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Jadwa Investment

October 2015

US Shale Oil at an Inflection Point

Summary

- This report follows up on a comprehensive analysis we published on the US tight/shale oil back in December 2013 (please see: *The outlook for unconventional oil and gas production*).

- In a period of high oil prices between 2010-2014, many smaller US exploration and production (E&P) companies took advantage of cheap and readily available financing to cover capex costs to expand shale oil production.

- US shale oil production continued to increase, year-on-year, even as oil prices tumbled 50 percent, from mid-2014 onwards, as timely hedges in oil prices combined with continued access to finance and increased operational efficiency helped to bring down breakeven costs of shale drillers.

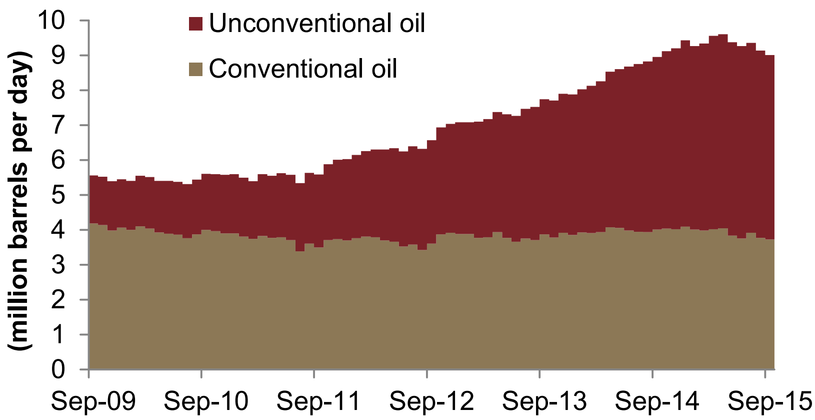
- Going forward, sustained drops in production are expected as oil hedges expire, financing from secured lending is tightened and the high yield debt market becomes too expensive.

- There will not be a collapse in shale oil production as a period of sector consolidation, via global integrated oil companies and private equity, ensures that shale oil remains a key player in the global oil market going forward.

- Aside from shale oil, the lower oil price environment will also impact global oil supply, with capex cuts in major integrated oil companies leading to tighter oil markets from 2017 onwards.

- Although the fight for market share will lead to lower short term oil revenue, Saudi Arabia is likely to be the main beneficiary when global oil markets become tighter and prices rebound by 2020.

Figure 1: US conventional vs. unconventional oil production



Source: Energy Information Agency (EIA) and Jadwa Investment

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Overview

A comprehensive analysis of the US tight oil was published by us back in December 2013.

Global oil prices have dropped by 50 percent since July 2014...

...and we therefore see it necessary to revisit the topic of US tight oil and gas and refresh our conclusions.

We look at the future of US tight oil and what implications this has for Saudi Arabia's own oil policy.

We published a comprehensive analysis of the US tight oil (often referred to as shale or unconventional oil) back in December 2013 (please see: *The outlook for unconventional oil and gas production*). In this report we documented, amongst other things, the rapid development of tight oil, which jumped from virtually nothing in 2004 to around 5.4 million barrel per day (mbpd) by mid-2015. Tight oil in the US currently represents 51 percent of total US oil production and has been the main source of year-on-year production growth in the country from 2008 onwards (Figure 1). Since publishing the report back in 2013, the global oil market has witnessed massive change, specifically through oil prices dropping by 50 percent since July 2014. Whereas previously the global oil industry viewed $100 per barrel (pb) as the norm, we are now in a period of volatility and uncertainty, with the concept of $100 pb having been firmly banished and not likely to return any time soon. As a result, in the context of lower global oil prices, we see it necessary to revisit the topic of US unconventional oil and gas and refresh our conclusions and findings from our initial report on tight oil.

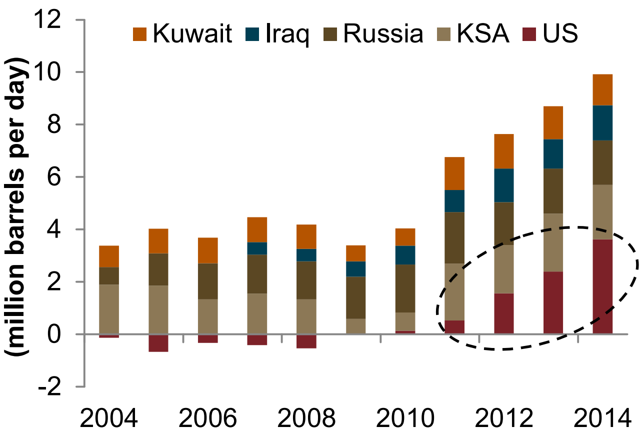
The oil price fall, which started in mid-2014, will provide the key timeline in our 'before and after' analysis. Through analysis of key indicators in the US unconventional sector, such as production, rig counts, company financials and forecasted year-on-year growth, before mid-2014 and contrasting it with analysis a year later, in mid-2015, we will be able to present a clearer outlook of the future of US unconventional oil and what implications this has for Saudi Arabia's own oil policy, both in the immediate and longer term.

US shale crude oil and gas plays

At the end of 2014, the US had registered the highest net cumulative crude oil production in the last decade.

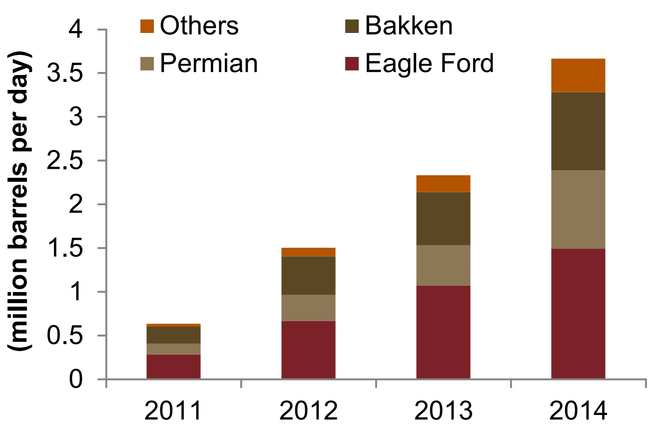
At the end of 2014, the US had registered the highest net cumulative crude oil production in the last decade, beating the likes of traditionally large oil producers such as Saudi Arabia and Russia. In the ten years to 2014, the US increased total crude production by 3.6 mbpd, with accelerated growth in production from 2011 onwards (Figure 2). Of this, the Bakken, Permian and Eagle Ford shale plays (Table 1) contributed 3.3 mbpd, or 91 percent, of the total (Figure 3).

Figure 2: Cumulative growth in crude oil production: 2004-14



Source: EIA and Jadwa Investment

Figure 3: Cumulative US unconventional crude oil production by play: 2011-14



Source: EIA and Jadwa Investment

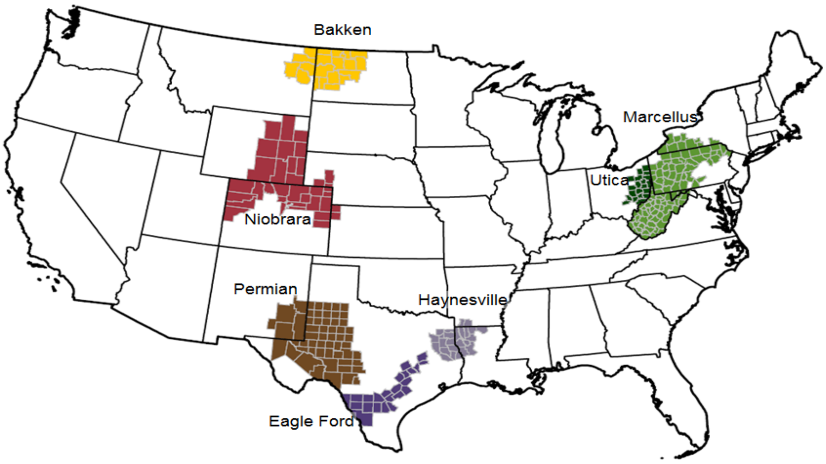
The Bakken, Permian and Eagle Ford shale plays contributed 3.3 mbpd, or 91 percent, of the total US production.

The Permian play is the largest unconventional oil play, producing 35 percent of total US unconventional crude oil production.

Permian:

The Permian Basin, which is located in West Texas and southeastern New Mexico, saw its first well drilled in 1925. Horizontal drilling and hydraulic fracturing has unlocked huge oil reserves, with the most productive formations in the Permian being the Spraberry, Wolfcamp, and Bone Spring. In mid-2015 the Permian play was the largest unconventional oil play, producing 2 mbpd, equivalent to 35 percent of total US unconventional crude oil production. The Permian play also produced a total of 6.3 billion cubic feet per day (bcf/d) of gas, a large portion of which was non-associated.

Table 1: US unconventional crude oil and gas basins



Source: EIA Drilling Productivity Report, 2015

Eagle Ford oil production totaled 1.6 mbpd….

Eagle Ford:

Eagle Ford in South Texas is the second largest tight oil play in the US. At mid-2015, oil production from the play totaled 1.6 mbpd and produced a large amount of gas, at 7 bcf/d.

...and in Bakken it was 1.2 mbpd.

Bakken:

Bakken in North Dakota and Montana was the first tight oil play to be significantly developed in the US. It was the third most productive play at mid-2015, with total production of 1.2 mbpd of light sweet oil. It also produced 1.5 bcf/d of gas, although the North Dakota Pipeline Authority estimates that as much a third of this was flared due to lack of pipeline infrastructure.

Four other plays make up the rest of the US unconventional crude oil production.

Others:

Four other plays make up the rest of the US unconventional crude oil production. The largest of these is the Niobara play, which produced a total 440 thousand barrels per day (tbpd) at the mid- 2015 and 4.5 bcf/d of gas. The Utica, Marcellus and Haynesville plays make up the rest of the unconventional crude oil production.

The shale oil 'revolution'

The main factors contributing to rapid development of the US unconventional oil output were...

Both endogenous and exogenous factors combined to bring about the rapid development of the US unconventional oil output. Key factors in this 'revolution' included*:

Technological advancement:

In most cases, the presence of large unconventional deposits in the US had been known for many years but in order for these to be exploited the right conditions had to prevail namely technological advancement and high oil prices. The first of these conditions was met through a technique called hydraulic fracturing.

...the refinement of technology in order to develop hydraulic fracturing…

The refinement of technology in order to develop hydraulic fracturing was possible due to the existence of a competitive and dynamic onshore oil service industry which had built up during the long history of crude oil production in US.

Ideal geology and low population density:

….less densely populated areas in the US...

Shale deposits in the US are generally large and shallow which makes them ideal for exploitation. The US also has a relatively low population density, at 33 inhabitants per km². This compares to the UK, at 255, Germany, at 229, and China, at 129, inhabitants per km². Less densely populated areas in the US made it easier to grant oil exploration and production (E&P) companies leases and licenses for oil exploration in large areas of land. The US also has a legal system which rewards landowners for the profitable extraction of the hydrocarbon resources under their ground.

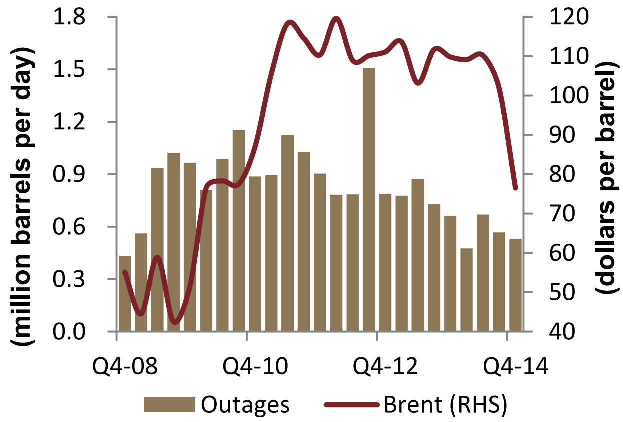
Large number of independent companies:

...large number of exploration and production (E&P) companies only focused on the upstream sector….

Independent companies have been a major component of the unconventional boom. Whereas larger integrated companies, such as Shell, BP and Exxon Mobil, are involved in all aspects of the oil business, independents only operate in the upstream E&P space. Most independent E&P companies are classified as small or mid-cap.

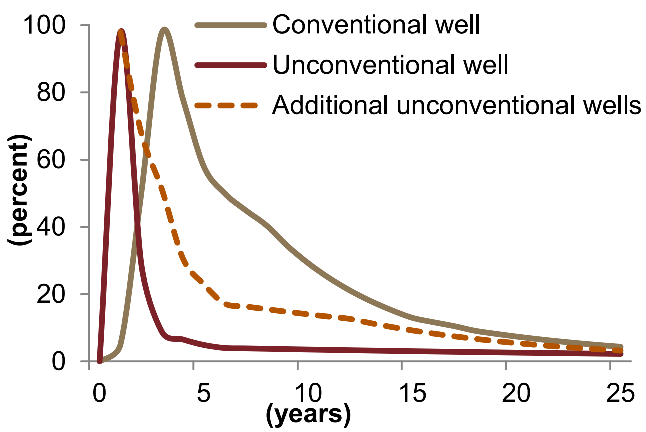
As unconventional production began to accelerate, US investor confidence in the shale sector increased as well. This saw a number

Figure 4: Cumulative outages (Libya, Iran, Yemen, S.Sudan and Syria) and Brent oil prices



Source: JODI, Thomson Reuters and Jadwa Investment

Figure 5: Production curves at conventional and unconventional wells (100 = peak production).



Source: EIA and Jadwa Investment

*Note: For a more detailed analysis on this please refer to Jadwa's report: The outlook for unconventional oil and gas production

...sustained period of high oil prices above $100 per barrel (pb).

Unconventional oil production is characterized by very short periods between the initial stage and the second stage of producing oil.

Decline curves in production for typical unconventional wells are steep…

...meaning drilling intensity is much higher when compared to conventional wells.

Full cycle costs include finding and development (F&D) spending, internal rate of return (IRR), and taxes.

of smaller and medium sized E&P companies entering the market and gaining access to cash from the high-yield bond market and/or through leveraged loans (see Box 1: Shale oil financing).

<u>Oil prices at $100 per barrel</u>

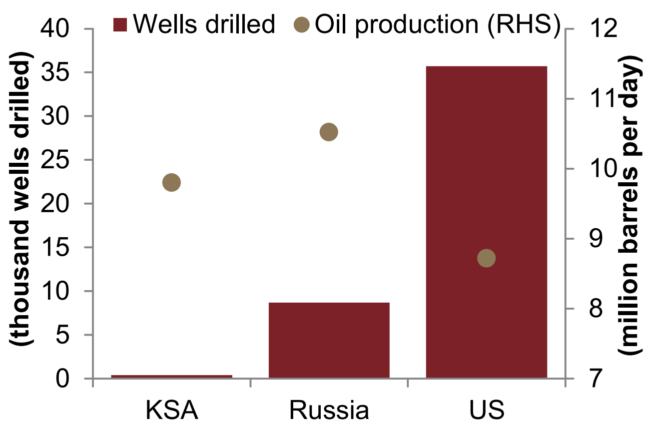
Global production outages in a number of countries added to the risk premium in crude oil prices. In particular outages in five countries (Libya, Iran, Yemen, (South) Sudan and Syria), peaking at 1.6 mbpd, meant global crude oil spare capacity narrowed significantly, all of which contributed to pushing prices to around $100 pb from 2011-2014 (Figure 4). This period of sustained high prices encouraged capital expenditure (capex) on high cost projects such as US unconventional oil.

Shale oil economics

Unconventional oil production is characterized by very short intervals in between the initial stage of acquiring land and drilling licenses to the second stage of developing wells and producing oil. This contrasts with conventional production where it can take two to three years from the initial stages before any oil is produced. Another major differentiator between unconventional and conventional wells is seen once production begins. Whereas conventional wells may not plateau for several years, beyond which production stabilizes for an extended period, decline curves in production for typical unconventional wells are steep, with first year declines in production around 69 percent and overall declines in the first five years around 94 percent (Figure 5). The consequence of such steep decline curves is that unconventional oil fields require a disproportionally larger number of wells to produce similar levels of oil, when compared to their conventional counterparts. For example, in 2014 Saudi Arabia and Russia achieved average production of 9.8 mbpd and 10.5 mbpd, respectively, through drilling 399 and 8,688 additional wells, whilst nearly 36,000 new wells were drilled in the US for an average production of 8.7 mbpd (Figure 6).

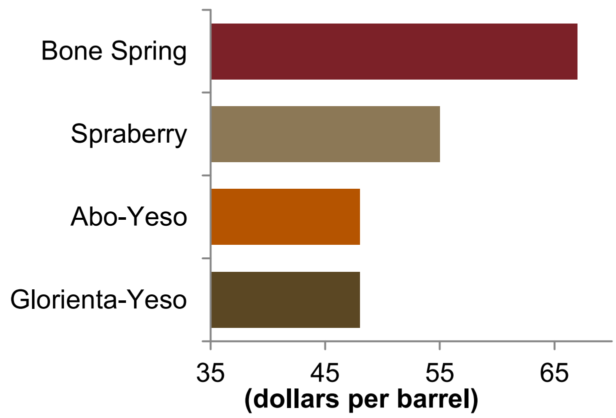
The high capital intensive nature of shale oil means that a proper assessment of both full and half cycle costs need to be carried out before engaging in new drilling projects. Full cycle costs incorporate total costs in any given unconventional project. This includes finding and development (F&D) spending, such as purchasing or leasing of

Figure 6: Drilling intensity much higher in unconventional vs. conventional fields



Source: Schlumberger and Jadwa Investment

Figure 7: Half-cycle breakeven prices at selected oil-producing formations at the Permian play



Source: EIA, Rystad Energy and Jadwa Investment

Half cycle costs refers to the marginal cost of drilling and producing from an additional well.

land and performing seismic tests. It will also include an appropriate internal rate of return (IRR), and taxes, where relevant. Half cycle costs refers to the marginal cost of drilling and producing from an additional well, when land and other sunk costs have already been made (Table 2).

Once the well is producing oil, operating costs become more important.

Once the well has been drilled and oil is being produced (i.e. it has been completed), operating costs (or shut-in prices) become more important. The wellhead price (the market price of oil at well surface less transport costs) should be, in theory, equal to or more that than the shut-in price in order for a company to continue operating a drilled and completed well. Although there is no exact measure of wellhead prices, a US E&P company may use the US oil benchmark West Texas Intermediate (WTI) oil futures as an indicator.

Breakeven price refers to the oil price need to cover either full or half cycle costs at a well.

Two companies engaged in the same play may have different breakeven costs.

Breakeven prices vary between $30 pb to $75 pb in different parts of the Bakken play.

Breakeven price refers to the oil price needed to cover either full or half cycle costs at a well. Breakeven prices are not uniform for all E&P companies and depend on a number of variables. Two companies engaged in the same play may have different breakeven costs due to acreage (land) quality even though they operate in the same formation. For example in the Permian shale play, there are a number of formations, such as the Glorienta-Yeso, Abo-Yeso, Spraberry and Bone Spring, all of which have different breakeven prices (Figure 7). A company's full cycle cost may also be comparatively lower due to first mover advantage through lower acreage costs. According to North Dakota's Department of Mineral Resources full cycle breakeven prices vary between $30 pb to $75 pb in different parts of the Bakken play whereas half cycle costs can be as low as $15 pb. It is more appropriate to consider half-cycle costs in the short-term, since this reflects the cost of additional wells where sunk costs are excluded. In the longer term, full-cycle cost become more relevant since further output requires acquisition of more acreage.

The breakeven price of any formation which includes both unconventional oil and gas will be lower than that for oil alone.

Breakeven prices are further complicated by the cost structure of unconventional gas, which, on a per barrel basis, is considerably lower than oil. Most US E&P companies involved in unconventional sector produce both oil and gas. Industry estimates put unconventional gas breakeven prices at a range between $3- $5 per million British thermal units (mBtu), which equates to around $18 to $30 per barrel of oil equivalent (boe). The breakeven price of any formation which includes both unconventional oil and gas will

Table 2: Full and half cycle costs of unconventional oil production

		Sunk Costs	Land acquisition and F&D costs
Full cycle costs		Land acquisition	The cost of acquiring land to explore for oil and gas.
Full cycle costs		Finding and development costs	Cost related to geological and geophysical work, licensing rounds and costs of drilling exploration wells. Infrastucure to be built to gain access to remote sites.
Full cycle costs	Half cycle costs		Costs of acquiring, constructing, and installing production facilities and drilling development wells.
Full cycle costs	Half cycle costs	**Operating costs**	**Excluding land acquisition F&D costs**
Full cycle costs	Half cycle costs	Well operation & maintenance	Operating the well including pumping and artificial lift.
Full cycle costs	Half cycle costs	Labor	Cost of labor employed.
Full cycle costs	Half cycle costs	Transport costs	Cost of transporting its product to market can vary depending on mid-stream oil infrastructure available.
Full cycle costs	Half cycle costs	Taxes	A company will either pay production taxes or royalties to the host state. This could be either a fixed royalty percentage or a production sharing agreement.
Full cycle costs	Half cycle costs	Internal rate of return (IRR)	A sufficient rate of return after taxes.

Source: Oil & Gas Journal, Evaluate Energy and Jadwa Investment therefore be lower than breakeven prices for oil alone. All three of the major shale formations (Permian, Bakken and Eagle Ford) hold both shale gas and oil reserves.

Box 1: Shale oil financing

US E&P companies have financed capex by turning to equity and debt markets.

These financing options played an important role in sustaining US independent E&P shale oil production.

As mentioned above, shale oil requires a very high level of drilling activity to prevent steep decline rates. When considering that the sector is made of large number of small and medium-sized companies, the relative upfront costs associated with such intensive drilling can be significant. In the early years of shale oil production E&P activity was centered around the productive basins of Bakken, Eagle Ford and Permian but as high oil prices prevailed and the industry expanded, less productive acreage was brought on-line leading to higher capex costs and a widening funding gap (Figure 8). The inability of US shale oil E&P companies to cover capex through their own means saw them turning to equity and debt markets in order to raise finances.

Shale oil requires a very high level of drilling activity to prevent steep decline rates.

As less productive acreage has been brought on-line, capex costs have increased.

During the financial crisis of 2008-09 some of the better placed E&P companies were able acquire less well-off companies and assets relatively cheaply and push forward onto listing on the US equity markets. As a result such companies were able to gain access to cheap finance, due to record low US interest rates, even in the backdrop of constrained lending. The equity market was not an option for more newer and smaller entrants into the industry since most of these companies were classified as non-investment grade (or junk bond) status. Financing for such E&P companies was therefore sought from the high-yield bond market and/or secured loans. These financing options have played an important role in sustaining US independent E&P shale oil production in the last few years (Figure 9).

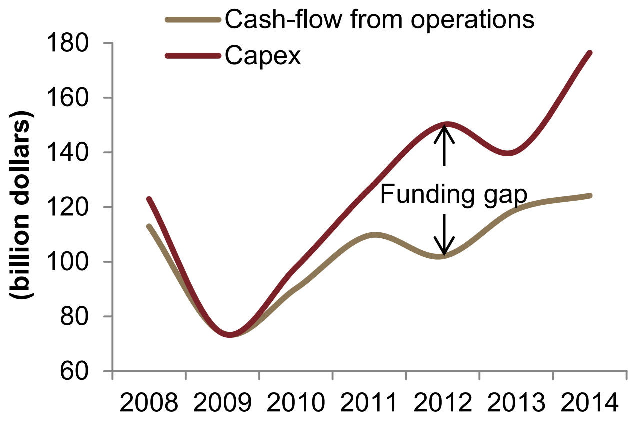
At the end of the high oil price cycle

Shale oil output had been growing steadily in the first six months of 2014.

Production:

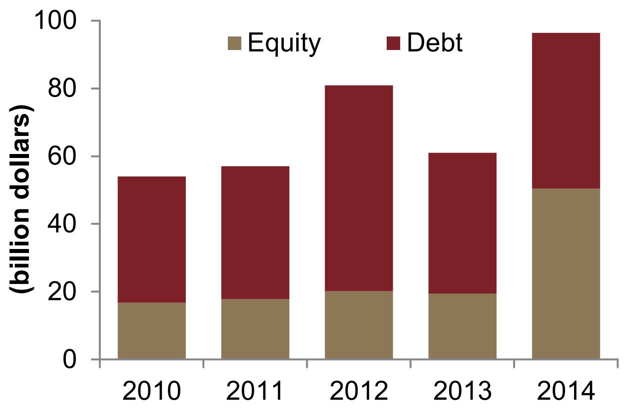
Shale oil output had been growing steadily in the first six months of 2014, prior to when oil prices started their downward trend. Year-on-

Figure 8: Funding gap in listed US shale oil E&P companies



Source: Bloomberg Intelligence and Jadwa Investment

Figure 9: US E&P capital raising by type



Source: Bloomberg, Oil & Gas Journal and Jadwa Investment year growth of total US crude oil production in H1 2014 averaged just over 1 mbpd with around 80 percent of the yearly growth being made up from the Permian, Bakken and Eagle Ford plays. In its July 2014 publication of the Short Term Energy Outlook (STEO), the EIA was forecasting similar rates of growth for the second half of 2014 with slightly lower annual growth for 2015, at 0.8 mbpd.

Rig count:

The number of oil rigs totaled around 1,000 at mid-2014.

The number of rigs drilling for oil in the three major shale plays totaled around 1,000 at mid-2014, in line with the average of the previous three years.

Financing:

By mid-2014 US shale E&P companies had raised $32 billion through equity and debt, up 10 percent year-on-year.

As mentioned above, the US shale oil industry is made up of numerous small and medium cap companies. Most of these companies took advantage of the low interest rate environment and higher risk appetite of lenders and investors in recent years to obtain financing via the high yield corporate bond market. By mid-2014 US shale E&P companies had raised $32 billion through equity and debt, up 10 percent year-on-year.

Capex:

US E&P capex in shale oil & gas had reached a total of $176 billion by 2014, rising by 26 percent year-on-year, and up a staggering 139 percent, in total, since 2009.

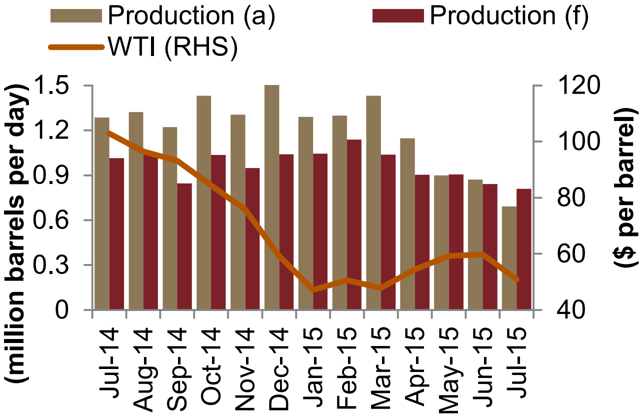
Resilience at low prices

So far, the impact of lower oil prices has not dramatically affected shale oil output even as…

...oil rigs at the three major shale plays dropped from a total of 996 in July 2014 to 420 a year later.

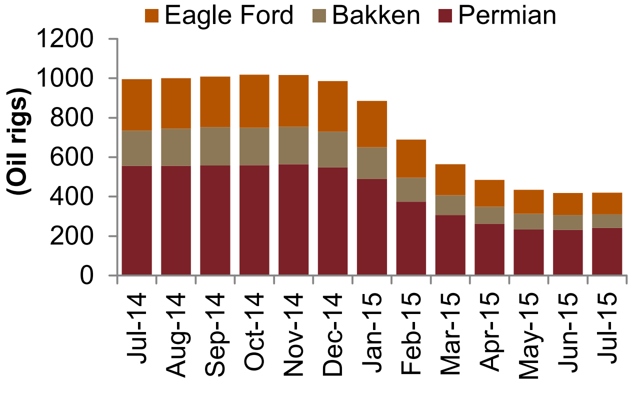
A sustained drop in oil prices saw Brent and WTI decline from $105 and $101 pb, in mid-July 2014 to $43 and $40 pb by mid-August 2015. The impact of lower oil prices has not dramatically affected shale oil output even though a downward trend has started to emerge. In fact actual output exceeded the EIA's STEO forecasts from July 2014. The EIA had predicted average growth in US production at just below 1 mbpd over the year, in July 2014, but actual growth averaged 1.2 mbpd over this period (Figure 10). This higher than forecasted production was reached even as a record fall in the number of oil rigs was registered. Oil rigs at the three major

Figure 10: US actual (a) vs. forecasted (f) crude oil production (year-on-year growth).



Source: EIA and Jadwa Investment

Figure 11: Oil rig count at top three shale oil basins.



Source: EIA and Jadwa Investment

Production has been maintained through:

shale plays dropped from a total of 996 in July 2014 to 420 a year later (Figure 11).

The key to this higher than projected output in face of lower oil prices and a declining rig count is due to:

Capital raising:

i) US shale E&P companies continued raising finance in the equity and debt markets in 2015.

US shale E&P companies continued raising funds in the equity and debt markets in 2015. The combination of hedging (see below) and a general lack of investment yield elsewhere in the US, given record low interest rates, saw lenders continuing to show interest in the shale energy sector. By mid-2015 US shale E&P financing had reached record levels, with $44 billion in debt and equity raised in the first half of 2015, representing an increase of 35 percent, year-on-year.

Cost and capex reduction:

ii) Even with capex spending declining, shale oil producers maximized output by allotting capital to their highest return assets.

As oil prices dropped, it became clear that budgeted capex would also have to be cut. Unsurprisingly therefore, drilling and completion capex budgets at the three major shale basins were down by 40 percent, year-on-year, in 2015, to $34 billion. But even with capex spending declining, shale oil producers maximized output by allotting capital to their highest return assets, a process called ‘high-grading’. That is, producers continued their drilling programs in the most economical oil rich basins and focused capex cuts on low capital efficiency areas.

Capex was also reduced through the deferral of completing wells…

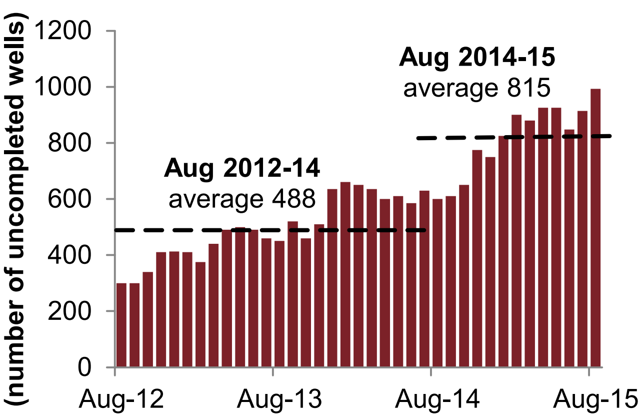
...resulting in a buildup of wells that have been drilled but are awaiting completion (DUCs).

Capex was also reduced through the deferral of completing wells, with drillers preferring to wait until oil prices rise in the future. This has resulted in a buildup of wells that have been drilled but are awaiting completion, also referred to as drilled uncompleted wells (DUCs). The number of DUCs has risen sharply in the last year. For example in North Dakota, where part of the Bakken shale formation sits, DUCs averaged 488 in the two years to June 2014, but after oil prices declined, the average rose to 815 in the year to June 2015 (Figure 12).

Increasing operational efficiency:

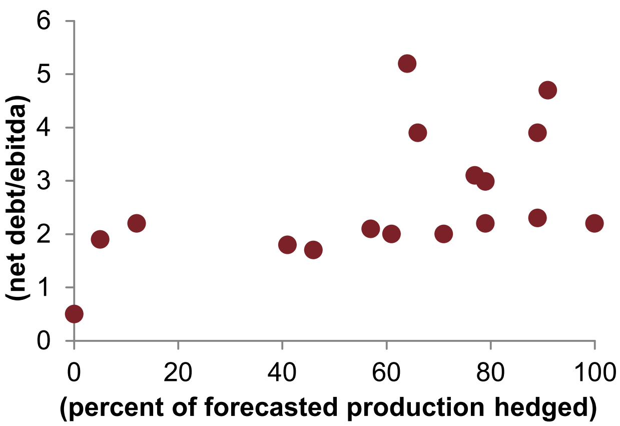
US shale producers also reacted by bringing down costs via

Figure 12: Rising number of drilled uncompleted wells



Source: North Dakota Department of Mineral Resources and Jadwa Investment

Figure 13: Selected US E&P companies debt ratios and percentage of 2015 hedged production



Source: Bloomberg Intelligence and Jadwa Investment *iii) US shale producers also reacted by bringing down costs via streamlining drilling and extraction.*

streamlining drilling and extraction. Two techniques have been key in this cost reduction; pad drilling and zipper fracking. Pad drilling has shorted drilling times since it allows digging multiple wells from a single location rather than disassembling and reassembling a drilling rig at a new location for each new well. The time taken to extract oil from a well has also been reduced through the use of zipper fracking, which allows fracturing operations to be carried out concurrently at two horizontal wells which are parallel to each other.

Hedging:

iv) A number of US E&P companies took out timely hedges against the price of oil back in 2014.

Some companies locked in prices of up to $86 per barrel as recently as Q2 2015, when WTI averaged $58 pb.

A number of US E&P companies took out timely hedges against the price of oil back in 2014. Producers were able to lock in oil prices in the short term by purchasing insurances from banks and traders, thereby reducing volatility in future prices. The hedges have been crucial in providing some highly indebted E&P companies relief from declining oil prices. Some companies locked in prices of up to $86 per barrel as recently as the second quarter of 2015, when WTI averaged $58 pb, over the same period. Hedges have largely been carried out by small or mid-cap companies since these companies typically exhibit higher indebtedness and therefore require hedging a greater proportion of production (Figure 13).

Uncertain outlook

Going forward shale oil companies are likely to face a more challenging financial environment.

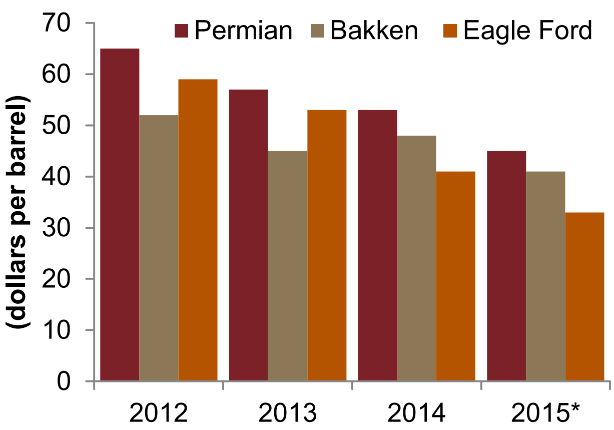
We have noted how the US shale oil sector has shown financial ingenuity and an efficient use of technology in coping with the onset of low oil prices and, as a result, has managed to bring down their costs (Figure 14). But going forward shale oil companies are likely to face a more challenging financial environment as more restrictive lending will lead to steep declines in crude oil production.

Hedges expiring:

The majority of the WTI oil hedges will expire in the next two years.

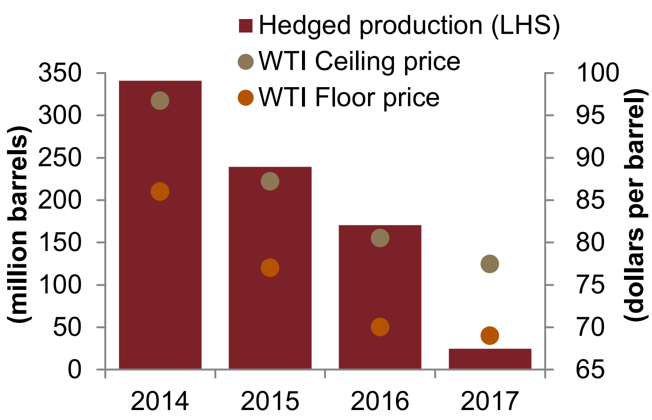
The price at which US E&P companies can hedge depends on the WTI forward curve, but these future prices of oil have fallen in line with the spot price of crude. This means hedges that were put in place when oil was closer to $100 pb will gradually expire and, since forward curves for WTI are now lower, companies will find it difficult to replace these hedges at economical prices. Looking at data on 30

Figure 14: Declining half-cycle breakeven oil prices



Source: EIA, Rystad Energy and Jadwa Investment
*Mid 2015

Figure 15: Hedged production and prices at 30 US listed E&P companies



Source: Thomson Reuters, Public Filings and Jadwa Investment
Note: 2014 based on Q2 2014 data, other years from Q2 2015 data

In 2014 350 million barrels were hedged but this will drop to only 24 million by 2017.

US listed E&P companies, we can see that majority of the WTI oil hedges will expire in the next two years. We can see that in 2014, 340 million barrels of crude oil were hedged at an average WTI price between $97-86 pb. In 2017, the same group of companies are expected to have hedged only 24 million barrels, at a lower prices of between $77-69 pb (Figure 15).

High-yield market troubled:

A rising number of defaults and yield spreads widening to distressed levels.

As outlined above, US energy companies borrowed heavily via the high yield bond market to finance drilling and exploration when oil prices were high. At Q3 2015, total high yield energy debt issued totaled $259 bn, up 163 percent from $80 billion in 2009. As oil prices have dropped, the ability of such companies to service principal and interest has become more difficult, leading to a rising number of defaults and yield spreads widening to distressed levels. This has resulted in investors exiting the high-yield market and the bonds losing value (Figure 16). All of this makes future debt issuance more challenging for the US high yield energy sector.

Reserve write-downs restricting secured lending:

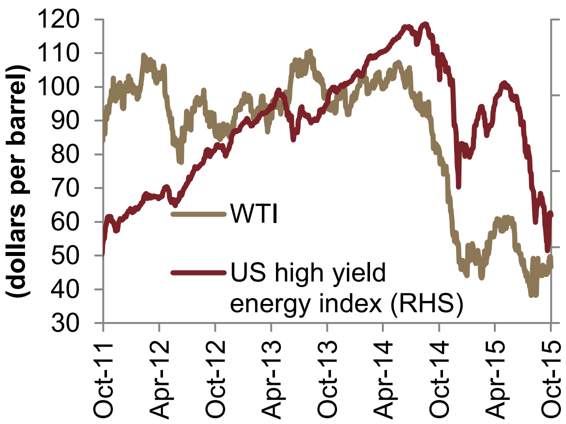
Proved oil and gas reserves are the main asset underpinning how much E&P's can borrow...

...as oil prices have dropped, so too have the value of proved reserves, leading to major write-downs in shale oil companies.

It is widely expected that bearish sentiments towards oil prices will mean tougher restrictions on lending.

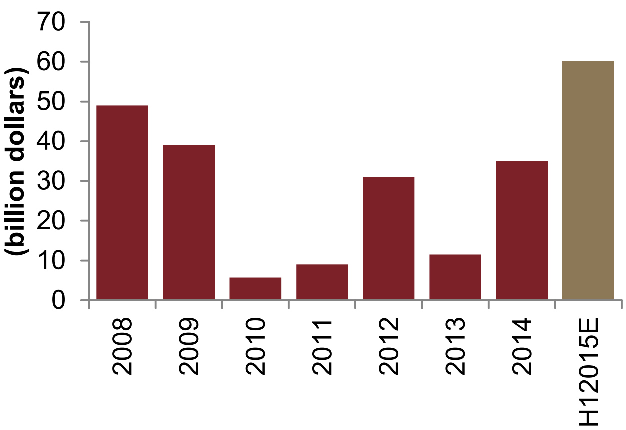
US E&P companies are also facing more difficulty in obtaining financing via secured lending. Proved oil and gas reserves are the main assets underpinning how much E&P's can borrow through leveraged finance. As oil prices have dropped, so too have the value of proved reserves, leading to major write-downs in shale oil companies, the scale of which is highlighted by impairment charges in H1 2015. North American E&P impairments reached a total of $60 billion in the first half of 2015, which is more than the previous high of $49 billion in 2008 (Figure 17). The write-downs in oil and gas reserves will of course reset many E&P companies' borrowing base. It is widely expected that bearish sentiments towards oil prices will mean tougher restrictions on lending, resulting in raising the financial pressure on medium and smaller sized shale drillers. Furthermore, regulatory pressure is also increasing on banks with the US Office of the Comptroller of the Currency (OCC), a federal regulator, highlighting the increased risks in lending to certain E&P companies and suggesting that loans which are at risk of, or already, defaulting, to be moved to specialist debt recovery firms.

Figure 16: US high yield energy index and WTI prices



Source: Thomson Reuters and Jadwa Investment

Figure 17: North American E&P impairments



Source: IHS and Jadwa Investment

Listed US E&P companies capex in 2015 and 2016 will record consecutive year-on-year declines from record levels seen in 2014.

Capex and production falling:

The expiration of oil price hedges, rising costs of debt issuance and restrictive reserve based lending will all combine to reduce US E&P revenue, depress profit margins and pressure cash flows. Ultimately this will dramatically impact future capex. Listed US E&P companies' capex in 2015 and 2016 will record consecutive year-on-year declines from record levels seen in 2014. Capex at 61 listed US E&P firms totaled $176 billion in 2014 but will decline by 46 percent, year-on-year, in 2015 to $95 billion, and then to $88 billion in 2016 (Figure 18). Capex cuts have already begun to effect US shale oil production. According to the EIA's latest STEO, year-on-year growth in shale has been decelerating and the continued lower price environment will result in US crude oil production growth dropping at a more rapid pace in the last quarter of 2015, with sustained drops throughout 2016 (Figure 19).

Shale oil production not collapsing

A total collapse of shale oil production will not happen…

...as M&A's take place as larger oil companies or private equity buys up assets.

Although the US shale industry will face intense financial pressure, with an increased likelihood of a number of companies exiting the market, this will not mean a total collapse of shale oil production. The US E&P sector still has strong companies with low debt and cost base which are better placed to withstand a prolonged period of lower oil prices. But even those companies finding it difficult to raise financing may survive as a wave of mergers and acquisitions (M&A) take place as larger oil companies or private equity buy up assets.

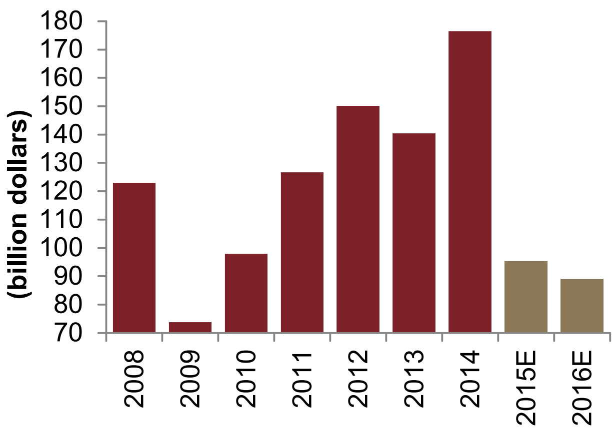
Integrated oil account for around 5 percent of total US shale oil resources.

Natural resources-focused private equity funds at $32 billion in the first half of the year, compared with $20 billion in all of 2014.

Currently, larger integrated oil accounts for around 5 percent of total US shale oil resources and difficult operating conditions for smaller producers present an ideal time for them to move in and acquire firms that have attractive assets in terms of acreage, technology or expertise. On the private equity side, although there have been some notable acquisitions in the shale oil sector already, the build-up of natural resources-focused private equity funds to $32 billion in the first half of the year, compared with $20 billion in all of 2014, suggests that more aggressive targeting of shale firms will occur the longer oil prices stay low (Figure 19).

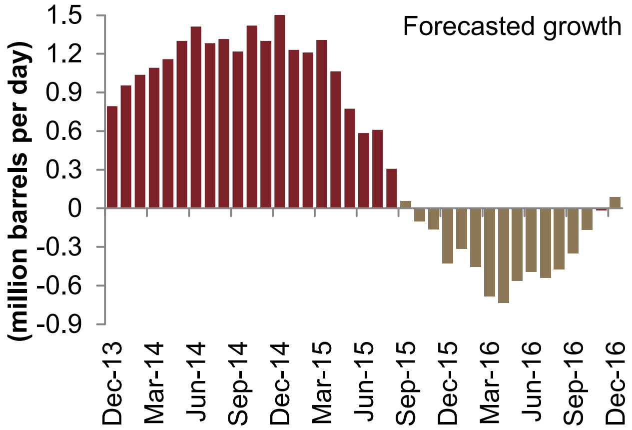
Finally, although a number of US E&P companies will not survive the

Figure 18: US listed E&P capex in 2015 & 2016



Source: Bloomberg and Jadwa Investment

Figure 19: Year-on-year growth in US crude oil production



Source: EIA and Jadwa Investment

DUCs give shale producers the option of leaving oil inventory underground until more favorable prices transpire.

next year or two, those that do will have an advantage. As we have noted, the number of drilled and uncompleted wells, or DUCs, have been rising in the last year and these can be produced within a two to three week period. This gives shale producers the option of leaving oil inventory underground until more favorable prices transpire. Ultimately, we see US shale oil becoming a highly elastic form of oil supply, with any sustained changes in the price of oil likely to be met with swift changes in oil supply.

Global production excluding US shale oil

So far, we have focused solely on US shale oil and while this is an important area within global oil markets, some attention has to be paid to non-shale oil developments in order to get a firmer grip on where global oil markets will be at the end of the decade.

The period of sustained high prices, encouraged capex in exploration activity in very high cost oil projects.

The 15 largest listed integrated companies saw combined annual capex increase from $239 billion in 2009 to $305 billion in 2014.

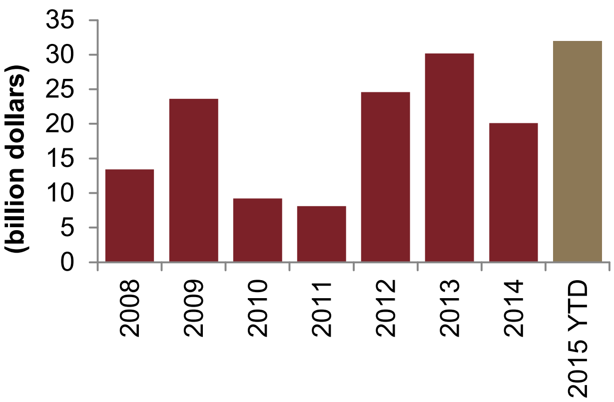
The period of sustained high prices, with Brent averaging around $100 pb from 2011-2014, not only encouraged record shale oil growth, but it also saw record capex rises for exploration activity in very high cost oil projects. The 15 largest listed integrated companies saw combined annual capex increase from $239 billion in 2009 to $305 billion in 2014. The global appetite for expensive oil projects increased along with this rising capex, with a number of previously uneconomical projects being studied for potential development (Table 3).

Table 3: Largest oil projects previously under study in 2014

Project	Country	Category	Required $ per barrel
Christina Lake	Canada	Oil sands	128
Block CI-514	Cote d'Ivoire	Ultra Deepwater	127
Pitu	Brazil	Ultra Deepwater	124
Gato do Mato	Brazil	Ultra Deepwater	121
Nsiko	Nigeria	Ultra Deepwater	120
N.W Territories	Canada	Arctic	109
Alaska	US	Arctic	109
Yucatan	US	Ultra Deepwater	99

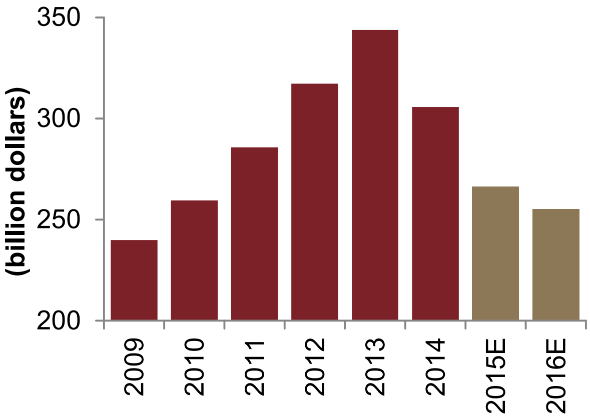
Source: Evaluate Energy and Jadwa Investment

Figure 20: Raised funds by natural resources-focused private equity



Source: Preqin and Jadwa Investment

Figure 21: 15 largest listed global integrated oil companies capex



Source: Bloomberg and Jadwa Investment

As oil prices have dropped a round of capex cuts have also been carried out by integrated oil companies, with declines expected in 2015 and 2016.

The longer time line for conventional oil means many of these project deferrals and cancellations will not impact the oil market until after 2017.

As oil prices have dropped a round of capex cuts have also been carried out by integrated oil companies, with year-on-year declines expected in 2015 and 2016, further to those already seen in 2014 (Figure 21). The economics of more expensive new projects have now become questionable leading to investment being pulled back or deferred on a number of oil projects worldwide. According to industry estimates a total of 600 tbpd of oil projects is expected to be cancelled or deferred by 2020. Since conventional production can take two to three years from the initial stages before any oil is produced, many of these project deferrals and cancellations will not impact the oil market until after 2017 (Figure 22).The implication of these cuts are key to understanding how oil prices could recover over the next few years.

Global oil balances and OPEC

Moderate economic growth, declining usage of oil in the global energy mix will see lower annual demand growth than the last five years...

Using global oil and supply forecasts from the International Energy Agency's (IEA) *Medium-Term Oil Market Report,* we can attempt to map global oil balances to 2020. The IEA sees global oil demand increasing by an average of 1.1 mbpd from 2016-20, less than the average yearly growth of 1.3 mbpd between 2010-14. Factors such as moderate economic growth, declining usage of oil in the global energy mix and less intensive use of oil in emerging markets, partly as result of lower structural oil demand in China, are factors behind this lower growth.

...but lower capex will see lower supply increases from 2016-2020.

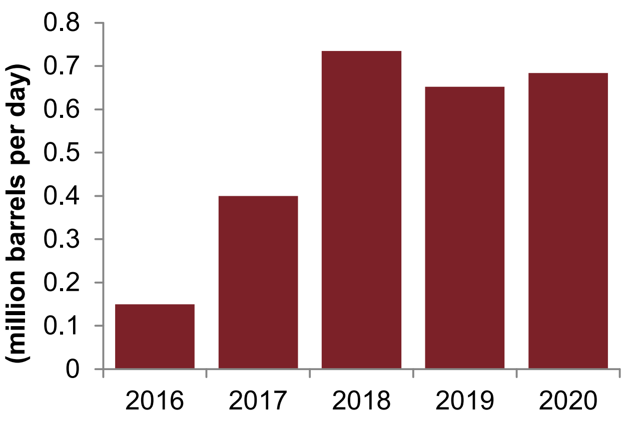
The IEA sees non-OPEC supply reaching 60 mbpd by 2020, with annual growth around 500 tbpd, much lower than the average annual growth rate of 1.5 mbpd observed between 2010-14. As noted above, the main factor behind this decline is the cut in capex by both US E&Ps and global integrated oil companies.

The 'call on OPEC' will rise incrementally every year to 2020…

...although if we assume that OPEC's output remains around its three year average, then global oil markets will not balance until 2019.

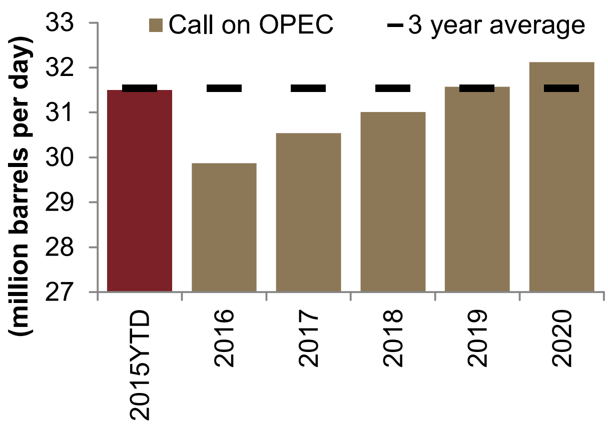
Subtracting non-OPEC supply from total demand in the IEA's forecasts leaves the oil supply needed in order to balance the oil market, otherwise known as the 'call on OPEC'. We can see the 'call on OPEC' rising incrementally every year, from a total of 29.9 mbpd in 2016 to 32.1 mbpd in 2020. We can also see that OPEC's 2015 year-to-date production is close to the three year average of 31.5 mbpd. If we assume that OPEC's output remains around its current and 3 year average, then global oil markets will not balance until

Figure 22: Cumulative deferrals/reductions in oil capacity to 2020



Source: Thomson Reuters, Morgan Stanley and Jadwa Investment

Figure 23: Call on OPEC 2016-2020



Source: IEA, OPEC and Jadwa Investment

We believe cuts in OPEC output will only occur after 2016.

2019 (Figure 23).

We believe cuts in OPEC output will only occur once there has been a sizable and sustained drop in non-OPEC supply, which is likely to be after 2016. The main logic behind not cutting OPEC production back in November 2014 was to ensure that the organization did not lose market share to higher marginal cost non-OPEC producers. The policy of maintaining output by OPEC has been successful, so far. As noted, there have been a round of capex cuts across major international oil companies and from US shale producers, with the latter expected to show negative year-on-year growth in 2016. Any reduction in OPEC oil production now would raise oil prices, relieving financial pressure on many high cost producers, including some US shale oil companies, thereby allowing these producers to encroach on OPEC market share.

Implications for Saudi oil policy

Currently, Saudi Arabia is faced with competition from non-OPEC and OPEC.

Lower oil prices have put intense fiscal pressure on a number of non-Gulf OPEC members and this has resulted in free-for-all in market share….

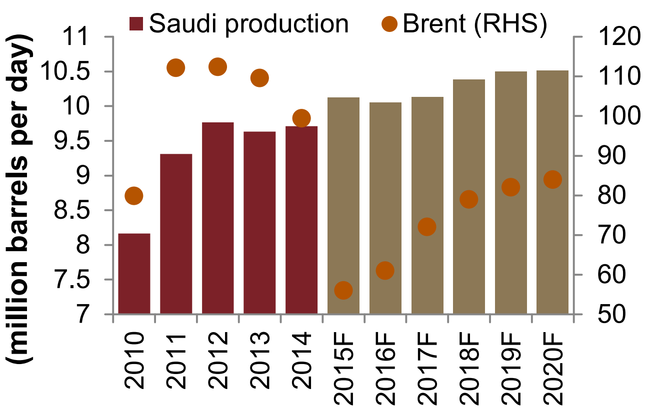
...whilst any sustained improvement in oil prices is also likely to be met with swift increases in US shale oil supply.

As a result Saudi oil production will remain at around current levels up till 2020, in order to ensure market share is maintained.

Currently, Saudi Arabia is faced with competition from non-OPEC and OPEC. Lower oil prices have put intense fiscal pressure on a number of non-Gulf OPEC members and this has resulted in free-for-all in market share. Iran's agreement with the P5+1 paves the way for potentially increased yet gradual output in Q4 2015 and beyond, whilst Iraq is also pumping near record exports and Libya also has upside for growth. Although a number of US E&P companies will not survive the next year or two, those that do will come out stronger and leaner. So far US shale oil has been responsive to lower prices, but any sustained improvement in prices is also likely to be met with swift increases in oil supply. As noted, the number of DUCs have been rising in the last year and taking into account that these can be produced within a two to three week period, it gives shale producers the option of leaving oil inventory underground until more favorable prices transpire.

As a result, we see Saudi oil production averaging at 10.1 mbpd in 2015 and, even as shale oil growth slows in 2016, competition amongst OPEC members will see yearly Saudi production remaining at 10.1 mbpd in 2016 as well. Higher global demand for OPEC oil from 2017 onwards and increased domestic consumption, as result of rising refinery intake, will keep Saudi oil production above 10

Figure 24: Saudi crude oil production and prices to 2020.



Source: JODI, Thomson Reuters and Jadwa Investment

In the meanwhile the Kingdom has ample room to continue an elevated level of spending to support the economy through a period of lower oil prices.

mbpd until 2020. Although Saudi Arabia's current strategy of maintaining market share will result in lower levels of oil revenues in the short-term, it will ultimately benefit the Kingdom in a few years time. As production in high-cost non-OPEC producers starts to slow down in response to lower prices, Saudi Arabia will reap a larger share of a larger market by 2020. Although oil prices are not likely to reach the $100 pb by the end of the decade, they will be higher than current levels, and the resulting larger crude output in a higher priced environment will ensure improved oil revenues (Figure 24). In the meanwhile, the recent deficit financing strategy adopted by the Saudi government, involving both reserve withdrawals and debt issuance, demonstrates the Kingdom has ample room to continue an elevated level of spending to support the economy through a period of lower oil prices.