جدوى للإستثمار
Jadwa Investment

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Recovery in Oil Prices: Rebound in US Shale Oil?

Summary

- Whilst heavy cost-cutting measures, technological improvements and hedging allowed US crude oil production to remain positive in 2015, this will not be the case in 2016. During Q1 2016, US oil production saw its first year-on-year decline in eight years and this decline is expected to continue throughout the remainder of 2016.

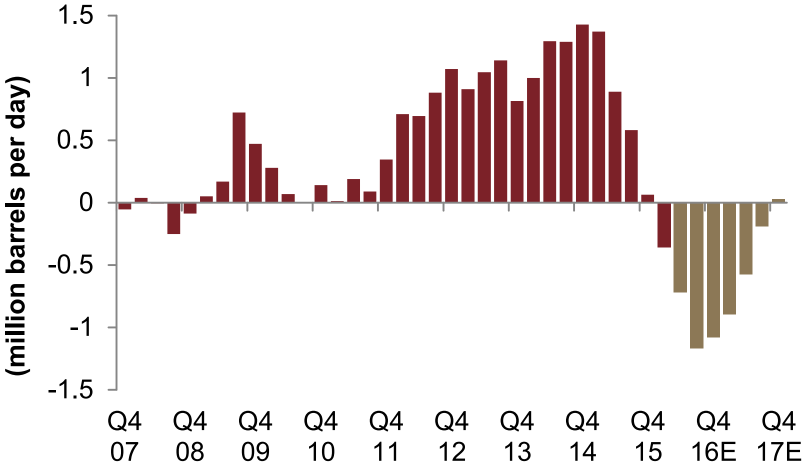
- Falling oil prices resulted in a significant reduction in the US rig count but through various cost-cutting and efficiency measures shale oil companies improved well productivity, thereby stemming a major decline in oil production, until now. Latest data shows that production at the three major shale oil fields has peaked and so larger declines are forecasted going forward.

- Despite this, the recently observed uptick in oil prices presents shale oil companies with a potential life-line. Not only does it raise the possibility of hedges being taken out again, a revival in prices could also see investor interest in the sector being reignited.

- In addition, an increasing number of shale oil companies are restructuring under chapter 11 bankruptcies, thereby prolonging oil production. Concurrently, the number of drilled uncompleted wells (DUCs), all of which can be brought on-line relatively quickly, have risen in recent months.

- All of these developments mean that even as current oil and financial indicators point to declining production in the next two years, it is not totally beyond the realms of possibility that actual production turns out to be better than expected.

Figure 1: Actual and forecasted year-on-year change in US crude oil production



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US oil production saw its first year-on-year decline in eight years in Q1 2016…

...and will continue to decline throughout the remainder of 2016…

...but the recently observed uptick in oil prices could see a less sharper decline than projected.

Overview

In our report US Shale Oil at an Inflection Point (published October 2015) we highlighted that a combination of factors, including banks rolling back credit lines and declining appetite for high yield energy debt, would precipitate the decline in unconventional oil (also referred to as shale or light tight oil). Whereas heavy cost-cutting measures, technological improvements and hedging allowed US crude oil production to remain positive in 2015, this will not be the case in 2016. US oil production saw its first year-on-year decline in eight years in Q1 2016, with a drop in unconventional oil specifically contributing to this decline. According to Energy Information Administration (EIA) data, US production will continue to decline throughout the remainder of 2016, resulting in total US oil production falling by 9 percent year-on-year in 2016 compared to an average growth of 14 percent between 2012-15 (Figure 1).

The recently observed uptick in oil prices gives many shale oil producers the opportunity, if not to reverse year-on-year production declines, but certainly to make the decline in production less sharper than projected. After mapping recent trends in US unconventional production below, we assess how near-term oil production could turn out to be higher than what is currently being forecasted.

The main contributor to production decline has been US unconventional oil.

Two major unconventional oil fields, which contribute 48 percent of total unconventional production have seen declines.

Recent Trends

In its recent monthly report, the EIA stated that total US crude oil production fell for the seventh consecutive month to 8.98 million barrels per day (mbpd) in April 2016, a 7.4 percent decline compared to the same period last year. Conventional US oil production has remained fairly flat in the last few years so the main contributor to this decline has been unconventional oil (Figure 2).

Two out of the three major unconventional oil fields (or plays), Bakken and Eagle Ford, which together contribute 48 percent of total unconventional production, have seen declines in production. Bakken saw a decline of 19 percent since its peak in December 2014 and Eagle Ford's fall has been steeper, by 29 percent, since its peak in March 2015. Total declines in US unconventional oil could have been much steeper if not for the Permian play (40 percent of unconventional production). The Permian is a collection of both

Figure 2: US crude oil production declining as a result of declines in unconventional oil

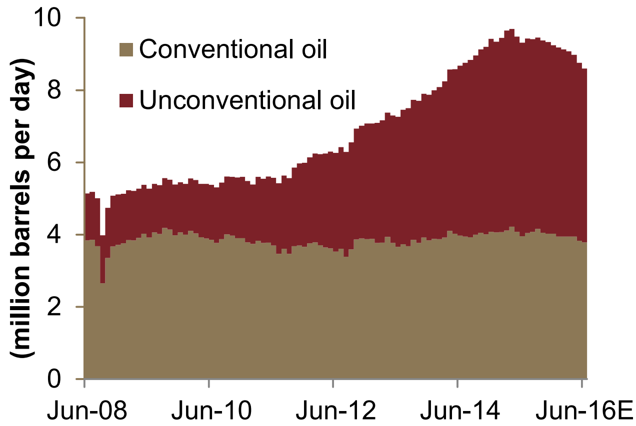
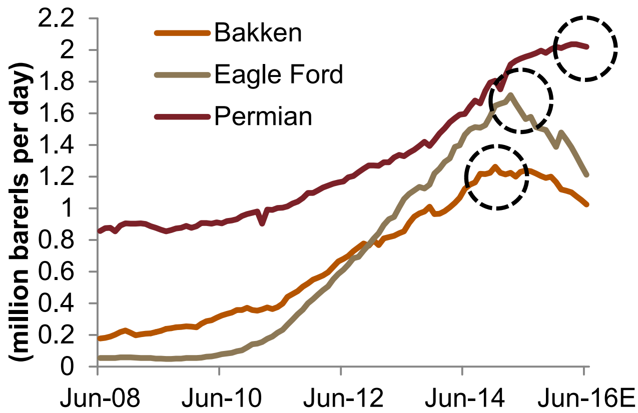


Figure 3: Crude oil production peaked at Bakken, Eagle Ford and Permian



Recently, the third major play, Permian, peaked and so it too will see declining production.

conventional and unconventional plays. Prior to US shale oil production boom, the play had been producing close to 1 mbpd from conventional wells. This makes Permian's production base very mature and since it is declining very slowly it masks the true rate of unconventional production decline. Despite this, the EIA estimates that Permian production has peaked, so it too will see declining production moving forward, but probably at slower rates compared to both Bakken and Eagle Ford (Figure 3).

Falling oil prices have resulted in a significant reduction in the rig count...

...but through the use of pad drilling and zipper fracking shale oil companies have improved well productivity…

...thereby stalling the decline in oil production until now.

Decline curves in production for typical unconventional wells are steep, with first year declines in production around 70 percent (compared to 4-5 percent for a conventional well). This requires a disproportionally larger number of unconventional wells to produce similar levels of oil. Falling oil prices resulted in squeezing the shale oil sector and this was visibly seen through a significant reduction in the rig count. Under normal circumstances, lower rigs would result in lower oil production. But shale oil companies have demonstrated ingenuity and nimbleness to temporarily avoid such a decline. As rigs declined, US shale producers reacted by bringing down costs and drilling in the most economical oil rich basins and streamlining drilling and extraction through the use of pad drilling (multiple wells from a single rig location) and zipper fracking (fracturing carried out concurrently at two wells). Such techniques improved overall well productivity by extracting larger quantities of oil more rapidly. As a result, whilst total rigs in the three major shale plays dropped by 80 percent between October 2014 and May 2016, production per rig increased by 87 percent over the same period (Figure 4). But as production declines have begun to be observed in all three major shale plays, it now seems that such techniques have been exhausted and are not sufficient enough to offset the steep decline rates from older (or legacy) wells (Figure 5).

Shale Financing

A key reason for the decline is the more challenging financial environment faced by E&P companies.

The key reasons for the recently observed decline in unconventional oil production can be directly linked to the more challenging financial environment faced by shale exploration and production (E&P) companies. Lower oil prices have wreaked havoc on E&P cash flows. Aggregated data on 61 listed E&P companies shows that cash flow from operations fell by 50 percent year-on-year in 2015. In a period of high oil prices between 2010-14, many shale E&P

Figure 4: Rig count and production per rig at Bakken, Eagle Ford and Permian

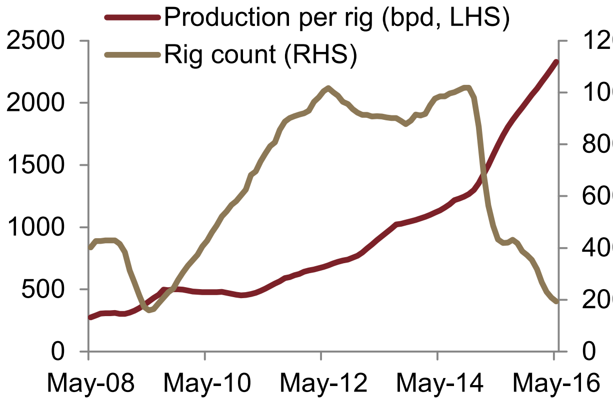
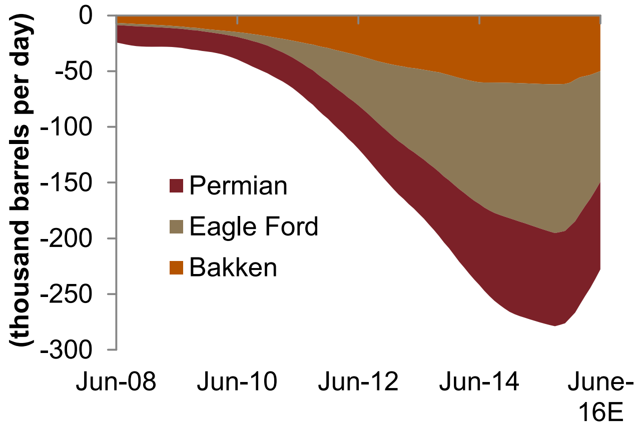


Figure 5: Legacy production changes at Bakken, Eagle Ford and Permian



As oil prices have dropped, so too have the value of oil reserves, leading to a major write-down in assets…

...consequently, banks have redetermined E&P companies' reserve based-loans.

Additionally, yield spreads in high yield energy bonds have widening to distressed levels…

...making borrowing from high yield bond markets too expensive.

Restrictive lending and the higher cost of borrowing has pushed E&P's capital expenditure down.

companies took advantage of cheap and readily available financing to plug the funding gap between cash flow and capital expenditure. But this has become increasingly more difficult to do in the last year.

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 these reserves, leading to a major write-down in E&P companies' assets. Consequently, banks have redetermined E&P companies' reserve based-loans. Figure 6 shows data from semi-annual redeterminations on 15 E&P companies, which together account for 8 percent of total US unconventional oil output. Since March 2015, we can see that reserve-based credit lines have been cut by 25 percent, or $3.75 billion.

Semi-annual redeterminations are usually only carried out on medium to small oil producers. In reviews prior to March 2015, banks were more lenient towards borrowers in the backdrop of declining prices partly because some of these companies had locked-in higher prices through hedges. These historical hedges are now mostly expired and with oil prices trending down year-on-year since 2014, the financial pressure on medium and smaller shale drillers has intensified (Figure 7). The slight uptick in oil prices in recent months complicates the picture with respect to redeterminations, going forward. Higher prices may prompt some shale companies to take out new hedges, although doing so will not be cheap or easy, which could see some reprieve for E&P companies' credit lines (see Hedging section below for more detail).

Similarly, small to medium-sized E&P companies borrowed heavily via the high yield bond market to finance drilling and exploration when oil prices were high. 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 bankruptcy filings (Figure 8). Additionally, yield spreads in high yield energy bonds have widened to distressed levels resulting in investors exiting the high-yield energy market and the bonds losing value.

The consequence of more restrictive lending practices and the higher cost of borrowing has pushed E&P's to focus on capital expenditure (capex) in trying to plug the funding gap. We can see that between 2010-14 capex in 61 listed companies grew by an annual average of 20 percent. In 2015, as cash flows dropped 50 percent year-on-year, E&P's had no option but to cut capex too,

Figure 6: Reserve-based lending for 15 small and medium-sized E&P companies

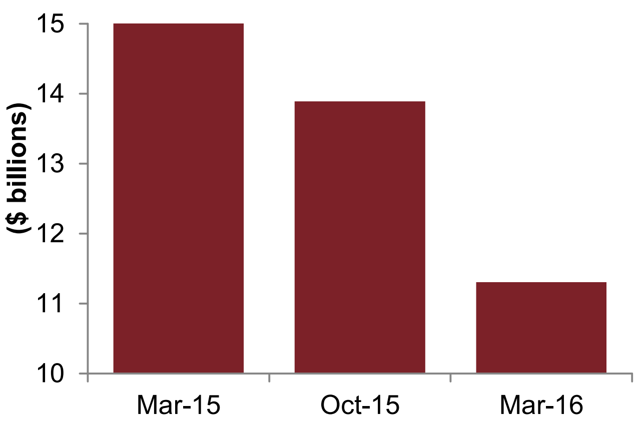
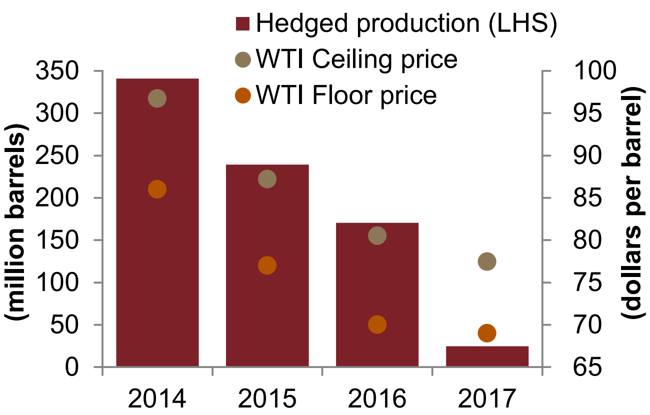


Figure 7: Hedged production and prices at 30 US listed E&P companies



which declined by 42 percent over the same period. Despite this, the shale industry will need to cut capex further with consensus forecasts expecting an even sharper cut than previously, at 56 percent year-on-year in 2016, bringing total capex on par with 2004 levels (Figure 9).

Implications of the Recent Oil Price Recovery

The recent rebound in prices presents shale oil companies with a potential lifeline...

We have seen oil prices rise recently as temporary outages in Canada and Nigeria have accelerated the recovery following lows seen in January 2016. Part of this recovery has also been due to historic and anticipated declines in US unconventional oil. Ironically, the rebound in prices presents shale oil companies with a potential lifeline. Specifically, renewed hedging, debt restructuring and the bringing on-line of DUCs, could see oil from shale sources rebound in the near-term.

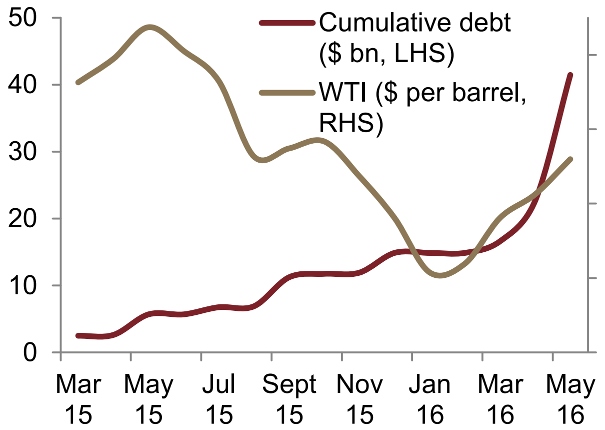
...through…

Hedging:

...renewed hedging…

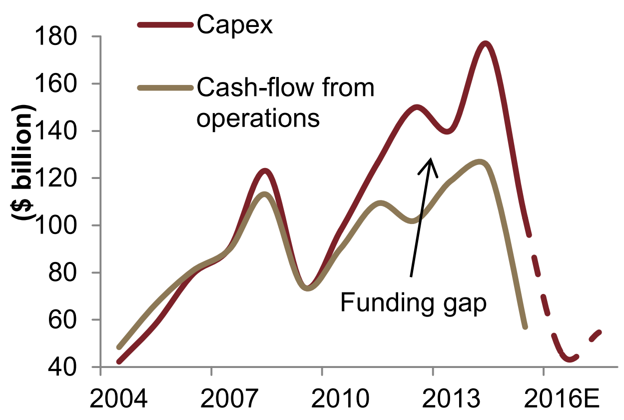
As we noted above, a large number of historical hedges will have expired by 2017, but the recent uptick in prices could see the return in hedging activity. This is partly down to more restrictive lending practices by banks which include strict debt covenants for financially troubled E&P companies. Included in some of these agreements is the stipulation that some percentage of oil production must be hedged to protect against price declines so to maintain predictable cash flows. Nevertheless, the decision to hedge, even in the currently improved oil price environment, presents its own challenges. Firstly, the costs associated to hedging are much higher than two years ago. Oil prices have been highly volatile since mid-2014, with volatility levels at the end of 2015 close to peak levels seen during the global financial crisis (Figure 10). Although volatility has come down in recent months, it still is higher than the two year period since mid-2012. Higher volatility level implies higher risk which ultimately translates into higher premiums for E&P's wishing to hedge production, all of which adds to existing financial pressure. The experiences of the Mexican government provides an indicative example of the rising costs related to hedges. In 2015, the Mexican Ministry of Finance spent $773 million for put options giving it the right to sell 228 million barrels at an average oil price of $76.4 pb. In 2016, the amount spent to secure the rights to sell slightly fewer barrels, 212 million, at a lower average price of $49 pb, cost the government 41 percent more, at $1.09 billion.

Figure 8: 29 US E&P bankruptcy filings since March 2015 equal to cumulative debt of $41 bn*



*Note: Bankruptcy filings for companies with loans of $100 mn and above

Figure 9: Listed US E&P companies' cash flows and capital expenditure rapidly declining



Secondly, locking-in prices at current levels, with WTI trading above the $45 pb mark, cannot guarantee liquidity or fulfill lender's stipulated conditions beyond the shorter term. We have noted how the 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, have managed to bring down their well-head (or half cycle) operating costs (Figure 11). Nevertheless, current prices would just about cover such costs in three of the major shale basins. In order for new fields to be brought on-line, full cycle costs would have to be covered, including costs such as acquiring or leasing land, finding and development costs etc., which are significantly higher for financially challenged E&P companies. Overall, hedges, if used, would provide temporary relief for producers therefore potentially prolonging output, but their role would be less significant than in the past.

Bankruptcies:

Even if an E&P company runs into financial difficulty there are still options for it to carry on operating under the US bankruptcy code. As noted above, there has been a rising number of bankruptcies in the last year or so. Under normal circumstances, as companies declare bankruptcy, they will sell off assets to pay creditors and, as this happens, oil production declines, pushing overall shale production down. This is known as chapter 7 or liquidation bankruptcy under the US bankruptcy code. But since 2015, only one E&P bankruptcy (with debts of more than $100 mn) has filed under Chapter 7, the other 28 filings have been under chapter 11. Chapter 11 bankruptcy allows companies to restructure their debts and continue operating. Ultimately, if an E&P company can convince creditors that it can return to financial health in the future and fulfill debt obligations after reorganization under chapter 11, it will be able to continue operating and producing oil.

...debt restructuring…

Chapter 11 is acceptable to creditors for two main reasons. Firstly, current WTI spot prices are higher than operating costs at most shale plays, so the best way to extract maximum value, in the context of depressed oil asset values, is to keep oil flowing from drilled wells. This makes even more sense if creditors believe that oil prices will rise further in the near term, thereby storing the oil and selling it at higher prices, reaping even more profit. Secondly, the long dated maturity of the currently outstanding $136 billion of US

Figure 10: Current implied oil price volatility remains high

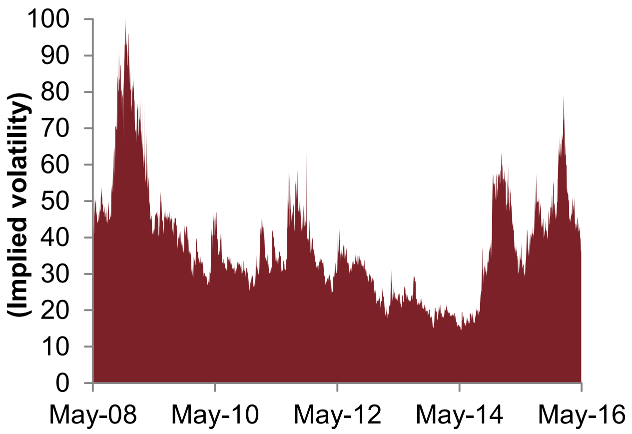
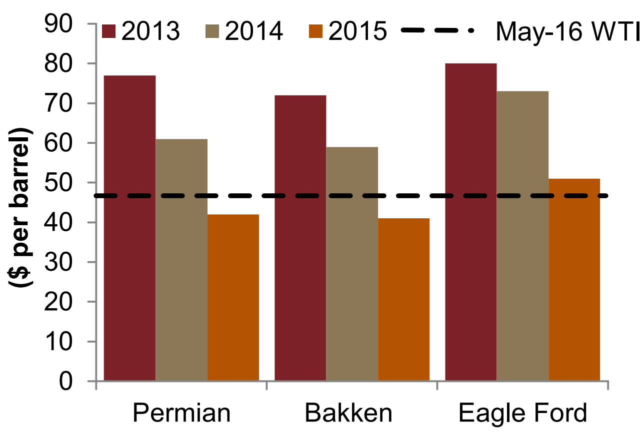


Figure 11: Well-head breakeven prices and May 2016 WTI average price



high yield energy debt gives both debtors and creditors more time to agree on a mutually beneficial outcome. Around 75 percent of all high yield energy debt in the next decade is due between 2020-23, with only 8 percent due in the next two years (Figure 12).

DUCs:

...and bringing on-line of DUCs.

When oil prices started their decline in mid-2014, many E&P producers kept drilling wells, but did not extract oil from these wells, effectively leaving crude oil in storage in the ground- often referred to as drilled uncompleted wells or DUCs. Latest available data shows that DUCs consistently rose until December 2015 (Figure 13). In the recent past, a number of E&P companies' have said that prices around the mid-$40 pb would move them to bring DUCs on-line. With WTI averaging $47 pb in the six weeks to mid-June 2016, media reports cited some E&P companies doing exactly that. Whilst bringing DUCs on-line would provide only a short term boost to shale oil production, it would nevertheless result in overall US production not declining as quickly as projected.

Rebound in Shale Oil Production is Possible

All the above developments could see actual production turning out to be flatter than expected.

Whilst a decline in US shale oil will help to rebalance global oil markets there will be no collapse in shale production. Shale oil has shown remarkable resilience in the last few years and the industry has continuously adapted by lowering overall costs. In fact the recently observed uptick in oil prices presents shale oil companies with a potential life line. Not only does this raise the possibility of hedges being taken out again, a revival in prices could also see investor interest in the sector being reignited. In addition, an increasing number of shale oil companies are restructuring under chapter 11 bankruptcies, thereby prolonging oil production, and the number of DUCs that can be brought on-line have also risen. All of these developments mean that even as current oil and financial indicators point to declining production in the next two years, it is not totally out of the realms of possibility that actual production turns out to be better than expected.

Figure 12: Long dated maturity of US high yield energy sector debt

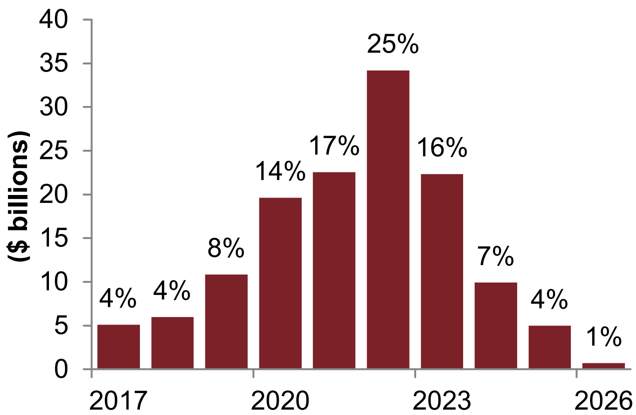
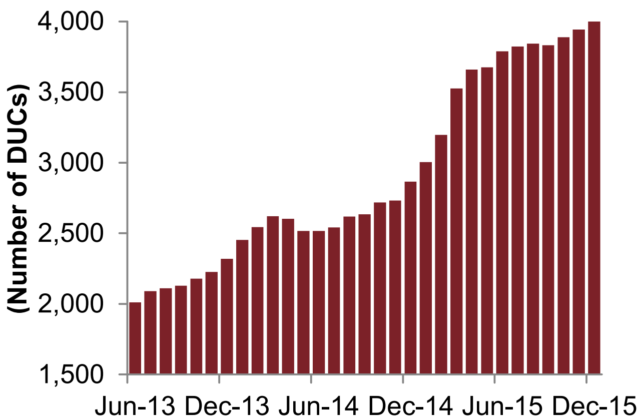


Figure 13: Rising level of DUCs



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