KIMMERIDGE
Energy

When Will the Hamster Fall From the Wheel? Production Declines and Rig Efficiency in an Unconventional World.

May 2014

Henry & Darcy: The Physical Laws of Oil Industry

Twist the cap off a bottle of Coke and watch the bubbles rush out of the liquid. We've all done it and kids occasionally wonder what was keeping the bubbles in the liquid before the cap was removed. The answer was given in 1803 by the British chemist William Henry. Before it's opened, the pressure in the bottle is higher than the surrounding environment and as a result, the gas is trapped in the liquid. Once opened, the gas rushes out due to the difference in pressure between the air and the gas in solution. Moreover, once the gas begins to escape, the rate of gas expulsion undergoes an exponential decline.

This 200-year-old idea may seem academic but the principle it represents is crucial to determine the limits of the growth rate in US oil and gas resource recovery. The one further factor you need to consider in addition to Henry's Law is a similar equation called Darcy's Law, which explains the movements of fluids or gases from the medium they are trapped in. At its core, Darcy's Law says that a fluid will flow more quickly through a medium if it is more permeable and if the pressure gradient is higher.

The twin laws of Henry and Darcy explain why unconventional wells decline faster than conventional ones. In conventional wells, which are not fracked, the pressure difference between the producing reservoir and surface equalizes exponentially, but uniformly, as would be expected from a constant permeability system, with the rate of decline defined by the pressure gradient and reservoir permeability. In contrast, in a fracked reservoir there are two types of permeability, fracture permeability and matrix permeability, which have materially different properties. This results in very rapid initial production facilitated by fracture permeability, often lasting up to six months, which then declines rapidly as those fractures are depleted. As the well ages, flow rates then plateau at a lower decline reflecting the underlying low matrix permeability of the reservoir. Put more simply, fracked wells initially have more permeability than conventional wells because they are fracked, but the underlying reservoir permeability is significantly lower, meaning that the steady-state production level after the fracks are emptied is much lower.

Unfortunately for the oil and gas industry, this change is altering and undermining the success story that is the revival in US onshore production. In this research note we will demonstrate that:

1. Unconventional wells decline more quickly than conventional wells.
2. The growth in unconventional wells is driving a mix shift in the production base, raising the overall decline rate of the US production base for both oil and natural gas.
3. The acceleration in decline rates has been masked by improvements in drilling but this will ultimately moderate.

Combined, these factors lead us to the conclusion that US production growth is not only capital intensive, operationally intensive and high decline, but that the improvement in drilling required to support the production base is becoming hard to sustain. Current rig levels suggest that based on decline rates and rig productivity, growth in oil production in the lower 48 states will continue, but at a decelerated pace around 15%, which is down from 25% in 2012, and that natural gas production may decline in the coming year which would make re-filling natural gas inventories very difficult. Switching rigs between oil and gas could change these numbers slightly, but since the number of rigs that produce oil and gas is finite in the short-term, a scenario of growing gas as well as oil production with a flat rig count is unlikely.

[1] The formal statement of Henry's Law is that "at a constant temperature, the amount of a given gas that dissolves in a given type and volume of liquid is directly proportional to the partial pressure of that gas in equilibrium with that liquid." See http://en.wikipedia.org/wiki/Henry's_law.

Framing the Decline Debate: Why It Matters

At the most basic level, the aim of the oil and gas industry every year is to replace its production (Fig. 1). To replace this decline through production the industry needs to drill new wells. All else being constant, the number of new wells required depends on the rate of decline. The higher the decline, the more production is lost each year and the more new wells are required. However, if the average production and recovery of hydrocarbons per well increases, fewer wells are required to produce an equivalent volume.

In theory this can be gauged by watching the rig count. However, if the numbers of wells per rig changes, this further complicates the calculation. For example, if more wells are drilled per rig due to rig efficiency and each well contributes more, then there could be a high decline rate, a falling rig count, but flat production.

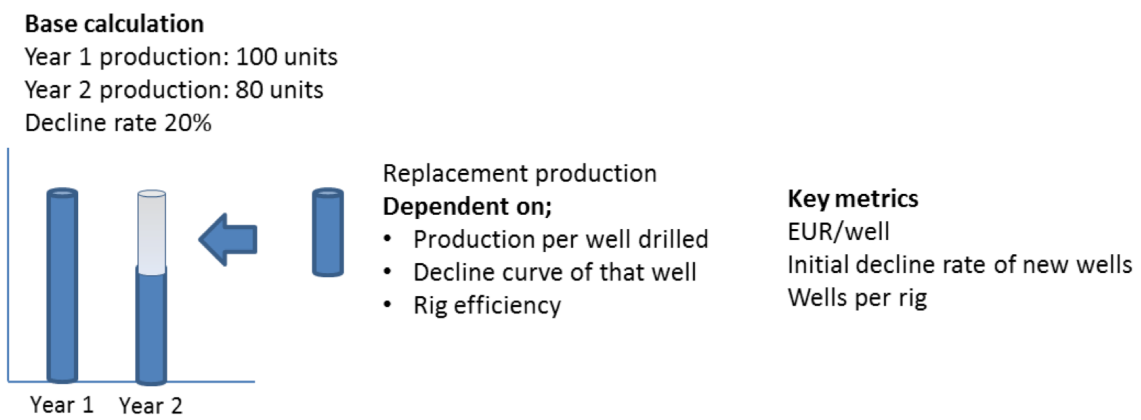

Figure 1: Schematic of Production and Decclines

New Wells: How Fast Are They Declining?

For decades, new US onshore oil and gas wells were relatively predictable. On a cumulative basis each well produced around 40% less in the second year compared to the first year and there was little difference between gas and oil. Even with the moderate increase in average well depth (and therefore implied pressure), initial decline rates have been broadly flat. However, since 2010 this has changed dramatically. Not only has the average first year decline rate increased to 45-50%, but oil wells, which in the past had slightly flatter decline rates than gas wells, have now eclipsed gas wells in terms of first year declines (Fig. 2).

Fundamentally this shift appears to be a direct result of fracking. Fracking a rock creates permeability and accelerates the flow rate of the fluid or gas through that rock. This fracture permeability is temporary but effective. As such, as fracking accelerates, so do flow rates and decline rates, and as fracking has grown (or the number of wells fracked), so too has the decline rate.

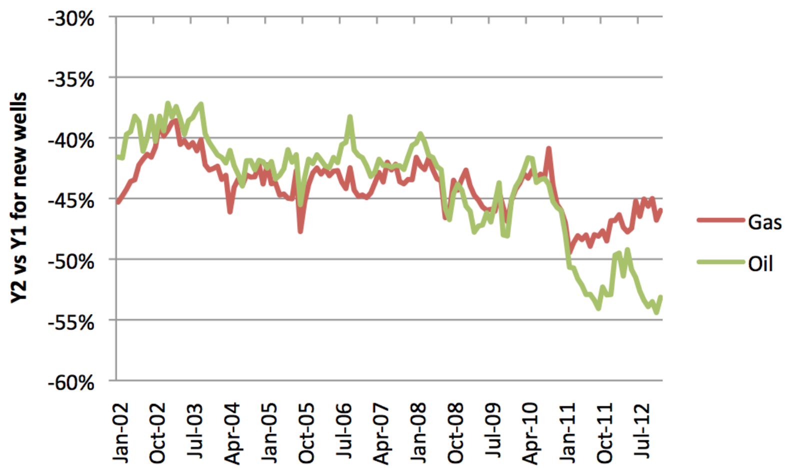

Figure 2: Average decline in production year 2 versus year 1, US Onshore Lower 48, 2002-2012

How Much Needs to be Replaced: Understanding Rates of Decline

To understand the implication of the decline rate of new wells, we must also consider a larger phenomenon. A portion of current production comes from new wells but a large amount comes from old wells too. The mix of all of these wells will yield a total decline rate for the US, which we can split into oil and natural gas. This measure, which we call the aggregate decline rate, is crucial because it represents how much new production must be added in a given year just to keep production at the same levels as the year before.

Over the past five years, the US onshore industry has seen a dramatic shift in its aggregate decline rate. From 2001 to 2008 the production base had an annual aggregate decline rate of around 15% per year for liquids and 20% for gas (Fig. 3). However, around 2006-2008 this began to accelerate and it has now reached 25% for both. These changes may sound small but they are significant. In gas, for instance, with a 20% decline rate and a production base of 58 billion cubic feet per day (Bcfd) in 2008, the upstream industry had to deliver 12 Bcfd of new production each year to hold volumes flat. However, as of 2013 with a higher base of 70.2 Bcf and a 26% decline rate, the industry has to add 18 Bcfd each year to stay flat. In oil, the numbers are even more challenging. In 2008 with a 15% decline rate and a base of 5 million barrels per day (mmbpd) the industry needed 0.75 mmbpd of additional supply each year. Today at 25% and 7.4 mmbpd this equates to 1.85 mmbpd of new volumes, which is the equivalent of Angola's entire offshore industry.

So what has led to such a dramatic shift in the base rate? There can only be two drivers, both of which are at play here. First, as production increases the mix of new wells versus old wells shifts, with new wells having higher decline rates than old ones. Second, the particular new wells that are being added decline at much higher rates than the new wells that were drilled in the past. Taken together, sustaining or growing production in the US is facing a double challenge.

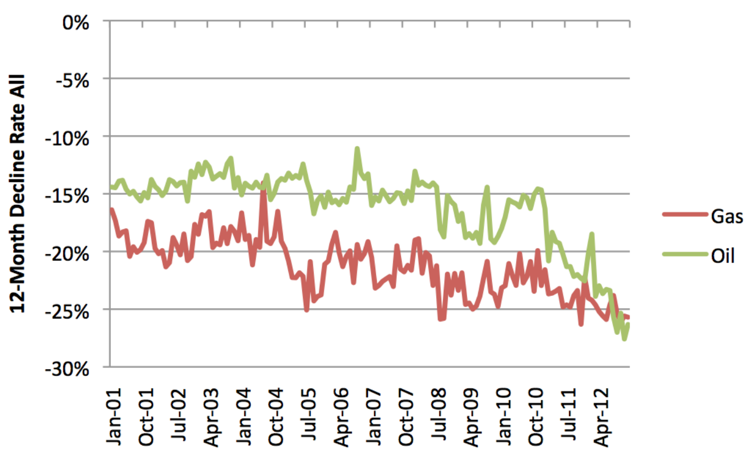

Figure 3: Average First Year Decline Rate for New Wells, US Onshore Lower 48, 2001-2012

How Much Can Be Added: Starting Small and Building Up

Given that we can quantify the amount of declines that the US onshore base is facing, the next question is whether those declines can be offset. There are generally two constraining factors limiting industry's ability to add more production in a given year. One is capital availability and the other is rig availability. In this piece we will consider the usefulness of the rig count as a leading indicator of production, in part because the rig count is one of the default methodologies used by industry analysts. The goal of our analysis is to define the parameters of how many active drilling rigs would be required to sustain or grow onshore US production of oil and gas.

Our analysis in this piece does not account for the economics of production or for specific geology. Trends of costs (economics) and rock quality (geology) are obviously important for forecasting growth, but our analysis of declines can focus on the results without separating out each factor.

Instead of jumping directly to conclusions about the US as a whole, we will begin by showing the effects in each of the major areas that has contributed to recent US onshore production growth. Once we have demonstrated the methodology on the scale of the individual play, we will aggregate it up into the macro discussion.

Disaggregating the Decline Effect: The New Plays

The recent US onshore resurgence in production of both oil and natural gas has been driven by horizontal drilling and fracking in unconventional plays. We have broken out eight new plays and looked at production from horizontal wells there: the Barnett Shale, Fayetteville Shale, Haynesville Shale, Granite Wash, Permian Basin, Bakken Shale, Eagle Ford Shale, and Marcellus Shale.

Looking first at the oil plays it is clear we have seen dramatic growth. Oil production in the onshore lower 48 has nearly doubled in just five years, driven mainly by horizontal drilling in the Eagle Ford, Bakken, and Permian. At the same time, production excluding these key horizontal plays has remained flat (Fig. 4, page 7).

In natural gas production a similar story is emerging, but with a different group of shale plays. Historically the natural gas basins have declined more rapidly than the oil ones (although this trend has reversed in the last three years with the rise in tight oil production). As a result, shales such as the Marcellus, Barnett, and Eagle Ford have quickly made up an ever-increasing share of production and now account for 25% of all volumes (Fig. 5, page 8).

The change in the share of production was driven by the newly allocated rig count, shifting from gas to oil. Before the collapse in natural gas prices and drilling in early 2009, there were over 1,300 rigs working in plays other than the eight new plays. Since then that number has never again reached 1,100. Instead, now half of the country's onshore rigs are horizontals active in these eight shale plays (Fig. 6, page 8).

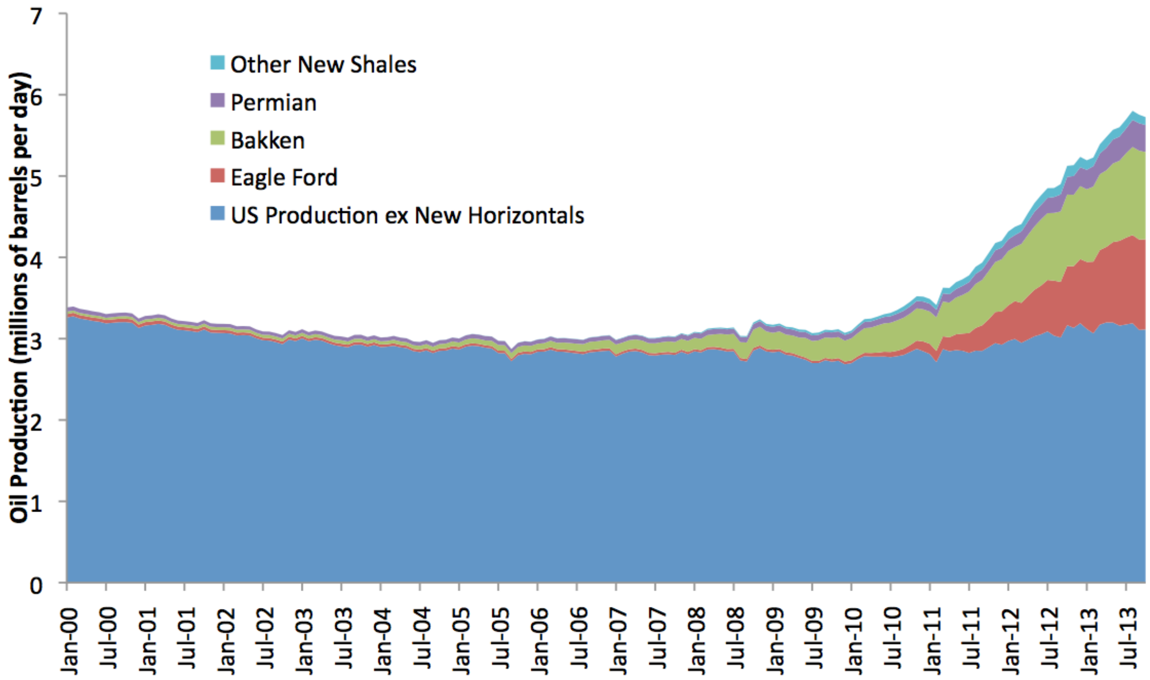

Figure 4: Daily Oil Production US Onshore Lower 48 by Source, 2000-2013

[2] We included the Marcellus Shale in the combined numbers for the eight basins but we were unable to analyze its decline properties separately since volumes are reported in Pennsylvania on a six-month schedule rather than monthly. See Methodology section at the end of the note.

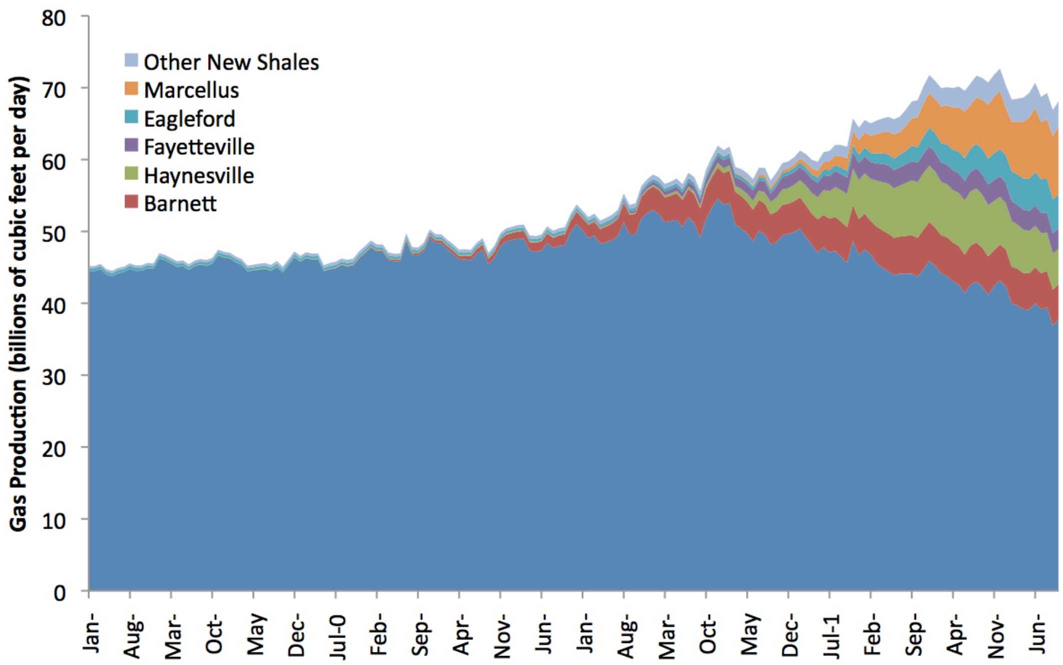

Figure 5: Daily Gas Production US Onshore Lower 48 by Source, 2000-2013

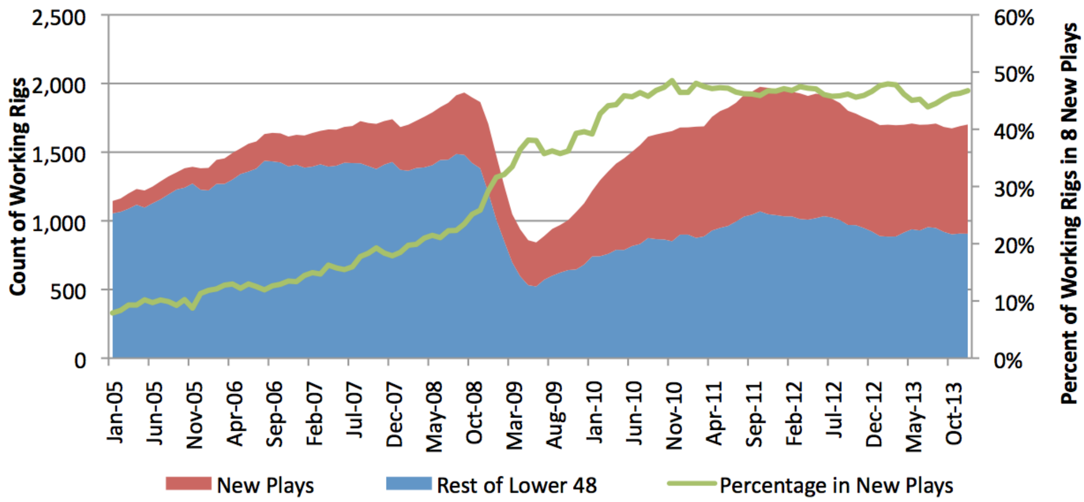

Figure 6: Onshore US Lower 48 Rig Count split into Horizontal Rigs working in new Shales vs all other rigs, 2005-2013

Diving into the Plays: Rigs, Production, Efficiency

To discuss the implications of the decline rates it is logical to start at the play level. The premise is simple: rigs drill wells; wells produce oil and gas. If you know how many rigs are in an area, how many wells those rigs can drill, and how much oil and gas each well will produce, then you have the information you need to predict how much new supply will be added in a given period. If you know the decline rate, you can estimate production.

Barnett – Increased Efficiency Sustained Production for Longer than Expected

We begin in the Barnett Shale in Texas. As for all the shale plays, we have calculated three major trends from the Barnett Shale data going back to the beginning of the play. These are:

1. The decline rate for the play as a whole
2. Average wells drilled per rig per month (trailing 12 months)
3. Average new volume per new well drilled (trailing 12 months)

Using these trends we can calculate for any given month what is the required rig count to keep production flat. By comparing that calculated measure with the actual rig count, we can determine whether production should be rising or falling.

As evident in Figure 7, when the actual rig count has dipped below the required rig count, production falls. This first occurred in the Barnett in 2008-2009 when natural gas prices fell but production only dipped slightly. The reason for the subsequent recovery is that as the rig count fell, the average volume per well rose steadily (most likely due to longer laterals and more frac stages per well) and the number of wells that each rig drilled rose as well. Consequently, the number of rigs required to keep production flat dropped. This kept volumes increasing until 2012-2013, when the rig count fell too low to keep up. While the eventual outcome was expected, it was still surprising that the Barnett Shale could lose 100 drilling rigs and not see volumes decline for four years and proved many analyst forecasts (including ours) to be overly pessimistic (Fig. 7 and Fig. 8).

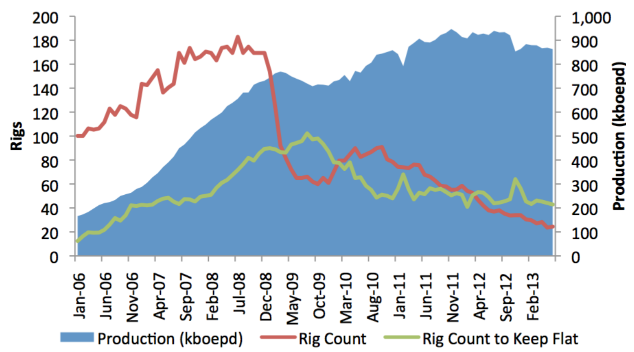

Figure 7: Barnett Production and Rig Counts – Only since 2012 has the rig count fallen below the level required to sustain production.

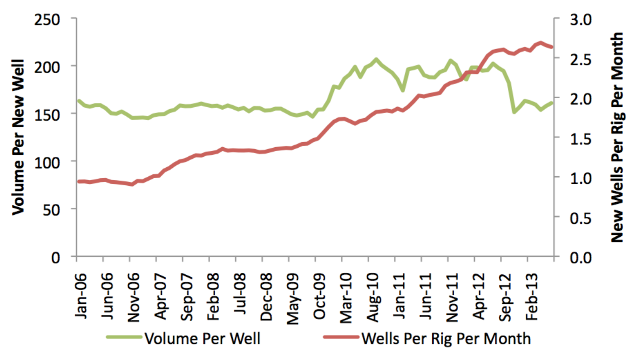

Figure 8: The reason was that over 2007-2012 the number of wells drilled per rig rose consistently.

Fayetteville - Efficiency Gains Continue to Drive Volumes

In contrast, we looked at the same measures in the Fayetteville Shale, which is relatively younger than the Barnett. There, production has yet to fall despite large decreases in the number of working rigs. In part this is because volumes per well have improved slightly, but most of the change is due to improvements in drilling efficiency, with rigs yielding many more wells per month than they did in the past.

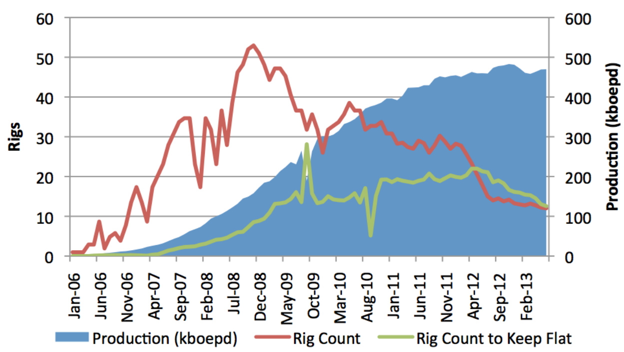

Figure 9: Fayetteville production has flattened but not yet declined...

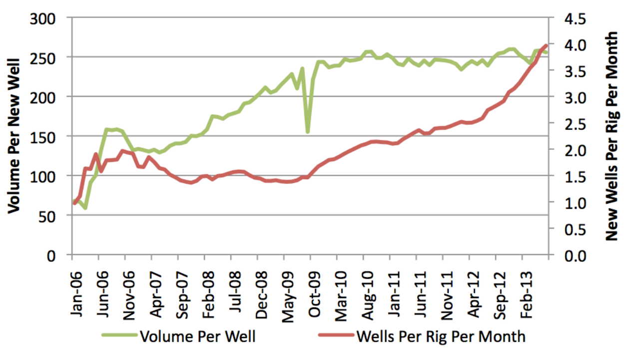

Figure 10: ...due to sharp annual increases in number of wells drilled per rig.

Permian - High Rig Count Still Driving Rapid Growth

Looking next at the Permian we see similar trends, albeit in a basin that is in a different stage in its lifecycle than the Barnett or Fayetteville, reflecting the premium pricing of oil versus gas that has been true for the past few years. In the Permian, production from horizontal wells has risen rapidly since 2010 and shows no sign of turning over. Indeed, our latest numbers show that while 100 horizontal rigs would be needed to keep production flat, there are now over 200 rigs working which should lead to continued growth.

However, the correlation between rig count and production should be tighter in the Permian because the past few years have not seen much change in the number of wells drilled per rig or in the average volume per well – this is largely due to the play being early in its life-cycle, with operators still experimenting with longer laterals, different completion methodologies and different landing zones. Again, our data shows that these measures of productivity are also crucial for predicting future volumes. Despite this discovery phase, like other plays there has been some increase in the average number of wells drilled per rig.

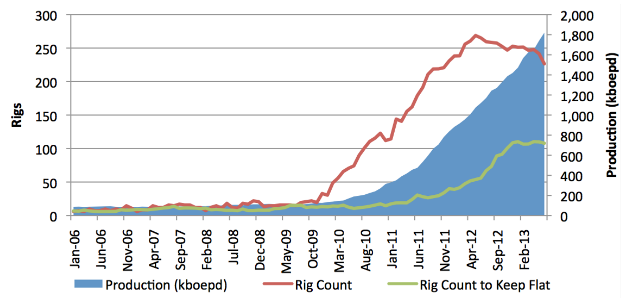

Figure 11: Permian Volumes (from Horizontal Wells) Rising along with Rising Rig Count

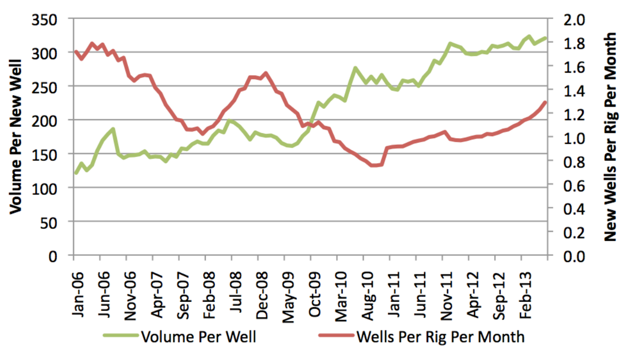

Figure 12: Rig Efficiency Measures in Permian Have Remained Flatter Since 2010

All Shale Plays: Which Are Rising and Falling?

For each of the seven shale plays, we have calculated all three of these key metrics: decline rates, wells per rig, and volumes per well. To see what has occurred over the past few years, we have looked at the decline rates per play and at the change in the measure of efficiency of rigs per well and wells per rig. The results are shown in the table below. In all plays, the number of wells drilled per rig increased between 2011 and 2013, but by different amounts. The story of volumes per well is different, though. Only the Eagle Ford and Permian saw meaningful increases. Taken together with the decline rate and the change in rigs, we see that production is falling in the Haynesville and the Barnett, and staying relatively flat in the Fayetteville. In contrast, the other plays which are oilier continue to see production growth, including annual growth rates over 40% in both the Eagle Ford and the Permian.

	1H13 versus 2011 (CAGR)				2012 Average Decline Rate
	Production	**Rig Count**	**Avg Well/Rig /Month**	**Volumes/New Well**	
Barnett	-1%	-36%	14%	-9%	-31%
Bakken	38%	1%	21%	-2%	-37%
Eagle Ford	74%	16%	11%	8%	-46%
Fayetteville	4%	-33%	25%	2%	-37%
Granite Wash	13%	-11%	14%	-18%	-59%
Haynesville	-6%	-48%	24%	-3%	-49%
Permian	46%	43%	3%	6%	-32%

Figure 13: Measures of Activity and Annual Productivity Changes in the New Shale Plays, 2013 vs. 2011

Given all of the data above and the relationships that it yields, we can calculate what today's rig count suggests for future production from the unconventional basins, assuming different levels of efficiency and production gains. Using data for the year ended in June 2013 , we have calculated the average decline rates, average number of wells per rig, and average volume for each new well. We then took the rig count for the most recent month available, March 2014, and determined the following: if there is no change in the number of wells per rig and the volumes per well, then today's rig count would suggest that the Bakken, Eagle Ford, and Permian could grow but that the Barnett, Fayetteville, Haynesville, and Granite Wash will decline more than 10% over the coming 12 months.

	Production June 2013 (kboed)	Decline Rate June 2013	Rig Count March 2014	Predicted Vol Aug 2014 (kboped)	Predicted YoY Change
Barnett	863	-24%	20	761	-12%
Bakken	1,166	-44%	167	1,227	5%
Eagle Ford	1,820	-48%	232	2,102	15%
Fayetteville	470	-33%	9	423	-10%
Granite Wash	302	-55%	51	254	-16%
Haynesville	963	-47%	43	871	-10%
Permian	475	-35%	251	784	65%

Figure 14: Modeled Forward 12-Month Production Change for the Shale Plays assuming no further productivity gains

[3] We use June 2013 as the latest time for which data from all of the basins is fully complete.

While these numbers may seem dire, the evidence above shows that efficiency gains have been improving every year, especially in terms of wells drilled per rig. We have also run sensitivities to estimate the degree to which efficiency improvements would add to volumes from these plays. In order to have a total of 10% growth from these plays, BOTH volumes per well and wells per rig would have to improve by 5% year over year in 2014. And in order to add over 1 million barrels per day equivalent of volumes, those improvements would have to be over 10% in both categories.

Estimated Change in Wells/ Rig AND Volumes/Well	Incremental Volumes	Change in Volume
-5%	81	1%
0%	362	6%
5%	658	11%
10%	968	16%
14%	-18%	-59%
24%	-3%	-49%
3%	6%	-32%

Figure 15: Sensitivity of Production Growth to Changes in Rig Efficiency, New Shale Plays

Are Such Increases Possible?

The obvious conclusion is that in order for production from shale plays to grow, both volumes per well and wells per rig must increase. The data however appears to show that achieving both will be challenging. In the past three years in particular, the measure of volumes per well have remained relatively flat in nearly all plays except for the Haynesville. On average, the compound annual growth rate in volumes per well has been negative at -3% per year. (The most likely explanation for the improvement in the Haynesville is that the rig count fell very dramatically and operators high-graded their drilling locations to focus on the most economic acreage.)

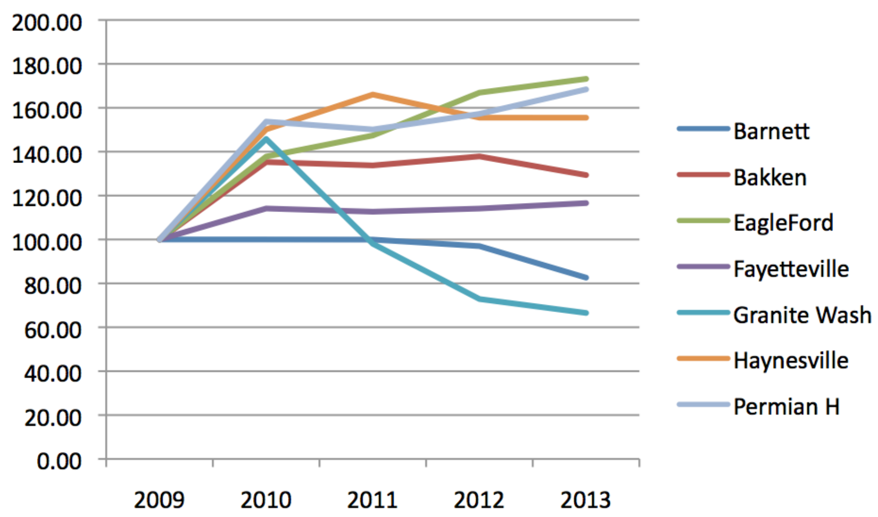

Figure 16: Volumes per well in the shale plays indexed to 2009=100

In terms of well per rig, though, there has been significant operational improvement across a number of plays in the past 2-3 years, at a CAGR of +14% on average. A portion of this can be explained by the production learning curve improvements within a given play. In the beginning of a play's development, the landing zone (where the lateral well "lands" in the formation) and completion type (size and type of frack) are still being optimized through trial and error. As these questions are answered, drilling efficiency improves and the lessons are disseminated to other operators in the basin (Fig. 17).

We believe the operating efficiency improvement will continue, but there are natural limits on the number of days in which a well can be drilled, capping the improvements.

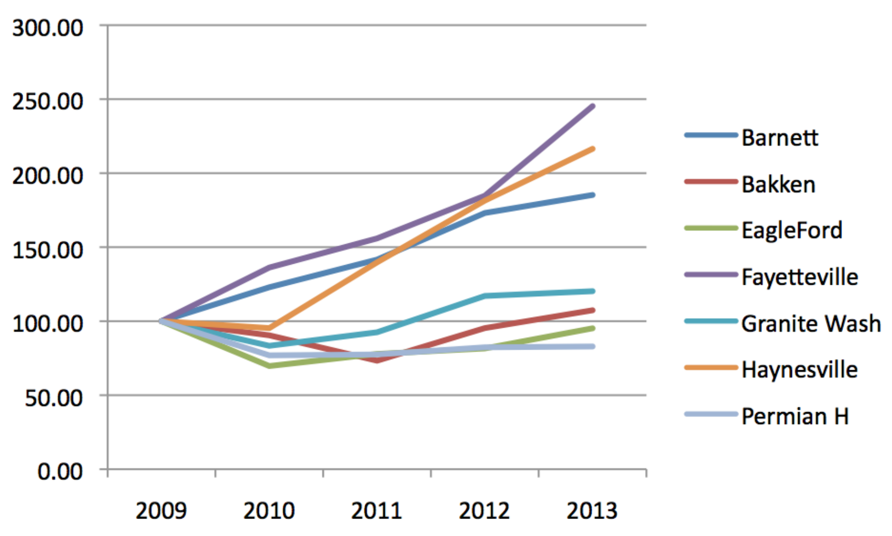

Figure 17: Wells Drilled per Rig in the shale plays indexed to 2009=100

What Efficiency Increases are Likely?

If we assume the trends in the seven plays continue, with average wells per rig increasing 14% this year and volumes per well decreasing 3%, the current rig count suggests that total volume from these plays would increase by 11% over the next year. In the years 2009-2012 the average volume growth from these plays was 44% per year, because it offset declines in the US base as a whole. A growth rate of only 11% from these plays would be a massive disappointment.

Scaling Up the Analysis: What Does the US Rig Count Suggest

Using a similar methodology, we have calculated what the current rig count suggests for overall US production of oil and gas. Since the split between gas wells and oil wells is imprecise and inconsistent across the US states, and because the very same wells often produce both, we are not able to do any per-well metrics. However, we can calculate the average contribution per rig, since the rigs are split between oil- and gas-directed.

We have modeled two scenarios for productivity per rig – one where productivity per rig stays constant with the past year and the other where the productivity per rig changes in line with the past three-year change. The improvements in productivity per rig that have occurred in the unconventional basins have not been mirrored in the rest of the lower 48 drilling. Instead, a bifurcation has occurred. Productivity per rig outside the seven shale plays in natural gas plays has increased dramatically, by an average of 18% per year. In the oil plays, productivity has declined by 26%. In reality this makes sense – given the much higher price for oil it is worth targeting lower volume opportunities, while in gas the reverse is occurring.

Under either scenario, the decline and rig data suggest a deceleration in oil and a faster decrease in gas production for the US lower 48 than is widely believed to be likely based on consensus estimates. In the past year natural gas production in the lower 48 grew by 2%, but our model shows that at current productivity levels it is likely to decline by 9% per year and even considering the drilling improvements seen in the past year, it will still decline at 5% per year. In oil, the most recent year showed a 18% increase in volumes but this is likely to decelerate to 10-16% in the coming year.

				Assuming No Change in Rig Productivity		Last 3	Assuming Change in Rig Productivity Avg 2009-12			
	Production June 2013	Decline Rate Current	Expected Volume Decline	Volumes from New Wells	Est YoY Volume Change	Years Rig Productivity Change	Volumes from New Wells	Est YoY Volume Change	Actual Production Aug 2012	Actual YoY Change
Oil Production (kbbld)										
Low er 48 Ex 7 Basins	3,169	-21%	-655	729	2%	-26%	543	-4%	3,060	4%
7 Basins	2,431	-49%	-1,187	1,676	20%	30%	2,177	41%	1,703	43%
Total	**5,600**		**-1,842**	**2,405**	**10%**		**2,720**	**16%**	**4,763**	**18%**
Gas Production (mmcfd)										
Low er 48 Ex 7 Basins	48,929	-19%	-9,372	6,786	-5%	28%	8,703	-1%	47,874	2%
7 Basins	21,769	-37%	-8,163	4,584	-16%	18%	5,429	-13%	21,691	0%
Total	**70,698**		**-17,535**	**11,371**	**-9%**		**14,131**	**-5%**	**69,565**	**2%**

Figure 18: Modeled future 12-month growth in Oil and Gas for shale plays and rest of Lower US 48, under two different productivity scenarios

[4] The simplifying assumption here is that the oil contributed from gas wells offsets the gas contributed from oil wells. This is debatable but without it the analysis is challenging.

Conclusions

A good understanding of trends in decline rates and drilling productivity is necessary to frame the possible outcomes for US supply going forward. While consensus opinion holds that US oil production will continue to grow and natural gas production will not decline, today's rig count does not suggest that is likely. What consensus seems to be missing is the dual challenge that exists precisely because of recent growth rates. First, as unconventional wells increase in the mix, the average decline rate of new wells is increasing. Second, as production grows, the mix of new wells versus base production gets more challenging every year. Overcoming these obstacles would require drilling efficiency and productivity to improve dramatically more than it has in recent years. We believe that such unprecedented improvements are unlikely, and therefore, there is cause to be more bullish on commodity pricing going forward.

Appendix: Methodology

This note relies heavily on the Baker Hughes rig count and on production data from DI Desktop. DI Desktop collects production numbers from the states on a monthly basis. From 2005-2013, on average the total DI Desktop volumes from the lower 48 have been 101% of what the EIA reports for oil and 105% for natural gas. The standard deviation is less than 5%. As a result, we have been able to consider the DI dataset to be comprehensive.

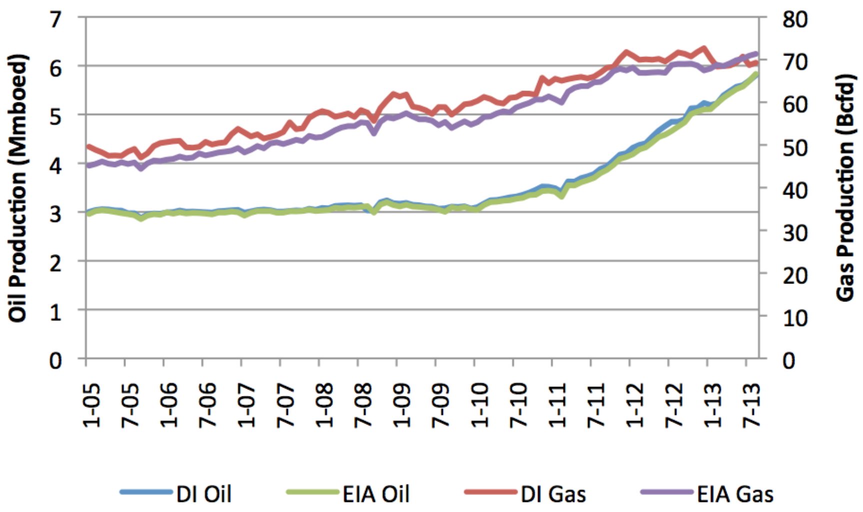

Figure 19: Comparison of Total Lower 48 Oil and Natural Gas Production in the EIA dataset and the DI dataset

DI Desktop has monthly production figures for most of the states but Pennsylvania reports production on a six-month basis, which DI assumes is evenly distributed across the period. This accounts for most of the lumpiness in comparing the DI and EIA datasets for gas production. This also accounts for why we were unable to do the above detailed analysis on the Marcellus decline rates.

In order to define the other seven basins, we used a list of counties and assumed that all horizontal wells within those counties belonged to the play in question. This allowed us to compare the Baker Hughes horizontal rig count with the horizontal wells on production. The list of counties included follows.

Basin	Counties Included	Total Horizontal Wells from DI Desktop
Eagle Ford Shale	**Texas:** Atascosa, Bee, Brazos, Burleson, Caldwell, Dewitt, Dimmit, Fayette, Frio, Gonzales, Grimes, Karnes, La Salle, Lavaca, Lee, Leon, Live Oak, Madison, Maverick, McMullen, Milam, Robertson, Walker, Webb, Wilson, Zavala	17,978
Barnett Shale	**Texas:** Archer, Clay, Cooke, Dallas, Denton, Ellis, Erath, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Somervell, Stephens, Tarrant, Throckmorton, Wise, Young	14,886
Fayetteville Shale	**Arkansas:** Cleburne, Conway, Faulkner, Independence, Van Buren, White	4,931
Bakken Shale	All of **North Dakota** and all of **Montana**	10,074
Granite Wash	**Texas:** Hemphill, Roberts, Wheeler **Oklahoma:** Beckham, Custer, Roger Mills, Washita	2,240
Permian Basin	**New Mexico:** Chaves, Eddy, Lea, Roosevelt **Texas:** Andrews, Borden, Cochran, Coke, Crane, Crockett, Crosby, Culberson, Dawson, Ector, Edwards, Fisher, Gaines, Garza, Glasscock, Hale, Hockley, Howard, Irion, Jones, Kent, Lamb, Lubbock, Martin, Mitchell, Midland, Nolan, Pecos, Reagan, Reeves, Schleicher, Scurry, Sterling, Stonewall, Sutton, Taylor, Terrell, Terry, Tom Green, Upton, Ward, Winkler, Yoakum	8,626
Haynesville Shale	**Louisiana Parishes:** Bienville, Bossier, Caddo, De Soto, Natchitoches, Red River, Sabine, Webster **Texas:** Harrison, Nacogdoches, Panola, Rusk, Sabine, San Augustine, Shelby	4,333
Marcellus Shale	All of West Virginia and all of Pennsylvania EXCEPT: Erie, Crawford, Mercer, Lawrence, Beaver	5,481

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Contact Kimmeridge

New York
400 Madison Avenue,
Suite 14C, New York, NY 10017

London
Thornton House, Thornton Road
London, England SW19 4NG

Houston
952 Echo Lane, Suite 364
Houston, TX 77024

info@kimmeridgeenergy.com