



November 2017

Completion Design Changes and the Impact on US Shale Well Productivity

I. Introduction

The 2014 oil price downturn caused the US unconventional oil and gas industry to undertake an array of cost-cutting measures affecting both capital and operational expenditures. Focus shifted towards operational efficiency, well design, and the maximization of each dollar spent, and away from the gold rush mentality that had characterized the former \$100/b price environment. Perhaps counterintuitively, the emphasis on efficiency has helped to propel consecutive years of well productivity gains¹ across several shale plays. These gains have continued into 2017, even as the industry still grasps at profitability. This paper seeks to build on our previous work – including the 2016 OIES paper [Unravelling the US Shale Productivity Gains](#) – on well productivity gains. Specifically, it examines the continued productivity growth across multiple US shale plays and attempts to identify the factors contributing to this growth, as well as address some of the potential economic constraints.

Drilling, completing, and producing shale or tight oil and gas wells has always been both an art and a science. Over the past three years, in a sub-\$60 oil price environment, this has never been more true. A combination of science, technological advancement, and brute force experimentation has led to broad productivity gains across the shale patch. In the long run, the shale industry will continue to improve well productivity, but in the short run, economic constraints could imperil productivity gains as operator profitability faces renewed scrutiny. But – geologically and technologically speaking – there is certainly room to grow.

We have interviewed engineers and technical experts from a wide range of industry fields over the past year to ascertain exactly what factors are driving increases in well productivity. The jury remains out. It is quite apparent that there are many known unknowns regarding sub-surface science, and the industry is actively trying to unlock these. There is much room to grow. Well productivity can and will continue to improve as these enigmas are solved.

Efficiencies have been found in nearly all stages of the drilling and completions process (although it has been the service companies who have borne the brunt of pricing concessions). One example is the reduction in spud to total depth times, coupled with increased drilling precision. The speed and cost at which wells are drilled, from spud to total depth, is a mere fraction of what it was in 2014. Bakken and Eagle Ford wells can be drilled in under a week. Some Denver Julesburg Basin wells are drilled in less than three days. Despite the more rapid pace, precision has improved.² Geosteering advances have

¹ 'Productivity gains' refers to increasing hydrocarbon output per well.

² EOG Resources' comment on precision targeting in Q2 2017 earnings call reinforces this point: "These latest Eagle Ford wells really demonstrate the impact that precision targeting makes on well performance. Successfully steering the lateral into the 10 or 20 feet of the highest quality pay of any given target can significantly enhance the well's ability to achieve EOG's premium drilling hurdle." EOG Resources, Q2 2017 Earnings Call, Seeking Alpha.

made notable strides in the past three years. Wells that take only a few days to drill are landing more accurately in zone, which means that the subsequent fracturing treatments are working more effectively than they might have in previous years.

As important as drilling efficiencies and precision are, the most meaningful advances made during the downturn are related to completion designs. Operators and service companies continue to experiment with and tweak completion designs, usually resulting in positive outcomes. The use of greater sand (proppant) and water (fluid) volumes has paved the way to productivity gains in multiple plays and is probably the single largest contributor to recent productivity advances. However, the specific factors contributing to these gains are far less well understood. It is not the gains themselves that are in dispute, but what exactly is occurring beneath the surface to make these gains possible that remains subject to vigorous debate.

Operators, service companies, and analysts have varying opinions on what exactly is happening downhole during and after the hydraulic fracturing process. For example, the transport of proppant and, in turn, the flow of fluid is not well understood. The efficacy of a design tweak is easily confirmed by observing a well's production volumes over time compared to its peers, but the industry has not yet isolated enough variables to know exactly why a design change may or may not work. One limitation is that the fracture network and the flow around the wellbore cannot be perfectly mapped. Although many operators have invested in reservoir mapping and imaging, many operators use neither of these technologies. Microseismic monitoring can better help one understand how far fractures extend, but it is not perfect. Proppant tracers also help, but they do not show the full extent of the fracture network being created and in turn the flow of fluid, or which fractures are contributing to oil production.

This is where the short-cycle, rapid-fire nature of the shale industry delivers unique benefits. Compared to more capital intensive offshore or mega-projects with lead times measured in years rather than weeks, individual well costs are relatively low, generally well under \$10 million each, and hundreds or thousands of shale wells are drilled each month across the USA. This means that the thousands of shale wells drilled over the past several years provide an enormous sample for the industry to learn from, and they have generated immense amounts of data.

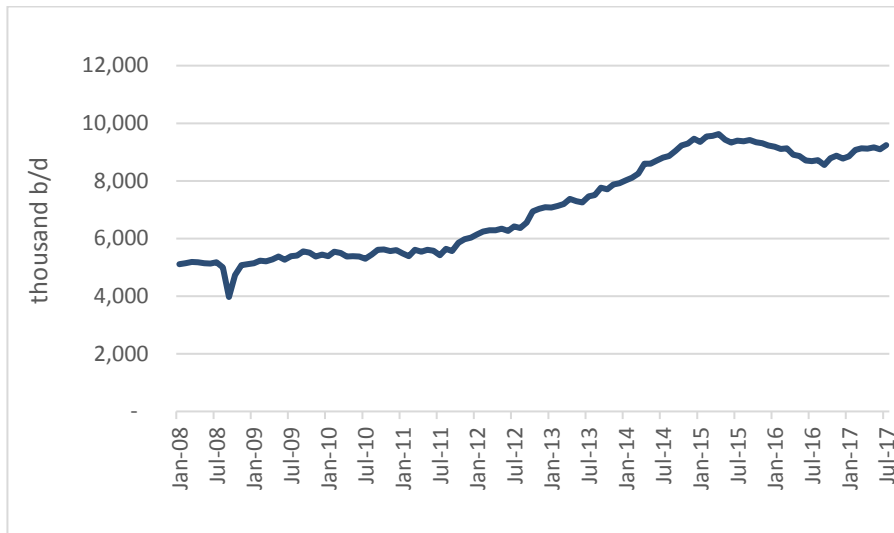
Another benefit, more closely related to the 'art' side of things, is that shale development is conducive to a 'guess and check' approach to problem solving. With even modestly sized shale E&Ps drilling and completing hundreds of wells per year, there is much opportunity to experiment and make brute force attempts at increasing productivity. High intensity completions, discussed at length later in this paper, are a simplistic, but surprisingly effective method and are arguably a prime example of brute force gains. This does raise an important question, to which there is as yet no answer. If productivity gains are currently driven primarily by what appear to be rather simplistic guess and check changes to completion design, how much running room is left for the use of such methods, and at what point will scientific and technological research become the primary driver for productivity growth?

II. Production and productivity overview

US oil production currently sits just shy of 9.3 million barrels per day (mb/d) as of July 2017, having rebounded from its 8.6 mb/d bottom in September of 2016 (Figure 1). The production recovery over the course of 2017 has been supported in part by US shale, primarily the Permian Basin, but also by renewed production growth in the Gulf of Mexico.



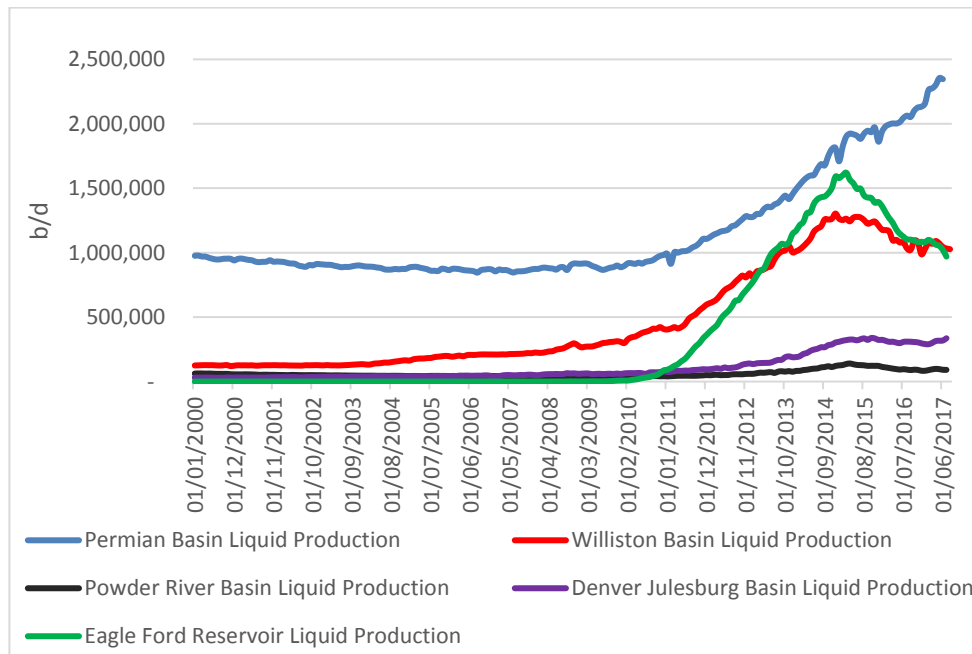
Figure 1: US oil production (thousand b/d)



Source: EIA.

Activity has remained dynamic in the Permian Basin throughout 2017. Production rose by over 500,000 barrels per day (b/d) from December 2015 to June 2017 and this largely offset faltering growth levels in other US shale plays (Figure 2). Total US shale production, including the Williston Basin/Bakken, Eagle Ford reservoir, Permian Basin, Powder River Basin, and Denver Julesburg Basin, equates to nearly 4.8 mb/d, representing over half of US oil production volumes.

Figure 2: US shale liquids production by play (b/d)

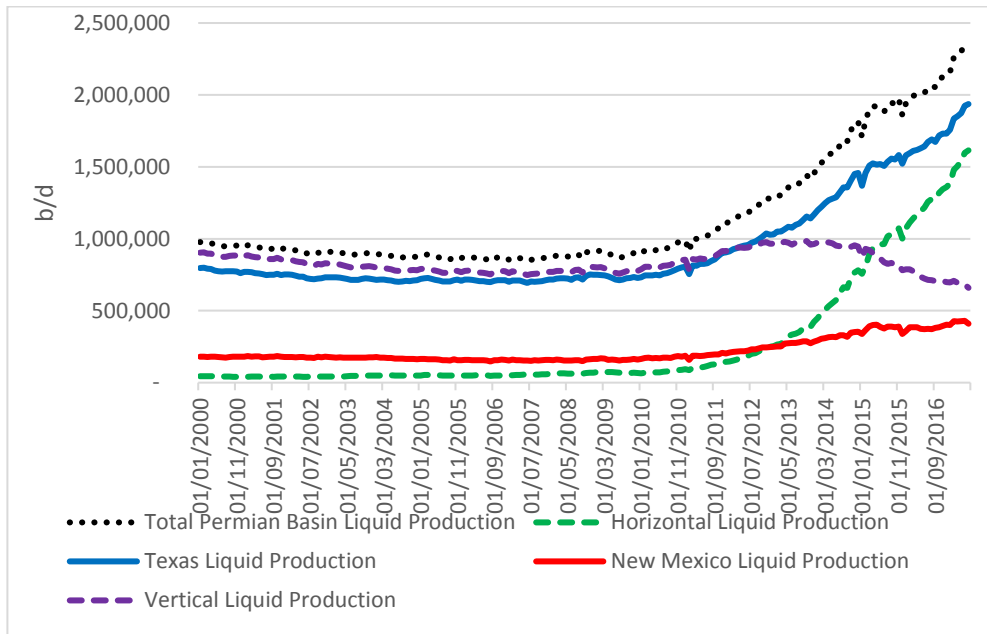


Source: PetroNerds, DrillingInfo.

Permian Basin oil production volumes advanced to over 2.3 mb/d in June 2017, largely driven by horizontal production gains in Texas specifically (Figure 3). Production volumes and overall activity levels in New Mexico have remained muted year-on-year. This is evident in the New Mexico Permian Basin horizontal decline curve shown in Figure 4.



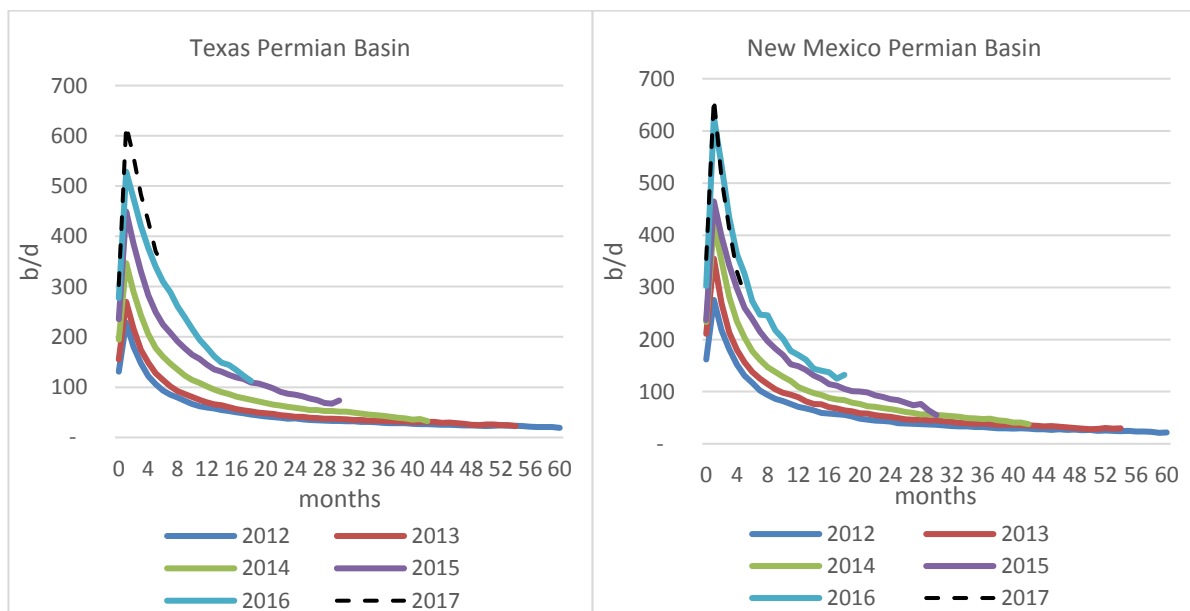
Figure 3: Permian Basin production by vertical and horizontal wells (b/d)



Source: PetroNerds, DrillingInfo.

Texas Permian Basin wells are averaging a 92 b/d increase in initial production rates year-on-year, a gain of nearly 20 per cent. The production curve has continued to shift up and to the right, indicating not only higher initial production rates, but higher production many months after initial production (Figure 4). Production from New Mexico Permian Basin wells is roughly in line with 2016 performance. Initial production rates have improved slightly, but 2017 wells are not significantly outperforming their 2016 peers. Several factors could be causing this. The sample size of wells on the New Mexico side of the Permian Basin is far smaller than that of the Texas side through the first half of 2017. The New Mexico portion also has less operator diversity, meaning that operational changes by just a few operators could impact production levels.

Figure 4: Permian Basin horizontal decline curves (Texas and New Mexico) (b/d)

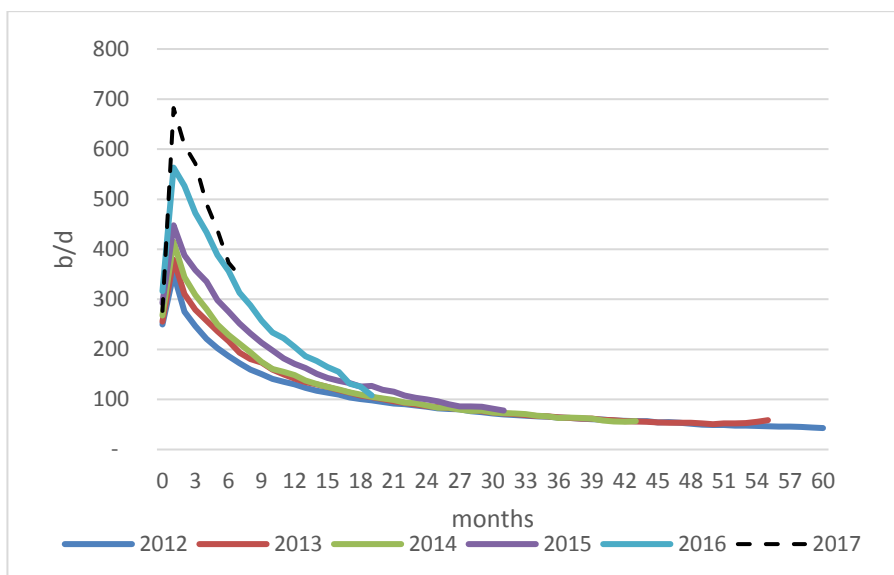


Source: PetroNerds, DrillingInfo.

Total production levels have continued to falter somewhat in the Eagle Ford, Williston Basin, and Powder River Basin, but productivity gains have not. These gains enable overall production volumes to be maintained with a few well additions each year.

Williston Basin initial production rates rose by 119 b/d on average over 2017 (see Figure 5). This is impressive, especially considering the year-on-year gains made last year (115 b/d year-on-year initial production rate increase).

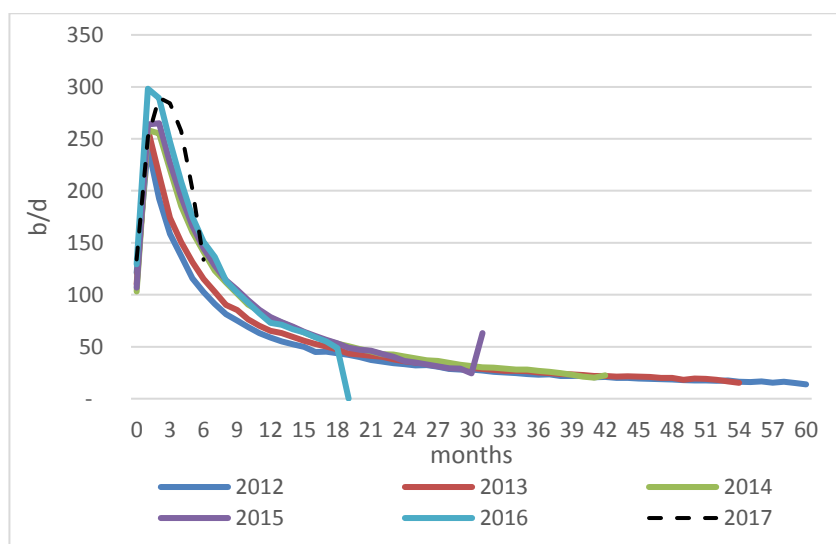
Figure 5: Williston Basin decline curves (b/d)



Source: PetroNerds, DrillingInfo.

The Denver Julesburg Basin has struggled to outperform year-on-year initial production rates, but production in the basin grew by nearly 20,000 b/d in the last several months. Significant productivity gains are being made by individual operators in certain areas. While average initial production rates were muted year-on-year, some growth is occurring in the later months (Figure 6).

Figure 6: Denver Julesburg Basin decline curves (b/d)

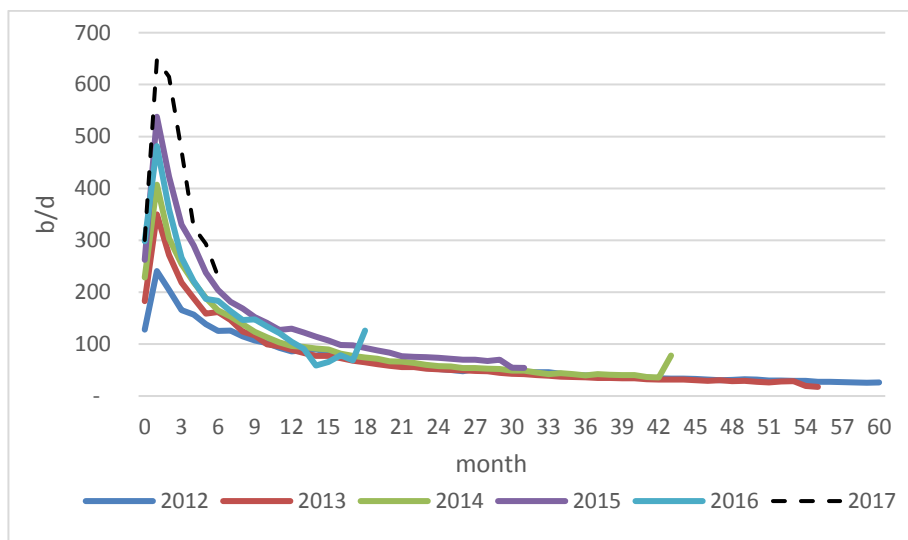


Source: PetroNerds, DrillingInfo.

Powder River Basin production has continued to decline and, like many other shale plays, far fewer wells were drilled this year than in previous years. However, these fewer wells are notably outperforming

their peers from past years, both in terms of initial production rates and gains in later months (Figure 7). As evidenced in Figure 7, productivity declined in 2016, due to lack of spending and activity in the Powder River Basin. But 2017 wells are greatly outperforming 2015 wells, posting a nearly 200 b/d initial production rate increase.

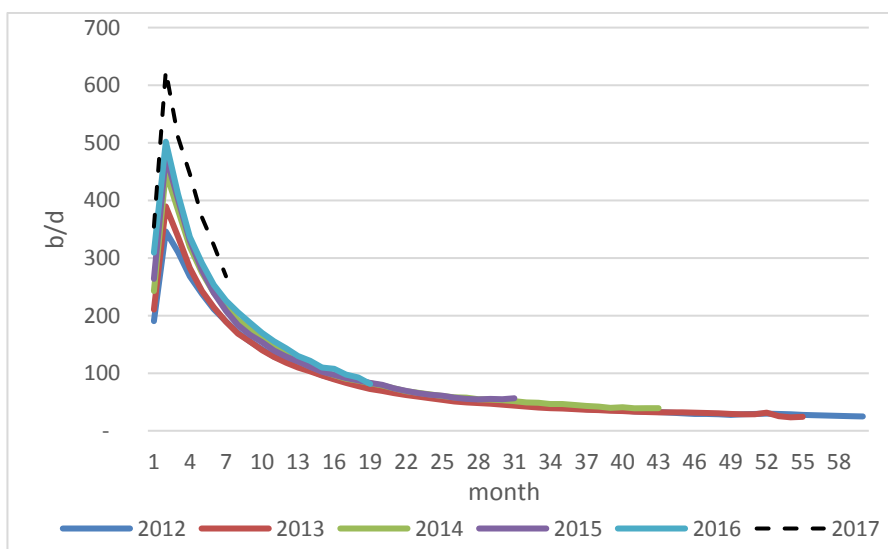
Figure 7: Powder River Basin decline curves (b/d)



Source: PetroNerds, DrillingInfo.

The Eagle Ford reservoir has also posted some incredible productivity gains for 2017, despite overall production declines. Due to the unique geological nature of the Eagle Ford reservoir and the breakdown of acreage ownership across condensate and oil windows, the Eagle Ford has struggled with productivity growth in the last few years. Decline curves, year-on-year, as seen in Figure 8, fall in line with one another. However, this year, initial production rates have risen by over 120 b/d. While far fewer wells have been brought online in 2017 than 2016, these 2017 wells have posted a strong upwards shift in productivity. Although operator concentration, specifically in the oil window, has contributed to these gains, outstanding wells have been drilled and completed across the play in 2017.

Figure 8: Eagle Ford horizontal decline curves (b/d)



Source: PetroNerds, DrillingInfo.

III. Primary factors behind productivity growth

The industry has made tremendous gains in productivity improvements over the past several years. One of the largest factors contributing to increased well productivity is a relatively simple completion design change. In the past few years, much emphasis has been placed on pumping increasingly larger volumes of proppant (sand) and fluid (water) at faster rates (higher pressures) downhole. The relationship between increased proppant and additional productivity is largely accepted, even if the specific factors behind the relationship are less well understood. This is among the most discernable factors contributing to recent productivity gains, but it is hardly the only one.

Operators have gained years of experience working through their geology, enabling millions of acres across several shale plays to be de-risked, generating massive data sets from which to draw upon. The experience gained from the tens of thousands of shale wells that have been drilled in recent years has dramatically improved reservoir knowledge and, with it, the ability to better apply the ever evolving technology. To put it simply, operators, in cooperation with service companies, are better able to identify the best pay zones and to land laterals more precisely within them. And they are doing this more quickly than ever before, thus reducing drilling costs. Still, a complete understanding of events happening downhole – completions and the fracture network response – remains elusive.

The shale sector has been through many iterations of completion design changes over several years, with varying types of downhole tools (plug and perf vs. sliding sleeves), proppant, and fluid coming in and out of favour. The ability to experiment and move completions designs in tandem with oil prices and service costs helped many operators to forgo exotic completion designs and components, in favour of simple but effective high-intensity completions. In combination, these factors have positively impacted rising oil output per well.

In tandem with the evolution of more precise geosteering and reservoir targeting, larger completion jobs have been a standout factor in well performance gains. The terminology for applying larger completion jobs, or increasing the quantity of proppant and fluid per foot, has become a bit hyperbolic and perhaps panders to the investor community. ‘High intensity completions’, ‘upsized completions’, ‘enhanced completions’, ‘version 3.0 completion’, ‘generation x frac’, and ‘high density fracs’, have all entered the E&P vernacular to describe the changing completion matrix over the past three years. These operators are all referring to essentially the same thing: massively increased quantities of proppant (namely sand), massively increased quantities of fluid (mainly slickwater), and the placement of more fractures along the wellbore through tighter cluster spacing of perforations. As mentioned above, the industry disagrees on what exactly is happening downhole once all this water and sand is applied, but they agree that larger completions jobs are working to increase the amount of oil and gas output per well.

Operators continue to tweak methods

Shale activity at \$100/b was characterized by the rapid pace at which companies brought new wells online to increase overall corporate production volumes and delineate or hold new acreage. Efficiency and long-term well productivity were a secondary concern. Now, several years into a hunt for further efficiencies and, ultimately, profitability, the industry’s activity can be characterized by a mix of innovation, determination, and desperation. Innovation remains a key stepping stone to profitability. The industry’s leading operators frequently echo the same sentiment about technological advancement in earnings calls, that is: *‘we are still in the early innings’*. Some would argue that more advances have been made in truly understanding the horizontal development of unconventional reservoirs over the last two years, than in the past decade.³ As operators have been forced to curb costs, they have also been forced to put more thought into each well.

³ EOG Resources, Q2 2017 Earnings Call.



In their last conference call (Q2 2017), EOG Resources discussed their geosteering technology and rock quality, reiterating the importance of these for well performance. They also discussed smaller changes – such as drill bit designs and mud motors – having a positive impact on cost and productivity:

... taking advantage of our new steering technology that we kind of developed to identify the best rock and then steer the well in the best 10 or 20 feet of that rock. As we mentioned in all these plays, the rock quality makes a huge difference in the productivity of each play ... we are just offsetting the cost inflation with improved technology and the design of bits, design of motors. We have our engineers doing both of those. We've got our own mud systems and mud engineers.

Q2 EOG Seeking Alpha.

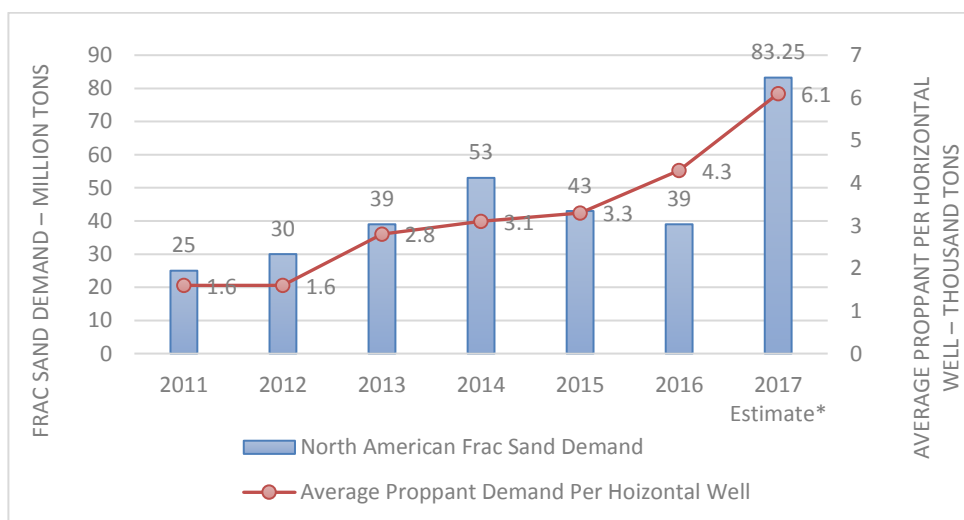
Centennial Resources discussed their completion design 'evolution' – increasing the amount of perforation clusters per stage, use of only slickwater as a fluid, and increasing proppant loading per lateral foot – in their last earnings call.

Centennial's technical team is focused on the continuous evolution of our completion design. All wells completed during the quarter, had 15 clusters per stage, 100% slick water, an average greater than 2,300 pounds of proppant per lateral foot. This represents a significant design change from wells completed in the previous quarters.

Q2 Centennial Seeking Alpha.

In our paper [Unravelling the US Shale Productivity Gains](#), we discussed the notable changes in approaches to drilling and completions, such as rock quality assessments, the importance of geosteering in keeping laterals in the highest quality rock, and optimizing the placement of fracs along the lateral. High intensity completions and well spacing were also discussed. A year later, the mantra has not changed dramatically. While each operator tends to focus on their strengths relative to those of their peers, geosteering, lateral placement, rock quality, completion advances, frac optimization, and proppant loadings are all commonalities when operators talk about productivity advancements. Some operators are making serious attempts to understand the how and the why behind these factors, but many are simply following the leads of their peers and applying similar methods to their own geology without necessarily performing the research on the front-end. Regardless, the basic logic is simple: crack more rock, extract more hydrocarbons, see Figure 9 which illustrates the rise in both use and demand of proppants.

Figure 9: Proppant demand and usage



Source: Emerge Energy Services, Q2 Investor Presentation, 8 August 2017, using WSJ and Spears and Associates. *2017 Estimate average using consensus, TPH, Jeffries, GS estimates.

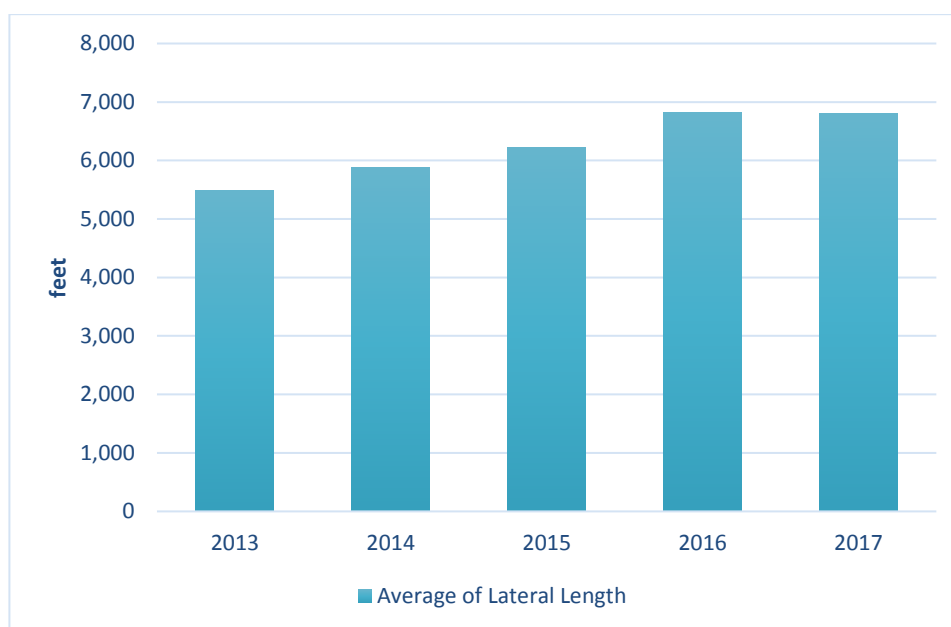
Note: Proppant demand in recent years, noted extensively in this report, has largely been sand, not resin coated sand or ceramic proppants.

It does not take billions of dollars and a rock lab to identify better lateral placement. EOG Resources' peers often copy their completion moves without necessarily applying the front-end rock science. While such 'copycat' wells are not necessarily 100 per cent optimal, the end result – increased productivity – more or less transfers over. Better drilling and completions designs are leading to productivity gains across the board. Pump two or three times as much sand down the well as you did in 2014 (using slickwater instead of a gel or hybrid fluid), layer in a better understanding of your reservoir, increase the horsepower and rate you are pumping, and add more perforations per stage along your lateral – then boom, you often end up with a better well than you did in years past. And of course, extend the length of your lateral, where you can.

A note on lateral lengths

The average lateral length of a shale or tight oil well has, for the most part, increased year on year. All things being equal, increasing lateral length will increase well productivity, as it exposes a well to additional pay zone. It is certain that the productivity curves shown in the previous section have benefited from longer lateral lengths (but by far more in some oil plays than in others – Bakken wells have averaged two miles in length for years). Figure 10 shows the average lateral length for active Permian Basin horizontal wells by year.

Figure 10: Average Permian Basin lateral lengths by year (feet)

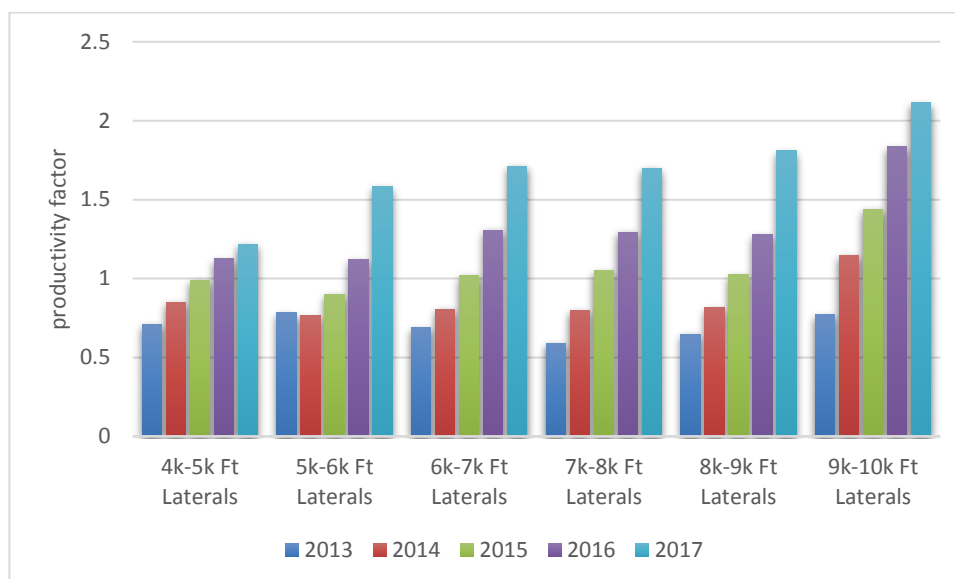


Source: DrillingInfo Data, PetroNerds calculations (for wells with known lateral data).

* 2017 sample is partial-year data.

The average Permian Basin horizontal well lateral length grew from 5,500 feet in 2013 to 6,800 feet in 2016, but average lateral lengths have not increased through the first half of 2017. However, increasingly long laterals are only part of the productivity story. Figure 11 shows productivity for Permian Basin horizontal wells by year, isolated by lateral length segments. Within each 1,000 foot segment, productivity has grown each year. This tells us that productivity is growing independently of lateral length expansion.

Figure 11: Permian Basin horizontal well productivity by lateral length segment



Source: DrillingInfo Data, PetroNerds calculations (for wells with known lateral data).
 * 2017 sample is partial-year data.

Note: Well productivity indexed to a base curve, which equals 1.

Beefed up completions and small grain sand – what could be happening with the frac?

The use of 100 mesh sand in well stimulation is not new. What is new is the method of application to gain outstanding results in Permian Basin formations. SPE Paper 6374, 1977.

Completions may be using more proppant, but for some, that proppant has gotten smaller. In some places, the industry has recently trended towards smaller grain/finer mesh frac sand. Operators are using sizeable quantities of 100 mesh (essentially fine grain frac sand) in the Permian Basin and in the Marcellus shale.⁴ This seems to be increasing well productivity, but there is no clear evidence or agreement as to why. What constitutes the optimal volume, quality, and size of sand is a highly debated matter in the industry. There is limited data on the use of finer mesh sand as a proppant and how it correlates with medium and long-term well productivity. There are also issues with reporting the use of mesh size and quality accurately, as sand types are often mixed or occasionally defined differently by operators.

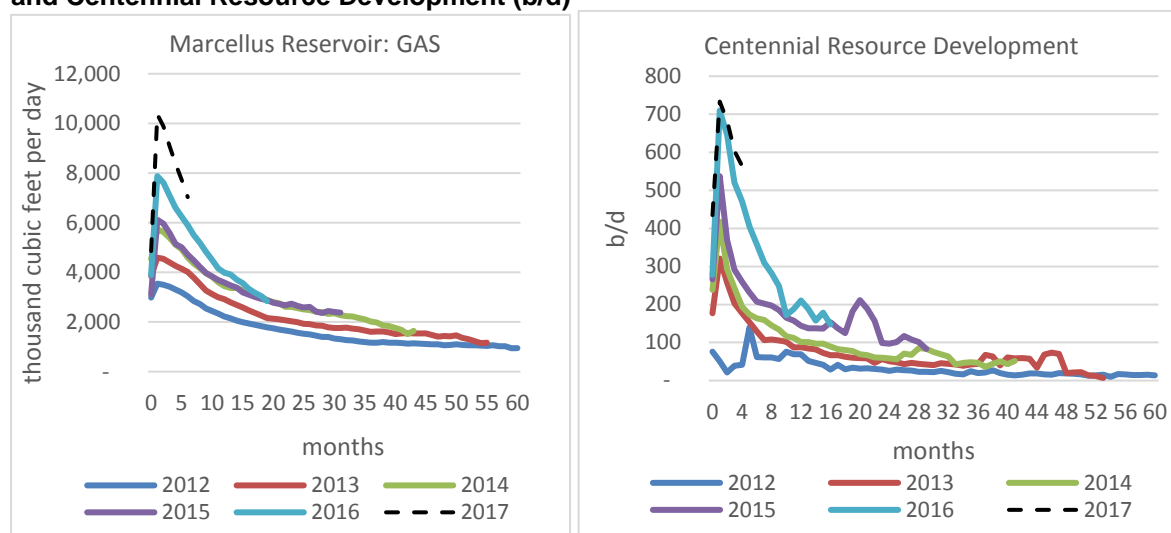
The changes involved with high intensity completions are far subtler than can be explained by simply increasing sand volume. As proppant volumes have risen, so have fluid volumes; this is equally, if not more, important as the fluid needs to carry the proppant and help to create the fracture. The additional fluid volumes themselves may be having an impact independent of the proppant they carry. Furthermore, the use of thinner, less viscous, fluids such as slickwater, formerly used in the 1970s, has seen a resurgence in the past three years due to their lower cost and ability to carry cheaper sand. At the moment, productivity gains cannot be attributed to any single variable.

Some operators clearly favour smaller grain mesh size for completion jobs, particularly in the Permian Basin. EOG Resources has been known to use finer mesh sand in completions for years. And now Centennial Resource Development, run by Mark Papa, EOG's former CEO, has openly talked about

⁴ Smart Sand Q2 2017 Earnings Call via Seeking Alpha.

using predominately 100 mesh sand in all their completions. Carrizo,⁵ among others, has also mentioned using 100 mesh sand. Frac sand companies attribute nearly half of their Permian Basin demand to 100 mesh sand.⁶ These same frac sand companies see a continued rise in demand for 100 mesh frac sand in the Marcellus shale, where operators seem to be mixing larger and finer mesh sand. When examining the decline curves (see Figure 12) for the Marcellus reservoir and Centennial Resource Development (Permian only), finer mesh frac sand certainly sounds interesting given how well these two seemingly unrelated well groupings have responded to a potentially similar shift in frac sand type.

Figure 12: Horizontal decline curves for the Marcellus Reservoir (thousand cubic feet per day) and Centennial Resource Development (b/d)



Source: PetroNerds, DrillingInfo.

Comments from Centennial Resource Development on increasing sand quantity pumped, adding additional perforation clusters, and moving from gel to slickwater as a primary fluid are telling.

While we continue to increase our profit per foot to help improve results one of our more recent advances includes increasing the number of perforated clusters per stage to 15. This increase in number of clusters per stage allows for a more efficient new well or a stimulated rock volume. Centennial uses tracers during stimulation to both monitor stage contribution as well as cluster efficacy.

Our current completion design is pumped with 100% Slickwater, £2,000 to £2,500 per lateral foot of Proppant over 80% of 100 Mesh sand, 15 clusters per stage, and approximately 210 feet of stage basin.

We've made great progress domain from Gel to Slickwater we've made great progress progressing to use of 100 Mesh sand and right now the Delaware twisting quite a bit is on the clusters and cluster spacing and number of clusters and things like that. And then once we kind of get that, where we, we think it's optimized

⁵ 'So far, we've pumped a significant number of spacing test from plug-to-plug, as well as varying our sand content. So when we pump the 2,000 pounds per foot job, we're going with pure slickwater and 100 mesh and then we've done some test as well at 200-foot spacing, which we've done 48 tests at 200-foot spacing using 2,000 pounds and 1,600 pounds per foot, and we've also got some spacing test at 150 feet where we're pumping 2,000 pounds per foot. Largely, when we get up to 2,000 pounds per foot, there we are pumping a slickwater state. So we're doing this in combination with the down-spacing work that we've done so far.' Carrizo Q2 2017 Earnings, Seeking Alpha.

⁶ Fairmont Santrol (but also reiterated by others) 'I also think it's important to think about the demand mix versus the supply mix. So if 40% of the market, which is today and that will evolve over time, if 40% of the market is 100 mesh and 40% is 40/70 and 20% is the remainder, but that the supply coming online is either 80% to 100% 100 mesh, that gives you an idea of the gate is actually the 100 mesh, which should moderate the supply coming online as far as getting commitments to take volume in the future.' Q2 2017 Earnings, Seeking Alpha – To be clear, frac sand companies do have an interest in maintaining demand for finer mesh sand, especially in the Permian Basin, as most of their new mines and in-basin assets are predominately 100 mesh and 40/70 reserves.

then we'll go to the concept of what's the optimum spacing between wells. The whole frac theory now is kind of short, shorter fatter fracs if you will rather than longer, thinner fracs, and as the whole industry is kind of gone that way.

Centennial Q1 2017 Seeking Alpha.

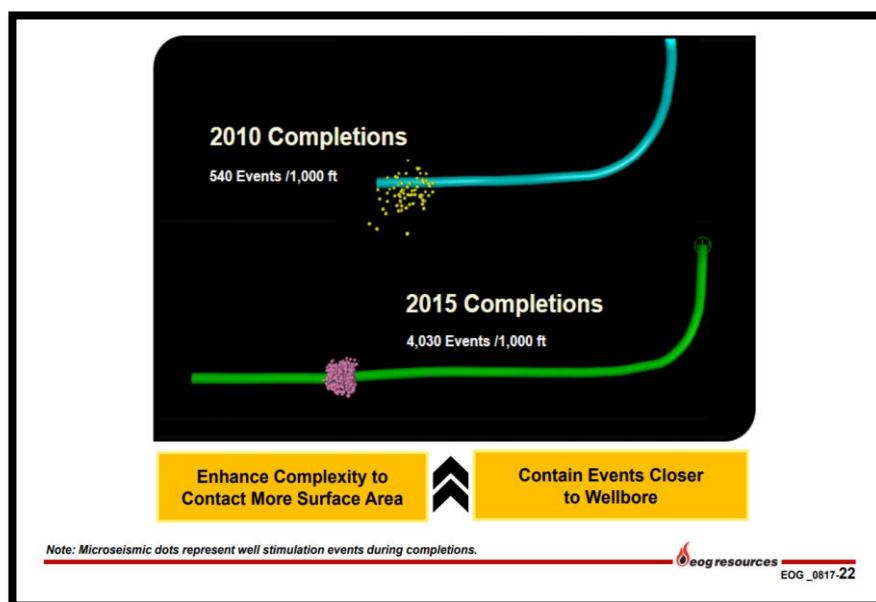
While 100 mesh sand does start to sound like the answer here, it should be reiterated that the impacts of both sand size and quality of sand on production performance are highly debated within the industry. Ask ten completion engineers for their thoughts on this and you will probably get ten very different answers – we did. Additionally, definitions of 100 mesh differ. Sometimes it refers to a combination of finer sand sizes and qualities. Add in potential discrepancies between suppliers and everything starts look a bit more opaque. It should also be noted that frac sand companies, with mines in the Permian Basin, have an incentive to promote the use of 100 mesh and 40/70 because it is their predominant regional reserve base.

But, all that aside, and for the sake of discussion, what could 100 mesh and other similar smaller/finer sand grains and mesh sizes be doing that larger or coarser grain sands might not be doing?

Pumped in vast quantities at high pressure with slickwater, finer mesh sand could be helping to open fractures that may not otherwise be accessible by larger proppant. It may also be increasing the amount of rock contacted or fractured. Before the downturn, expensive ceramics were still used in the Bakken formation because operators and service providers alike thought that the strength and sphericity of ceramics were needed in the Bakken to enhance conductivity or flow of oil around the proppant within the fracture. The use of ceramics and resin-coated sand quickly evaporated with the drop in oil prices. It was swiftly replaced with cheaper sand used in much larger quantities, likely offsetting the need for such conductivity.

If the goal is to break up more rock along the wellbore, it is intuitive that using a smaller mesh sand can access smaller fracture networks that larger sands cannot. EOG Resources show images in their investor presentations indicating that they are trying to frac closer to the wellbore (Figure 13). Theoretically, if one could do that, then 100 mesh might be the right proppant, but no operator can either truly dictate where that frac is going, or adequately determine how far it goes. So, the images in the presentations are a bit simplistic. Centennial also mentions this directly in their first quarter 2017 earnings call noted above. *'The whole frac theory now is kind of short, shorter fatter fracs if you will rather than longer, thinner fracs, and as the whole industry is kind of gone that way.'*

Figure 13: EOG resources: high density versus old completion technology



Source: EOG Resources, Q2 2017 Investor Presentation.

However, because we do not always know how far the frac goes and where it goes, we also do not know what part of that fracture is contributing to production. If, by pumping vast amounts of finer mesh sand during a hydraulic fracturing treatment, fractures extend as far out as they did if one were to pump a larger grain sand, it does not necessarily mean that the entire fracture length is contributing to production. Longer fracs with more distance might also be created, but they might not be contributing to production; smaller mesh sand size could be creating a more complex fracture network closer to the wellbore, thus impacting production volumes both in the short term (yielding higher initial production rates – or IPs) and in the long term (yielding flatter decline curves).

It should also be noted that most operators do not just use a single sand type or quality in their completions. Adding other sizes of sand may aid in the productive qualities of 100 mesh or similar fine grain sands. Centennial, for example, mentions that they use 80 per cent 100 mesh and 20 per cent 40/70 in their completions. While 40/70 is not as small as 100 mesh, it is still considered a finer mesh sand. And it is likely that most operators use a combination of sand sizes in their fracture treatments. Geology is also playing a role here. Both EOG Resources and Centennial Resource Development are predominately in the Delaware Basin – EOG in the northern portion and Centennial in the upper to middle portion. Finer mesh sand may not be conducive to all reservoirs.

Clearly the science is not perfect here and accurate reporting of sand use, size, and quality would be needed to determine if finer mesh sand as a proppant was truly a leading contributor to recent productivity gains. Medium and long-term production data, in addition to better isolation of variables, is needed to determine this. Right now, it is likely that a combination of factors and efforts, including geology and sand volumes, are aiding productivity gains. This is where the art and science of the oil and gas industry come into play; art might be leading here.

Near-term limitations in productivity gains: capital expenditures and free cash flow

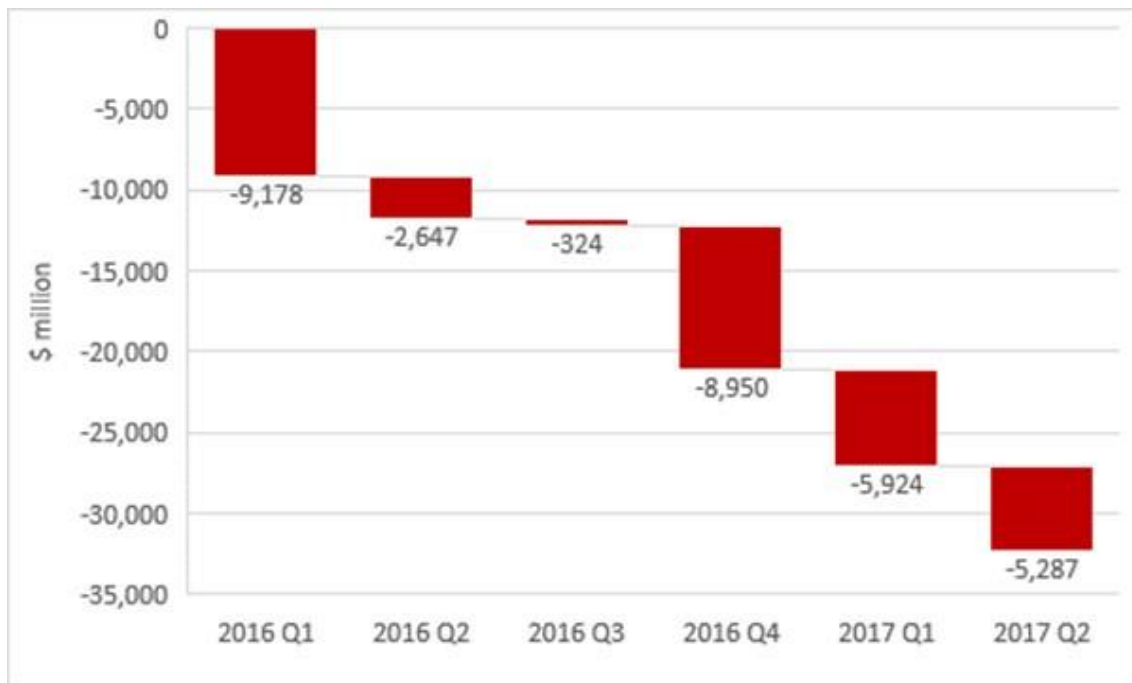
The productivity gains outlined in this report have been made possible by operators' ability to spend capital despite a sector that continues to burn billions of dollars in cash each year. Capital is needed for everything from acreage acquisitions to sand purchases. However, as investors begin to focus more on free cash flow and profitability capital expenditures, and in turn production growth, could face headwinds.

Dating back to before the price collapse in 2014, industry critics have called out US shale for its high production costs and lack of positive 'free cash flow' – a metric that quantifies operational profitability after accounting for capital expenditures. Figure 14 shows that since the first quarter of 2016, the 40 US-based E&Ps tracked by PetroNerds' HedgeAware platform have accumulated over \$32 billion in negative free cash flow. Many sceptics believed that financing and funding capacities would tighten considerably with lower oil prices, borrowing base redeterminations, and rising interest rates. But financing and spending capacity have remained remarkably resilient.

The impact of borrowing base redeterminations has been muted at best, and while there have been bankruptcies – well over 100 since January 2015⁷ – many operators have emerged from bankruptcy and many more have averted it all together. The nimble service sector that helped support US operators in their height of activity in 2014 reduced their prices through 2016, with pressure from operators. This meant pain for the service providers, but survivability for all. By and large, operators continued to drill and complete wells with the help of efficiency gains, reduced costs from service providers, and the ability to continue spending capital without massive penalties from equity markets. This capital was spent, at least in part, on large completion jobs, and has resulted in production growth for many operators. A lot of these wells, on a half-cycle breakeven basis, are economic and they help to bring in cash and keep these operators afloat. However, full-cycle profitability, when acreage costs and overheads are included, remains elusive.

⁷ Haynes and Boone figures show 120 bankruptcies for E&Ps in North America between January 2015 and July 2017.

Figure 14: Net free cash flow for 40 US-based E&P (million US\$)



Source: HedgeAware – By PetroNerds.

Despite negative free cash flow, many publicly traded companies were rewarded throughout the downturn due to their ability to increase production and prove up new acreage. Increased production has typically, but not always, been met with increases in capital expenditures (CAPEX) and often with an increase in negative free cash flow. Many industry observers and analysts alike have questioned when the US shale sector will start becoming cash flow neutral and begin to generate cash. In 2016, unsurprisingly, when frac sand and service costs were just about rock bottom, many operators were briefly free cash flow positive. However, free cash flow again turned negative as many operators ramped up spending and activity grew (predominately in the Permian Basin) in the last quarter of 2016 and the beginning of 2017 (Figure 15). Many operators grew production significantly in the last quarters of 2016 through the beginning of 2017, to the detriment of free cash flow. Some of these operators have been able to maintain production levels, reduce spending, and move toward free cash flow neutrality. However, many operators also increased oil production, spending, and deepened their negative free cash flow hole. Oil prices also played a significant role here.

Figure 15: Capex, free cash flow for 40 US-based E&P (million US\$) and production (b/d)



Source: HedgeAware – By PetroNerds.

There is a growing sense that the tide is finally turning; investors are now beginning to look for profits from these publicly traded operators, with the spotlight being on balance sheet stabilization, capital discipline, and ultimately free cash flow. How strong this investor sentiment is and will be over the next couple of quarters is not yet known. In 2015, the activist investor David Einhorn singled out Pioneer Natural Resources as a ‘mother-fracker’, basically asserting that the industry was a Ponzi scheme and that Texans were ‘*all hat and no cattle*’. Pioneer’s stock was impacted, but rebounded and has since been far more impacted by recent discussions around their gas-to-oil ratio (GOR). But lately more analysts have come out of the woodwork to discuss operator performance and free cash flow. This summer, an article in the *Wall Street Journal* aptly captured the dilemma with the title ‘Shale Produces Oil, Why Not Cash’. Later this summer, BHP Billiton agreed to step out of US shale entirely, due to activist pressure.⁸

And just recently, Schlumberger reiterated some concerns of US shale operators in its third quarter earnings call.

In North America land where the E&P companies have added significant CapEx over the past year, the production growth is so far falling short of expectations, driven by supply chain inflation, operational inefficiencies and the need to step out from the Tier 1 acreage. This has led to a moderating investment appetite where the previous pursue to production growth is now being balanced out with an equal focus on generated solid financial returns and operating within cash flow.

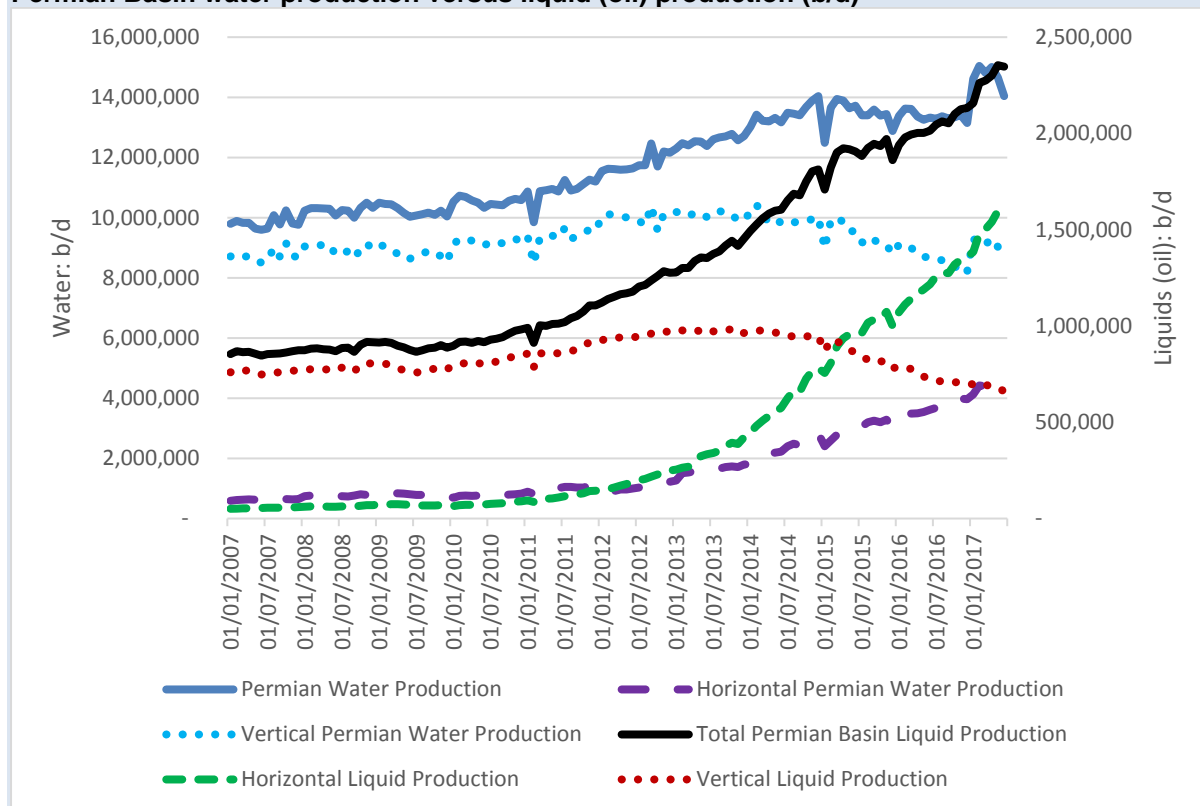
This moderation can be seen in the flattening trend of the U.S. land rig count during the third quarter and it is also reflected in our customers’ 2018 activity outlook. The more tempered activity outlook for U.S. land combined with the short cycle nature of the business has an immediate impact on the outlook for production growth, which for 2017 and 2018 has been revised down by 100,000 and 500,000 barrels per day respectively. This clearly has a material impacts on the global supply and demand balance.

Schlumberger Q3 Earnings Call, Seeking Alpha, 20 October 2017.

⁸ ‘BHP bows to activist pressure to exit US shale’, Jamie Smyth, Hudson Lockett, and Pan Kwan Yuk, 21 August 2017, *Financial Times*.

Water production, particularly in the Permian Basin, could be a problem for many operators as costs come into acute focus. Wells in the Permian Basin produce far more water than their peers in the Powder River, Denver Julesburg, Eagle Ford, and even the Bakken. Permian Basin water production stands at 14 mb/d, nearly seven times the figure for oil production (roughly 2.4 mb/d). Horizontal wells account for over 4 mb/d of water production while producing just 1.6 mb/d of oil.

Permian Basin water production versus liquid (oil) production (b/d)



Source: PetroNerds, DrillingInfo.

IV. Conclusion

Clearly, investor sentiment is changing, but this does not mean that the story of US shale has been told. Technologically speaking, this industry has room to grow. The industry is tackling numerous scientific known unknowns, all of which can contribute to greater productivity and efficiency. Different types of investors will view operators differently for several reasons. Some investors may prioritize free cash flow more than production growth. Others may seek expansion of asset bases and look for execution by operators. But in the near term, operators may have to restrain spending, even if that means less sand. Analysts and operators should appreciate the fact that investors do not always know E&Ps and their activity as intimately as they should. These operators should be viewed as individuals and not lumped together as a whole. While free cash flow is still in the red, many operators are turning the corner; they are doing so around \$50 WTI. The operators that can rein in spending, maintain production levels, and show how they will get to free cash flow neutrality may well be able to survive renewed investor scrutiny over the coming quarters.