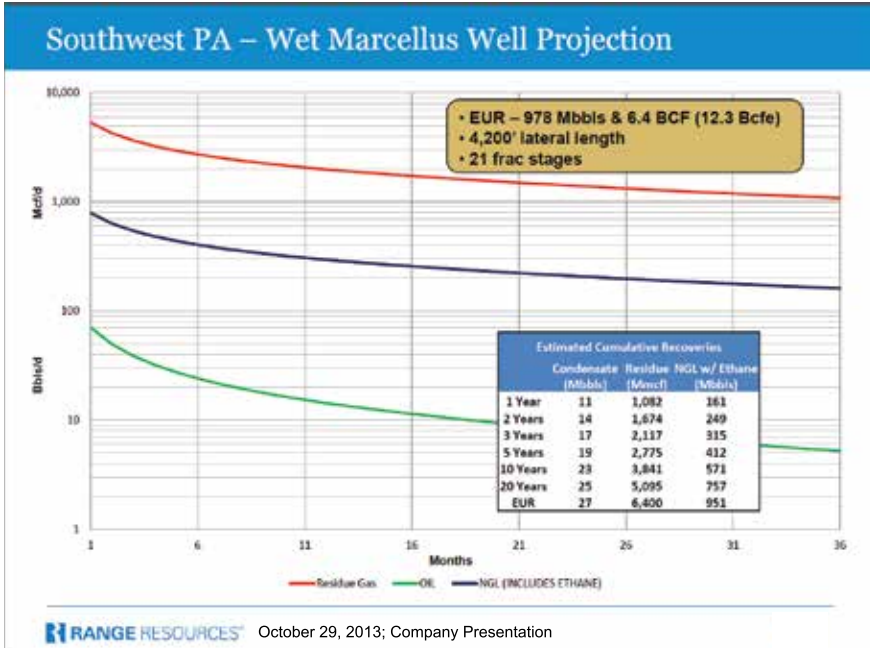


Figure 36 cites the estimated cumulative recoveries over 20 years, demonstrating that signing a lease signifies a long-term partnership. This is why, when looking at the whole pattern, I don't care too much about the up-front signing bonus; I'd rather focus on the long-term implications.

As a part of the plans for developing the shale gas resources (and consistent with the language in the leases), the drilling companies organize their leases into "units," which we discussed earlier. Typically, a unit is about a square mile (640 acres) in size. Many of the leases we have seen are good for five years. Once drilling commences, the lease is "held by the production" from anywhere in the unit. Royalties are paid to the landowners based on the portion of the unit their land represents. (Note: Royalties are usually paid on gross receipts, minus the cost of marketing and transportation. Landowners should pay attention to their statements when they arrive.)

Here's how it comes together:

- The drilling company signs a lease with the landowner, then buys and sells with other drilling companies to get nice, large, economical blocks of land that it will organize into units.
- In order to hold the lease, it will drill at least one well in the unit sometime in the first five years to hold all the leases in the unit.
- To get all the available gas out of a unit may require between six and 10 wells, but it may not drill those right away. Remember, the drilling company has a 50-100 year time horizon. It doesn't want to bring all that gas to market in 10 years—it wants to spread it out. So it will drill what it must in the first five years to hold the lease, and then drill for production over a much longer time period.

Our thinking is companies will start drilling for production near their existing processing facilities and pipelines, and expand from there over time.

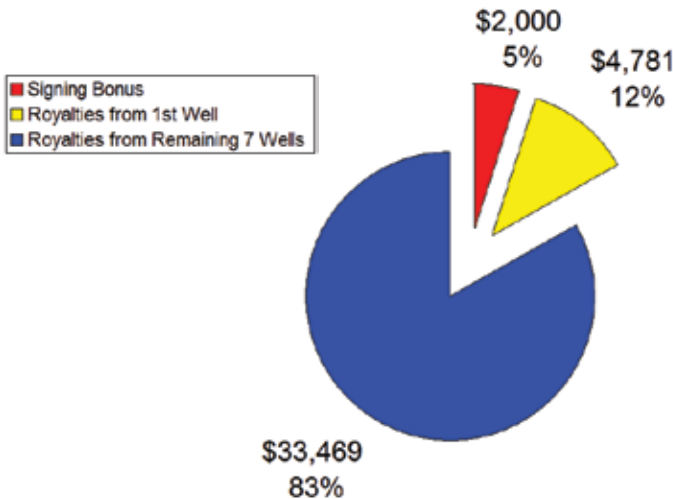
The bottom line for the landowner is to understand which unit (or units) their land is in, and to realize that, while a well in their unit is very likely to be drilled in the first five years to simply hold the lease, drilling for production may not happen for years. Dry holes may also be possible, though we haven't heard of one in the area yet.

The third thing we've done is to try to come up with an estimate of the total amount of money the landowner will see from this gas over the lifetime of the drilling effort. (This is not an estimate of earnings in any one year.)

We've assumed a price of \$4 per MMBtu for the reasons given earlier. Using a typical Marcellus Shale dry gas pad in Southwestern Pennsylvania, we came up with ~\$30,000-\$40,000 per acre to the landowners over the life of the wells in the unit. The natural gas income to the landowner arrives in three parts. We've depicted this graphically in Figure 37:

Figure 37 Per Acre Estimate of Pre-Tax Cumulative Dollars Received by the Landowner over the life of a typical Marcellus Shale Dry Gas Well in SW PA

Per Acre Estimate of Pre-Tax Cumulative Dollars Received by the Landowner Over the Life of a Typical Marcellus Shale Dry Gas Well in Southwestern Pennsylvania*

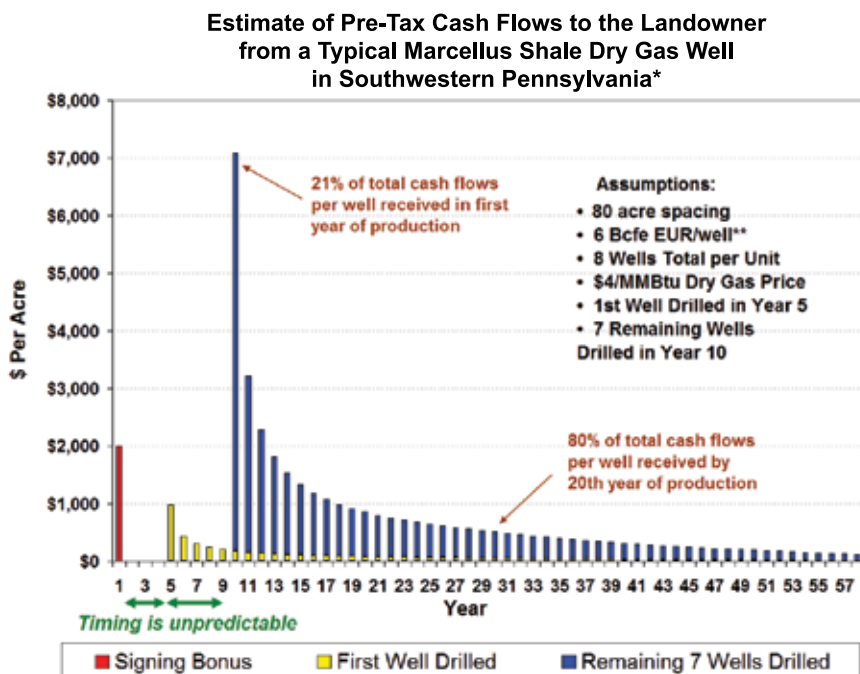


* Typical Marcellus Shale dry gas well pad as of 8/1/13: assumes 58 year well life, 80 acre spacing, 6 Bcfe EUR (Estimated Ultimate Recovery) per well, 8 wells total, \$4/MMBtu Dry Gas Price.

As you can see from Figure 37, the bonus money paid at lease signing is modest compared to the royalties that will be generated by gas production.

From Figure 38, you can see that the timing of royalty checks is unpredictable—they'll come, but not necessarily in the immediate future:

Figure 38 Estimate of Pre-Tax Cash Flows to the Landowner from a typical Marcellus Shale Dry Gas Well in SW PA



* Typical Marcellus Shale dry gas well pad in SW Pennsylvania as of 8/1/13

** EUR = Estimated Ultimate Recovery

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After a bit of research, we learned that the signing bonus and the royalties are all treated as normal income for tax purposes, and taxed in the year in which they are received. The drilling company, however, does not withhold any portion of the payments for taxes. That means the landowner must put aside about a third of any payment he receives to pay the taxes, (to avoid getting caught short at tax time), and ought to look into paying estimated taxes to avoid penalties. The cash flows are also large enough that the landowner might want to think past the new tractor or kitchen remodel, and start thinking about how to put that money to work over the long term.

Considerations for Figures 37 and 38—Estimating Royalties per Acre

Oil & Gas (O&G) companies estimate total gas yields over the life of their Marcellus wells to be about 6 billion cubic feet equivalent. Today's spot price for natural gas is approximately \$4/thousand cubic feet (Mcf). **We are assuming that natural gas prices remain at \$4/Mcf for the life of the well.** Therefore, total revenues per well are \$24 million; $6,000,000 \text{ Mcf} \times \$4/\text{Mcf} \text{ market price} = \24 million . (Note the conversion from billion to thousand cubic feet equivalent.)

O&G companies estimate that 15% of gross revenues will be paid in marketing and transportation fees; therefore, royalties less expenses equal \$20.4 million: $\$24 \text{ million} - (\$24 \text{ million} \times .15) = \20.4 million .

Most O&G companies are granting at least 15% royalties to the landowner; therefore, total royalties per well are equal to \$3.06 million; $15\% \times \$20.4 \text{ million} = \3.06 million .

O&G companies assume a well spacing of 80 acres and, it looks to us, the units they are putting together are about 640 acres in size. To hold the leases on a unit of 640 acres, they need to drill one well in the unit. To calculate royalties on the "lease holding well," we've divided \$3.06 million by the 640 acres in the unit, resulting in \$4,781/acre.

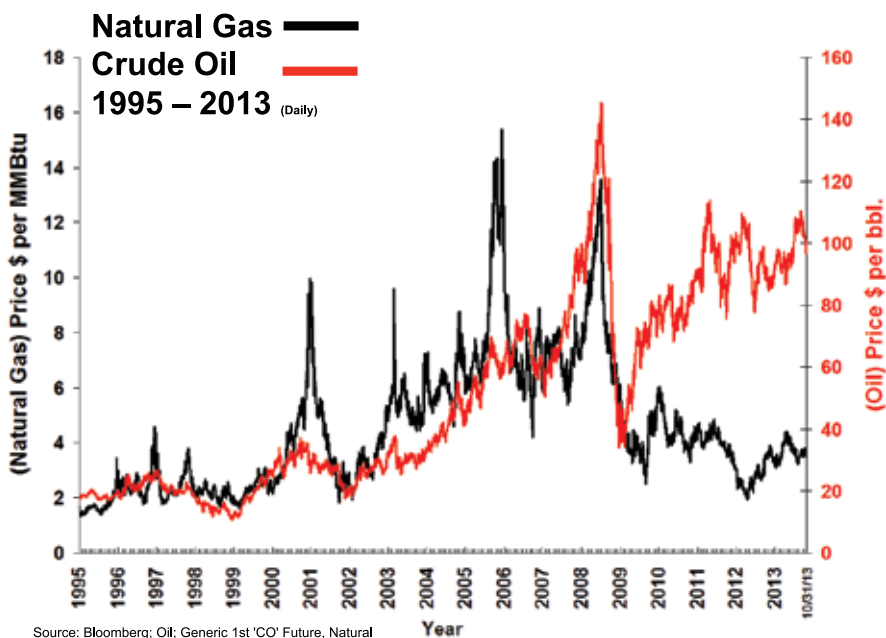
To fully develop the unit, the O&G company would need to drill seven more wells: $\$3.06 \text{ million} \times 7 \text{ wells}$, divided by 640 acres, results in \$33,469/acre for the "production wells." The royalty curves on Figure 38 illustrate an approximate distribution of pre-tax cash flows over time. Approximately 21% of the total gas output of a well is realized during the first year and 80% by year 20. A well's life may exceed 50 years.

Reality versus Reality—The Driver for Investment

Shale Gas: An Investor's Perspective

So what does this opportunity look like to the investor? As stated in my opening comments, “reality versus reality” is the driver:

Figure 39 Natural Gas and Crude Oil Prices, 1995-2013



Source: Bloomberg; Oil; Generic 1st 'CO' Future, Natural Gas; Generic 1st 'NG' Future delivery to Henry Hub

Once again, this is the biggest spread I've ever seen between two versions of energy—and I believe it's unsustainable. We think there is enough available natural gas that the price stays below \$5 MMBtu.

Figure 40 The United States at Night



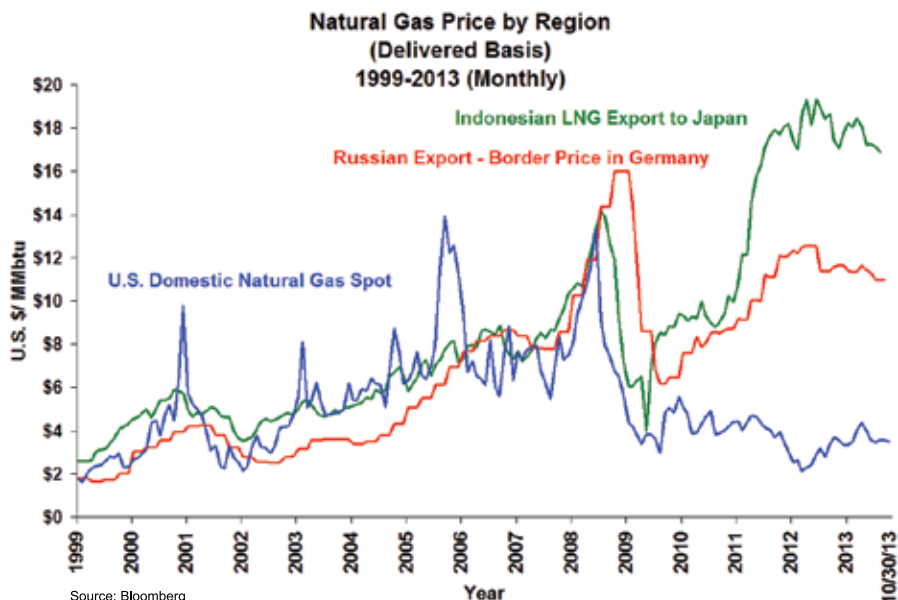
Source: Examiner.com; 12/6/12

Can you pick out Chicago? Look for Lake Michigan, and you'll find Chicago...

Let's go northwest from Chicago. Can you see the Twin Cities?

If we go northwest from the Twin Cities, we're at Williston, North Dakota, where they are flaring the natural gas from the oil wells because they don't have the pipelines for shipping. That light wasn't there five years ago! And, if we have any sense at all, that light won't be there five years from now, but it's contingent upon the successful implementation of a gas pipeline alongside the proposed Keystone Pipeline XL for oil. The XL pipeline will have capacity to transport 830,000 barrels of oil per day to Midwest and Gulf Coast refineries, reducing American dependence on oil from Venezuela and the Middle East by up to 40 percent. It has a projected in-service date of 2015.

Figure 41 Natural Gas Price by Region (Delivered Basis), 1999-2013



On Figure 41, the blue line tracks the U.S. domestic natural gas spot price. The red line represents the Russian export/border price in Germany. The green line represents Indonesian LNG (liquefied natural gas) exports to Japan. Can you spot when the tsunami hit Fukushima?

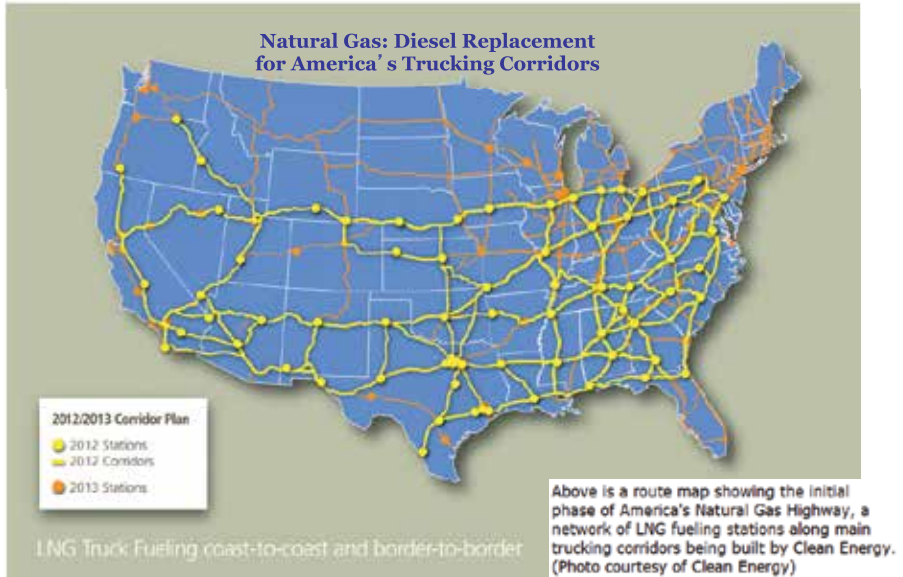
What can we learn from Figure 41?

In the U.S., natural gas sells for \$4 per Mcf; in Europe, the price of natural gas is \$12 per Mcf. In Japan, however, natural gas sells at \$18 per Mcf—and the reason it's \$6 more expensive than in Europe is because it costs an extra \$6 to compress, freeze, and decompress LNG. What's not on this chart, is that in Williston, North Dakota natural gas is free (it's being flared). So, depending on where you are located, you can get natural gas for zero; \$4 per Mcf; \$12 per Mcf; or \$18 per Mcf.

Some people say we shouldn't export natural gas. Well, why do we export corn and wheat? I think it's pretty much the same thing. Realize that the United States is already a net exporter of petroleum products such as gasoline, diesel, and jet fuel. The transition from net importer to net exporter took place two years ago, resulting from increased supplies of U.S. crude oil and inexpensive domestic sources of natural gas.

Figure 42 America's Natural Gas Highway; The Clean Energy Solution

America's Natural Gas Highway® The Clean Energy Solution



Source: Clean Energy Fuels; <http://www.cleanenergyfuels.com/buildingamerica.html>

There are already more than 1,100 natural gas fueling stations in the U.S.—about half of them are open to the public.

Clean Energy, headquartered in Newport Beach, CA, is the largest provider of natural gas fuel for transportation in North America, fueling over 30,000 vehicles each day at approximately 400+ fueling stations throughout the United States and Canada. (California has the nation's most extensive natural gas fueling infrastructure.) Figure 42 comes directly from Clean Energy's annual report.

As you can see from Figure 42, Clean Energy intends to build "America's Natural Gas Highway," with LNG (liquefied natural gas) and CNG (compressed natural gas) fueling stations at strategic locations along the interstate highways. Many of the fueling stations will be located at Pilot-Flying J Travel Centers already serving truckers across the country.

Does this sound familiar?

In the 1950s, over-the-road trucks (and farm tractors) ran on gasoline because diesel engines were harder to start. Diesel fuel, however, was cheap because it requires less refining. As a result, the demand for diesel engines increased—and once we got smart about making diesel engines easy to start—over-the-road trucks went from predominantly gasoline to predominantly diesel in less than a decade! (Today, the price of diesel fuel is higher than the price of gasoline—it's simply a matter of supply and demand.)

What's Next?

Natural Gas Liquids (NGLs)

- Emphasis is being placed on products downstream of ethylene.
- Liquefied Petroleum Gas (LPG) exports will continue to increase, with the U.S. playing a key role.

Crude Oil

- North American production continues to grow—mostly from “unconventional” resources; (i.e. horizontal drilling and fracking).
- U.S. refined product exports continue to grow, enabled by increasing crude oil supplies.

Natural Gas

- Markets will grow substantially, including power generation and Liquefied Natural Gas (LNG) exports.
- The fueling stations are being built and the engines are now available to convert the U.S. truck fleet from diesel to natural gas.

How do you play it as an investor?

Figure 43 Natural Gas

Natural Gas

Exploration & Production

Cabot Oil & Gas
Chesapeake Energy
Range Resources
Rex Energy
Southwestern Energy

Oil & Gas Services

Halliburton Company
Schlumberger LTD
Baker Hughes

Distribution

Clean Energy

Engine Conversion

Westport Innovations
Fuel Systems
American Power Group

LNG Plant Construction

Chicago Bridge
Fluor Corp.
KBR Inc.

Feedstock

U.S. chemical companies

Figure 43 lists examples of companies that are involved in the natural gas industry.

As I just discussed, we think the next area of opportunity is in transportation, particularly over-the-road trucking. We've invested in companies that drill for the natural gas and those that service them, but we're also invested in companies that modify truck engines to burn natural gas, and companies that are building and supplying the fueling stations.

A note on measuring natural gas quantities

There are two common ways of measuring quantities of natural gas bought and sold:

- *Volume is measured in cubic feet with the most common denominations being hundreds of cubic feet (Ccf) and thousands of cubic feet (Mcf).*
- *Energy content is measured in British Thermal Units (BTU) with the most common denominations being 100,000 BTUs (a Thermal Unit or Therm) and a million BTUs (abbreviated MMBtu).*

The energy content of a cubic foot of natural gas varies from about 900 BTUs to 1,050 BTUs, but a decent approximation is that one cubic foot of gas provides 1,000 BTUs of energy. So a Therm is roughly equal to a Ccf; an Mcf is roughly equal to an MMBtu. Wholesale pricing is usually in dollars per MMBtu. Retail pricing on your gas bill varies. We've seen dollars per Mcf; dollars per Ccf; dollars per Therm; and dollars per MMBtu.

Current and future portfolio holdings are subject to risk.

Company holdings and sector allocations are subject to change and should not be considered a recommendation to buy or sell any security.

The opinions expressed are those of Muhlenkamp & Co. and are not intended to be a forecast of future events, a guarantee of future results, nor investment advice.

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