Seeking Alpha α

Commodities | **Market Outlook** | **Editors' Picks**

Oil Bears - Can They Have Their Cake And Eat It Too?

Nov. 16, 2018 11:38 AM ET | 2 Likes
by: Blue Quadrant Capital Management

Summary

- Recent market action seems disconnected to fundamental reality and overly fixated with the near-term outlook.
- Unlike 2015-16, the recent oil price correction mainly the result of a strategic miscalculation by OPEC to reverse 2016 production cuts too quickly.
- A consequent correction in oil price and energy equities may further depress global capital investment exacerbating medium-term supply risks.
- Continued demand growth implies either much higher service activity in the years to come or an eventual supply deficit and much higher oil prices.
- As a result, it is not possible or rationale for market participants to have a negative view on both energy producers and oil service companies concurrently.

In this article we will review the current state of the global oil (NYSE:USO) market taking into account some of the latest data and developments since we last covered the sector about six months ago. We will then discuss the recent severe correction in the oil price and implication for the equities of oil producers (NYSE:XOP) and oil service companies. Specifically, we will highlight what we believe is at present an extreme disconnect in investor or market perceptions. ***Broadly speaking, we will outline why we think this time it is different and why oil sector bears cannot both be negative on the outlook for energy producers and oil service companies, at the same time.***

The decline in oil prices between 2014 and early 2016 was driven by rising production from the U.S. (as a result of the shale revolution) and to a lesser extent in Iraq, where oil production recovered following three decades of under-investment and civil unrest.The growth in production swamped demand growth and forced OPEC along with some other countries, most notably Russia, to institute a series of significant production cuts. These production cuts ultimately proved successful in removing excess oil inventories from the market and bringing us to a point in the middle of this year, where an increase in production from OPEC and Russia was likely required.

In this prior article we said that the future direction of oil prices would now more than likely be dictated by OPEC (more specifically Saudi Arabia) and Russia and whether or not they would bring to an end the production cuts agreed upon in 2016. We noted that with future US production growth likely to fall short of global demand growth going forward and OECD oil inventories having returned to within the five-year average, without an increase in production from OPEC and Russia, oil prices would likely continue rising even possibly exceeding $100 per barrel.

Indeed, this is exactly what has transpired. As the table below shows, OPEC increased its production from an average of 32.2mn in Q2 2018 to 32.9mn (and despite the decline in Iranian and Venezuelan production) barrels per day (bpd) in October. Meanwhile, concurrently Russia increased its production from roughly 10.6mn to 11.4mn bpd or 800,000 bpd, translating into a total production increase of around 1.5mn bpd.

Table 5 - 9: OPEC crude oil production based on *secondary sources*, tb/d

	2016	2017	1Q18	2Q18	3Q18	Aug 18	Sep 18	Oct 18	*Oct/Sep*
Algeria	1,090	1,043	1,014	1,026	1,059	1,057	1,057	1,054	*-4*
Angola	1,718	1,634	1,562	1,493	1,472	1,462	1,512	1,533	*22*
Congo	216	252	306	324	317	317	318	324	*5*
Ecuador	545	530	515	519	528	530	528	525	*-3*
Equatorial Guinea	160	133	134	127	124	124	123	131	*8*
Gabon	221	200	195	182	184	186	184	186	*3*
Iran, I.R.	3,515	3,813	3,817	3,818	3,604	3,609	3,452	3,296	*-156*
Iraq	4,392	4,446	4,441	4,480	4,629	4,642	4,654	4,653	*0*
Kuwait	2,853	2,708	2,704	2,708	2,798	2,803	2,797	2,764	*-33*
Libya	390	817	991	889	892	955	1,054	1,114	*60*
Nigeria	1,556	1,658	1,780	1,653	1,711	1,723	1,768	1,751	*-17*
Qatar	656	607	593	602	609	616	595	609	*14*
Saudi Arabia	10,406	9,954	9,949	10,114	10,422	10,404	10,502	10,630	*127*
UAE	2,979	2,915	2,850	2,873	2,982	2,969	3,018	3,160	*142*
Venezuela	2,154	1,911	1,545	1,383	1,242	1,240	1,211	1,171	*-40*
Total OPEC	**32,851**	**32,623**	**32,394**	**32,190**	**32,573**	**32,637**	**32,773**	**32,900**	**127**

Notes: Totals may not add up due to independent rounding.
Source: OPEC Secretariat.

Source: OPEC Secretariat

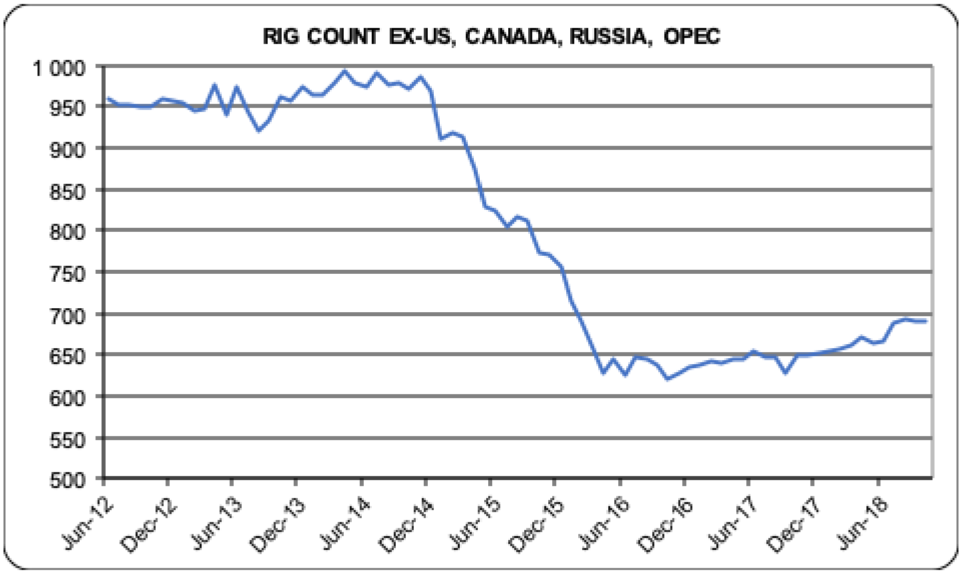
If we add into the mix U.S. production growth that continues to show robust momentum, despite some of the logistical constraints emerging in the major US oil basin, the Permian, it is not surprising that the oil market is now facing a surplus in H1 2019 as well as rising inventories, once again. ***However, in contrast to the 2014-16 period, the decline in oil prices over the past month has been driven mainly by a strategic miscalculation***. OPEC and Russia chose to rapidly increase production in order to avert a potential supply squeeze from rising demand and the imposition of sanctions on Iran.

As discussed, a gradual increase in production from OPEC and Russia earlier this year in order to prevent a further decline in global oil inventories and maintain a balanced market through 2019, was necessary. However, they appear to have moved too hastily. Perhaps preferably they should have waited for a definitive reduction in Iranian production and exports before ramping up their own production so significantly. Naturally, geopolitical considerations may have also impacted their decision-making process, specifically an attempt to lower the oil price in order to assist the Trump administration ahead of the U.S. mid-term elections.

As we argued in the article penned in May, if OPEC and Russian production returned to their peak levels recorded in late 2016 too soon, it was likely despite continued demand growth as well as slowing U.S. production growth, that the oil market would probably remain in balance for much of 2019. However, we also argued that this benign supply backdrop was unlikely to last long and in the context of continued under-investment and risks to US shale growth, a deficit would return to the oil market by 2020. The ramifications of reversing the coordinated 2016 production cuts too rapidly and placing renewed pressure on oil prices will more than likely be continued under-investment only exacerbating potential projected supply deficits in 2020 and beyond.

Given the potential for a surplus in global oil markets in H1 2019 and some of the excessive speculative positioning (long) in the oil market a mere two months ago (as market participants discounted the potential disruption in Iranian supply), it is not surprising that we have had a correction in the oil price. However, what has been quite surprising has been the equally severe correction in the equity prices of energy producers as well as oil service companies concurrently.

Why do we say this? Well, nothing has really changed except for the fact that OPEC and Russia jumped the gun in terms of returning their production levels back to their prior peak levels. Upstream capital investment in 2018 is still expected to fall well short of the prior cycle peak in 2014. This is particularly the case if we exclude the U.S., Canada, Russia and OPEC countries. As the chart below shows the rig count in oil producing countries outside of these aforementioned countries has hardly recovered much since the cyclical trough in early 2016.



Source: Baker Hughes, Blue Quadrant Capital Management

In late 2012, the oil-producing countries incorporated in the above chart produced some 26mn bpd. At present, (likely as a result of the completion of legacy projects approved prior to 2015) and based on the same comparative set of countries, production has actually increased to 28mn bpd. The question is whether these countries can still sustain this level of production (10% higher than six years ago) with a rig count that is still some 30% lower? Have oil productivity levels improved by more than 70% in these countries over the past few years? Perhaps, but it's not likely and the most probable scenario going forward, if we assume a static rig count in these regions, is that production from these countries will decline.

Therefore, we know that in order for global oil markets to remain in balance beyond H1 2019, OPEC and Russia are probably going to have to eventually produce at or near their maximum capacity by the end of 2019 anyway. Given that U.S. production will also still need to grow by at least 1mn bpd over the next 12 months to accommodate projected demand growth, this is in fact a very bullish outlook for oil service companies.

As we can observe in the two tables below, even if we make some optimistic assumptions in terms of OPEC production going forward, total U.S. production will still need to grow fairly considerably over the next four years. The first table presented here models projected oil production levels for OPEC, Russia, Canada and non-OPEC, Russia, U.S., Canadian production. This allows us to formulate a residual which is really the level of required U.S. production.

GLOBAL OIL PRODUCTION AND PROJECTIONS 2018 TO 2022

	Oct-18	BASELINE 2016	Q4-2014	SUSTAINABLE CAPACITY	2020	2021	2022	RIG COUNT 2014	RIG COUNT CURRENT
Figures in thousands									
ALGERIA	1070	1089	1130	1090	1090	1090	1090	49	46
ANGOLA	1500	1751	1720	1600	1500	1600	1600	14	4
CONGO	330	324	0	340	330	330	330	5	4
ECUADOR	520	548	550	540	520	540	540	20	8
EQ GUINEA	120	190	0	130	120	130	130	1	0
GABON	190	202	240	190	190	190	190	7	4
IRAN	3340	3700	2800	3850	3000	3000	3000	n/a	n/a
IRAQ	**4650**	**4560**	**3500**	**4900**	**4900**	**5200**	**5500**	**60**	**60**
KUWAIT	**2760**	**2808**	**2670**	**2920**	**2920**	**2920**	**3000**	**43**	**50**
LIBYA	1120	1110	670	1100	1200	1200	1200	8	8
NIGERIA	1700	1751	1880	1720	1751	1751	1751	15	15
QATAR	610	650	690	620	620	650	650	9	9
SAUDI ARABIA	*10650*	*10544*	*9530*	*12000*	*10650*	*11000*	*11500*	112	122
UAE	**3200**	**3013**	**2750**	**3350**	**3350**	**3400**	**3450**	**38**	**58**
VENEZUELA	1260	2067	2440	n/a	700	700	700	60	25
TOTAL OPEC	*33020*				*32841*	*33701*	*34631*		
OPEC NGLs	7000				7000	7000	7000		
RUSSIA	11400				11600	11700	11800		
NON-OPEC, RUSSIA, US, CANADA	*28100*				*27100*	*26100*	*26100*		
CANADA	5100				5300	5400	5500		

Source: IEA, EIA, Blue Quadrant Capital Management

Based on the above projections, we expect little change in total OPEC production over the next two years compared to recent levels of around 33mn bpd. This is mainly as a result of an expected further reduction in Iranian production (from 3.3mn bpd to 3mn bpd) and Venezuelan production (from 1.26mn to 0.7mn bpd). These production declines will likely be offset by increased production from the Arab Gulf OPEC member states.

In formulating our OPEC projection, we have assumed that an individual member country (which we concede may not be accurate) will be able to produce at its reported maximum sustainable level of production UNLESS its current rig count is below the rig count reported in Q4 2014, in which case we assume the current level of production is going to be as good as it gets, so to speak.

As we can see looking more closely at the table above, we project that Iraq, Kuwait and UAE production will continue to grow over the next few years eventually reaching or modestly exceeding their current stated sustainable production capacity. Regarding Saudi Arabia, we have projected that their production levels will not exceed current levels until 2021 at which point it will reach 11mn bpd and grow to 11.5mn bpd by 2022, close to its reported level of sustainable capacity.

Why do we not expect Saudi Arabia to grow its production over the near-term? Well, the country’s current rig count is only some 10% higher than it was in late 2014 when the country’s production was only 9.5mn bpd. In other words, the rig count in Saudi Arabia will likely need to increase further in order for Saudi Arabian production to exceed 11mn bpd, sustainably.

The following are some of the other assumptions we have made with regard to the above model:

- We assume Russian oil production will continue to grow albeit modestly from current levels. Although Russia in theory could significantly increase its production by tapping into its reserves in the Arctic Sea, production from this region is generally only regarded as feasible with oil prices above $100.
- We assume that OPEC NGL production will remain the same over the forecast horizon.
- We assume that non-OPEC, Russia, U.S., Canada production will decline from 28mn bpd in 2018 to 27.1mn in 2020, 26.1mn in 2021 and remain at that level in 2022. This assumption naturally predicated on the concurrent assumption that the rig count in these regions remain at current levels.
- We assume a modest further increase in Canadian oil production, taking into consideration the very severe logistical constraints the energy sector in that country is facing and likely to continue to face until at least 2020.

Based on these assumptions and projections we obtain the following projected required growth in U.S. oil production looking out to 2022, presented in the table below. The demand figures we use to compute the residual required U.S. oil production levels is based loosely on projected IEA demand levels or demand of around 100mn bpd in Q4 2018, rising to 106mn bpd by the **end of 2022** or average production growth of roughly 1.5mn bpd per annum.

THE "CALL" ON US OIL PRODUCTION 2018 - 2022

GLOBAL DEMAND (Q4)	100000	N/A			102800	104300	105800
CALL ON THE US	15380				18959	20399	20769
US NGLs Production	4380				4500	4500	4500
REQ US OIL PRODUCTION	11000				14459	15899	16269
CURRENT US OIL PRODUCTION	11600		REG GROWTH IN US OIL PRODUCTION		2859	1440	370

Source: IEA, EIA, Blue Quadrant Capital Management

If we take the current level of oil production in the U.S. (as per the Energy Information Agency or EIA) of around 11.6mn bpd (which may be somewhat overstated due to the inclusion of Natural Gas Liquids or NGLs), we can see that U.S. oil production will need to grow by 2.8mn bpd by the end of 2020 and by very nearly 4.6mn bpd by the end of 2022. We have made the simplifying assumption that incremental NGL growth in the US will not necessarily detract (thus maintaining an output forecast of 4.5mn bpd) from required oil production levels, due to the robust growth in U.S. petrochemical capacity between 2017 and 2020, which may not be factored into the IEA's overall global oil demand growth scenarios.

Returning back to our assessment of required U.S. production growth, some may say that incremental growth of 4.6mn bpd off an existing base of 11.6mn bpd over four years is not improbable or impossible. However, the incremental growth in U.S. oil production will have to come entirely from the various shale basins (at least at prices below $65), which despite significant growth over the last few years, still only accounts for roughly 60% of total U.S. oil production.

As we can see in the table below, if we only factor in existing oil production from the various shale basins (currently at roughly 7mn bpd) then total production from these basins will need to grow by 68% to nearly 12mn bpd by the ***end of 2022*** in order for the U.S. to meet its potential supply growth obligations. In our calculations we assume Californian, Gulf of Mexico and Alaskan production will remain static while the remaining conventional onshore production will decline by 400,000 bpd (as all new investment is earmarked for more economical shale production).

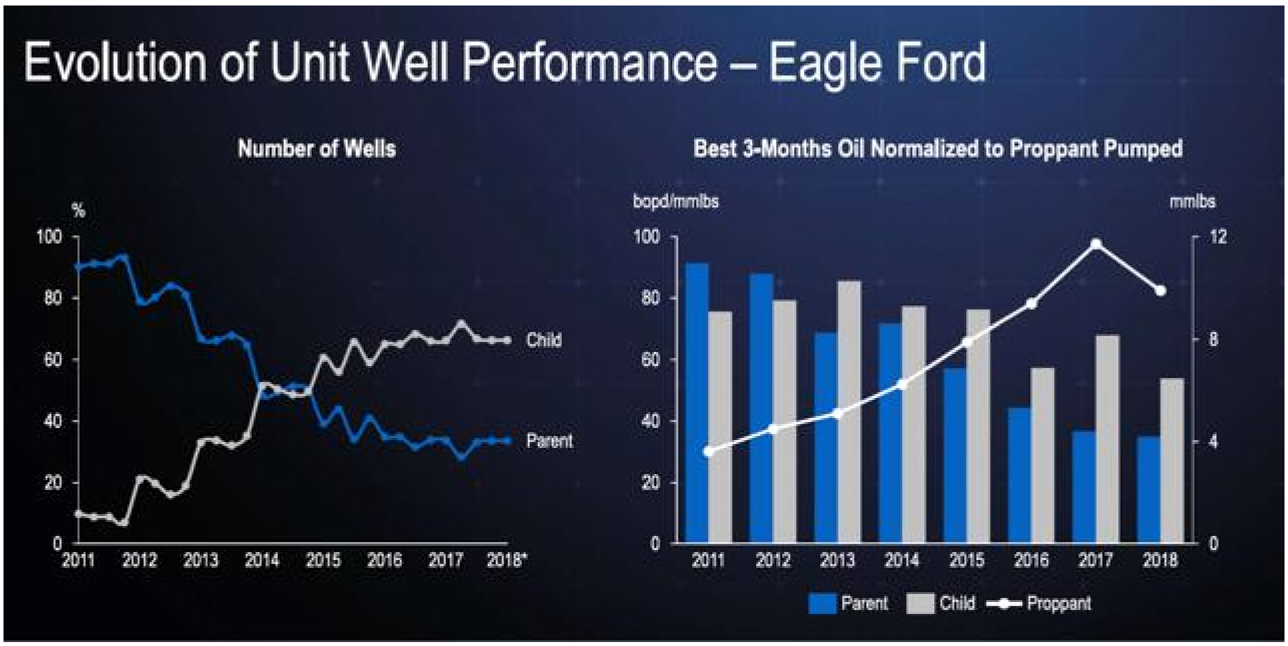
US OIL PRODUCITON GROWTH 2018 - 2022 (BREAKDOWN)

	End-2018	*2022*	
ALASKA	460	460	
GOM	1700	1700	
CALIFORNIA	470	470	
OTHER CONVENTIONAL	2000	1600	
SHALE BASINS	**7000**	**11770**	**4770**
	11630	16000	

Source: IEA, EIA, Blue Quadrant Capital Management

Whether or not this is technically possible no one can really say for sure and certainly we must give the shale operators the benefit of the doubt particularly given how U.S. oil production growth has continued to surprise to the upside. Naturally we still have some doubts that production from the various shale basins can grow this aggressively at prices between $50 and $70 per barrel.

However, if it is technically possible for U.S. shale production to grow by this quantum over the next four years, what we can say with much greater certainty is that the U.S. Rig count will need to increase significantly as well over coming years. Although there is always the potential for increased productivity, this appears increasingly unlikely. In this regard we present a slide taken from the most recent Schlumberger (NYSE:SLB) presentation that suggests as a result of increasing “parent-child” well interference (wells drilled in the same area later on do not perform as well as the first wells), adjusted for proppant usage, well productivity in the Eagle Ford is already declining.



Source: Schlumberger

The data suggests that as the number of “child” wells drilled exceeds “parent” wells, increasingly productivity will decline. Notably, the Permian has just reached this crossover point this year, suggesting the potential for a similar headwind with regard to productivity gains, in this basin. One of the most notable talking points we have come across is a recent study conducted by Chevron that parent wells producing below the “bubble point” have a much greater negative impact on the productivity of child wells nearby.

In regions such as the Eagle Ford and the Bakken, where there appears to be a large gap between initial reservoir pressure and the bubble point, this only becomes an issue many years (some research suggests around 5 to 6 years) after the first parent wells have been drilled. Assuming an operator has drilled so-called ‘ in-fill’ wells in the meantime, the impact on productivity may be limited.

However, if we look at the table below taken from a published article that details the various pressure gradients and reservoir depths of the three main oil basins, we can see that parts of the Permian (particularly in the Midland basin) may have a much lower ‘gap’ between the initial reservoir pressure and the regional bubble point pressure. This would imply a greater impact on productivity in these areas of the Permian once the so-called “cross-over” point is reached and the number of child wells exceed the number of parent wells being drilled. We acknowledge that our interpretation in this regard may be completely incorrect and welcome any feedback to the contrary.

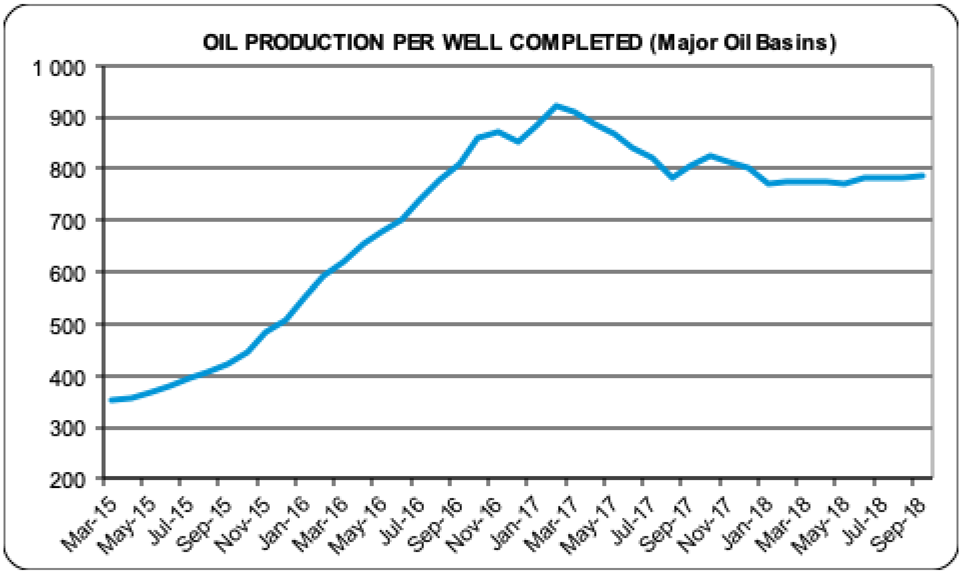
Table 1—Summary of pressure gradient and depth of pay zones

Reservoirs	Pressure gradient (psi/ft)	TVD depth of pay zones (ft)
Eagle Ford	0.60 – 0.80	7,500-11,000 (oil window)
Bakken	0.45 – 0.75	9,000-11,000
Permian Wolfcamp Shale	0.55 – 0.75	5,500-11,000

Source: Society of Petroleum Engineers

Nevertheless, despite these data points and the comments from Schlumberger we will assume for the purposes of this article that productivity in the various shale basins will remain largely static over the next four years. In fact, we should also point out that if we take oil production from the three main shale oil basins, the Permian, Eagle Ford and Bakken and compare this metric to the number of wells drilled or completed, we have not, as yet, seen a meaningful decline in productivity in these basins.

The below chart shows production relative to the number of wells completed on a monthly basis. The ratio has declined somewhat since early 2017 but at this stage is likely a function of the large absolute increase in the number of completions (+50%) since early 2017 as drilling activity rebounded following the 2014-16 slump. If the number of completions were to hold steady at current levels for the next 12 months, overall production would still grow for a period before flat-lining and hence leading to increased overall productivity levels, or at least over the short-term.



Source: EIA data, Blue Quadrant Capital Management

In short therefore, there is nothing that points to an imminent or catastrophic decline in shale productivity levels although the issues pointed out earlier does equally suggest to us that further productivity increases are also unlikely. We should also point out that even a 10% decline in productivity would not necessarily substantially negatively impact the equity values of most of the larger shale producers. A 10% decline in productivity would imply a 10% increase in costs. On a cost base of say $25 per Boe (barrel of oil equivalent), this incremental cost would be offset by a mere $5 rise in the oil price assuming 50% of a producers output is oil.

Furthermore, the shale industry could also come up with new techniques or innovations that may help mitigate some of the evolving technical issues such as Parent-Child well interference. As an example, some operators have adopted a development methodology called “Cube” drilling where all available locations (including all stacked pay-zones) in a specific acreage unit are developed simultaneously. This approach they argue will ensure that actual production levels remain consistent with prior projected type curves.

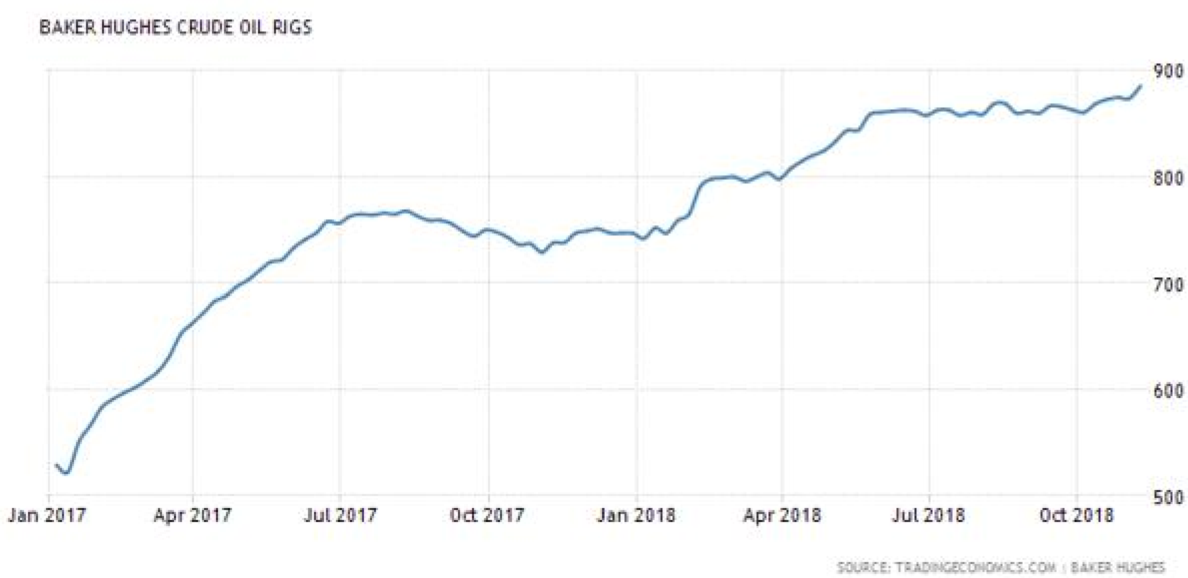
Nevertheless, if productivity levels do decline, smaller operators or those operating in “non-core” areas could face much larger (relative to the major companies) cost increases. However, to the extent that it negatively impacts on long-term production profiles, this would more than likely lead to higher oil prices over time given the unexpected shortfall relative to consensus. This would either largely offset the increase in costs from the decline in productivity or it would be a boon to operators with superior core acreage not plagued by the same issues or at least to the same extent. Alternatively, it would imply a much greater level of required service activity as a 10% decline in productivity implies a 10% increase in the number of completions and associated drilling activities in order to maintain the same long-term production profile.

Nevertheless, assuming static productivity levels, if we target a production level of roughly 10.5mn bpd (including existing conventional production in the Permian) from the three major oil shale basins (Permian, Eagle Ford and Bakken) which currently account for 80% of total shale oil production (therefore assuming the residual basins will account for the remaining 600,000 to 700,000 bpd of required production growth), we calculate* that these three basins would need to increase their cumulative rig count by roughly 500 rigs. These, admittedly very rough calculations, ***assume static productivity and no deterioration in legacy decline ratios.***

**The calculation assumes a monthly increase of 8 rigs in the Permian and the 3 cumulatively in the Eagle Ford and Bakken.*

This implies a more than 50% increase in the U.S. oil rig count from current levels will be required over the next four years in order for the U.S. to meet global demand growth under a fairly benign OPEC supply backdrop (i.e. production in Saudi Arabia reaching 11.5mn bpd and a loss of less than 1mn bpd in Iranian production).

As we can see in the chart below, despite the relatively high oil prices that have prevailed this year (or prior to the most recent correction), the U.S. oil rig count with the exception of the last few weeks has actually struggled to grow since June. The key question that investors should ask themselves is whether the U.S. oil rig count can really grow by 50% (to around 1400), without the incentive of much higher oil prices?



Source: Tradingeconomics, Baker Hughes

How realistic are existing long-term U.S. shale oil production forecasts?

A recent report published by Kimmeridge Energy made an impression on us in that it provided more clarity on the extent of " core" acreage in the various shale oil basins, something that we think will have a greater impact on long-term U.S. production forecasts as opposed to technical issues such as "Parent-Child" well interference. The report was fairly detailed in its assessment of the relative productivity and economics of the various shale basins in the U.S. (from an oil perspective). In the report they estimated the total size of the " core" acreage within each basis. Core acreage is generally likely to be classified as economically viable at prices below $50 per barrel.

However, what stood out to us if we look at the table below, is the fact that according to their calculations, the bulk of the remaining core acreage is really only situated in the Permian (Delaware and Midland sub-basins).

Play/Basin	Core Area (Million Acres)	Core Counties
Delaware Basin	3.5	Lea, Eddy, Reeves, Culberson, Loving, Ward
Eagle Ford	2.6	Webb, La Salle, McMullen, Live Oak, Karnes, DeWitt, Gonzales
Bakken	1.3	McKenzie, Williams, Mountrail, Dunn, Richland, Billings
Midland Basin	0.8	Midland, Glasscock, Reagan, Upton
Three Forks	0.6	McKenzie, Williams, Mountrail, Dunn

Exhibit 15: Comparison of core areas in tight oil plays (IHS, DrillingInfo and Kimmeridge estimates)

Source: Kimmeridge Energy

Why do we say this? Well, if make another assumption that each well requires roughly 160 acre (this metric can, admittedly vary widely) spacing and we add up all the wells drilled (completions) since 2014 in the Bakken including the Three Forks area it amounts to roughly 6,700 wells compared to a possible total of 12,000 locations or 50% based on the above outlined 1.9mn core acreage in the Bakken. Further to this we should note we are only taking into account wells drilled since 2014 so the actual amount is much higher, although we acknowledge not all wells drilled in the Bakken over the past decade would have been in these so-called " core" areas either.

In the Eagle Ford the total number of wells completed since 2014 is almost 12,000 compared to a possible total of 16,000* or 75% based on the above assumed core acreage of 2.6mn. Naturally, many wells drilled in the Eagle Ford in the early years were gas wells, although we can say that the bulk of the wells drilled since 2014 are likely to have been oil wells (given the collapse in natural gas price since 2012). So, on balance, we don't think these high-level estimations are that far off from reality and would suggest that on the current "run-rate" of monthly completions in these basins, there remains only 6 years of core inventory left in the Bakken and perhaps even less in the Eagle Ford.

**In the Eagle Ford and to a lesser extent the Bakken there are in some areas more than one 'pay-zone' which implies a higher number of potential well locations. However, for these two basins we don't think this feature is that material in contrast to the Permian where in the Midland basin (a stacked play) for example an operator typically has up to 5 pay-zones that they can exploit in a single 160 acre drilling unit.*

Further to this, our research suggests that only a handful of companies (typically listed) own the remaining core acreage in these basins and they are very unlikely to increase production significantly or extend operations into non-core areas in the absence of **much higher** prices. In fact over the past year we have seen many of these companies exercise significant restraint in their capital investment plans and instead targeting a slower rate of growth in order to reach a point of free cash flow generation sooner rather than later.

Smaller and/or private operators in these basins will quite possibly run out of available core acreage (if they haven't already) much sooner and their contribution to total production in these basins could well decline and at an aggregated level lead to overall output from these basins leveling off or even starting to decline within the next few years. This may happen even if some of the larger companies operating in these basins retain large tracts of core acreage that enable them to continue producing or growing production for many years to come.

This ultimately would imply that most if not all of the required U.S. production growth looking out beyond 2020 will have to come from the Permian basin. But even here the core acreage in this basin has become highly concentrated in recent years due to ongoing mergers and acquisitions. We doubt that these larger companies that control large tracts of core acreage in the Permian would significantly increase their production without the incentive of much higher prices.

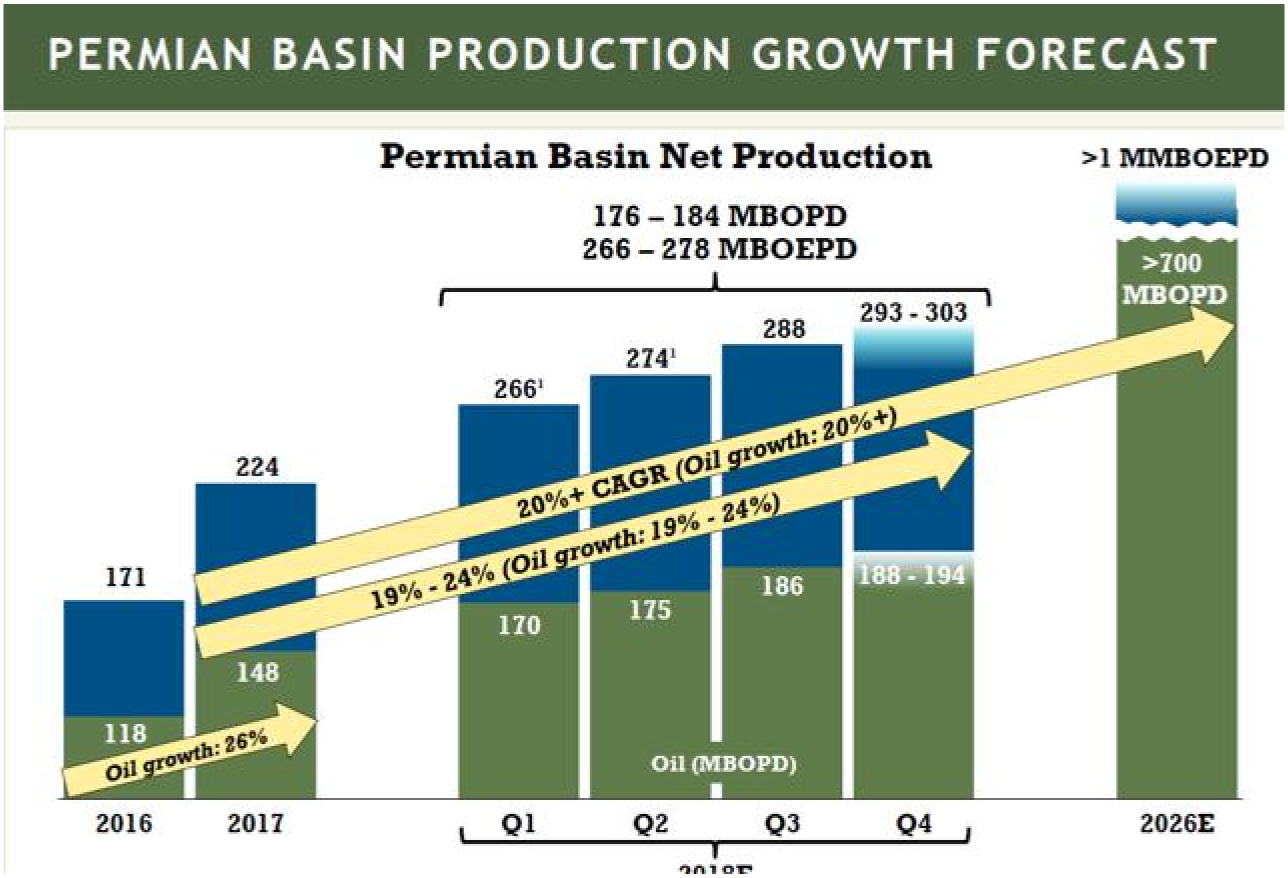
A case in point is Pioneer Natural Resources (NYSE:PXD). As we can see from the slide below taken from one of their recent presentations, a mere 17 companies control more than 55 Billion Barrels of Oil Equivalent in the Permian. This equates to more than 110,000 well locations which is more than our rough estimate of around 90,000 core well locations based on the Kimmeridge data.

Company	Horizontal Rig Count	Number of Locations	Net Resource (BBOE)
Pioneer	20	20,000+	10
ExxonMobil	20>30 in 2018	7,000	6
Apache	16	5,000+	75 TCF 3 BBO[1]
Parsley Energy	16	8,000+	-
Concho	15	19,000+	8
Chevron	15	1.5 MM acres	9.3
EOG	14	6,300+	6
Oxy	14	2,800	2
Anadarko	10	10,000+	4
Diamondback	9	4,300+	-
Devon	9	6,500+	-
Cimarex	9	325,000 acres	-
WPX	7	6,400+	-
RSP Permian	6	5,000+	3.4
Encana	5	3,450	3.3
Noble	4	4,000+	2
ConocoPhillips	3	1,400	1.8
	191 rigs (~55% of Permian total)	>110,000 locations	>55 BBOE

Source: Pioneer Natural Resources

Also worth noting from the slide above is that these same 17 companies only accounted for 55% of all rigs operating in the basin, providing some indication of how significant the relative contribution from smaller or private operators in the basin still is.

More pertinent to the debate looking at the slide below, we can see that PXD itself (second largest Permian operator based on the above metrics) plans to grow oil production at a steady rate of around 20% per annum over the next 10 years.



Source: Pioneer Natural Resources

Given that the remaining available " core" acreage in the Eagle Ford and the Bakken appears quite limited it would suggest that the vast majority (80%+) of U.S. oil production growth of between 4mn bpd and 5mn bpd required over the next four to five years will have to come from the Permian. Further to this, if we extrapolate PXD's projected annual growth rate to the other majors in the basin and assume that they currently account for 80% of production (which is probably too high), then it is not inconceivable that over the medium-term annual growth in U.S. oil production could slow to around 500,000 bpd, far below the recent pace of growth. It is important to note that this slowdown in growth could materialize **even if there is no** deterioration in industry productivity.

Conclusion

Based on the analysis in this article we can reach two important conclusions. Global oil demand will continue to grow over the next four to five years and with international (outside of Russia and OPEC) upstream investment still significantly depressed, a large portion of this growth will have to be satisfied by the U.S. and those OPEC members with spare capacity. Even if this supply growth does materialize in a sufficiently timely manner to keep oil prices at current levels it would **STILL** imply a much higher level of oil service activity going forward.

In contrast, if these production requirements cannot be met by the U.S. and OPEC, then it will require a step-up in broader international upstream investment, which will require higher oil prices ($80+?) for a sustained period of time, a positive outcome for oil producers and in particular U.S. shale oil companies with large tracts of “ core” acreage. Very simply, the oil bears can’t have their cake and eat it. In other words, they cannot be bearish on the oil price and therefore energy producers as well as oil service companies concurrently. ***Something will have to give somewhere, at some point***.

Disclosure: I/we have no positions in any stocks mentioned, and no plans to initiate any positions within the next 72 hours.

I wrote this article myself, and it expresses my own opinions. I am not receiving compensation for it (other than from Seeking Alpha). I have no business relationship with any company whose stock is mentioned in this article.

Comments **(0)**